

**BEFORE THE  
PUBLIC UTILITIES COMMISSION  
OF THE  
STATE OF CALIFORNIA**

In The Matter of the Application of San Diego  
Gas & Electric Company (U 902 G) and  
Southern California Gas Company (U 904 G)  
for a Certificate of Public Convenience and  
Necessity for the Pipeline Safety & Reliability  
Project

Application 15-09-013

**REDACTED**

Phase One

Direct Testimony of Catherine E. Yap

On Behalf of

Southern California Generation Coalition

April 17, 2017

|        |                                                                                                                                                                                                         |    |
|--------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----|
| 1.     | Introduction .....                                                                                                                                                                                      | 1  |
| 2.     | Summary of Recommendations .....                                                                                                                                                                        | 2  |
| 3.     | The Applicants' Proposal .....                                                                                                                                                                          | 3  |
| 4.     | Applicants' Forecast of Peak Cold Day Demand Is Overstated. ....                                                                                                                                        | 6  |
| 4.1.   | Table 1 Does Not Reflect Recent Declines in the Electricity Forecast.....                                                                                                                               | 7  |
| 4.2.   | The Applicants' Table 1 Does Not Reflect the CEC's 2015 Mid-Case Achievable Energy Efficiency Forecast Despite the Commission's Previous Directions to Use this Forecast in Resource Planning. ....     | 8  |
| 4.3.   | The Applicants' Table 1 Does Not Reflect Any Increase in Energy Efficiency that Should Come About in Response to SB 350 Requirements. ....                                                              | 9  |
| 4.4.   | The Applicants' Table 1 Includes Demand that Under the Applicants' Proposal Could Be Served by SoCalGas Through Distribution Line 1026 and Line 1600 Independently of the SDG&E Transmission Lines..... | 10 |
| 5.     | The Applicants Advocate the Construction of Line 3602 as the Solution to Several Problems.....                                                                                                          | 13 |
| 5.1.   | Problem 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..... | 14 |
| 5.1.1. | As Demonstrated Previously, Applicants' Forecast of 1-in-10 Year Cold Day Demand Is Overstated But Even Their Forecast Shows Demand Below the 570 MMcf/d Capacity of Line 3010 by 2023.....             | 17 |
| 5.1.2. | Any Deficit Between the 570 MMcf/d Provided by Line 3010 and the 1-in-10 Year Cold Day Demand During the Next Six Years Could Not Be Met by Building a New Pipeline.....                                | 18 |
| 5.1.3. | A Short Term Deficit Can Be Met Through Deliveries at Otay Mesa. ....                                                                                                                                   | 18 |
| 5.2.   | Problem 2: The Threat of Insufficient Transmission Capacity to Meet Core Customer Needs in the Event of an Outage on Line 3010.....                                                                     | 20 |
| 5.2.1. | Commission policy does not require pipeline redundancy .....                                                                                                                                            | 22 |
| 5.2.2. | A Line 3010 Outage Is a Low Probability Event.....                                                                                                                                                      | 24 |
| 5.2.3. | Safety Measures that the Commission Has Directed the Applicants to Pursue Will Help Improve System Reliability.....                                                                                     | 24 |
| 5.3.   | Alternative Solutions for Problem 2: .....                                                                                                                                                              | 25 |
| 5.3.1. | Alternative 1: Core Demand Could Be Served Through the Otay Mesa on an Interruptible Basis as Supplemented by As Available Supplies of LNG at Costa Azul.....                                           | 27 |
| 5.3.2. | Alternative 2: Core Demand Could Be Served Through Otay Mesa Utilizing Firm Capacity Rights on North Baja .....                                                                                         | 29 |
| 5.3.3. | Alternative 3: Core Demand Could Be Served Through the Utilization of Firm LNG Storage at Costa Azul .....                                                                                              | 32 |
| 5.3.4. | Alternative 4: Core Demand Could Be Served Through a Combination of Transmission Rights on North Baja and the Utilization of LNG Storage at Costa Azul. ....                                            | 37 |

|          |                                                                                                                                                                                                                                                                                                      |    |
|----------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----|
| 5.4.     | Problem 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. ....                                                                                                                            | 38 |
| 5.4.1.   | The Applicants Admit that the Chance of an Unscheduled Outage of the Entire Moreno Compressor Station is Small. ....                                                                                                                                                                                 | 39 |
| 5.4.2.   | The Applicants' Claim that the Electric System's Winter Dependence on Gas-Fired Generation Could Endanger Electric Reliability Is Undermined by the Aliso Canyon Report Which Found a Very Low Electric Generation Requirement for Natural Gas During a 1-in-10 Year Cold Day. ....                  | 41 |
| 5.4.3.   | The Applicants Claim that the SDG&E Electric System Is Dependent on Natural Gas Availability Throughout the Year, Which Makes It Vulnerable to Supply Disruption Without the Addition of Line 3602. ....                                                                                             | 45 |
| 5.4.3.1. | The Applicants Claim that SDG&E Loads Exceed Maximum Import Capability in Some Hours, Which Makes the Electric System Dependent on Natural Gas. ....                                                                                                                                                 | 46 |
| 5.4.3.2. | The Applicants' Assume that a Line 3010 Outage Would Be the Equivalent of an N-1 Event, but Instead a Pipeline Outage Would Create a Multiple Failures Event that Would Not Be Required to Meet the NERC N-1 or N-2 Reliability Standard. ....                                                       | 49 |
| 5.4.3.3. | An Assessment of Potential Consequences of a Pipeline Failure on Electric Reliability Should Be Performed Considering a Full Range of Options for Reinforcing the Electric System. ....                                                                                                              | 52 |
| 5.4.3.4. | The Applicants Claim that Limitations on Imperial Irrigation District's S-Line Further Limits the Importation of Power into SDG&E During Certain Hours. ....                                                                                                                                         | 59 |
| 5.5.     | Alternative Solutions to Problem 3: .....                                                                                                                                                                                                                                                            | 61 |
| 5.5.1.   | Alternative 1: System Operator Purchases LNG Storage at Costa Azul in Coordination with Core. ....                                                                                                                                                                                                   | 61 |
| 5.5.2.   | Alternative 2: Upgrade the S-Line, Which Would Significantly Increase the Level of Imports Allowed Across the SWPL Line and Correspondingly Reduce the Reliance on Natural Gas-Fired Generation. ....                                                                                                | 64 |
| 5.5.3.   | Alternative 3: Develop Greater Coordination with CENACE Which Might Allow Reliance on CFE's Gas-Fired Generation in Rosarito to Meet Emergency Conditions. ....                                                                                                                                      | 66 |
| 5.5.4.   | Alternative 4: Pursue the Installation of Devices such as Synchronous Condensers and Connect Existing Solar and Wind Generators Inside the SDG&E Import Cut Plane that Have the Requisite Inverter Control Technology to Minimize the Dependence on Gas-Fired Generation for Voltage Stability. .... | 67 |

Attachment B: Answers to Phase One Scoping Memo Questions 1-10

Attachment C: Brian Rahman, Review and Assessment of San Diego Gas & Electric Ability to Service Firm Load with Loss of Significant Gas Supply, April 14, 2017

Attachment D: Z-Global Electric Transmission Map

Attachment E: Applicants Response to SCGC-11

Attachment F: SoCalGas/SDG&E Response to SCGC-12

Attachment G: Applicants Response to Energy Division Request 2

Attachment H: Applicants Response to TURN-08

Attachment I: Applicants Response to ORA-09

Attachment J: Applicants Response to SCGC-10

Attachment K: Applicants Response to SCGC-05

Attachment L: Applicants Response to SCGC-13

Attachment M: Applicants Response to SCGC-14

Attachment N: Applicants Response to Sierra Club-04

Attachment O: Applicants Response to Sierra Club-07

Attachment P: Applicants Response to SCGC-06

Attachment Q: Applicants Response to SCGC-18

Attachment R: Applicants Response to SCGC-07

Attachment S: Applicants Response to SCGC-04

Attachment T: Applicants Response to Sierra Club-06

Attachment U: IEnova 2015 Annual Report, excerpts

Attachment V: Energy Information Administration (“EIA”), Monthly Price of U.S. Natural Gas LNG Imports

Attachment W: 16-IEPR-02, Aliso Canyon Winter Risk Assessment Technical Report (“Aliso Canyon Report”), Prepared by the Staff of the California Public Utilities Commission, California Energy Commission, the California Independent System Operator, the Los Angeles Department of Water and Power, and Southern California Gas Company at 11 (August 23, 2016), excerpts.

Attachment X: Bloomberg Article, February 7, 2017

Attachment Y: CAISO, NREL, First Solar, Using Renewables to Operate a Low-Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant, 2017, excerpts

Attachment Z: North Baja Pipeline Customer Listing January 1, 2017.

Attachment AA: North Baja, Unsubscribed Capacity, April 9, 2017.

Attachment AB: North Baja Tariff, Part 4.1, v.3.0.0, excerpt

Attachment AC: EIA, Today in Energy, “Expanded Panama Canal reduces travel time for shipments of U.S. LNG to Asian markets,” June 30, 2016

1 Direct Testimony of Catherine E. Yap  
2 On Behalf of  
3 Southern California Generation Coalition  
4

5  
6 **1. Introduction**

7 This testimony is presented by Catherine E. Yap on behalf of the Southern California  
8 Generation Coalition (“SCGC”). SCGC members are electric generation customers of Southern  
9 California Gas Company (“SoCalGas”).<sup>1</sup> Ms. Yap has over 35 years’ experience preparing and  
10 delivering testimony before this Commission as well as in other jurisdictions. Ms. Yap’s  
11 qualifications are set forth in Attachment A.

12 On September 30, 2015, San Diego Gas and Electric Company (“SDG&E”) and Southern  
13 California Gas Company (“SoCalGas”) (jointly, “SDG&E/SoCalGas” or “Applicants”) filed  
14 Application (“A.”) 15-09-013 proposing to replace the existing 16-inch Line 1600 located in  
15 SDG&E’s service territory with a new 36-inch Line 3602.<sup>2</sup> Applicants propose that the existing  
16 Line 1600 be derated from being a transmission line to being a high pressure distribution line and  
17 left in operation.<sup>3</sup> At the Commission’s direction, Applicants augmented their showing twice:  
18 First, they filed an amended application, testimony, and cost effectiveness analysis on March 21,  
19 2016.<sup>4</sup> Second, they served updated and supplemental testimony on February 21, 2017.<sup>5</sup>

20 The November 4, 2016, Scoping Memo and Ruling of Assigned Commissioner (“Scoping  
21 Memo”) as modified by the Assigned Commissioner’s and Administrative Law Judge’s  
22 December 22, 2016, Ruling (“Ruling”) established two phases for this proceeding and set forth a

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23 <sup>1</sup> The Utility Reform Network (“TURN”) has reviewed a draft of this testimony and strongly supports the  
24 testimony, aside from Sections 5.4 and 5.5., which TURN has not reviewed.

25 <sup>2</sup> A.15-09-013 at 4, 5.

26 <sup>3</sup> *Id.* at 4.

27 <sup>4</sup> Joint Assigned Commissioner’s and Administrative Law Judge’s Ruling Requiring Amended Application  
28 and Seeking Protests, Responses and Replies, January 21, 2016 at 21.

<sup>5</sup> Assigned Commissioner’s and Administrative Law Judge’s Ruling Modifying Schedule and Adding  
Scoping Questions, December 22, 2016 at 11, 13, 14.

1 series of questions for parties to address in each phase of the proceeding. This testimony  
2 responds to the Applicants' updated and supplemental testimony as well as Phase One Questions  
3 1 through 10 set forth in the Scoping Memo and Ruling, which are presented in Attachment B.

## 4 **2. Summary of Recommendations**

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

11 The Commission should recognize that existing Commission policy does not require  
12 pipeline redundancy. The Applicants suggestion that the core faces risk of a supply interruption  
13 if Line 3010 were to fail, which is a very unlikely occurrence, is based on an overly negative view  
14 of the available resources in northern Baja California. Instead, the Commission should recognize  
15 that if Line 3010 were to fail, core demand could be served under several potential arrangements  
16 that use existing pipeline and/or liquefied natural gas ("LNG") supply infrastructure in northern  
17 Baja California and deliver gas through Otay Mesa. Each of these alternatives is far more cost  
18 effective than the proposed Line 3602 pipeline and would involve far fewer environmental  
19 impacts due to the use of existing infrastructure.

20 The Commission should recognize that the Applicants have overstated the dependency of  
21 their electric system on gas-fired generation, particularly during 1-in-10 year cold day events.  
22 The Applicants have further overstated their dependency on natural gas because their claim that  
23 voltage stability requirements limit import capability in the absence of local gas-fired generation  
24 is predicated on their need to meet an N-1 or N-2 reliability standard in the face of a pipeline  
25 outage that creates, instead, a multiple failure event that triggers other National Electric  
26 Reliability Council ("NERC") criteria. The Commission should require the Applicants to work  
27 with the California Independent System Operator ("CAISO") staff and Commission staff to  
28

1 assess the consequences to electric reliability associated with the failure of Line 3010 or the  
2 Moreno Compressor Station while considering a full range of options for reinforcing the electric  
3 system, particularly those options that would reduce dependency on gas-fired generation.

4 The Commission should recognize that in the event of a failure of Line 3010 or the  
5 Moreno Compressor Station, essential EG demand for natural gas could be met through the use of  
6 gas delivered from the Energia Costa Azul LNG terminal with EG requirements remaining  
7 subordinate to core needs.

8 The Commission should recognize that several other alternatives remain to reduce the  
9 Applicants electric system dependency on gas-fired generation. These other alternatives include  
10 upgrading the Imperial Irrigation District's ("IID") "S-Line" to eliminate a substantial limitation  
11 on imports across the Southwest Power Link ("SWPL") line and correspondingly reduce gas-fired  
12 generation, developing greater coordination agreement with Centro Nacional de Control de  
13 Energia ("CENACE") (northern Baja California's system operator) potentially enabling reliance  
14 on Comision Federal de Electricidad's ("CFE") generating resources located in Rosarito to  
15 provide assistance with voltage stability and/or frequency stability in emergency circumstances,  
16 and installing additional devices such as synchronous condensers and connecting existing  
17 renewable generators inside the SDG&E import cut plane that have the requisite inverter control  
18 technology to enable injection of reactive power in accordance with CAISO requirements.

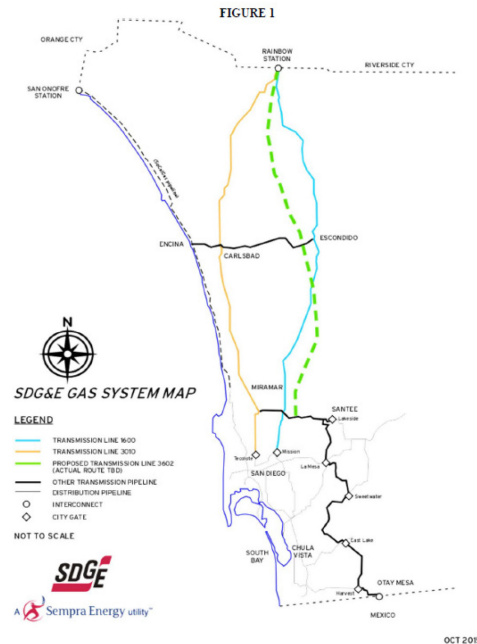
### 19 **3. The Applicants' Proposal**

20 Line 1600 is the smaller of two transmission lines that run south from Rainbow Station to  
21 deliver gas received at Rainbow from SoCalGas' transmission system. About 90 percent of the  
22 supplies delivered from SoCalGas are carried over the other transmission line, Line 3010.<sup>6</sup> The  
23 location of the two lines is shown below in Figure 1:<sup>7</sup>

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24  
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26  
27 <sup>6</sup> Updated Direct Testimony of David Bisi ("Updated Bisi Direct") at 2.

28 <sup>7</sup> *Id.* at 4.



Line 1600 is nearly 50 miles in length.<sup>8</sup> The Applicants propose to de-rate the 45 miles of Line 1600 from Rainbow to the interconnection with Lines 3011 and 2010 at Kearny Villa Pressure Limiting Station to a pressure of 320 psig, which they assert would convert the line from Rainbow to Kearny Villa from being a transmission line to being a distribution line.<sup>9,10</sup> Line 1600 extends 4.7 miles beyond Kearny Villa Pressure Limiting Station to the Mission Pressure Limiting Station. However, the Applicants do not submit any proposals about the southernmost 4.7 miles of Line 1600, saying: “The southern 4.7 miles of Line 1600 are outside the scope of their Application. Whether the southern 4.7 miles of Line 1600 are hydrotested, replaced or derated to distribution service will be determined separate and apart of this Application.”<sup>11</sup>

Line 1600 is a 16-inch transmission pipeline built in 1949 and put into service without pressure testing.<sup>12</sup> The Applicants have already reduced the pressure in Line 1600 twice, once in

<sup>8</sup> Updated Bisi Direct at 2.

<sup>9</sup> Updated Direct Testimony of Norm G. Kohls (“Updated Kohls Direct”) at 15.

<sup>10</sup> Attachment S: Applicants Response to SCGC-04, Q.4.15.3.

<sup>11</sup> Attachment S: Applicants Response to SCGC-04, Q.4.15.1.

<sup>12</sup> Amendment to Application (“Amended Application”), March 21, 2016, Volume 1 at 10.

1 2011<sup>13</sup> and again in 2016 at the Commission's direction.<sup>14</sup> Under Commission orders and  
2 California statute, if the Applicants continue to operate Line 1600 at transmission pressures, they  
3 must either hydrotest or replace the line.<sup>15</sup> The Applicants assert that Line 1600 can be safely  
4 operated at distribution pressures, which they claim would negate the need to either pressure test  
5 or replace the line from Rainbow to Kearny Villa.<sup>16</sup>

6 The Applicants claim that if Line 1600 is removed from transmission service, they need to  
7 augment their transmission system by building a 36-inch pipeline, the proposed Line 3602, which  
8 would add 200 MMcf/d to SDG&E's current winter transmission capacity of 630 MMcf/d.<sup>17</sup>  
9 Figure 1 shown above demonstrates that Line 3602 would have a significantly different route than  
10 Line 1600, although it would cross over Line 1600 at one point. The Applicants propose to tie  
11 Line 3602 to Line 1600 through an existing cross tie, Line 1601, near Escondido, at the point of  
12 intersection of the two lines south of Escondido, and again through another existing cross tie,  
13 Line 2010, near the point at which the proposed Line 3602 would interconnect with Line 2010.<sup>18</sup>

14 In the complete absence of Line 1600, Line 3010 by itself is capable of delivering a  
15 maximum of 570 MMcf/d, which the Applicants assert is insufficient to meet SDG&E's current  
16 forecast of its 1-in-10 year cold day demand.<sup>19</sup> In addition, the Applicants argue that without the  
17 construction of a new transmission pipeline, the SDG&E system would be dependent upon a  
18 single pipeline, Line 3010, which would make the gas system vulnerable to interruption if  
19 problems developed in that line.<sup>20</sup> The Applicants claim that relying solely on Line 3010 could  
20 also risk interruption to electric load because SDG&E's electric system is depends on local area  
21

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22 <sup>13</sup> *Id.* at 11.

23 <sup>14</sup> Resolution SED-1, August 18, 2016.

24 <sup>15</sup> Amended Application, Volume 1 at 4.

25 <sup>16</sup> Updated Kohls Direct at 15.

26 <sup>17</sup> Updated Bisi Direct at 10.

27 <sup>18</sup> Updated Kohls Direct at 12-13.

28 <sup>19</sup> Updated Bisi Direct at 7, Footnote 11.

