BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) For Authority To Recover North-South Project Revenue Requirement In Customer Rates And For Approval Of Related Cost Allocation And Rate Design Proposals	Application 13-12-013 (Filed December 20, 2013)

OPENING BRIEF OF THE UTILITY REFORM NETWORK CONCERNING SEMPRA'S PROPOSED NORTH-SOUTH PIPELINE PROJECT

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1 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Sempra's proposal[1] to spend an estimated $621 million to build a new pipeline represents the ultimate solution in search of a problem. TURN does not deny that noncore customers sometimes do not deliver sufficient gas to the so-called "Southern System" to maintain minimum flow requirements. However, the resulting reliability "problem" has been and can continue to be solved much more inexpensively by simply continuing today's "system support tools," which include a) having Gas Acquisition deliver sufficient gas for core customer demand on the Southern System, b) having the SoCalGas system operator purchase additional pipeline capacity and gas supplies to meet minimum flow requirements when noncore customers do not deliver sufficient gas, and c) providing transportation tariff discounts for customers bringing gas into Blythe. These existing tools can be improved, and can be augmented with additional operational and tariff changes as discussed in Section 4 of this brief.

The overwhelming evidence in this proceeding supports the following findings and conclusions:

- The costs of system support (procurement by the system operator and tariff discounts for gas at Blythe) increased only during the two-year period 2011-2013, but decreased in 2014 and 2015;
- The system operator could contract for multi-year baseload capacity and supplies to assure reliable deliveries;

[1] This application was submitted by SoCalGas and SDG&E, jointly referred to as "Sempra." However, since most of the witnesses are actually SoCalGas staff, TURN often refers only to "SoCalGas" as the sponsoring utility.

- Transferring support services to Gas Acquisition could reduce procurement costs;
- Implementing already authorized system low operational flow ("Low OFO") tariffs will ameliorate reliability problems due to system-wide supply shortages;
- The only potential reliability problem that is not addressed by existing and improved operational support tools would be the occurrence of a *force majeure* event on the El Paso Natural Gas South Mainline delivering gas to Blythe;
- There are additional alternatives, such as purchasing LNG imports from Mexico or building an above-ground LNG facility, that could provide emergency supplies during a *force majeure* event;
- Implementing a Southern System-specific low operational flow order system could provide the necessary economic incentives for noncore customers to deliver gas to Blythe;
- Sempra has failed to adequately analyze the costs and benefits of various alternatives to continuing or improving reliable natural gas deliveries to Blythe;
- If the Commission does authorize the North-South pipeline, it should set a hard cost cap due to the extreme uncertainty in forecast costs, and it should limit the amount of the revenue requirement allocated to core customers, since core customers have consistently supported the minimum flow requirements at Blythe.

The Commission should thus dismiss Sempra's application without prejudice. The Commission should require Sempra to evaluate potential Southern System minimum flow issues after the implementation of the new low operational flow order ("Low OFO") system and reduced monthly balancing tolerances. If Sempra believes there is still a problem after implementing those changes for at least two years, it should first institute a Southern System specific Low OFO system before resubmitting the North-South pipeline application.

One may wonder, given the evidence in this proceeding, why Sempra has proposed the construction of the North-South pipeline, without conducting any serious cost-effectiveness analysis of alternatives. The answer, not surprisingly, is that Sempra is using the classic trick of having utility ratepayers subsidize assets that will be used to benefit Sempra's unregulated affiliate. Sempra LNG built the Costa Azul Liquefied Natural Gas ("LNG") import terminal in Baja Mexico in 2008. That facility has remained mostly idle due to the dramatic transformation in the domestic natural gas market. But just this past February, Sempra signed a Memorandum of Understanding with Mexico's Pemex to convert the facility into an LNG export terminal. The only thing that is missing to convert the corporate albatross into another cash cow is a reliable and consistent source of gas to the terminal. Ironically, while Sempra alleges that the North-South pipeline is designed to protect against gas flows to Mexico from the El Paso pipeline, its true purpose appears to be to flow gas down to Mexico on the Sempra system. The North-South pipeline is overdesigned to have considerable excess capacity, and together with Sempra's planned Line 3602 through San Diego, it will provide a very reliable source of gas all the way down to Mexico.

2 SEMPRA HAS FAILED TO PERFORM THE REQUISITE COMPARISON OF ALTERNATIVES TO DETERMINE THE COST EFFECTIVENESS OF THIS RELIABILITY PROJECT

The Sempra utilities have requested that the Commission authorize a large capital investment, with a nominal revenue requirement exceeding $2.782 billion[2] over the life of the

[2] Updated Direct Testimony of Garry Yee, p.4