<sup>20</sup> *Id.* at 7.

gas-fired generation.<sup>21</sup> The Applicants also claim that relying upon deliveries through the Otay Mesa receipt point to augment capacity to Line 3010 would require SDG&E customers to compete for limited capacity on the North Baja/Gasoducto Rosarito/TGN pipeline system,<sup>22</sup> exposing them to higher costs for their gas supply<sup>23</sup> and making them vulnerable to decisions by a foreign government.<sup>24</sup>

#### 4. Applicants' Forecast of Peak Cold Day Demand Is Overstated.

The Applicants present in their updated testimony their most recent forecast of 1-in-10 year cold day combined core and noncore demand for gas years, April 2016 - March 2017 through April 2035 - March 2036, which is presented in the Applicants' Table 1:

Table 1: SDG&E 1-in10 Cold Day Demand (MMcf/d)<sup>25</sup>

| Operating Year <sup>a/</sup> | Core | Noncore C&I | EG  | Total |
|------------------------------|------|-------------|-----|-------|
| 2016/17                      | 366  | 60          | 152 | 578   |
| 2017/18                      | 374  | 61          | 153 | 588   |
| 2018/19                      | 374  | 61          | 154 | 589   |
| 2019/20                      | 374  | 62          | 154 | 589   |
| 2020/21                      | 374  | 62          | 154 | 590   |
| 2021/22                      | 373  | 62          | 146 | 581   |
| 2022/23                      | 372  | 62          | 138 | 572   |
| 2023/24                      | 371  | 62          | 130 | 563   |
| 2024/25                      | 370  | 62          | 123 | 556   |
| 2025/26                      | 370  | 62          | 116 | 548   |
| 2030/31                      | 374  | 62          | 103 | 539   |
| 2035/36                      | 381  | 61          | 103 | 546   |

<sup>a</sup> An Operating Year is April through March.

The peak cold day forecast shown in the Applicants' Table 1 overstates SDG&E's real winter peak needs for a number of reasons. It relies upon an outdated electricity forecast. It reflects projected energy efficiency effects that are limited to the cumulative effect of outdated estimates

<sup>21</sup> Updated Direct Testimony of S. Ali Yari ("Updated Yari Direct") at 4.

<sup>22</sup> Updated Direct Testimony of Paul Borkovich ("Updated Borkovich Direct") at 5.

<sup>23</sup> *Id.* at 9.

<sup>24</sup> Applicants Supplemental Testimony at 42-43.

<sup>25</sup> *Id.*, Attachment A at 2.

of energy efficiency measures rather than relying on the CEC's forecast. It does not reflect the increased levels of energy efficiency associated with the requirements established by SB350.<sup>26</sup> Last, it includes both demand that is currently served by a distribution line, Line 1026, and demand that under the Applicants' proposal would in the future be served by a distribution Line 1600.

#### 4.1. Table 1 Does Not Reflect Recent Declines in the Electricity Forecast.

The Applicants assert that their peak day forecast is essentially an extension of the forecast that SDG&E filed in the 2016 California Gas Report ("CGR").<sup>27</sup> The 2016 CGR was based on the CEC 2016 Electricity Forecast developed for the 2016 Integrated Energy Policy Report ("IEPR"). On January 25, 2017, the CEC approved the California Energy Demand Update Forecast, 2017-2027, ("CEDU 2016") for SDG&E's service territory.<sup>28</sup> The CEDU 2016 forecast shows a decline in SDG&E electricity loads net of self-generation and energy efficiency. A comparison for SDG&E's service territory of the 2016 IEPR electricity forecast that was adopted in January 2016 versus the CEDU 2016 forecast adopted in January 2017 is shown below in Table 2:

Table 2: Effects of Updated CEC Electricity Forecast<sup>29</sup>

|                                           | 2016 | 2017 | 2018 | 2019 | 2020 | 2025 | 2030 | 2035 |
|-------------------------------------------|------|------|------|------|------|------|------|------|
| Difference 2016 IEPR vs 2016 CEDU         | -3%  | -4%  | -4%  | -3%  | -3%  | -3%  | -1%  | 1%   |
| Gas Savings relative to 2016 CGR (MMcf/d) | -8   | -9   | -9   | -8   | -7   | -6   | -1   | 1    |

<sup>26</sup> Stats. 2016, Chap. 547.

<sup>27</sup> Supplemental Testimony at 83.

<sup>28</sup> CEC Docket 16-IEPR-05, Resolution 17-0125-6, (January 25, 2017).

<sup>29</sup> IEPR Electricity demand forecast from the California Energy Commission: [http://www.energy.ca.gov/2015\\_energypolicy/documents/2016-01-27\\_load\\_serving\\_entity\\_and\\_Balancing\\_authority.php](http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balancing_authority.php), Mid-Case LSE and Balancing Authority Forecast.xls, "form1.1c" tab. SDG&E loads only. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is -0.33%. Compared with CEDU Electricity demand forecast from the California Energy Commission: [http://www.energy.ca.gov/2015\\_energypolicy/documents/2016-01-27\\_load\\_serving\\_entity\\_and\\_Balancing\\_authority.php](http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balancing_authority.php), Mid-Case LSE and Balancing Authority Forecast.xls, "form1.1c" tab. SDG&E loads only. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is -0.07%.

Table 2 shows a three to four percent decline in net energy usage each year from 2016 to 2025, which translates into an 8 to 9 MMcf/d decline in natural gas usage through 2019 and a 6 to 7 MMcf/d decline in natural gas usage from 2020 through 2025, falling off somewhat after that.

**4.2. The Applicants' Table 1 Does Not Reflect the CEC's 2015 Mid-Case Achievable Energy Efficiency Forecast Despite the Commission's Previous Directions to Use this Forecast in Resource Planning.**

The projected energy efficiency effects in Table 1 are based on an outdated assessment of achievable energy efficiency that falls considerably short of the level forecasted by the CEC in its mid forecast of additional achievable energy efficiency ("AAEE") case. The Commission previously relied on the CEC's mid-AAEE forecast in considering long-term procurement for Southern California Edison ("SCE") and SDG&E following the 2012 retirement of the San Onofre Nuclear Generating Station ("SONGS").<sup>30</sup> In that decision the Commission indicated that "across the SCE and SDG&E areas we expect the mid-level of savings to occur."<sup>31</sup>

In the 2016 CGR both Pacific Gas and Electric Company ("PG&E") and SoCalGas relied upon the CEC's 2015 forecast of AAEE while SDG&E used the "cumulative net load impact includes all energy efficiency programs from SDG&E's integrated gas and electric energy efficiency programs."<sup>32</sup> When questioned, SDG&E admitted that, in fact, it relied upon the "CEC's AAEE 2013 forecast that was revised in April 2014."<sup>33</sup> SDG&E's forecast is both outdated and inconsistent with the forecasted AAEE relied upon by the other gas utilities.

A comparison of the Applicants' statement of year-by-year cumulative achievable energy efficiency savings with the CEC's 2016 mid-range forecast of AAEE shows the CEC's forecast to be considerably higher than SDG&E's. Table 3 shows the annual difference in cumulative AAEE between SDG&E's forecast and the CEC mid-range AAEE adopted for the CEDU 2016 forecast:

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<sup>30</sup> D.14-03-004, slip op. at 62-63.

<sup>31</sup> *Id.* at 63.

<sup>32</sup> Attachment E: Applicants Response to SCGC-11, Q.11.4.

<sup>33</sup> Attachment F: Applicants Response to SCGC-12, Q.12.6.

Table 3: Annual Incremental Increase of AAEE in 2016 CEDU vs SDG&E

| Combined Gas & Electric<br>Energy Efficiency Savings MMcf/d | 2016 | 2017 | 2018 | 2019 | 2020 | 2025 | 2030 | 2035 |
|-------------------------------------------------------------|------|------|------|------|------|------|------|------|
|                                                             | 1    | 3    | 5    | 6    | 6    | 8    | 11   | 13   |

The Applicants' Table 1 should be adjusted to reflect the higher level of energy efficiency reflected in the CEC's CEDU 2016 mid-range forecast of AAEE.

**4.3. The Applicants' Table 1 Does Not Reflect Any Increase in Energy Efficiency that Should Come About in Response to SB 350 Requirements.**

As discussed previously, Table 1 is largely based on the forecast that SDG&E prepared for the 2016 CGR. The 2016 CGR makes clear that it does not in any way reflect any increased levels of energy efficiency associated with the requirements of SB 350. The report states:

SB 350, which was passed in fall 2015, requires the CEC, in coordination with the CPUC and the local public utilities, to set EE targets that double the CEC's AAEE mid-case forecast, subject to what is cost-effective and feasible. This legislation will undoubtedly impact levels of EE savings. There are, however, a number of uncertainties that led the IOUs to treat SB 350 impacts qualitatively and defer incorporating estimates of this savings until the next California Gas Report.<sup>34</sup>

Thus, as the 2016 CGR acknowledges, the forecast does not reflect in any way the increased efforts for energy efficiency that will be associated with SB 350. The potential increase in energy efficiency could be as large as a doubling of the energy efficiency levels incorporated in the forecast. Table 4 below shows the potential size of the incremental reduction that would correspond to a doubling of gas and electric energy efficiency.

Table 4: Potential Incremental Reduction Due to SB 350 AAEE Requirements

|                                             | 2016 | 2017 | 2018 | 2019 | 2020 | 2025 | 2030 | 2035 |
|---------------------------------------------|------|------|------|------|------|------|------|------|
| Gas Energy Efficiency Savings MMcf/d        | 0    | 1    | 1    | 2    | 3    | 5    | 9    | 14   |
| Gas Savings from Electricity Savings MMcf/d | 2    | 5    | 8    | 10   | 11   | 18   | 25   | 36   |
| Total MMcf/d                                | 3    | 6    | 9    | 11   | 13   | 23   | 34   | 50   |

<sup>34</sup> 2016 California Gas Report at 76 (footnotes omitted).

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Currently there are several large customers that utilize high pressure gas feeds and are served directly from Line 1600.<sup>37</sup> The Applicants say that they expect the derated Line 1600 would continue to be able to meet the demands of these large customers, provided any service pressure issues were addressed.<sup>38</sup> The Applicants claim that if Line 1600 were operated at 320 psig, the line's delivery volumes could not be counted as transmission volumes.<sup>39</sup> However, the Applicants continue to include the load of the customers that would be served through the derated Line 1600 as well as Line 1026 in the Applicants' overall forecasted demand that must be met under the one-in-ten cold peak day standard to determine the adequacy of the utility's *transmission* capacity.

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<sup>37</sup> Attachment G: Applicants Response to Energy Division Request 2, Q. 4.

<sup>39</sup> Attachment S: Applicants Response to SCGC-04, Q.4.7.

1 Lines 1600 and 1026 should be deducted from the forecast of 1-in-10 year cold day demand to  
2 reflect the fact that they are not served by the transmission system.

3 Two EG customers are located at either end of Line 1600.<sup>40</sup> The one to the north has [REDACTED]  
4 MW of installed capacity and the one to the south has [REDACTED] MW of installed capacity.<sup>41</sup> Each EG is  
5 a combustion turbine. [REDACTED]

6 [REDACTED] <sup>42</sup> [REDACTED] <sup>43</sup>  
7 [REDACTED] <sup>44</sup> [REDACTED]  
8 [REDACTED]  
9 [REDACTED] <sup>45</sup> Thus, at least 5 MMcf/d should be subtracted from 1-  
10 in-10 year cold day EG demand.

11 The Applicants should also be directed to deduct from the core 1-in-10 year cold day  
12 demand forecast an amount that would correspond to the portion of core requirements associated  
13 with communities along Lines 1600 and 1026. A similar calculation should be performed to  
14 determine the contribution of the industrial customer, [REDACTED], to 1-in-10 year cold day  
15 demand so it could be subtracted from the Noncore Commercial/Industrial demands. [REDACTED]  
16 [REDACTED] is located at the southern end of Line 1600.

17 The large customers served on Line 1600 may operate facilities that require high pressure  
18 gas feeds, but the large customers could continue to take service from Line 1600 even if it was  
19 derated to a Maximum Allowable Operating Pressure (“MAOP”) of 320 psig and operated at the  
20 Maximum Operating Pressure (“MOP”) of 300 psig as proposed by the Applicants.<sup>46</sup> The  
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22 <sup>40</sup> Updated Bisi Direct at 5.

23 <sup>41</sup> Attachment H: Applicants Response to TURN-08, Q.7.

24 <sup>42</sup> Attachment I: Applicants Response to ORA-09, Q.9.14.

25 <sup>43</sup> EIA Form 923 data for 2015.

26 <sup>44</sup> Attachment I: Applicants Response to ORA-09, Q.9.12, Q.9.14.

27 <sup>45</sup> 2016 California Gas Report workpapers at 145.

28 <sup>46</sup> Prepared Direct Testimony of Norm G. Kohls, Attachment A, Pipeline Safety and Reliability Report, Attachment XI, L-1600 De-rating Impacting Analysis, p. 1 (“In order to reduce the operating stress in Line 1600 to a level below 20% specified minimum yield strength (SMYS), it has been proposed to reduce the pressure in the

1 customers could utilize on-site compression to boost the pressure of the natural gas feed to levels  
2 that are required by their turbines. The large customers served from Line 1600 may already have  
3 on-site compression. Large customers in SoCalGas' service territory that require high pressure  
4 feeds are likely to have on-site compression if their equipment requires high pressure feeds  
5 because SoCalGas does not guarantee service pressure.<sup>47</sup> Similarly, SDG&E does not guarantee  
6 pressure.<sup>48</sup> Compressor costs are a relatively small portion of overall EG project development  
7 costs.<sup>49</sup>

8 Finally, Line 1026 can be relied upon to provide gas received at San Onofre independently  
9 of Lines 3010 and 1600. During the peak SDG&E system sendout on January 14, 2013 Line  
10 1026 supplied 1 MMcf/d.<sup>50</sup> Customers on Line 1026 are primarily core customers, so the 1  
11 MMcf/d should be subtracted from the 1-in-10 year cold day core demands.

12 Adjusting the figures in the Applicants' Table 1 to reflect the reductions shown in Tables  
13 2 through 4, in addition to the 1 MMcf/d reduction in core demand and 5 MMcf/d reduction in  
14 EG demand discussed previously, produces Table 5

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21 (continued...)

22 pipeline to an operating pressure of 300 psig with an MAOP of 320 psig between Rainbow pressure limiting station  
23 and Kearny Villa pressure limiting station.”)

24 <sup>47</sup> Attachment H: Applicants Response to TURN-08, Q. 9.

25 <sup>48</sup> *Id.*

26 <sup>49</sup> US Environmental Protection Agency, Catalogue of CHP Technologies, March 2015 at 3-13 to 3-14. For  
27 example, installed costs for fuel systems for combustion turbine applications range between \$0.75 million for a 3  
28 MW unit to \$3.7 million for a 44 MW unit assuming in both cases that the natural gas feed delivered by the utility in  
only 55 psig. Clearly, service from even a derated Line 1600 is at a delivery pressure that is more than five times the  
level in the example and, thus, would require significantly less compression which reduces costs.

<sup>50</sup> Attachment S: Applicants Response to SCGC-04, Q.4.9.

Table 5: After Applying Adjustments to Table 1

| Operating |      | Noncore |     |       |
|-----------|------|---------|-----|-------|
| Year a/   | Core | C&I     | EG  | Total |
| 2016/17   | 365  | 60      | 136 | 560   |
| 2017/18   | 372  | 61      | 132 | 565   |
| 2018/19   | 371  | 61      | 129 | 561   |
| 2019/20   | 371  | 61      | 128 | 560   |
| 2020/21   | 370  | 61      | 127 | 557   |
| 2021/22   | 368  | 61      | 119 | 548   |
| 2022/23   | 366  | 61      | 113 | 540   |
| 2023/24   | 365  | 61      | 106 | 531   |
| 2024/25   | 363  | 61      | 100 | 524   |
| 2025/26   | 362  | 60      | 82  | 505   |
| 2030/31   | 362  | 59      | 66  | 487   |
| 2035/36   | 363  | 57      | 57  | 477   |

My Table 5 shows that, taking into account the potential reductions in demand due to the mandate created by SB 350 as well as the effect of Lines 1026 and 1600, SDG&E gas demand for Line 3010 could be less than the standalone capacity of Line 3010 during the entire forecast period.

##### **5. The Applicants Advocate the Construction of Line 3602 as the Solution to Several Problems.**

The Applicants have concluded that constructing a new 36-inch transmission line and derating Line 1600 to distribution pressure is the best response to the Commission's requirement that they either pressure test or replace Line 1600. In justifying their proposal, the Applicants claim that the SDG&E system is vulnerable to several problems. First, the Applicants claim that system integrity would degrade if the capacity associated with Line 1600 were not replaced should Line 1600 be re-functionalized as a distribution line.<sup>51</sup> Second, the Applicants claim that without a replacement line such as Line 3602 the core customers would be vulnerable to supply interruption in the event of an outage on Line 3010.<sup>52</sup> Third, the Applicants claim that without a

<sup>51</sup> Applicants Supplemental Testimony at 108.

<sup>52</sup> *Id.*

1 replacement line such as Line 3602 the EG customers would be vulnerable to curtailment in the  
2 event of an outage on Line 3010 or an outage at Moreno Compressor Station.<sup>53</sup>

3 **5.1. Problem 1: The Threat of Insufficient Transmission Capacity to Meet 1-in-10**  
4 **Year Cold Day Demand If Line 1600 Is Reduced to Distribution Pressure for**  
5 **Safety Reasons as Proposed by the Applicants.**

6 SDG&E gas customers are currently served by a transmission system that includes a  
7 number of major transmission lines, which is shown in Figure 2 below.<sup>54</sup>

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27 <sup>53</sup> *Id.*

28 <sup>54</sup> Attachment J: Applicants Response to SCGC-10.4; ORA-9, Q.9.3, Q.9.14

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**Figure 2**

**Redacted**

1 Additionally, a small portion of SDG&E demand is served by a distribution line, Line 1026,  
2 which is owned by SoCalGas.<sup>55</sup>

3 Two of the SDG&E transmission lines, Lines 1600 and 3010, run in a north-south  
4 direction from Rainbow Station at the northern edge of SDG&E's service territory to the San  
5 Diego metropolitan area. Gas is delivered to Lines 1600 and 3010 by three SoCalGas  
6 transmission lines that run southward from the Moreno Compressor Station. Lines 1601 and  
7 [REDACTED] run in an east-west direction and act as cross ties between Lines 1600 and 3010. Line 2010  
8 also runs in an east-west direction from the Line [REDACTED] interconnection with Lines 1600 and 2010  
9 at Kearny Villa Station to the citygate at Santee. Line 3600 runs south from the interconnection  
10 with Line 2010 at Santee to an interconnection with Line 3012. Line 3012, in turn, runs from the  
11 interconnection with Line 3600 to the United States border with Mexico. Line 3012 interconnects  
12 with Transportadora de Gas Natural de Baja California ("TGN") at the international border at  
13 Otay Mesa.

14 Line 1026 runs south from San Onofre Station with gas flowing from Orange County into  
15 San Diego County. Line 1026 is operated at [REDACTED] psig<sup>56</sup> and is considered a distribution  
16 pipeline.<sup>57</sup> The line is used to distribute gas to coastal customers including one EG customer.<sup>58</sup>  
17 The nominal capacity of the line is 5 MMcf/d.<sup>59</sup>

18 Deliveries from the north through Lines 1600 and 3010 are possible up to 630 MMcf/d in  
19 the winter and 590 MMcf/d in the summer if Line 1600 operates at a pressure of 640 psig.<sup>60</sup>  
20 However, since July 9, 2016, Line 1600 has operated at 512 psig, which reduces the total capacity  
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22 <sup>55</sup> Attachment K: Applicants' Response to SCGC-5, Q.5.7.7. Applicants characterize Line 1026 as being  
23 used for distribution purposes in the coastal areas north of San Diego. See, also, Applicants' Response to SCGC-13,  
Q.13.2.

24 <sup>56</sup> Attachment L: Applicants Response to SCGC-13, Q.13.2.3.

25 <sup>57</sup> Attachment L: Applicants Response to SCGC-13, Q.13.2.4.

26 <sup>58</sup> Attachment L: Applicants Response to SCGC-13, Q.13.2.5.

27 <sup>59</sup> Attachment L: Applicants Response to SCGC-13, Q.13.2.4.

28 <sup>60</sup> A.15-09-013, Application at 3. This discussion refers to the delivery capability of this portion of the  
transmission system.

1 of the combination of Lines 3010 and 1600 by 35 MMcf/d<sup>61</sup> to 605 MMcf/d in the winter and to  
2 555 MMcf/d in the summer.

3 Deliveries up to 400 MMcf/d from the south through Otay Mesa and the SDG&E  
4 transmission network are possible throughout the year.<sup>62</sup> If gas were not flowing south from  
5 either Line 1600 or 3010, gas could flow north on the transmission lines extending north from  
6 Otay Mesa.<sup>63</sup> In the event of an outage on a portion of either Line 1600 or 3010, gas could be  
7 delivered north from Otay Mesa through Lines 3012, 3600, and 2010 into the SDG&E system.

8 As discussed previously, the capacity of the northern transmission lines, Lines 3010 and  
9 1600, is a function of their line pressures. According to the Applicants, reducing Line 1600 from  
10 the current 512 psig to 320 psig would result in the line being re-functionalized as a distribution  
11 line, and, thus, eliminate its contribution to transmission capacity.<sup>64</sup> The resulting transmission  
12 capacity of Line 3010 as a stand-alone north-to-south transmission line would be 570 MMcf/d,<sup>65</sup>  
13 which would fall below the Applicants' current projection of 1-in-10 year cold day requirements  
14 as shown in Applicants' Table 1. The Applicants claim that derating Line 1600 while failing to  
15 replace Line 1600 with the proposed Line 3602 would "degrade the Utilities' existing Gas  
16 System"<sup>66</sup>

17 **5.1.1. As Demonstrated Previously, Applicants' Forecast of 1-in-10 Year Cold**  
18 **Day Demand Is Overstated But Even Their Forecast Shows Demand**  
19 **Below the 570 MMcf/d Capacity of Line 3010 by 2023.**

20 The Applicants' current projections of 1-in-10 year cold day demands, as shown in the  
21 Applicants' Table 1, demonstrate that while the projected SDG&E peak demand exceeds 570  
22 MMcf/d during the years 2017 through 2023, it exceeds 570 MMcf/d only by between 2 and 20

23 <sup>61</sup> Attachment G: July 14, 2016, Letter to Tim Sullivan from Jimmie Cho at 2-3.

24 <sup>62</sup> Applicants Supplemental Testimony, February 21, 2017, at 25. This discussion refers to the delivery  
25 capability of this portion of the transmission system.

26 <sup>63</sup> *Id.* at 13-14.

27 <sup>64</sup> Attachment S: Applicants Response to SCGC-04, Q.4.7.

28 <sup>65</sup> Updated Bisi Direct at Footnote 11.

<sup>66</sup> Applicants Supplemental Testimony at 108.

1 MMcf/d, which is no more than 3.5 percent. Furthermore, as discussed above, the Applicants’  
2 forecast is overstated because it fails to take into account the most recent electricity forecast, fails  
3 to fully reflect achievable energy efficiency goals, and includes demand that is currently or would  
4 in the future be served through distribution lines that can be served by SoCalGas independently of  
5 the SDG&E transmission system. Adjusting the Applicants’ forecast for these shortcomings  
6 produces the forecast level that is shown in Table 5, which demonstrates that the peak day  
7 requirements for Line 3010 are below the standalone capacity of the line during the entire forecast  
8 period.

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10 **5.1.2. Any Deficit Between the 570 MMcf/d Provided by Line 3010 and the 1-in-10 Year Cold Day Demand During the Next Six Years Could Not Be Met by Building a New Pipeline.**

11 The Applicants have proposed maintaining transmission pressure of at least 512 psig for  
12 Line 1600 in the interim period while the Applicants permit and construct their proposed Line  
13 3602.<sup>67</sup> However, even if the Commission were to deem it necessary to further reduce the  
14 operating pressure for Line 1600 in the near term so that Line 1600 would be functionalized as a  
15 distribution line, the Applicants’ proposal to construct a new pipeline would not solve the short-  
16 term capacity deficit. According to the Applicants’ proposed schedule, a new pipeline would not  
17 be finished until the end of 2020,<sup>68</sup> which they recognize is optimistic given their statement: “The  
18 Utilities will update this schedule once the Commission sets a schedule for Phase 2 of this  
19 proceeding.”<sup>69</sup> Thus, the new pipeline if it were approved could not be completed much before  
20 the end of the deficit period.

21 **5.1.3. A Short Term Deficit Can Be Met Through Deliveries at Otay Mesa.**

22 If the 1-in-10 year cold day demand for natural gas were to exceed the demand shown in  
23 Table 5, the short-term deficits could be addressed through deliveries into the SDG&E system at  
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26 <sup>67</sup> Updated Kohls Direct at 26

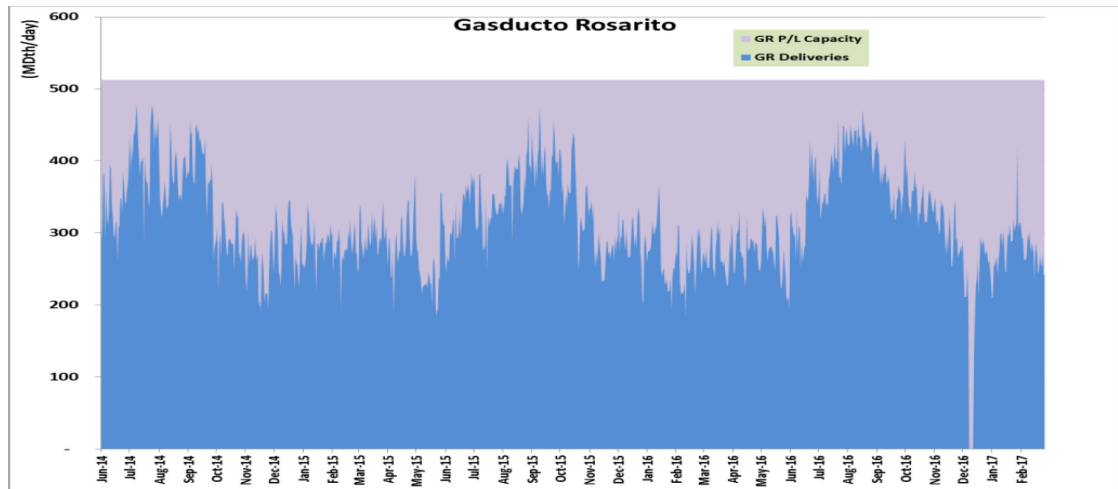
27 <sup>68</sup> *Id.*

28 <sup>69</sup> *Id.*, Footnote 24.

Otay Mesa.<sup>70</sup> The Applicants acknowledge that they have relied upon deliveries of gas at Otay Mesa in the past when shortfalls have arisen between customer demands and deliveries across Lines 3010 and 1600.<sup>71</sup>

A review of the daily deliveries across Gasoducto Rosarito over the past three years demonstrates very clearly that there is sufficient delivery capacity in the system during the winter months to accommodate peak day demand if that demand, contrary to the forecast in Table 6, were to exceed the 570 MMcf/d standalone capacity of Line 3010. Figure 3 graphically displays both the deliveries and available capacity on a daily basis on Gasoducto Rosarito:

Figure 3<sup>72</sup>



The Applicants acknowledge that the System Operator has obtained gas supplies 22 times<sup>73</sup> through Otay Mesa.<sup>74</sup> Furthermore, in February 2011 when the Applicants were unable to obtain adequate supplies on several of their upstream suppliers because of a severe well freeze-up

<sup>70</sup> *Id.* The Applicants acknowledge that they addressed the peak cold day event on January 14, 2013, in part by drafting the system by 15 MMcf.

<sup>71</sup> Applicants Supplemental Testimony at 14.

<sup>72</sup> Attachment L: Applicants Response to SCGC-13, Q.13.15.

<sup>73</sup> Two of these occasions correspond to a second purchase of gas on February 2, 2011 and January 15, 2013.

<sup>74</sup> Attachment M: Applicants Response to SCGC-14, Q.14.9., Attachment SCGC 14.9\_Daily OM Cost Info.xlsx.

1 due to extreme cold weather, the Applicants bought gas from the Energia Costa Azul liquefied  
2 natural gas (“LNG”) terminal.<sup>75</sup>

3 If circumstances were to arise where no gas supply were available to augment available  
4 supply, the System Operator would interrupt EG customer usage to the point that allowed the  
5 Applicants System Operator to balance the system. SoCalGas Rule 41 states: “The Utility  
6 System Operator shall communicate with the California Independent System Operator (CAISO)  
7 and other Electric Grid Operators on an as-needed basis to help maintain the reliability of the  
8 Utility’s natural gas system and the electric grid. Such communications may result in operational  
9 changes by the Utility System Operator and changes in electric grid operations and electric  
10 generation dispatch order by CAISO and other grid operators.”<sup>76</sup>

11 **5.2. Problem 2: The Threat of Insufficient Transmission Capacity to Meet Core**  
12 **Customer Needs in the Event of an Outage on Line 3010.**

13 The Applicants admit that they do not need to build Line 3602 to meet the Commission’s  
14 capacity standards.<sup>77</sup> Instead, they argue that the new Line 3602 is needed to improve system  
15 resiliency that will ensure the ability to meet customer needs under all circumstances.<sup>78</sup> The  
16 Applicants suggest that core customers could potentially be interrupted in some scenarios that  
17 they have considered.<sup>79</sup> In other words, Line 3602 is being proposed as an insurance policy that  
18 would guard against system failure under all possible circumstances no matter how small the  
19 probability of occurrence.

20 The Applicants identify a system vulnerability that would arguably affect service to core  
21 customers in order to demonstrate the need to improve system resiliency, that is, the possibility  
22 that Line 3010 could fail. Applicants claim that without Line 3010 the capacity of the SDG&E

23 <sup>75</sup> *Id.*; Staff of the FERC and the North American Electric Reliability Corporation (“NERC”), Report on  
24 Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011,  
<http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf> (“FERC/NERC Staff Report”) at 115.

25 <sup>76</sup> SoCalGas Rule 41, Special Condition 30 at Sheet 11.

26 <sup>77</sup> See, for example, Updated Bisi Direct at 10; Applicants Supplement Testimony at 19, 28, 30.

27 <sup>78</sup> Schneider Direct at 2.

28 <sup>79</sup> Attachment F: Applicants Response to SCGC-12, Q.12.4., Attachment “SCGC DR 12 Q4 – Scenario  
Analysis Final\_corrected 022117.xlsx” at tab, “Gas”.

transmission system is severely limited. The Applicants state: “Without Line 3010, only gas supply transported via Line 1600 is available, reducing the total capacity of the SDG&E system to 150 MMcfd. This level of capacity is just sufficient to serve only the core load on the SDG&E system in the summer operating season – the time when core demand is at its lowest level”<sup>80</sup> If Line 1600 were derated to being a distribution line, however, then according to the Applicants without the construction of Line 3602, a loss of Line 3010 would leave SDG&E without any north-to-south transmission capacity.<sup>81</sup> Thus, the Applicants raise the specter of a situation that could arguably cause curtailments to core customers.

The workpapers to the Applicants’ Cost Effectiveness Analysis (“CEA”) identifies customer demands associated with various times of the year and weather. As discussed previously, the Applicants’ demand forecast is overstated. Therefore, considering the Applicants’ projections of daily core demands by season provides a very conservative context within which to evaluate the various alternatives for meeting these requirements. The Applicants’ projections are presented in Table 6 below:

**Table 6: Applicants’ Definition of Typical Core Customer Demand by Season (MMcf/d)**

|             | <b>Summer<br/>Low-EG<br/>Day</b> | <b>Summer<br/>High-EG<br/>Day</b> | <b>Spring<br/>Day</b> | <b>Fall Day</b> | <b>Winter<br/>Day</b> | <b>Winter 1-in-<br/>10 Year<br/>Day</b> |
|-------------|----------------------------------|-----------------------------------|-----------------------|-----------------|-----------------------|-----------------------------------------|
| Core Demand | 100                              | 100                               | 170                   | 180             | 310                   | 350                                     |

*Source: Applicants Response to SCGC-12, SCGC DR 12 Q4 - Scenario Analysis Final\_Corrected 022117.xlsx*

If there were a complete loss of Line 3010, there would be a need for transmission capacity capable of meeting core demands. Table 7 demonstrates that the level of core demands varies more than threefold during the year, which makes capacity alternatives that could be tailored seasonally more cost effective than one which provides a fixed amount of capacity annually.

<sup>80</sup> Updated Bisi Direct at 6 (footnotes omitted)

<sup>81</sup> Applicants Supplemental Testimony at 109.

1 Building a new pipeline as an insurance policy against service loss is an excessively  
2 expensive approach. At the direction of the Assigned Commissioner, the Applicants have  
3 produced a cost effectiveness analysis to consider various alternatives to the project.<sup>82</sup> However,  
4 the Applicants have very carefully considered “big project” alternative infrastructure additions  
5 that are similar in scope to the proposed pipeline.<sup>83</sup> Not surprisingly, these alternatives have very  
6 high costs associated with them. The question that remains unanswered is whether other less  
7 costly alternatives to a new pipeline exist that would offer sufficient levels of insurance for core  
8 customers against loss of service associated with the various possible outcomes that the  
9 Applicants have identified.

#### 10 **5.2.1. Commission policy does not require pipeline redundancy**

11 The Commission has established standards for the gas utilities to follow in determining  
12 the appropriate level of transmission capacity. While this policy requires a certain amount of  
13 slack capacity, this policy does not require the construction of redundant pipelines.

14 The Commission addressed the policy in 2002 after SDG&E ran short of capacity and had  
15 to curtail EG customers repeatedly during the 2000-2001 gas year. After reviewing the situation,  
16 the Commission found: “In balancing the concerns over who pays for this excess capacity against  
17 the increased reliability the excess provides, the Commission finds it is in the interest of all gas  
18 transmission users to adopt a 1-in-10 (one curtailment in ten years), cold year conditions,  
19 reliability standard for SDG&E.”<sup>84</sup>

20 The Commission revisited standards for planning transmission capacity in a decision  
21 issued in 2006. The Commission addressed the appropriate relationship between the amount of  
22 transmission capacity and the amount of customer demand for all three large gas utilities,  
23 SDG&E, SoCalGas and Pacific Gas and Electric Company (“PG&E”). The Commission again  
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25 <sup>82</sup> *Id.*, Attachment B.

26 <sup>83</sup> *Id.*, Attachment B, pp. 13-18. For example, they have considered the cost of looping Gasoducto Rosarito,  
27 building four new LNG storage and regasification facilities, as well as several alternative routes for building a new  
28 pipeline.

<sup>84</sup> D.02-11-079, slip op. at 9.

1 found that a 1-in-10 cold year standard was appropriate, although the Commission added dry  
2 hydro conditions to the criteria:

3           There is nothing scientific about choosing a 1 in 10 year standard,  
4           but there is something very logical about planning and maintaining  
5           a backbone system that can support an average day in a challenging  
6           year. It must be remembered that even in such a year, customers  
7           will often place significantly higher-than-average demand on each  
8           utility's gas supply system. The system must serve demand every  
9           year, not just during an average one. Looking at severe weather  
10          conditions over a rolling ten-year period appears adequate. It is  
11          reasonable to require that each of the utilities (PG&E, SoCalGas,  
12          and SDG&E) to plan for one-in-ten year cold and dry conditions,  
13          and we will direct them to do so.<sup>85</sup>

14 In adopting the 1-in-10 year cold and dry year standard, the Commission explicitly recognized the  
15 level of slack capacity that was reflected in the standard: "As such, we conclude that the proposed  
16 effective slack capacity standard in a one-in-ten cold dry year ranges from 11% to 16% for  
17 SoCalGas and 16% to 21% for SDG&E. PG&E proposes an annual capacity utilization of 80-  
18 90%, which is the equivalent of a reserve margin of 11-25% during cold temperature and dry  
19 hydroelectric conditions."<sup>86</sup> The Commission made it clear that it expected all elements of the  
20 utilities' transmission systems to be considered in making the determination of whether they met  
21 the standard: "In assessing the adequacy of in-state infrastructure, the utilities shall consider the  
22 physical system as a whole (the interaction of backbone pipelines, storage, and local  
23 transmission) including the probability of storage withdrawal and the deliverability of withdrawn  
24 gas during periods of peak demand."<sup>87</sup>

25           More recently, the Commission eliminated the distinction between firm and interruptible  
26 customers for system planning and curtailment purposes. "Settling Parties agree that capacity  
27 open seasons are no longer required to be conducted in potentially capacity constrained areas and  
28 that SoCalGas and SDG&E's end-use noncore rate schedules will no longer distinguish between

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26           <sup>85</sup> D.06-09-039, slip op. at 25.

27           <sup>86</sup> *Id.* at 26.

28           <sup>87</sup> *Id.* at Ordering Para 6.

1 firm and interruptible transportation service (except for SoCalGas Schedule No. G-BTS,  
2 Backbone Transportation Service).”<sup>88</sup>

3 Thus, the requirements associated with each customer class under 1-in-10 year cold and  
4 dry year circumstances is to be considered in determining the amount of capacity that is required,  
5 not redundancy. The Commission has never established a need to add duplicate pipeline capacity  
6 in anticipation of a potential outage on a pipeline as the Applicants propose in this proceeding.

### 7 **5.2.2. A Line 3010 Outage Is a Low Probability Event**

8 The Applicants postulate two levels of pipeline outage on Line 3010 when conducting  
9 their cost benefit analyses. They have however not admitted that the probability associated with  
10 either of these events is small. The Applicants do acknowledge that the core would only be  
11 affected by a complete loss of Line 3010.<sup>89</sup> Data regarding historical outages on Line 3010  
12 reveals however that there has only been one unplanned outage, lasting one day, on Line 3010  
13 during its entire 57-year operating history.<sup>90</sup>

14 Occasional planned outages for maintenance are to be expected. There have been 20 of  
15 these outages over the years lasting between ½ day and three days with 70 percent of the outages  
16 lasting one day.<sup>91</sup>

### 17 **5.2.3. Safety Measures that the Commission Has Directed the Applicants to** 18 **Pursue Will Help Improve System Reliability.**

19 The Commission has directed the gas utilities to rigorously pursue activities that enhance  
20 the safety of their pipeline networks. These safety activities include patrolling lines, running  
21 regular inspections to detect any external corrosion, and in-line inspections (“ILI”), which rely  
22 upon pigging including transverse field inspection (“TFI”).<sup>92</sup> The same activities that enhance  
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24 <sup>88</sup> D.16-07-008, slip op. at 7.

25 <sup>89</sup> Updated Bisi Direct at 6.

26 <sup>90</sup> Attachment N: Applicants Response to Sierra Club-04, Question 2.

27 <sup>91</sup> *Id.*

28 <sup>92</sup> Applicants Supplemental Testimony at 95-96; There is no difference between a TFI tool and a Circumferential Magnetic Flux Leakage (“CMFL”) tool. Applicants Response to SCGC-15, Q.15.17.1.

safety will also enhance reliability. Repairs can be performed more regularly and at scheduled times rather than unexpectedly and on a potentially larger scale.

The Commission has directed the gas utilities to increase their attention to operation and maintenance practices that enhance pipeline safety.<sup>93</sup> Enhanced safety inspections, such as establishing ongoing line patrols, pigging lines with transverse magnetic head, and regular visual external visual examinations, should work to enhance reliability as well as safety.

### 5.3. Alternative Solutions for Problem 2:

There are a number of alternative solutions available to address the Applicants' Problem 2. Under these various options, deliveries of gas could be made at Otay Mesa, which would utilize the pipeline system that runs through northern Baja California. Figure 4 depicts the pipeline system that includes North Baja, Gasoducto Rosarito, and TGN, which I will refer to as the NB-GR-TGN pipeline system:

Figure 4: Map of North Baja-Gasoducto Rosarito-TGN Pipeline System<sup>94</sup>



<sup>93</sup> See for example D.12-04-010, slip op. at 22.

<sup>94</sup> Energía Costa Azul, Bill Keller, LNG Interagency Permitting Working Group, July 25, 2006, at 12, excerpt from map. Note that the name Gasoducto Bajanorte has been updated to its current name, Gasoducto Rosarito to avoid confusion and the location of the Yuma Lateral has been added.

North Baja is a domestic pipeline operated under North American Energy Standards Board (“NAESB”) and Federal Energy Regulatory Commission (“FERC”) standards. Contracting shippers can hold firm capacity rights. However, if pipeline capacity is not utilized by the shippers, the capacity may be used by other shippers on an interruptible basis.

The two Mexican pipelines, Gasoducto Rosarito and TGN, are operated in the manner reasonably consistent with NAESB and FERC standards.<sup>95</sup> The capacities of the three pipelines are shown in Table 7:

Table 7<sup>96</sup>

| Pipeline            | Capacity                                        | Info Source                                                                                                                                                                                                                                                                              |
|---------------------|-------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| North Baja Pipeline | 500 MMcfd (Southbound)                          | <a href="http://www.tcplus.com/North%20Baja">http://www.tcplus.com/North%20Baja</a>                                                                                                                                                                                                      |
| Gasoducto Rosarito  | 500 MMcfd (Westbound)<br>534 MMcfd* (Westbound) | <a href="http://www.gasoductorosarito.com/english/about-us.html">http://www.gasoductorosarito.com/english/about-us.html</a> (English version)<br><a href="http://www.gasoductorosarito.com/quienes-somos.html">http://www.gasoductorosarito.com/quienes-somos.html</a> (Spanish version) |
| TGN                 | 800 MMcfd (Westbound)<br>940 MMcfd* (Westbound) | <a href="http://www.tgndebajacalifornia.com/english/index.html">http://www.tgndebajacalifornia.com/english/index.html</a> (English version)<br><a href="http://www.tgndebajacalifornia.com">http://www.tgndebajacalifornia.com</a> (Spanish version)                                     |

\*SoCalGas/SDG&E confirmed with IEnova that the correct capacities are listed in the Spanish (not English version).

The NB-GR-TGN system has only two points at which natural gas can be delivered into the system for delivery into SDG&E at Otay Mesa: Ehrenberg, at the California/Arizona border, and the Energia Costa Azul LNG terminal.

Delivered LNG at Costa Azul is not cost competitive with domestic U.S. sources of natural gas so the terminal is unused.<sup>97</sup> The only deliveries of LNG are infrequent and only as required to keep the equipment in a cold and ready status.<sup>98</sup> There is a small amount of “boil-off” gas that is produced and released into the LNG Spur that leads northward from the Energia Costa Azul terminal to the interconnection at Tecate<sup>99</sup> with the Gasoducto Rosarito line.<sup>100</sup> Aside from

<sup>95</sup> Gasoducto and TGN are regulated by Comisión Reguladora de Energía (“CRE”) in a manner reasonably consistent with FERC regulation. <http://www.cre.gob.mx/documento/ingles.pdf>

<sup>96</sup> Attachment M: Applicants Response to SCGC-14. Q.14.7.

<sup>97</sup> Attachment U: IEnova 2015 Annual Report at 23.

<sup>98</sup> *Id.*

<sup>99</sup> Attachment L: Applicants Response to SCGC-13, Q.13.9.4.

the boil-off gas, the only source of gas for the NB-GR-TGN system is Ehrenberg. All deliveries from Ehrenberg into the NB-GR-TGN system pass through North Baja pipeline, so firm rights on that line can determine whether gas will flow downstream on Gasoducto Rosarito.

**5.3.1. Alternative 1: Core Demand Could Be Served Through the Otay Mesa on an Interruptible Basis as Supplemented by As Available Supplies of LNG at Costa Azul.**

One alternative that is available is relying upon supplies of gas delivered to Otay Mesa using interruptible capacity on all three pipelines. The gas supply could be supplemented as needed with purchases of gas from Energia Costa Azul LNG terminal on an as-available basis.

This alternative is least expensive because no fixed payments are required to reserve pipeline capacity or LNG storage. The pipeline capacity is paid for if and when it is utilized. On the other hand, there is no assurance that the pipeline capacity will be available on any given day because the capacity has not been reserved. As shown previously in Figure 3, there are considerable quantities of interruptible capacity available on the North Baja-Gasoducto Rosarito system on most days during the winter months when the core's loads would be the greatest. However, there are a few days during the winter over the last several years that capacity has been more constrained. The seasonal breakdown of capacity availability on Gasoducto Rosarito is shown in Table 8 below:

**Table 8: Gasoducto Rosarito  
Available Capacity by Season (MMcf/d)<sup>101</sup>**

|        | average | minimum |
|--------|---------|---------|
| winter | 236     | 92      |
| spring | 231     | 126     |
| summer | 143     | 32      |
| fall   | 177     | 38      |

(continued...)

<sup>100</sup> For a typical storage tank boil off amounts to about 0.05 percent of LNG volume on a daily basis. 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. Thus, the boil off would be expected to amount to no more than 1.7 MMcf/d if the tank were full.

<sup>101</sup> Attachment L: Applicants Response to SCGC-13, Q.13.15.

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

The core's use of interruptible capacity could be supplemented, however, with purchases of gas from the Energia Costa Azul LNG terminal. Thus, if the Gas Acquisition Department were unable to obtain sufficient gas for delivery through NB-GR-TGN, the Gas Acquisition Department could purchase gas from IEnova LNG which maintains LNG supplies at the Energia Costa Azul LNG terminal.<sup>102</sup> Purchases of supplies of gas from the Energia Costa Azul LNG terminal would be more expensive than supplies of gas from the U.S. However, purchases of this type would be made very infrequently and only if the domestic supplies were unavailable or undeliverable.

The System Operator has previously relied upon purchased gas from the Energia Costa Azul LNG terminal during a period where domestic gas supplies were severely limited. As shown in Table 9 below, the System Operator purchased gas from the Energia Costa Azul LNG terminal several times during February 2011:

Table 9<sup>103</sup>

| Flow Date | Otay Mesa Delivered Price (Dollars per Dth) | SoCal Avg Border Price (Dollars per Dth) | Added Cost (Dollars per Dth) |
|-----------|---------------------------------------------|------------------------------------------|------------------------------|
| 2/2/2011  | 8.50                                        | 4.5377                                   | 3.9623                       |
| 2/2/2011  | 15.00                                       | 4.5377                                   | 10.4623                      |
| 2/3/2011  | 12.75                                       | 5.5641                                   | 7.1859                       |
| 2/4/2011  | 10.00                                       | 6.0126                                   | 3.9874                       |

The southwestern U.S. was experiencing extreme cold conditions during the period February 2, 2011, through February 4, 2011, and the System Operator purchased 295 MDth during the three

<sup>102</sup> Attachment U: IEnova 2015 Annual Report at 23.

<sup>103</sup> Attachment M: Applicants Response to SCGC-14, Q.14.10.

day period from the Energia Costa Azul LNG terminal.<sup>104</sup> As shown in Table 9, the System Operator paid a premium for the gas purchased from Energia Costa Azul. However, since the gas was purchased only when required, the increased cost was justified.

If we rely upon the System Operator's recorded cost differentials associated with delivering gas through Otay Mesa, it is possible to calculate the level of cost exposure for the core under different scenarios using the information presented previously in Tables 6 and 8. Table 10 shows the type of cost variation associated with varying the season assumed for the pipe failure as well as the amount of capacity available on Gasoducto Rosarito:

Table 10<sup>105</sup>

| <b>Illustration of Core Exposure to Daily Cost Premiums<br/>from Relying upon Gas Deliveries at Otay Mesa</b> |             |
|---------------------------------------------------------------------------------------------------------------|-------------|
| Failure in summer, average capacity availability                                                              | \$64,035    |
| Failure in summer, minimum capacity availability                                                              | \$468,710   |
| Failure in winter, average capacity availability                                                              | \$807,470   |
| Failure in winter, minimum capacity availability                                                              | \$1,561,568 |
| Failure in peak winter, average capacity availability                                                         | \$1,071,129 |
| Failure in peak winter, minimum capacity availability                                                         | \$1,825,226 |

The highest cost scenario is associated with the 1-in-10 year cold day core demand of 350 MMcf/d assuming minimal (92 MMcf/d) capacity on Gasoducto Rosarito, which requires the remaining 258 MMcf/d of demand to be met with supplies from Costa Azul. However, the \$1.8 million daily cost premium would only be borne by the core if a pipeline outage were to actually occur and then only for the duration of the pipeline outage. This cost would be much less than the core's share of the \$86 million first-year annual revenue requirement associated with Line 3602.

### **5.3.2. Alternative 2: Core Demand Could Be Served Through Otay Mesa Utilizing Firm Capacity Rights on North Baja**

A second alternative that exists is to acquire firm capacity rights on one or more of the pipelines. At the time the NB-GR-TGN system was developed, entities could contract for firm

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<sup>104</sup> Attachment M: Applicants Response to SCGC-14, Q.14.9, Attachment SCGC 14.9\_DailyOM Cost Info.xlsx.

<sup>105</sup> *Id.*

delivery rights on any or all segments of the pipeline system. Furthermore, since the pipeline was designed to be capable of delivering gas in a bi-directional fashion, capacity rights exist on both the south-to-west direction as well as the east-to-north direction.

Some entities made sure that they had matching rights for the entire route over which their gas supply was to be delivered. Others apparently did not, relying instead on affiliates and/or interruptible capacity on some segments of the NB-GR-TGN system. The mismatch is illustrated in Table 11, which shows a comparison of firm capacity rights on North Baja versus Gasoducto Rosarito. The table also highlights downstream capacity on North Baja's Yuma Lateral extension to clarify the relationships.

**Table 11: Firm Capacity Rights: North Baja vs. Gasoducto Rosarito<sup>106</sup>**

| Firm Capacity (Dth) | North Baja Southbound | Gasoducto Rosarito Westbound or Yuma Lateral Eastbound |                        |
|---------------------|-----------------------|--------------------------------------------------------|------------------------|
| APS                 | 11,000                | APS                                                    | 62,750 EB to Yuma      |
| IID                 | 18,500                | IID                                                    | 18,500 EB to Yuma      |
|                     | 29,500                | Total EB                                               | 81,250                 |
| Intergen            | 135,000               | Intergen                                               | 133,900 WB to Mexicali |
| Sempra LNG          | 125,000               | TDM                                                    | 104,030 WB to Mexicali |
| Shell               | 37,000                | IEnova LNG                                             | 396,550 WB to TGN      |
| Toyota              | 880                   | Total WB                                               | 634,480                |
| Total               | 297,880               |                                                        |                        |

Table 11 demonstrates clearly that three electric generators ("EGs"), Arizona Public Service Company ("APS"), Imperial Irrigation District ("IID"), and InterGen,<sup>107</sup> have firm rights over the North Baja and Gasoducto Rosarito systems, with gas flowing to Yuma for APS and IID and gas flowing to the La Rosita (Energia Azteca) plant in Mexicali for InterGen. The fourth EG, Termoelectrica de Mexicali ("TdM"), which is owned by a Sempra Energy affiliate, Sempra

<sup>106</sup> Attachment Z: North Baja Pipeline Customer Listing January 1, 2017; Attachment U: IEnova 2015 Annual Report at 100.

<sup>107</sup> InterGen owns the La Rosita (Energia Azteca) power plant near Mexicali in Baja California. <http://www.intergen.com/where-we-are/project-portfolio/la-rosita-mexicali-mexico>

1 Mexico,<sup>108</sup> relies on the capacity rights of another Sempra Energy affiliate, Sempra LNG &  
2 Midstream (“Sempra LNG”), or interruptible capacity to transport gas on North Baja for delivery  
3 into Gasoducto Rosarito to supply the TdM power plant in Mexicali.<sup>109</sup>

4 Currently, only 327,380 Dth per day of firm capacity rights are subscribed on North Baja,  
5 leaving 166,670 Dth/d unsubscribed firm capacity as of April 9, 2017.<sup>110</sup> Therefore, despite the  
6 fact that the capacity on Gasoducto Rosarito is heavily subscribed, nearly one-third of the peak  
7 summer season deliveries to Gasoducto Rosarito at Ogilby rely upon interruptible transportation  
8 service across North Baja. Table 11 also demonstrates that the primary holder of westbound  
9 capacity on Gasoducto Rosarito is IEnova LNG, another Sempra Energy subsidiary.<sup>111</sup>

10 The availability of North Baja firm capacity rights creates an opportunity for the  
11 Applicants to acquire firm southbound capacity rights on North Baja. These rights would ensure  
12 that gas delivered into North Baja for delivery into to Gasoducto Rosarito at the interconnection  
13 between the two pipelines at Ogilby would be delivered to SDG&E at Otay Mesa for several  
14 reasons. First, as shown in Table 11, there is more westbound capacity on Gasoducto Rosarito  
15 than there is southbound capacity on North Baja.

16 Second, an entity holding firm rights (and exercising them) on the upstream pipeline,  
17 North Baja, could prevent an entity that holds firm rights on the downstream pipeline, Gasoducto  
18 Rosarito, from exercising its rights. The downstream rights holder would be unable to move its  
19 gas on North Baja to the interconnection with Gasoducto Rosarito unless some interruptible North  
20 Baja capacity were available. If a holder of firm westbound rights on Gasoducto Rosarito cannot  
21 move gas south across North Baja for delivery into Gasoducto Rosarito at Ogilby, the holder of  
22 Gasoducto Rosarito firm westbound capacity will not be able to utilize his Gasoducto Rosarito

23  
24 <sup>108</sup> Sempra Energy 2016 Annual Report, p. 10.

25 <sup>109</sup> Sempra Energy sells gas to TdM. *Id.*

26 <sup>110</sup> Attachment AA: North Baja, Unsubscribed Capacity,  
[http://www.tcplus.com/North%20Baja/UnsubscribedCapacity#sort=LocationName&sort\\_direction=ascending](http://www.tcplus.com/North%20Baja/UnsubscribedCapacity#sort=LocationName&sort_direction=ascending)

27 <sup>111</sup> Sempra Energy’s subsidiary, Sempra Mexico, includes a subsidiary, Infraestructura Energetica Nova,  
28 S.A.B. de C.V. (“IEnova”), which in turn includes operating companies including IEnova LNG. Sempra Energy  
2016 Annual Report at 9, 108.

rights, making the capacity available to the holders of North Baja firm southbound transportation rights.

Furthermore, firm capacity on the North Baja pipeline is relatively inexpensive. The posted tariffed rate for firm capacity on the system is \$3.9984 per Dth-month,<sup>112</sup> which would amount to only \$8 million/year for the 166.67 MDth/d of capacity that is currently available on North Baja. The North Baja capacity could be held on a relatively short-term basis, such as two-year, allowing the amount of capacity held to be tailored to near term needs.<sup>113</sup> The Applicants could include a right of first refusal to the capacity to assure that they would be able to obtain the same or adjusted amounts of capacity for future periods. Alternatively, the Applicants could contract for the available firm North Baja capacity for a longer term. In either case, the \$8 million annual cost of North Baja firm capacity would be much less than the core's share of the \$86 million first-year annual revenue requirement associated with Line 3602.

### **5.3.3. Alternative 3: Core Demand Could Be Served Through the Utilization of Firm LNG Storage at Costa Azul**

Neither the available interruptible capacity across the NB-GR-TGN system nor the unsubscribed firm capacity on North Baja would provide sufficient capacity to meet winter core loads in the event of a total outage on Line 3010. As an alternative, either in combination with capacity across the NB-GR-TGN system or by itself, a firm supply from LNG storage at Costa Azul could be relied upon to meet core demand if Line 3010 were to fail. In order to do this, however, the Applicants would have to assure that LNG supplies would be held in storage at Costa Azul.

The two LNG tanks at Costa Azul represent potential storage capacity for SDG&E core customers. Each tank holds 160,000 cubic meters of LNG, which is the liquid equivalent to 3.39 Bcf of natural gas.<sup>114</sup> The 3.39 Bcf volume of gas from just one of the two tanks represents about

<sup>112</sup> Attachment AB: North Baja Tariff, Part 4.1, v.3.0.0. <http://www.tcplus.com/North%20Baja/Tariff/>

<sup>113</sup> Attachment AA: Capacity in the amount of 166.67 MDth is currently posted on the North Baja website on a two-year contract basis, but the capacity is available for a longer period if the customer is interested. Contract rights could also be rolled-over in two-year increments.

<sup>114</sup> One cubic meter of LNG produces 21.189 cubic feet of natural gas. U.S. Department of Energy, Liquefied Natural Gas: Understanding the Basic Facts, August 2005, DOE/FE-0489 at 9.

1 10 days of gas supply to core demand in the winter months and about 50 days of gas supply to  
2 core demand in the summer months.<sup>115</sup>

3 It is not clear that it would be necessary to store the LNG equivalent of 3.39 Bcf on an  
4 ongoing basis as insurance against a Line 3010 outage. According to the Energy Information  
5 Administration (“EIA”), it would take about five days to ship a cargo of LNG from the terminals  
6 on the U.S. Gulf Coast to a terminal in Ecuador.<sup>116</sup> The time for shipping to Costa Azul would  
7 likely be similar. According to Bloomberg’s Business Week, a terminal in Peru is currently  
8 actively shipping cargos to Europe.<sup>117</sup> Given its proximity to Costa Azul, shipments could  
9 potentially take less time than five days. The shipments from Peru are sold to traders like Shell  
10 who in turn sells the gasified LNG.<sup>118</sup>

11 If new supplies of LNG can be transported to Energia Cost Azul in five days or less, only  
12 half of one Costa Azul LNG storage tank may be sufficient to cover core needs if Line 3010 were  
13 to go out of service during the winter peak. Furthermore, the stores of LNG could be spread  
14 across a greater number of days by relying upon gas delivered across NB-GR-TGN to meet a  
15 portion of the demand. For example, planning for a peak core requirement of 350 MMcf/d while  
16 desiring to spread the LNG stores over six days would require an LNG takeout rate of only 282  
17 MMcf/d with the 68 MMcf/d balance of gas requirements being met with deliveries from  
18 Ehrenberg. Similarly, spreading the LNG stores over seven days would require a takeout rate of  
19 only 242 MMcf/d, which would require 108 MMcf/d of deliveries from Ehrenberg to meet a peak  
20 core requirement of 350 MMcf/d.

23 <sup>115</sup> Attachment F: Response to SCGC-12, Q.12.4, SCGC DR 12 Q4-Scenario Analysis Final\_corrected  
24 022117.xlsx, at tab “Gas”.

25 <sup>116</sup> Attachment AC: EIA, Today in Energy, “Expanded Panama Canal reduces travel time for shipments of  
26 U.S. LNG to Asian markets,” June 30, 2016, <https://www.eia.gov/todayinenergy/detail.php?id=26892#>.

27 <sup>117</sup> Attachment X: Bloomberg Business Week article, “U.K. to Get First LNG From Peru While Still  
28 Waiting for U.S.”, February 7, 2017, <https://www.bloomberg.com/news/articles/2017-02-08/the-u-k-has-a-new-american-lng-supplier-and-it-s-not-the-u-s>.

<sup>118</sup> *Id.*

1 Three entities hold LNG storage tank rights at Costa Azul: IEnova LNG (50 percent  
2 share), Shell Mexico (25 percent share), and Gazprom Mexico (25 percent share).<sup>119</sup> Neither  
3 Shell Mexico nor Gazprom Mexico have delivered LNG to Costa Azul.<sup>120</sup> IEnova LNG has  
4 delivered only quantities of LNG that are sufficient to keep the two Costa Azul storage tanks cold  
5 so that they are available to receive LNG for the customers that contracted for Costa Azul  
6 capacity.<sup>121</sup> However, “each customer must pay for its full contracted LNG storage capacity and  
7 natural gas send-out capacity regardless of whether it actually delivers LNG to the terminal.”<sup>122</sup>  
8 Therefore, IEnova LNG, Shell Mexico, and Gazprom Mexico are each paying substantial  
9 amounts of money for capacity rights at an LNG terminal that is idle except for maintenance  
10 volumes of LNG.

11 IEnova LNG has the equivalent of one entire tank, Shell has the equivalent of one half of  
12 a tank, and Gazprom has the equivalent of one half of a tank of LNG storage capacity at Costa  
13 Azul. Thus, in order to obtain the maximum level of competition among the three suppliers that  
14 hold LNG storage capacity at Costa Azul, it would be necessary to limit the quantity of LNG held  
15 in storage for the core to one-half of a tank. This would assure that the three holders of Costa  
16 Azul storage capacity--Shell, Gazprom, and IEnova LNG-- would each qualify to bid since each  
17 already holds the rights to the equivalent of at least one-half of a Costa Azul LNG storage tank.  
18 Approaching all three entities with a request for binding proposals would provide the  
19 Commission with competitive bids to store LNG at Costa Azul as insurance for core customers  
20 against an outage of Line 3010.

21 This arrangement should appeal to the three prospective bidders. First, storing  
22 “insurance” LNG at Costa Azul for the core would offer the bidders an opportunity to offset some  
23 of the significant costs that each is bearing annually for unused capacity. Second, storing  
24 “insurance” LNG at Costa Azul for the core would offer an opportunity, albeit slim, to sell LNG

25 <sup>119</sup> Attachment U: IEnova 2015 Annual Report at 23, 56.

26 <sup>120</sup> *Id.* at 23.

27 <sup>121</sup> *Id.*

28 <sup>122</sup> *Id.* at 56.

1 in the event that there actually were a failure of Line 3010. Third, storing “insurance” LNG at  
2 Costa Azul for the core would offer one of the three bidders, IEnova LNG, the opportunity to  
3 offset its continuing cost associated with bringing LNG supplies to Costa Azul for the purpose of  
4 maintaining the cold temperature in the tanks. The supplies of LNG that would be held in storage  
5 for the core would eliminate this cost for IEnova LNG because storing the LNG supplies to be  
6 available to provide Line 3010 outage insurance would keep the tanks cold.

7 Contracting with the Applicants to keep one-half of a tank of LNG in storage for core  
8 protection would not interfere with a startup of LNG receipts at the terminal in the unlikely event  
9 that natural gas prices changed enough to make LNG imports at Costa Azul economic. Under  
10 this scenario, the core would no longer need to store LNG at Costa Azul, but the core could  
11 negotiate for an opportunity to buy LNG from the ongoing delivery of LNG at the terminal if the  
12 gas were required by an outage of Line 3010.

13 There is sufficient pipeline capacity for the delivery of gasified Costa Azul LNG to  
14 SDG&E at Otay Mesa. Table 11, above, demonstrates there is vacant capacity on Gasoducto  
15 Rosarito to the west of Mexicali that can be used to deliver gasified LNG. About 238 MDth of  
16 firm westbound capacity rights on Gasoducto Rosarito run only to Mexicali. Also, IEnova LNG  
17 owns firm rights across the entire length of Gasoducto Rosarito on a westbound basis, and it owns  
18 firm rights on TGN.<sup>123</sup> Much of this capacity is idle a great deal of the time so IEnova LNG  
19 should be incentivized to make a deal to use it.<sup>124</sup>

20 An indicator that IEnova LNG would be willing to contract to hold LNG in storage is that  
21 IEnova sold 295 MDth of gasified LNG from Costa Azul for delivery at Otay Mesa during the  
22 period, February 2 through 4, 2011, when gas supplies were running short over the U.S. interstate  
23 pipelines due to a freeze-up.<sup>125</sup>

24  
25 <sup>123</sup> Attachment U: IEnova 2015 Annual Report at 100.

26 <sup>124</sup> IEnova LNG has a contract with CFE and TdM to deliver between 120 MDth/d and 300 MDth/d of gas  
27 supplies. However, TdM is located near Mexicali so TdM’s portion of the gas would be delivered to Mexicali. *Id.* at  
28 59.

<sup>125</sup> Attachment M: Applicants Response to SCGC-14, Q.14.9., Attachment SCGC 14.9\_Daily OM Cost  
Info.xlsx.

1 In order to store one-half tank of LNG, the core would be required to purchase the LNG at  
2 market rates. LNG was imported during the five summer months, June 2016 through October  
3 2016, at an average price of \$3.19 per Mcf.<sup>126</sup> At that price, one-half of a tank of LNG would  
4 cost about \$5 million. At the previously posted 2011 rate for storage at Energia Costa Azul, a  
5 year's worth of storage for one-half of a tank of LNG would cost \$58 million.<sup>127</sup> However, given  
6 the competition among the three suppliers, IEnova LNG, Shell Mexico, and Gazprom Mexico,  
7 and the lack of activity at the Energia Costa Azul LNG terminal, it is likely that the cost of  
8 storage would be deeply discounted. Thus, I would expect that the storage costs for the one-half  
9 of a tank of LNG would be on the order of \$6 million per year.

10 Finally, there is a small amount of boil-off that occurs in the tank on a continuous basis.  
11 The LNG boil-off rate for LNG tanks is 0.005 percent.<sup>128</sup> The boil-off gas would have to be  
12 replaced periodically to maintain the LNG level at one-half of a tank. The boil-off gas itself  
13 could be delivered to SDG&E at Otay Mesa or sold to the LNG supplier at a rate equivalent to the  
14 cost of spot gas supplies sold at Ehrenberg. Thus, the net cost of one year's worth of boil-off gas  
15 would be about \$44,000 assuming the boil-off amounts were replaced during the summer.<sup>129</sup>

16 The cost to the core for storing LNG as insurance against a failure of Line 3010 would  
17 thus cost \$5 million initially for the LNG supply with a net cost annually of \$44,000 to replenish  
18 the supply. The core would then be charged \$6 million annually to store the LNG. This cost  
19 would be much less than the core's share of the \$86 million first-year annual revenue requirement  
20 associated with Line 3602.

21  
22 <sup>126</sup> Attachment V: Energy Information Administration ("EIA"), Price of U.S. Natural Gas LNG Imports,  
23 <https://www.eia.gov/dnav/ng/hist/n9103us3m.htm>.

24 <sup>127</sup> The Available Capacity and Regulated Rates for 2011 for Energia Costa Azul was previously available  
25 at [http://sempralng.com/lib/pdf/ECA\\_Electronic\\_Information\\_System\\_2011.pdf](http://sempralng.com/lib/pdf/ECA_Electronic_Information_System_2011.pdf) However, the posting has been  
26 removed and no other posting has been made.

27 <sup>128</sup> Modelling of Boil-Off Gas in LNG Tanks: A Case Study, E. Adom et al. / International Journal of  
28 Engineering and Technology Vol.2 (4), 2010, 292-296 at 294.

<sup>129</sup> The June LNG import price as reported by EIA (Attachment V) was compared with the prices of gas at  
El Paso Natural Gas South Main Line price as reported by the Applicants in their Response to SCGC-14, Q.14.9,  
Attachment SCGC 14.9\_Daily OM Cost Info.xlsx (Attachment M).

1                   **5.3.4. Alternative 4: Core Demand Could Be Served Through a Combination of**  
2                   **Transmission Rights on North Baja and the Utilization of LNG Storage at**  
3                   **Costa Azul.**

4                   Another alternative to ensure deliveries for the SDG&E core customers in the event of a  
5                   line 3010 outage even on a winter peak day would be a combination of firm capacity rights on  
6                   North Baja and contracting for LNG storage at Costa Azul. For example, the core could obtain  
7                   100 MMcf/d of firm capacity on North Baja, which would then cover the core's needs if an  
8                   outage occurred during the summer months. The core could then obtain Costa Azul LNG storage  
9                   to cover demand for some or all of the additional core demand during the remaining nine months.  
10                  If the outage to Line 3010 was expected to last more than five days, additional LNG could be  
11                  purchased for delivery to Costa Azul, or interruptible North Baja pipeline capacity could be  
12                  utilized to deliver supplies of domestic gas if available and more economical.

13                  It would be appropriate to request bids for a number of alternatives including the storage  
14                  of five days supplies capable of meeting core peak winter demand as well as smaller quantities.  
15                  Bids could also be requested for the sellers to shape the seasonal supply of LNG that is stored,  
16                  that is, to store more gas in the winter and less in the non-winter months so as to better match the  
17                  core's requirements. The idea would be try to minimize fixed costs for the core while at the same  
18                  time core requirements are appropriately ensured.

19                  LNG is more expensive than the core's domestic supplies,<sup>130</sup> but only very limited  
20                  quantities of LNG would have to be purchased under the alternatives that I propose. These  
21                  alternatives to building Line 3602 have key features in common. First, all of them would be  
22                  vastly less expensive than the projected \$600 million loaded and escalated cost, including  
23                  AFUDC and capitalized property taxes, of building Line 3602<sup>131</sup> and the \$2 billion revenue  
24                  requirement over the life of Line 3602.<sup>132</sup> Second, there would be no adverse environmental  
25                  effects because existing facilities would be used in each of the alternatives. Third, the Applicants

26                  <sup>130</sup> The System Operator purchased 295 MDth of LNG supplies between February 2 and 4, 2011, to cover a  
27                  supply shortfall created by a very severe freeze-up. The cost of that gas was 2.5 times as expensive as the gas would  
28                  have been if purchased at the border price. However, the gas simply was not available at the border.

<sup>131</sup> Direct Testimony of Michael Woodruff at Footnote 7 (p.5).

<sup>132</sup> *Id.* at 6.

1 and ratepayers alike would avoid the stranded cost of building a Line 3602 that will most likely  
2 result from California's achievement of its goals for reducing greenhouse gas emissions.

3 **5.4. Problem 3: The Threat of Curtailments to Electric Generators in the Event**  
4 **of a Partial or Full Outage on Line 3010 that Would Adversely Affect**  
5 **Electric Reliability.**

6 According to the Applicants, noncore customers are exposed to the double threat of a full  
7 Line 3010 outage and a reduction in deliverability on Line 3010 (partial outage) due to a loss of  
8 compression at Moreno Compressor Station ("Moreno"), which boosts pressures for delivery to  
9 the SDG&E system at Rainbow Station. The Applicants explain that nearly all gas supplies  
10 destined for use on the SDG&E system pass through the Moreno Compressor Station.<sup>133</sup> They  
11 say: "With a loss of some compression at Moreno, delivered pressure at Rainbow Station may be  
12 insufficient to maintain service to all SDG&E customers; the loss of all compression capability at  
13 Moreno (i.e., "free flowing" supplies from the SoCalGas system, as if bypassing Moreno  
14 Compressor Station) will only support an SDG&E demand of 340 MMcf/d..."<sup>134</sup>

15 The 340 MMcf/d that could be delivered with a Moreno Compressor Station outage would  
16 come close to meeting the core's demand during 1-in-10 year cold day conditions as shown  
17 previously in Table 6, but the noncore customers starting with EGs could be curtailed. The  
18 Applicants assert that the curtailment could result in the loss of firm electric customers.<sup>135</sup> The  
19 Applicants contend that the 36-inch diameter Line 3602 operating alongside Line 3010 could  
20 theoretically support the current SDG&E system capacity of 630 MMcf/d without any  
21 compression required at Moreno.<sup>136</sup> Further, under either a Line 3010 outage scenario or a  
22 Moreno Compressor Station outage, the proposed Line 3602 would provide enough capacity to  
23 meet the demand forecast for the 1-in10 year cold day design standard through the 2035/2036  
24 winter operating season.<sup>137</sup>

25 <sup>133</sup> Updated Bisi Direct at 7.

26 <sup>134</sup> *Id.* (footnote omitted)

27 <sup>135</sup> Updated Yari Direct at 1.

28 <sup>136</sup> Updated Bisi Direct at 8.

<sup>137</sup> *Id.*

1           The Applicants' concerns about a Moreno Compressor Station outage are overstated.  
2  
3       Likewise, their concern about the effect of either a Moreno Compressor Station outage or a Line  
4       3602 outage on electric reliability is overstated. Furthermore, just as there are preferable  
5       alternatives to Line 3602 to maintain service to core customers in the event of a line 3602 outage,  
6       there are preferable alternatives to Line 3602 to maintain electric reliability in the event of either  
7       a Moreno Compressor Station outage or a Line 3010 outage.

8                   **5.4.1. The Applicants Admit that the Chance of an Unscheduled Outage of the**  
9                   **Entire Moreno Compressor Station is Small.**

10          The Applicants admit that the chance of a complete unscheduled outage of the Moreno  
11       Compressor Station is small, although unscheduled outages of individual compressor engines do  
12       occur: "The chance of losing all compression at Moreno is relatively small, although such a  
13       situation did nearly occur at least once due to a malfunction in the Emergency Shut Down system  
14       at the station. Frequently, however, individual engines at the station unexpectedly fail or  
15       delivered pressures from SoCalGas to Moreno Compressor Station drop below that required for  
16       the compressors to operate."<sup>138</sup>

17          There are ten individual engines at Moreno. Table 12 shows the Applicants' record of 19  
18       individual engine failures between 2006 and 2015:  
19  
20  
21  
22  
23  
24  
25  
26  
27

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28                   <sup>138</sup> Updated Bisi Direct at 8.

Table 12<sup>139</sup>

| Recorded Engine Outages at Moreno Compressor Station |                            |          |                            |
|------------------------------------------------------|----------------------------|----------|----------------------------|
| Date                                                 | Duration of<br>outage (hr) | Date     | Duration of<br>outage (hr) |
| 03/06/06                                             | 1.0                        | 07/06/11 | 1.1                        |
| 07/01/06                                             | 1.5                        | 11/10/11 | 1.3                        |
| 11/30/06                                             | 1.5                        | 11/11/11 | 2.3                        |
| 10/24/07                                             | 1.5                        | 12/08/11 | 1.0                        |
| 08/18/08                                             | 1.0                        | 08/28/12 | 1.0                        |
| 08/19/09                                             | 0.8                        | 08/21/13 | 1.1                        |
| 08/24/09                                             | 1.0                        | 02/28/14 | 7.0                        |
| 01/25/10                                             | 1.2                        | 04/14/14 | 1.0                        |
| 02/01/10                                             | 0.8                        | 05/26/15 | 1.1                        |
| 02/03/11                                             | 2.1                        |          |                            |

On the days shown in Table 12, 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.

The failure of one engine out of ten does not seem to make any difference at all in the throughput of the downstream pipelines. Since the Applicants were able to provide daily flow data for Line 3010 from the latter half of 2011 to the present, the flow data for Line 3010 could be analyzed for the dates listed in the right side of Table 12 to determine whether the loss of a single engine for at least one hour made a demonstrable effect on the gas flow. There was no apparent effect. Even on the one day when an engine was out for seven hours, the flows were higher on that day than on either the previous day or the following day.

Although the Applicants raise the specter of Moreno outages that would reduce deliverability enough to adversely affect noncore service reliability, and, hence, electric service reliability, there does not seem to be any basis to support their hypothesis. The Applicants' hypothesis is based on nothing more than unfounded speculation that there could be impairment of service on some occasion when all ten engines at Moreno failed simultaneously.

<sup>139</sup> Attachment O: Applicants Response to Sierra Club-07, Q.7.6.

1           The Applicants have failed to demonstrate that a loss of all ten engines at Moreno is at all  
2 likely. Hypothetically if it were to occur, by the Applicants' own admission, the loss in service at  
3 Moreno would not affect service to core customers except on peak days. Likewise, as shown  
4 below, neither a Moreno Compression Station outage nor a Line 3010 outage would affect  
5 noncore customers and electric system reliability as claimed by the Applicants.

6           **5.4.2. The Applicants' Claim that the Electric System's Winter Dependence on**  
7 **Gas-Fired Generation Could Endanger Electric Reliability Is Undermined**  
8 **by the Aliso Canyon Report Which Found a Very Low Electric**  
9 **Generation Requirement for Natural Gas During a 1-in-10 Year Cold**  
10 **Day.**

11           The Applicants claim that insufficient winter gas transmission capacity could cause a  
12 curtailment of EGs, which in turn could cause blackouts in the SDG&E service territory:  
13 "Accordingly, it is possible that demand in San Diego may exceed the system capacity on a day  
14 with conditions that are higher than normal, but less than the CPUC's 1-in-10 year cold day  
15 demand standard, or during a high hourly peak condition. Either scenario may result in gas  
16 curtailments that also risk electric blackouts."<sup>140</sup> This concern is overblown as demonstrated by  
17 an assessment completed in August 2016 by the Commission, the CEC, the CAISO, and the Los  
18 Angeles Department of Water and Power ("LADWP") (jointly, "Joint Agencies").

19           The EG values shown in Table 1, the Applicants' forecast of gas requirements on a 1-in-  
20 10 year cold day, significantly exceed the minimum EG burn on a 1-in-10 year cold day that is  
21 actually required to maintain SDG&E electric system reliability. The Applicants' Table 1 values  
22 are based on a simulation of the CAISO markets that dispatch plants based upon incremental  
23 costs and transmission system constraints rather than an assessment of the minimum local area  
24 gas-fired generation required for electric reliability. Having a realistic picture of minimum EG  
25 requirements identifies the portion of the EG loads on the SDG&E system that may be safely  
26 curtailed during the winter months if the predictions regarding severe cold weather are  
27 communicated to the CAISO in a timely manner.

28           <sup>140</sup> Updated Bisi Direct at 15 (footnote omitted).

1 The benefit from electric-gas coordination was recognized when the Commission, the  
2 CEC, the CAISO, and the LADWP with SoCalGas support jointly assessed the implications of  
3 the current operational restrictions on Aliso Canyon for electric reliability as presented in the  
4 Aliso Canyon Winter Risk Assessment Technical Report (“Aliso Canyon Report”). The Aliso  
5 Canyon Report shows that electric system operators have the ability to minimize dependence on  
6 natural gas fired EGs. The Aliso Canyon Report recognized that there are limitations to the  
7 adaptability of the electric systems:

8 The ability for LADWP and California ISO to shift electric supply  
9 from the resources affected by Aliso Canyon to other resources in  
10 Southern California or outside of the SoCalGas/SDG&E service  
11 territories is limited based on timing and system conditions. The  
12 first limitation arises due to the need to maintain a minimum  
13 amount of local generation to ensure local reliability. The second  
14 limitation is due to limited ability to import energy into the area  
15 because of transmission constraints or supply availability. The  
16 ability to shift supply in the day-ahead market is greater and  
17 significantly decreases as real-time approaches.<sup>141</sup>

18 However, the Applicants’ EG forecast in Table 1 is based on a business-as-usual forecast of the  
19 WECC using the Ventyx model, not a specific analysis of the minimum EG requirements for a 1-  
20 in-10 year cold day.<sup>142</sup> The Ventyx model “dispatches plants economically to serve electricity  
21 demand. It minimizes cost while meeting local and system constraints.”<sup>143</sup> In other words, the  
22 Ventyx model simulates the characteristics of the various EG plants throughout California and  
23 other parts of the WECC that are bidding into the CAISO markets. On a peak cold winter day,  
24 the Ventyx model would simply place those EGs located in SDG&E’s service territory in the  
25 bidding order according to known plant characteristics without any regard to the weather situation  
26 in SDG&E’s area. A Ventyx model run would not identify the minimum amount of gas that

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27 <sup>141</sup> Attachment W: 16-IEPR-02, Aliso Canyon Winter Risk Assessment Technical Report (“Aliso Canyon  
28 Report”), Prepared by the Staff of the California Public Utilities Commission, California Energy Commission, the  
California Independent System Operator, the Los Angeles Department of Water and Power, and Southern California  
Gas Company at 11 (August 23, 2016).

<sup>142</sup> Attachment E: Applicants Response to SCGC-11, Q.11.2.

<sup>143</sup> *Id.*

1 would be required to maintain electric reliability in SDG&E's service territory on the 1-in-10 year  
2 cold day.

3 The alternate approach presented by the Joint Agencies in the Aliso Canyon Report  
4 determined the minimum amount of gas fired generation that would be required on a 1-in-10 year  
5 cold day in order to maintain electric system reliability.<sup>144</sup> The Joint Agencies concluded that  
6 only 96 MMcf/d of gas burn by electric generators in the combined SoCalGas and SDG&E  
7 service territories was required to provide the local generation needed to meet requirements in a  
8 post N-1 contingency event, and only 22 MMcf/d would be needed assuming normal pre-  
9 contingency conditions and the ability to import electricity into the LA Basin.<sup>145</sup> The Joint  
10 Agencies' analysis was described in the Aliso Canyon Report:

11 Reliability assessments are conducted based on the expected  
12 electrical system conditions for the operating time period being  
13 analyzed. This focus in this report is the upcoming winter  
14 [2016/2017]. These studies are performed using the applicable  
15 WECC seasonal base case, modified as needed to simulate the  
16 conditions expected for this season. This includes all planned  
17 transmission and generation outages. These conditions are modeled  
18 in an off-line power flow program that runs a battery of  
19 transmission and generation contingencies to determine minimum  
20 generation commitment and post contingency generation necessary  
21 to maintain NERC reliability requirements.

22 The winter power flow case was modeled to study the minimum  
23 generation required in the LADWP and California ISO systems to  
24 maintain electric system reliability. The fleet of resources  
25 dependent on gas supplied by SoCalGas inside the Los Angeles  
26 Basin and the Southern System were kept at minimum while  
27 maintaining reliability of the electric system. Additional  
28 assumptions include maximizing the electric transmission  
capability for imports into the southern electric system while  
maintaining electric system reliability.<sup>146</sup>

The Aliso Canyon Report cautioned that "although the electric system can operate with extremely  
low gas consumption during the winter months, doing so would result in increased energy  
dispatch costs."<sup>147</sup> Plants in the LA Basin or on the Applicants' Southern System would not be

<sup>144</sup> Attachment W: Aliso Canyon Report at 4-5.

<sup>145</sup> *Id.* at 31.

<sup>146</sup> *Id.* at 32.

<sup>147</sup> *Id.*

1 dispatched unless needed for reliability even if they were less expensive to operate than  
2 alternative facilities.

3 The Aliso Canyon Report states that the 96 MMcf/d of gas usage by gas-fired generation  
4 would be needed in the event of the most severe single contingency for the CAISO and LADWP  
5 balancing authorities but without the contingencies in each of the balancing authorities occurring  
6 simultaneously.<sup>148</sup>

7 A second analysis was conducted to determine the minimum energy  
8 and capacity requirements for LADWP and California ISO system  
9 within the SoCalGas service area under a post-contingency event  
10 during the 1-in-10-day winter operating conditions. To meet the  
11 requirement following the most severe single contingency, the  
12 minimum commitment of non-QF generation served by SoCalGas  
13 is 2,000 MW for the California ISO and is 585 MW for the  
14 LADWP. The energy commitment will be the greater of these two  
15 post-contingency needs as these contingencies are not assumed to  
16 be coincident events. These energy requirements were translated to  
17 a combined minimum gas burn of 96 MMcf/d was necessary to  
18 maintain electric reliability after the worst case contingency event  
19 for the combined LADWP and California ISO area.<sup>149</sup>

20 Given that the minimum generation commitment required for the CAISO balancing  
21 authority is 2,000 MW while the minimum generation commitment for the LADWP balancing  
22 authority is 585 MW, the CAISO used the higher of the two post-contingency requirements to  
23 determine the minimum gas burn. The minimum 96 MMcf/d gas burn by electric generators in  
24 the combined SoCalGas and SDG&E gas service territories would be the post-contingency need  
25 for gas in the southern California electric utility service territories in the CAISO balancing  
26 authority: Southern California Edison (“SCE”), the municipal utilities that have coordinating  
27 agreements with SCE, and SDG&E.

28 The CAISO has not revealed where in its balancing authority the largest N-1 occurrence  
would be. Therefore, it could reasonably be expected to occur in either SCE’s or SDG&E’s

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<sup>148</sup> In the Aliso Canyon Report, LADWP and CAISO were considered in their role of being balancing  
authorities: “The LADWP and California ISO balancing authorities include the municipal utilities of Anaheim,  
Riverside, Pasadena, Azusa, Banning, Colton, Burbank, and Glendale. The balancing authorities will be referred to  
as the LADWP and California ISO throughout the electric analysis section of this document.” *Id.* at 31, Fn. 10.

<sup>149</sup> *Id.* at 35.

service territory. If it occurred in SDG&E's service territory, the gas requirements would be expected to look like Table 13, below:

Table 13: Adjusted 1-in-10 Year Cold Day Demand  
with Minimum EG Requirements (MMcf/d)<sup>150</sup>

| Operating<br>Year a/ | Core | Noncore<br>C&I | Minimum<br>EG | Total |
|----------------------|------|----------------|---------------|-------|
| 2016/17              | 365  | 60             | 96            | 520   |
| 2017/18              | 372  | 61             | 96            | 529   |
| 2018/19              | 371  | 61             | 96            | 528   |
| 2019/20              | 371  | 61             | 96            | 528   |
| 2020/21              | 370  | 61             | 96            | 527   |

Table 13 only shows an outlook for the next several years because the CAISO is in the process of adapting its transmission planning to reflect “supporting advancement of preferred resources in meeting needs overall, and in particular in southern California” as well as “identifying transmission upgrades and additions needed to reliably operate the network and comply with applicable planning standards and reliability requirements.”<sup>151</sup> Furthermore, the CAISO expects “increased opportunity for non-transmission alternatives, particularly preferred resources and storage.”<sup>152</sup> Thus, the gas requirements associated with maintaining system reliability on a peak winter cold day might reasonably be expected to decline in the 2020s as the transmission system changes to accommodate the state's policy objectives.<sup>153</sup>

**5.4.3. The Applicants Claim that the SDG&E Electric System Is Dependent on Natural Gas Availability Throughout the Year, Which Makes It Vulnerable to Supply Disruption Without the Addition of Line 3602.**

The Applicants also suggest that a myriad of other circumstances would significantly endanger electric service in the SDG&E service territory. The Applicants describe the dependency of SDG&E's electrical system on local area gas-fired generation:

<sup>150</sup> The core and noncore C&I loads are from Table 5, which shows requirements after adjustments were made to the Applicants' forecast as shown in Table 1.

<sup>151</sup> CAISO, 2016-2017 Board Approved Transmission Plan at 2.

<sup>152</sup> *Id.*

<sup>153</sup> *Id.*

SDG&E's [electric] customer load is served by a combination of internal generation and power import. SDG&E's maximum power import capability is 3,500 MW....

...

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... That number will trend upward due to the projection of increasing electric customer demand through 2027.

Absent internal natural gas-fired electric generation due to a gas interruption, SDG&E's power import capability would be reduced to approximately 2,500 MW or lower.”<sup>154</sup>

According to the Applicants there are several reasons why SDG&E is so dependent upon natural gas to maintain electric reliability. First, gas-fired generation is required to meet electrical requirements because there is insufficient import capacity to meet peak loads without this generation and according to the Applicants that demand is increasing. Second, gas-fired generation located in the local area is required to maintain the import capability of SDG&E's system and without this generation the import capability diminishes. Third, there are hours in the year where the limitations on the capacity of the IID S-line further limits the Applicants ability to import power increasing the dependency on gas-fired generation.<sup>155</sup> Each of these claims must be evaluated in turn.

**5.4.3.1. The Applicants Claim that SDG&E Loads Exceed Maximum Import Capability in Some Hours, Which Makes the Electric System Dependent on Natural Gas.**

The Applicants claim that the maximum import capacity on the SDG&E system is 3,500 MW, but there are a number of hours in the year when the demand is higher than 3,500 MW, leaving SDG&E dependent upon gas-fired generation to make up the difference.<sup>156</sup> The Applicants concern is illustrated in Figure 5:

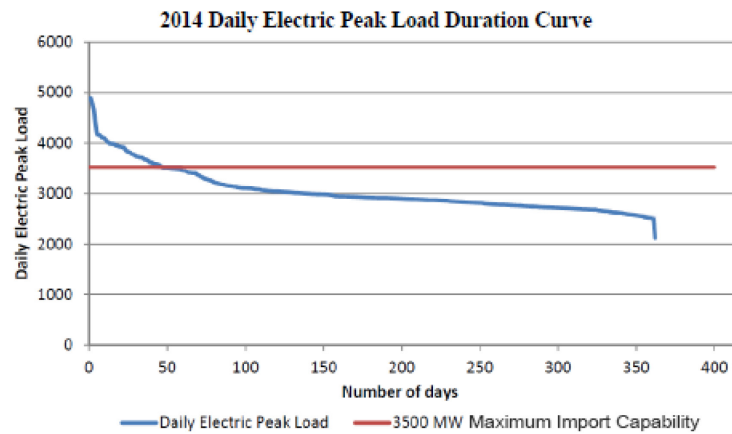
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<sup>154</sup> Updated Yari Direct at 14-15. (footnotes omitted)

<sup>155</sup> *Id.* at 16.

<sup>156</sup> *Id.* at 15.

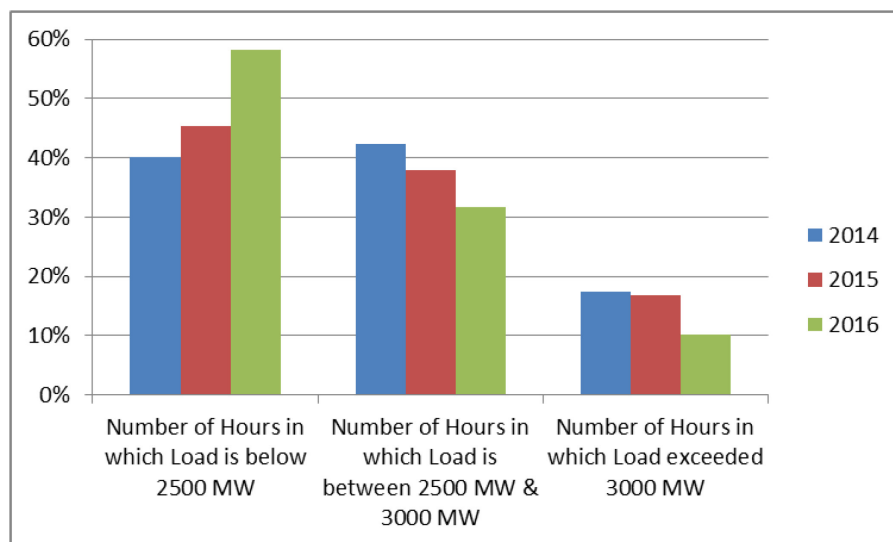
Figure 5<sup>157</sup>



However, 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. Furthermore, each of the 50 days identified in the graph have only a portion of the hours that approach the peak levels identified in the graph.

Worst of all, the Applicants' claim about dependency on gas-fired generation during peak periods rests on the assumption that the daily electric loads from 2014 are representative of the future. Figure 6 below shows how the peak hours have steadily declined between 2014 and 2016:

Figure 6<sup>158</sup>

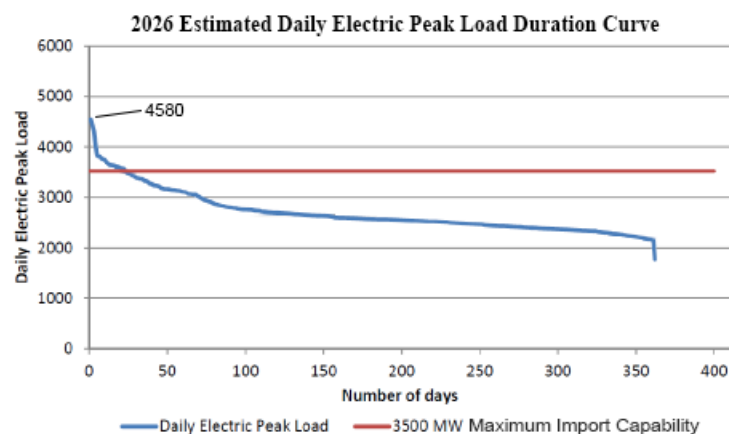


<sup>157</sup> *Id.* at 17. Figure 5 has been adapted from Mr. Yari's Table 3.

<sup>158</sup> Attachment T: Applicants Response to Sierra Club-06, Question 6.

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. In developing its 2016-2017 Transmission Plan, the CAISO used for SDG&E the CEC's 2026 1-in-10 year peak forecast adjusted for energy efficiency and behind the meter solar photovoltaics of 4,580 MW,<sup>159</sup> which is well below the nearly 5,000 MW shown above in Figure 5. Figure 7 below shows the comparison of the load curve reflecting the 2026 forecast level.

**Figure 7**



The figure 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 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. SDG&E forecasts these hours to be concentrated in the late afternoons in the months of July through September.<sup>160</sup> Thus, these higher EG gas requirements would coincide with the summer levels of core gas demands, which are approximately 100 MMcf/d, less than one-third of the core requirements projected for a winter peak cold day.

<sup>159</sup> Attachment C: Brian Rahman, Review and Assessment of San Diego Gas & Electric Ability to Service Firm Load with Loss of Significant Gas Supply ("Assessment of SDG&E"), April 14, 2017 at 3.

<sup>160</sup> A.15-12-012, SDG&E workpapers, April 29, 2016. By 2021 there are two hours in December afternoons that also show some incremental contribution to capacity requirements.

1                   **5.4.3.2. The Applicants' Assume that a Line 3010 Outage Would Be the**  
2                   **Equivalent of an N-1 Event, but Instead a Pipeline Outage Would**  
3                   **Create a Multiple Failures Event that Would Not Be Required to**  
                  **Meet the NERC N-1 or N-2 Reliability Standard.**

4                   According to the Applicants: The SDG&E import is defined as the sum of the flows on  
5                   the South of San Onofre 230kV lines (5 lines), TL50001 (500kV line from East County to  
6                   Miguel), TL50003 (500kV line from Ocotillo to Suncrest), and TL23040 (230kV line from Otay  
7                   Mesa to Tijuana).<sup>161</sup> The lines TL50001 and TL50003 are supplied at SDG&E's Imperial Valley  
8                   substation by, among other sources, the SWPL 500 kV line to Arizona, which has a maximum  
9                   thermal limited capacity of 2,598 MW.<sup>162</sup>

10                  The 230 kV line between Otay Mesa and Tijuana interconnects SDG&E with CFE. There  
11                  is a second 230 kV line that interconnects SDG&E with CFE (230 kV line from SDG&E's  
12                  Imperial Valley substation to CFE's Rosita substation).<sup>163</sup> The lines to CFE in Mexico, Path 45,  
13                  have a total capacity of 800 MW.<sup>164</sup>

14                  The South of San Onofre lines have a transfer limit of 2,200 MW, but without SONGS  
15                  operating the north-south flow is limited to about 580 MW.<sup>165</sup> The maximum combined import  
16                  capability is 3,500 MW<sup>166</sup> based on thermal limitations of those lines, but due to current operating  
17                  procedures the actual limit is about 3,000 MW.<sup>167</sup> Figure 8 below shows a simplified diagram of  
18                  the transmission lines in SDG&E and northern Baja California:

19  
20  
21  
22  
23                  <sup>161</sup> Attachment O: Applicants Response to Sierra Club Request 07, Q.1.a.

24                  <sup>162</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 5.

25                  <sup>163</sup> *Id.* at 6.

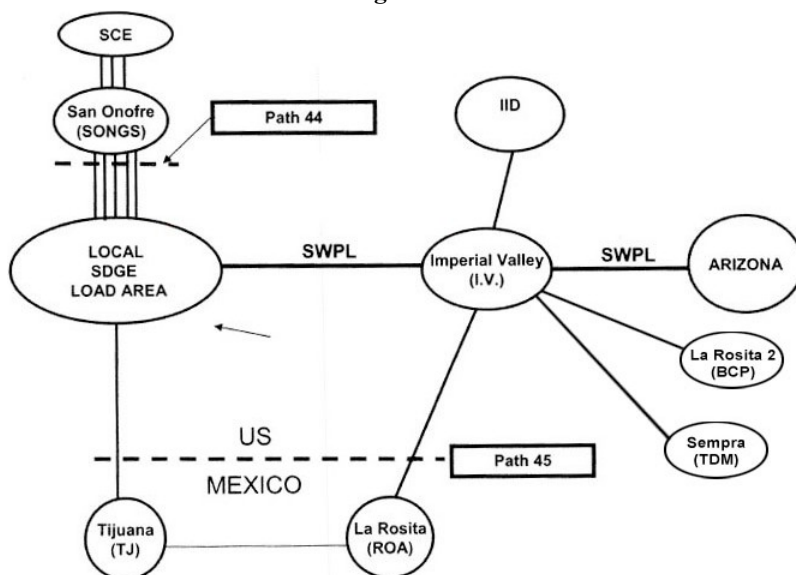
26                  <sup>164</sup> *Id.*

27                  <sup>165</sup> *Id.* at 7.

28                  <sup>166</sup> Updated Yari Direct at 15.

<sup>167</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 5-6.

Figure 8<sup>168</sup>



The Applicants claim that they must have local area gas-fired generation present to provide voltage stability.<sup>169</sup> 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.<sup>170</sup>

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 Ocotillo to Suncrest),”<sup>171</sup> *i.e.*, the loss of the two east to west SWPL lines from the Imperial Valley substation, following the loss of Line 3010 or the Moreno Compressor Station.

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.”<sup>172</sup> Thus, the

<sup>168</sup> CEC, Consultant Report, Challenges and Opportunities to Deliver Renewable Energy from Baja California Norte to California, June 2008, CEC-2008-004 at 27(edited).

<sup>169</sup> Attachment P: Applicants Response to SCGC-6, Q.6.5.5.

<sup>170</sup> Updated Yari Direct at 15.

<sup>171</sup> Attachment Q: Applicants Response to SCGC-18, Q.18.10.

<sup>172</sup> Attachment Q: Applicants Response to SCGC-18, Q.18.11.2.

1 Applicants construct a scenario in which they have to address the loss of either Line 3010 or the  
2 Moreno Compressor Station and simultaneously address the isolation of the SDG&E electric  
3 system from every import opportunity with the exception of the SONGS lines connecting SCE to  
4 SDG&E. The Applicants claim: “Voltage support is needed in the northern part of the  
5 system.”<sup>173</sup> They have effectively structured the question that they ask themselves in such a  
6 manner as to preclude any other answers than the one they are looking for, that is, system  
7 dependence on in-basin gas-fired generation and a need for Line 3602 to assure availability of  
8 that generation.

9 The Applicants err in framing an outage of Line 3010 or the Moreno Compressor Station  
10 as if, from an electrical perspective, it would be an N-1 event for which, under the NERC  
11 reliability standards, the Applicants should plan to avoid any loss of electrical load. In fact,  
12 however, the loss of a pipeline or compressor station that would result in an outage of multiple  
13 generators would be more like an N-10 situation under NERC rules.<sup>174</sup>

14 The electric reliability criteria that apply in a multiple failure situation are very different  
15 from the set of N-1 or N-2 reliability criteria that apply to a normal operating situation.  
16 Specifically, loss of load would certainly be permissible in a multiple failure event if not expected  
17 to preserve the reliability of the electric system.<sup>175</sup> In fact, the load shedding would undoubtedly  
18 occur due to automated actions by protective relay equipment.<sup>176</sup> In summary, while the electric  
19 system is planned in such a way as to minimize impacts on customers associated with single or  
20 even double outages, it is not planned to protect customer service in extreme events such as the  
21 loss of multiple generators due to a pipeline outage.<sup>177</sup>

22 The Commission should disregard the Applicants implicit assumption that they should  
23 construct a gas system that goes vastly beyond the properly understood NERC N-1 or N-2

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24 <sup>173</sup> Attachment Q: Applicants Response to SCGC-18, Q.18.11.1.

25 <sup>174</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 20.

26 <sup>175</sup> *Id.*

27 <sup>176</sup> *Id.*

28 <sup>177</sup> *Id.* at 19-20.

1 reliability requirements and, instead, insist that the application of electric reliability standards to  
2 the potential failure of Line 3010 or the Moreno Compressor Station be studied in coordination  
3 with CAISO and Commission staff to ensure that the issues do not get framed in such a manner as  
4 to bias the results. Under NERC Requirement R4, Part 4.5: “If the analysis concludes there is  
5 Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed  
6 to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.”<sup>178</sup>

7 A coordinated effort with the CAISO and Commission staff would lead to a better  
8 understanding of the consequences of the failure of Line 3010 without the expectation that  
9 physical gas system mitigation would be required.<sup>179</sup> Such a study would provide an opportunity  
10 to examine alternatives that might work to reinforce the electric system without costing gas  
11 ratepayers billions of dollars in future potentially stranded SoCalGas/SDG&E revenue  
12 requirement. A co-benefit could be enhancements to the electric system that would assist  
13 California in meeting statutorily mandated environmental objectives.

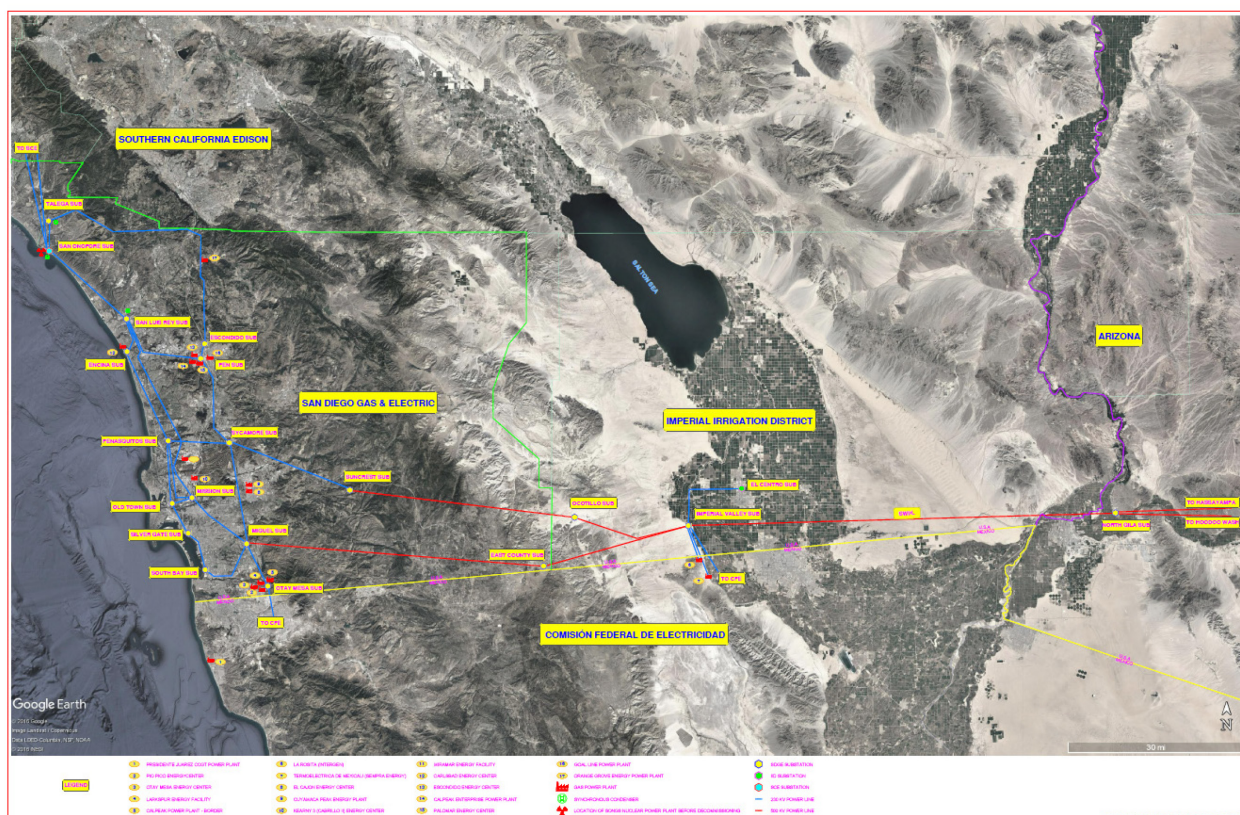
14 **5.4.3.3. An Assessment of Potential Consequences of a Pipeline Failure on**  
15 **Electric Reliability Should Be Performed Considering a Full**  
16 **Range of Options for Reinforcing the Electric System.**

17 For reference, Figure 9, below, shows the physical locations of the transmission lines  
18 interconnecting SDG&E as well as the location of the transmission substations and electric  
19 generators in SDG&E’s service territory. A larger version of this map is available as Attachment  
20 D.

21  
22  
23  
24  
25  
26  
27 <sup>178</sup> *Id.* at 20.

28 <sup>179</sup> *Id.*

Figure 9<sup>180</sup>



Voltage stability is the electrical system's ability to maintain voltage within acceptable parameters under normal operating conditions and to recover voltage to within acceptable parameters after a disturbance.<sup>181</sup> The required amount of voltage support is defined by studies of the electric system's behavior after an interruption of an intertie under various assumptions about customer loads and generation conditions.<sup>182</sup> The generating plant will typically respond to a loss of imports by "speeding up" in response to a falling frequency.<sup>183</sup> The generator's increased speed can help the connected system to return to the standard 60 Hertz frequency.<sup>184</sup> Similarly, the generating plant can produce reactive power in response to falling voltages.<sup>185</sup>

<sup>180</sup> ZGlobal. A larger version of this map is included as Attachment D to this testimony.

<sup>181</sup> Makasa, Kangombe Joseph, "Computational approaches for voltage stability monitoring and control in power systems" (2015). Doctoral Dissertations. 2453.h at 7.

<sup>182</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 11.

<sup>183</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 11.

<sup>184</sup> *Id.*

<sup>185</sup> *Id.*

1 The Applicants state: “After contingencies, some of the remaining electric transmission  
2 lines get extremely loaded, and loaded lines require reactive power. Absent a source of reactive  
3 power, voltage will decline to a point that a voltage collapse could take place.”<sup>186</sup> Applicants  
4 argue that the source of reactive power should be gas-fired generation because “natural gas-fired  
5 electric generation units, if on, can quickly provide the reactive power needed to support the  
6 voltage and prevent the system from going into a voltage collapse. Online natural gas-fired  
7 electric generation units also supply spinning MW reserves to meet electric demand.”<sup>187</sup>

8 While gas-fired generators definitely do provide reactive power to an electrical system,  
9 they are not the only option. For example, a synchronous condenser can be added to an electrical  
10 system to add and absorb reactive power.<sup>188</sup> The CAISO Board has approved the installation of  
11 several synchronous condensers in the northern part of SDG&E area: one at San Onofre  
12 substation and two at San Luis Rey substation, to be completed during 2017.<sup>189</sup> SDG&E placed a  
13 synchronous condenser in service at Talega substation during 2015.<sup>190</sup>

14 According to the Applicants, their studies yielding the conclusion that voltage stability  
15 issues limit imports to 2,500 MW in the absence of local area gas-fired generation have been  
16 based on “current system configuration and current resource availability.”<sup>191</sup> The three  
17 synchronous condensers to be completed in 2017 do not meet this criterion and, hence, appear to  
18 be omitted from the Applicants’ studies. Omission of these synchronous condensers would  
19 worsen the reactive power deficit created by the contingency situation in the Applicants’ study.

20 Furthermore, under the FERC’s Order 827,<sup>192</sup> Final Rule on Reactive Power  
21 Requirements for Non-Synchronous Generation: “[A]ll newly interconnecting non-synchronous

22 <sup>186</sup> Attachment E: Applicants Response to SCGC-11, Q.11.1.2.

23 <sup>187</sup> *Id.*

24 <sup>188</sup> Hawaiian Electric Companies’ PSIPs Update Report, December 23, 2016, Book 4 of 4 at O-14.

25 <sup>189</sup> CAISO Board Approved 2015-2016 Transmission Plan at 330.

26 <sup>190</sup> CAISO 2012-2013 Board Approved Transmission Plan, March 20, 2013 at 173.

27 <sup>191</sup> Attachment O: Applicants’ Response to Sierra Club-07, Q.1.f.

28 <sup>192</sup> Reactive Power Requirements for Non-Synchronous Generation; 155 FERC ¶ 61,277, Order No. 827 (2016).

1 generators will be required to provide reactive power at the high-side of the generator substation  
2 as a condition of interconnection.”<sup>193</sup> Many existing asynchronous generators such as wind and  
3 solar generators may already have inverters that are capable of producing reactive power even  
4 though they were not required by Order 827 to provide reactive power. There are already nearly  
5 700 MW of wind and solar generating plants connected to SDG&E’s East County and Ocotillo  
6 substations<sup>194</sup> that are located to the west of the Imperial Valley substation but east of the San  
7 Diego metropolitan area. With proper control software and telemetering these existing plants  
8 could become available to produce reactive power if they do not already have the requisite  
9 equipment.

10 A recent study published jointly by the CAISO, the National Renewable Energy  
11 Laboratory (“NREL”), and First Solar concludes that solar plants have the capability of producing  
12 reactive power in accordance with CAISO requirements. The existing solar plant’s reactive  
13 power capability was tested during 2016 at two different power levels, nearly full power output  
14 and extremely low power output.<sup>195</sup> The plant’s reactive power output was measured and  
15 compared with the CAISO reactive power requirement, demonstrating that the plant meets the  
16 expected reactive power capability.<sup>196</sup> The plant also demonstrated the capability of absorbing  
17 and producing reactive power at very low levels of power production.<sup>197</sup> Thus, solar arrays  
18 connected at primary voltage or above in the local area should be capable of producing and  
19 absorbing reactive power, taking on a role that has been previously provided by gas-fired  
20 generators in SDG&E’s area. Wind generators that use a similar inverter technology would be  
21 expected to have the same ability to produce reactive power that would meet CAISO  
22 requirements.

23 <sup>193</sup> CAISO, Reactive Power Requirements and Financial Compensation, Addendum to Draft Final Proposal,  
24 July 21, 2016 at 1.

25 <sup>194</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 4; Telephone conversation with Brian Rahman,  
26 March 16, 2017..

27 <sup>195</sup> Attachment Y: CAISO, NREL, First Solar, Using Renewables to Operate a Low-Carbon Grid:  
28 Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant, 2017 at 45.

<sup>196</sup> *Id.*

<sup>197</sup> *Id.*

1           The Applicants take a more limited view of how reactive power can be provided to the  
2 SDG&E system stating not only that gas-fired generators are needed, but that the generation must  
3 be local: “The voltage stability limitation...is a voltage instability phenomenon west of Imperial  
4 Valley. Only generation, that can provide voltage regulation, within the Import cut-plane and  
5 west of Imperial Valley, will provide voltage stability support.”<sup>198</sup> When asked whether there is a  
6 specific minimum amount of gas-fired generation that is required to overcome the limitations on  
7 importing power, the Applicants state that calculating the required amount of gas-fired generation  
8 is specific to each situation.<sup>199</sup> However, Applicants acknowledge: “A minimum amount of local  
9 gas fired generation will not avoid incurring the voltage stability limit but it could increase the  
10 power import level at which a voltage stability limit occurs.”<sup>200</sup>

11           Since reactive power does not travel electrically over great distances, as described by the  
12 Applicants, the generator or other source of reactive power must be located “within the Import  
13 cut-plane and west of Imperial Valley”.<sup>201</sup> As noted previously, wind and solar plants connected  
14 to SDG&E’s East County and Ocotillo substations have the potential to inject reactive power  
15 west of Imperial Valley substation.

16           Another source of gas-fired generation, shown in Figure 9, above, that is west of the cut  
17 plane and close to the San Diego load center is CFE’s Presidente Juarez powerplant, which is  
18 located about 20 miles south of the border in Rosarito.<sup>202</sup> Since downtown San Diego is only  
19 about 15 miles north of the border, Presidente Juarez is physically closer to downtown San Diego  
20 and the significant load centers surrounding metropolitan San Diego than are several gas-fired  
21 generators within SDG&E’s service territory, *e.g.*, the Orange Grove generating plant, which, as  
22 also shown in Figure 9, is located near the northern edge of SDG&E’s service territory. CFE is a  
23

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24           <sup>198</sup> Attachment L: Applicants Response to SCGC-13, Q.13.7.2.

25           <sup>199</sup> Attachment R: Applicants Response to SCGC-07, Q.7.4.

26           <sup>200</sup> *Id.*

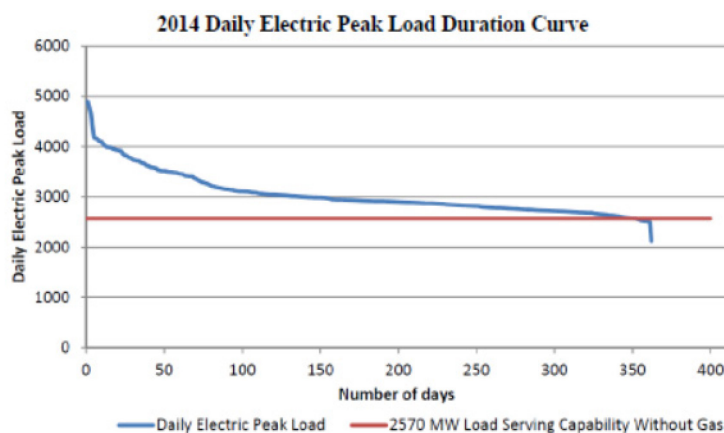
27           <sup>201</sup> Attachment L: Applicants Response to SCGC-13, Q.13.7.2.

28           <sup>202</sup> CEC, Consultant Report, Energy Supply and Demand Assessment for the Border Region, May 2005, CEC-600-2005-023 at 17.

member of WECC<sup>203</sup> and, as noted previously, is interconnected directly with SDG&E. CENACE, which is the independent operator in northern Baja California, has an existing emergency coordination agreement with the CAISO.<sup>204</sup> In addition, CENACE is currently considering joining the CAISO's energy imbalance market.<sup>205</sup>

Figure 10, below, shows the Applicants comparison of the 2014 load curve with the 2,570 MW of load serving capability with the absence of gas-fired generation.<sup>206</sup> The graph is followed by Figure 11 that shows the same comparison with the lower 2026 load levels.

Figure 10<sup>207</sup>



<sup>203</sup> See, <https://www.wecc.biz/Pages/Compliance-BajaCFE.aspx>.

<sup>204</sup> CAISO Operating Procedure 4410, Version 11, April 1, 2017 at 1, 11.

<sup>205</sup> CAISO New Release, October 18, 2016 at 1.

<sup>206</sup> Updated Yari Direct at 16. The Applicants acknowledge the existence of about 107 MW of “in-basin” resources that are not dependent on natural gas of which 37 MW is battery storage available for 4 hours. Thus, the 2570 MW is the 2500 MW import limitation plus 107 MW in basin resources less 37 MW of battery storage.

<sup>207</sup> *Id.* at 17.

Figure 11<sup>208</sup>

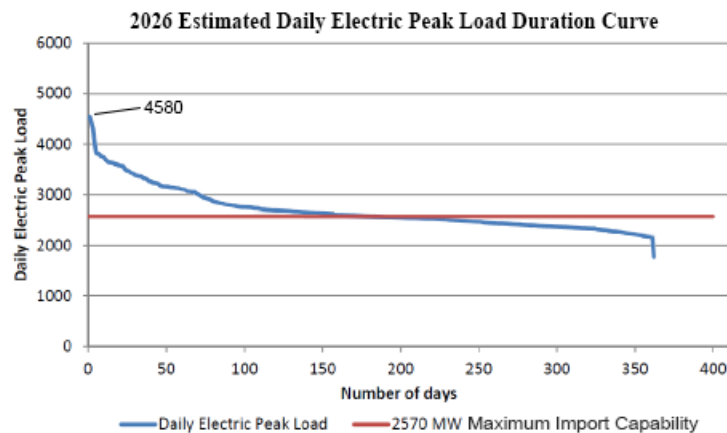


Figure 11 first shows that only about 80 days per year have hours with loads above 3,000 MW. Furthermore, no more than 200 days per year have hours with loads above the 2,570 MW of load serving capability with the absence of gas-fired generation that has been identified by the Applicants. Therefore, if we are trying to make up the difference between the 2,570 MW of load serving capability with the absence of gas-fired generation and the load, in the peak hours on each of these 120 days, we would need no more than 500 MW of gas-fired or other generation to meet the load requirements. If an efficient gas-fired generator provides the 500 MW, then the natural gas requirements would amount to about 82 MMcf/d if the generator ran all day at 100 percent load factor. However, given the fact that peak hours occur generally in the late afternoon and evening,<sup>209</sup> the plant load factor would be well below 100 percent with a corresponding reduction in the amount of natural gas consumed.

Furthermore, if the limit on power imports floats up as some local gas-fired generation is introduced as the Applicants have suggested,<sup>210</sup> it is likely that we would see an increase in power imports available to meet the loads on the highest 80 days. Since an increased level of power imports would be available to meet peak demands, the amount of gas-fired generation required to meet the difference between the load and the import levels would shrink relative to what is depicted in Figure 10 toward the 500 MW of local generation.

<sup>208</sup> *Id.* Graph has been adjusted to reflect the lower 2026 forecast.

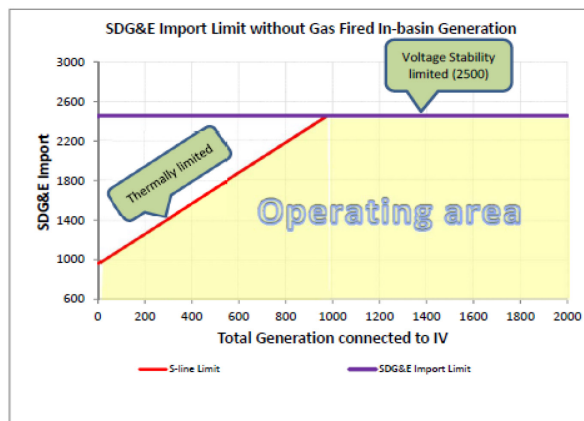
<sup>209</sup> A.15-12-012, SDG&E workpapers, April 29, 2016.

<sup>210</sup> Attachment R: Applicants Response to SCGC-07, Q.7.4.

#### 5.4.3.4. The Applicants Claim that Limitations on Imperial Irrigation District's S-Line Further Limits the Importation of Power into SDG&E During Certain Hours.

The Applicants raise an additional factor that limits their ability to import power. This factor is the thermal limitations on the IID "S-Line," which is a 230 kV transmission line running between IID's El Centro Substation and SDG&E's Imperial Valley Substation.<sup>211</sup> According to the Applicants, the rating of the S-Line is 370 mega volt-ampere ("MVA") (407 MVA emergency rating),<sup>212</sup> which limits imports more than the voltage stability limit when, in addition to no local gas-fired generation in SDG&E's area west of Imperial Valley substation, the total dispatch level of the generation that is connected to the Imperial Valley substation drops below 1,000 MW.<sup>213</sup> Generation connected to Imperial Valley substation includes solar generation as well as 1,080 MW of gas-fired generation.<sup>214</sup> Figure 11 replicates Mr. Yari's "Table 2" from his testimony to illustrate the issue:

Figure 11: Yari's Table 2<sup>215</sup>



<sup>211</sup> Attachment P: Applicants Response to SCGC-06, Q.6.5.2.

<sup>212</sup> Attachment J: Applicants Response to SCGC-10, Q.10.15.2. Transmission lines have an operating rating and an emergency rating that is 110 percent of the normal rating. The emergency rating can be followed immediately after an electrical disturbance. See, FERC and NERC study, Arizona-Southern California Outages on September 8, 2011, Causes and Recommendation, April 2012 at 8.

<sup>213</sup> Attachment P: Applicants Response to SCGC-06, Q.6.5.3.

<sup>214</sup> CAISO, 2016-2017 Board Approved Transmission Plan at 141.

<sup>215</sup> Updated Yari Direct at 16.

1 The Applicants state that the rating of the S-Line would have to be increased to at least 700 MVA  
2 to eliminate the effect.<sup>216</sup>

3 The S-Line causes the import limitation because the 230 kV line is the most constrained  
4 among the lines that are interconnected with the SWPL line at Imperial Valley substation.<sup>217</sup> The  
5 SWPL is a 500 kV transmission line with a maximum thermal capacity limit of 2,598 MW.<sup>218</sup>  
6 Under CAISO Operating Procedure 7820, which protects the S-Line against overloading if there  
7 is an outage on the SWPL, the SWPL flow is limited to less than four times the emergency  
8 capacity of the line, or in formulaic form:  $\text{SWPL flow} \times 0.25 < 407$ .<sup>219</sup>

9 The largest SWPL flow allowed under the CAISO Operating Procedure 7820 formula,  
10 1,628 MW, would be permitted only if the flows across the S-Line were zero.<sup>220</sup> However, flows  
11 across the S-Line are generally above zero, so flows across the SWPL line are reduced as required  
12 by the CAISO Operating Procedure 7820 formula.<sup>221</sup>

13 If the S-Line were upgraded so that it had a capability of 700 MVA (770 MVA  
14 emergency) as the Applicants have indicated, applying Operating Procedure 7820 would produce  
15 a new limit for SWPL:  $\text{SWPL flow} \times 0.25 < 770$  or 3,080 MW.<sup>222</sup> Under this scenario the S-Line  
16 would no longer be the limiting factor for the SWPL line from Arizona to the Imperial Valley  
17 substation. Instead, the capacity of the two SWPL lines connecting the Imperial Valley  
18 substation to the Miguel and Suncrest substations would become the new limiting factor.<sup>223</sup>  
19 These two lines are capable of importing a maximum of 2,700 MW under emergency  
20

21  
22 <sup>216</sup> Attachment J: Applicants Response to SCGC-10, Q.10.15.3.

23 <sup>217</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 5.

24 <sup>218</sup> *Id.*

25 <sup>219</sup> *Id.*

26 <sup>220</sup> *Id.* at 6.

27 <sup>221</sup> *Id.*

28 <sup>222</sup> *Id.* at 9, substituting 770 MVA for 800 MVA used in report.

<sup>223</sup> *Id.*

1 circumstances, which would then allow an increase of over 1,000 MW in flow across SWPL from  
2 the current 1,628 MW to 2,700 MW.<sup>224</sup>

3 Thus, using the Applicants' definition of import capability as being the sum of the imports  
4 across all three import paths, the upgrade of the S-Line would have the potential to expand the  
5 total import capability to over 4,000 MW, provided the voltage stability limitation can be  
6 addressed.

### 7 **5.5. Alternative Solutions to Problem 3:**

8 Just as there are much less expensive alternatives and more environmentally benign  
9 alternatives to constructing Line 3602 to maintain service to the core in Line 3010 outage  
10 situations, there are much less expensive and more environmentally benign alternatives to assure  
11 electric reliability in the SDG&E service territory in emergency circumstances that include the  
12 complete loss of Line 3010 or the complete loss of the Moreno Compressor Station.

13 If some level of continued dependence on gas-fired generation to maintain sufficiently  
14 high import limits is assumed, the question is whether an adequate supply of gas can be provided  
15 during emergency circumstances. As discussed previously, while there is good reason to be  
16 skeptical of the Applicants' insistence that only local gas-fired generation can address SDG&E's  
17 voltage stability issues, enough gas-fired generation inside of SDG&E's import-cut plane can be  
18 served even with an outage of Line 3010 or the Moreno Compressor Station to provide the  
19 amount of voltage support that would be needed to maximize electricity imports. Additionally,  
20 there are alternative electric solutions to assuring electric system reliability without constructing  
21 Line 3602.

#### 22 **5.5.1. Alternative 1: System Operator Purchases LNG Storage at Costa Azul in** 23 **Coordination with Core.**

24 The first alternative is for the System Operator to coordinate with Gas Acquisition to  
25 obtain and utilize gas supplies delivered across the NB-GR-TGN path. LNG supplies from Costa  
26 Azul, or, as discussed previously, LNG supplies from Costa Azul in combination with supplies of  
27 domestic natural gas brought from Ehrenberg utilizing firm or interruptible transportation on the

28 <sup>224</sup> *Id.*

NB-GR-TGN system could be relied upon as an alternative to meet core demand and essential EG demand if Line 3010 were to fail.

The essential EG demand corresponds to the gas-fired electric generation located inside of the SDG&E import cut plane that provides the voltage support necessary to raise the import limit to workable levels. For example, based on the Aliso Canyon Report described previously in Section 5.4.2, this essential EG demand corresponds on a 1-in-10 year cold winter day to the estimated 22 MMcf/d of gas burn that would be needed under normal pre-contingency conditions, while the amount of gas burn required under post N-1 conditions is 96 MMcf/d.<sup>225</sup> The amount of essential EG demand will vary however with the season, but essential gas-fired generation should be minimized pursuing Alternatives 2 to 4, which are described below.

This sharing arrangement can be demonstrated to be feasible by considering the combination of core and noncore demand throughout the year as shown in Table 14:

Table 14

| <b>Demand (MMcf/d)</b>   | <b>Summer<br/>Low-EG<br/>Day</b> | <b>Summer<br/>High-EG<br/>Day</b> | <b>Spring Day</b> | <b>Fall Day</b> | <b>Winter<br/>Day</b> | <b>Winter 1-in-<br/>10 Year<br/>Day</b> |
|--------------------------|----------------------------------|-----------------------------------|-------------------|-----------------|-----------------------|-----------------------------------------|
| Core                     | 100                              | 100                               | 170               | 180             | 310                   | 350                                     |
| Electric Generation (EG) | 100                              | 300                               | 220               | 270             | 165                   | 165                                     |
| Non-Core, Non-EG         | <u>75</u>                        | <u>75</u>                         | <u>75</u>         | <u>75</u>       | <u>62</u>             | <u>62</u>                               |
| <b>Total Demand</b>      | <b>275</b>                       | <b>475</b>                        | <b>465</b>        | <b>525</b>      | <b>537</b>            | <b>577</b>                              |

As previously, these figures are conservative because they are based on the Applicants' reliance on the 2016 California Gas Report. They illustrate the point that not all of the demand can be served on all occasions through Otay Mesa receipt point. Thus, CAISO in coordination with the System Operator would determine the appropriate dispatch of EG plants in the SDG&E service territory, given the constraints. However, as discussed below, there would be sufficient gas supplies to at least cover core demand plus the minimum 22 MMcf/d level required for electric reliability operations under pre-contingency circumstances, and on many days the Otay Mesa 400

<sup>225</sup> Attachment W: Aliso Canyon Report at 31.

1 MMcf/d capacity would allow significantly greater EG dispatch levels than the minimum  
2 required.

3 The 400 MMcf/d is sufficient to support core 1-in-10 year cold day requirements of 350  
4 MMcf/d plus an additional amount to cover minimum pre-contingency EG peak day requirements  
5 if the Line 3010 were interrupted on a 1-in-10 year cold day. As shown in Table 14, the gas  
6 available to supply EG demand on a 1-in-10 year cold day through Otay Mesa would be reduced  
7 under this scenario to 50 MMcf/d if Line 3010 were interrupted, but that is enough to cover the  
8 minimum required pre-contingency EG burn.<sup>226</sup> As discussed previously, while the study also  
9 found that 96 MMcf/d of gas burn by electric generators was required to provide the local  
10 generation needed to meet requirements in a post N-1 contingency event,<sup>227</sup> there is no NERC  
11 requirement that the Applicants be able to meet an N-1 outage following a loss of Line 3010 or  
12 Moreno Compressor Station without loss of electric load. Furthermore, the probability of these  
13 three events, 1-in-10 year cold day accompanied by a loss of Line 3010 followed by loss of the  
14 SWPL, occurring simultaneously is too small to be given much credence.

15 In addition to the 400 MMcf/d of gas delivered through Otay Mesa, gas could be provided  
16 through Rainbow via Line 1600 to serve two EG customers with a combined capacity of [REDACTED]  
17 MW, which translates to [REDACTED] MMcf/d at 100 percent load factor. Line 1600 would also continue to  
18 serve a large industrial customer that is served directly from the line, as well as the core  
19 customers who are served from Line 1600.

20 If an interruption of Line 3010 occurred during a non-winter month, the 400 MMcf/d  
21 would be used to meet core needs first and then EG and other noncore needs. Since core  
22 requirements would be much lower than the 350 MMcf/d level during these non-winter months,  
23 there would be more supply to meet EG and other noncore needs. In some cases, such as a  
24 relatively cool summer day, there would be no constraints, while on other days such as a hot  
25 summer day or a fall day, there would be some limitations on gas availability to EGs.

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27 <sup>226</sup> *Id.*

28 <sup>227</sup> *Id.*

1 In addition to the 400 MMcf/d of gas delivered through Otay Mesa, however, gas could be  
2 provided through Rainbow via Line 1600 to serve two EG customers with a combined capacity of  
3 ■■■ MW, which translates to ■■■ MMcf/d at 100 percent load factor. The availability of gas  
4 supply from Line 1600 for these two EG customers would be a factor that the CAISO in  
5 coordination with the System Operator would take into account in determining the appropriate  
6 dispatch of EG plants across southern California given the potential constraints on gas supply to  
7 EGs served through Otay Mesa because of a Line 3010 outage.

8 Line 1600 would also continue to serve a large industrial customer that is served directly  
9 from the line as well as the core customers who are served from the distribution systems that are  
10 fed from Line 1600. The delivery of gas to the distribution systems would offset the amount of  
11 gas required to be delivered through Otay Mesa to meet core requirements.

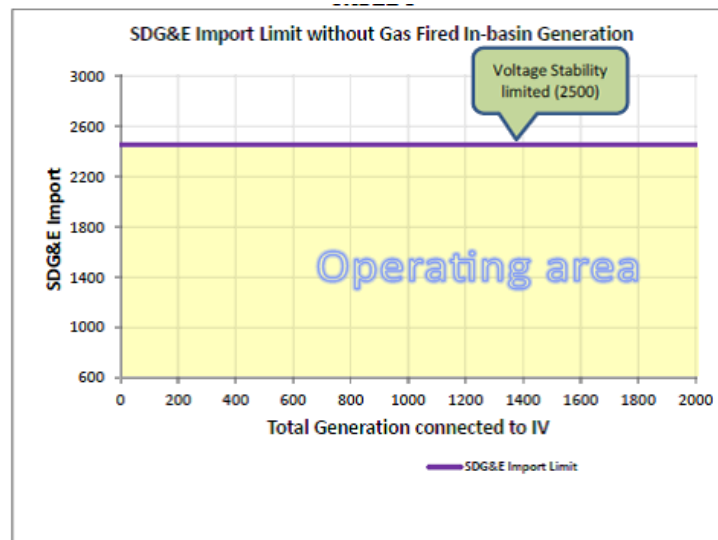
12 **5.5.2. Alternative 2: Upgrade the S-Line, Which Would Significantly Increase**  
13 **the Level of Imports Allowed Across the SWPL Line and Correspondingly**  
14 **Reduce the Reliance on Natural Gas-Fired Generation.**

15 Under this alternative the capacity of the IID S-Line would be doubled from 407 MW to  
16 800 MW by adding a second circuit on the line.<sup>228</sup> The increase in line capacity would eliminate  
17 the thermal limit on SWPL imports identified by the Applicants as occurring when less than  
18 1,000 MW of generation is connected to the Imperial Valley substation.<sup>229</sup> The benefit of  
19 eliminating the thermal limit on SWPL imports is illustrated in by comparing Figure 12 below to  
20 Figure 11, which is Yari's Table 2:

21  
22  
23  
24  
25  
26  
27 <sup>228</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 8.

28 <sup>229</sup> *Id.* at 9.

Figure 12



Expanding the capacity of the S-Line would allow for an overall increase in SWPL imports by about 1,072 MW,<sup>230</sup> which would increase access to solar and wind projects east of California. Expanding the S-Line would also benefit SDG&E by increasing its access to renewable resources in the IID area. The Imperial Valley is recognized as one of the highest potential sources of renewable geothermal generation, is designated as a Competitive Renewable Energy Zone (“CREZ”), and is included in the Renewable Energy Transmission Initiative 2.0 (“RETI”).<sup>231</sup>

The capacity of the S-Line could be increased from 407 MW to 800 MW for a cost of about \$38 million.<sup>232</sup> (It is also possible that special protection schemes might have to be added at Imperial Valley substation under this alternative for an additional \$10 million.)<sup>233</sup>

Expanding the S-Line would be vastly less expensive than the projected \$600 million loaded and escalated cost, including AFUDC and capitalized property taxes, of building Line 3602.<sup>234</sup> Furthermore, this alternative would enhance SDG&E’s access to sources of renewable energy in keeping the state’s goals to reduce dependency on fossil fuels.

<sup>230</sup> *Id.*

<sup>231</sup> *Id.* at 8.

<sup>232</sup> *Id.*

<sup>233</sup> *Id.* at 9.

<sup>234</sup> Direct Testimony of Michael Woodruff at Footnote 7 (p.5).

1                   **5.5.3. Alternative 3: Develop Greater Coordination with CENACE Which Might**  
2                   **Allow Reliance on CFE’s Gas-Fired Generation in Rosarito to Meet**  
3                   **Emergency Conditions.**

4                   Under this alternative SDG&E would be required to perform a power flow analysis that  
5                   assumes power would be made available by Mexico’s System Operator, CENACE, from CFE’s  
6                   Presidente Juarez power plant in the event of a loss of Line 3010. Such a study should be  
7                   consistent with WECC reliability criteria and should include all existing reactive power voltage  
8                   support, including all synchronous condensers approved in each of the CAISO Transmission  
9                   Plans including the 2016-2017 Plan.

10                  This alternative would also require studies of the existing SDG&E interconnection with  
11                  CFE as well as the examination of alternative generation and switching within CFE to confirm the  
12                  maximum south-to-north transfers.<sup>235</sup> The SDG&E/CFE interconnection is rated at 800 MW, but  
13                  the import capability is rarely used.<sup>236</sup> The net power exchange between SDG&E and CFE is  
14                  close to zero under CAISO’s current operating practices.<sup>237</sup> In the CAISO’s 2018 base case, the  
15                  power flow is actually assumed to be 100 MW flowing southward.<sup>238</sup> In addition, the Applicants  
16                  currently assume that a contingency involving the “loss of the 500 kV lines into SDG&E triggers  
17                  a CFE remedial action scheme (RAS) that opens the interconnection to SDG&E to protect CFE’s  
18                  internal lines from overloading.”<sup>239</sup>

19                  Instead, the expectation in this alternative would be to utilize the SDG&E interconnection  
20                  with CFE to allow power to flow north from CFE’s Presidente Juarez plant to provide reactive as  
21                  well as active power to supplement SDG&E’s needs in the event of a loss of Line 3010 or a  
22                  Moreno Compressor Station outage.<sup>240</sup> This alternative would also require SDG&E to examine  
23                  whether the reliance on CENACE to provide reactive power would enhance SDG&E’s ability to

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24                  <sup>235</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 12.

25                  <sup>236</sup> *Id.* at 6.

26                  <sup>237</sup> *Id.*

27                  <sup>238</sup> *Id.*

28                  <sup>239</sup> Attachment Q: Applicants Response to SCGC-18, Q.18.11.2.

<sup>240</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 6-7.

1 take power from SCE if it were made available through increased north to south flows along the  
2 SONGS tie lines.<sup>241</sup> If the CAISO were to dispatch generators in an “out-of-market” sequence, as  
3 much as 580 MW could potentially be made available through the SONGS tie lines, which is  
4 about 460 MW more than is assumed in the CAISO’s 2018 base case.<sup>242</sup>

5 To the extent that the power flow analyses demonstrated that substantial amounts of  
6 reactive power could be provided to the SDG&E area from CFE, the Commission would then  
7 direct SDG&E to negotiate an emergency coordination agreement with CENACE which would  
8 provide for CENACE to dispatch CFE’s Presidente Juarez power plant to provide voltage support  
9 to SDG&E in addition to meeting CFE’s local loads.

10 Under an emergency coordination agreement CENACE/CFE would call upon less  
11 efficient resources as required to provide the necessary resources to SDG&E. However, the cost  
12 associated with this alternative should be fairly low. The coordination agreement could take the  
13 form of a mutual aid agreement, in which case the cost might be limited to agreeing to reimburse  
14 the assisting party for incremental costs, such as increased fuel burn by less efficient powerplants,  
15 that are incurred while providing the assistance to the party in need. The cost of coordination  
16 would be vastly less expensive than the \$86 million first year revenue requirement and the \$2  
17 billion revenue requirement over the life of Line 3602.<sup>243</sup>

18 **5.5.4. Alternative 4: Pursue the Installation of Devices such as Synchronous**  
19 **Condensers and Connect Existing Solar and Wind Generators Inside the**  
20 **SDG&E Import Cut Plane that Have the Requisite Inverter Control**  
21 **Technology to Minimize the Dependence on Gas-Fired Generation for**  
22 **Voltage Stability.**

23 The CAISO’s current transmission plan already directs the addition of synchronous  
24 condensers.<sup>244</sup> However, to the extent that the need for reactive power is beyond the capability of  
25 the devices that will be installed through the end of 2017, an alternative to relying on gas-fired

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26 <sup>241</sup> *Id.* at 12.

27 <sup>242</sup> *Id.*

28 <sup>243</sup> Direct Testimony of Michael Woodruff at 6.

<sup>244</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 7.

1 generation inside the SDG&E import cut plane to provide reactive power is the addition of more  
2 of these devices in the SDG&E area.

3 Another alternative to relying on gas-fired generators to produce both active and reactive  
4 power is to locate and work with existing solar and wind generators that are interconnected with  
5 SDG&E substations, East County and Ocotillo, and have inverters that are capable being  
6 controlled so that they can provide reactive power in response to CAISO requirements. “A  
7 typical modern utility-scale PV power plant is a complex system of large PV arrays and multiple  
8 power electronic inverters, and it can contribute to mitigating the impacts on grid stability and  
9 reliability through sophisticated automatic “grid-friendly” controls.”<sup>245</sup>

10 This alternative to relying on gas-fired generators would require SDG&E to work with the  
11 CAISO in identifying each of the existing solar and wind generators that are located in SDG&E’s  
12 territory west of the Imperial Valley substation and that have the potential to install this  
13 technology. Many of the PV control capabilities that were demonstrated in CAISO/NREL/First  
14 Solar demonstration project have already generally been proven to be technically feasible, but  
15 they are not currently required to be included as part of the solar installation.<sup>246</sup> As characterized  
16 in the report, a controller would have to be already present at the plant or able to be installed in  
17 order for the plant to provide reactive power to the grid. The type of controller that is required is  
18 described in the CAISO/NREL/First Solar report:

19 A key component of this tested grid-friendly solar PV power plant  
20 is the plant-level controller (PPC) developed by First Solar. It is  
21 designed to regulate real and reactive power output from the PV  
22 power plant so that it behaves as a single large generator. Although  
23 the plant is comprised of individual inverters, with each inverter  
24 performing its own energy production based on local solar array  
25 conditions, the function of the plant controller is to coordinate the  
26 power output to provide typical large power-plant features, such as  
27 APC and voltage regulation through reactive power regulation<sup>247</sup>.

28 <sup>245</sup> Attachment Y: CAISO, NREL, First Solar, Using Renewables to Operate a Low-Carbon Grid:  
Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant, 2017 at 11-12.

<sup>246</sup> *Id.* at 12.

<sup>247</sup> *Id.* at 18.

1 New solar and wind projects will be required to install control technology under FERC  
2 Order 827, as discussed above. However, it is not clear whether existing plants will actually be  
3 required to install the control technology. The CAISO will very likely be working toward better  
4 integrating these existing solar plants into its system because the CAISO is facing periods where  
5 renewables have to be curtailed. If the CAISO sets standards for existing solar plants to require  
6 them to provide reactive power, the standards will incent the existing solar plants to invest in the  
7 control technology. Alternatively, SDG&E could provide incentives for the existing solar  
8 suppliers in its service territory that are located west of the Imperial Valley substation to install  
9 the control technology, software, and telemetering that would be required to enable these plants to  
10 produce or absorb reactive power as required by system conditions.

11 The cost associated with this alternative ranges from about \$65 million to install a  
12 synchronous condenser<sup>248</sup> to an unknown amount that might be required to incent installed solar  
13 plants to install the control technology that would be required to enable the renewable plants to  
14 provide the reactive power. The \$65 million cost of the synchronous condenser would be  
15 considerably less expensive than the projected \$600 million loaded and escalated cost, including  
16 AFUDC and capitalized property taxes, of building Line 3602.<sup>249</sup> The cost of incentives would  
17 be vastly less expensive than the \$86 million first year revenue requirement and the \$2 billion  
18 revenue requirement over the life of Line 3602.<sup>250</sup>

26 <sup>248</sup> Attachment C: Brian Rahman, Assessment of SDG&E at 9.

27 <sup>249</sup> Direct Testimony of Michael Woodruff at Footnote 7 (p.5).

28 <sup>250</sup> *Id.* at 6.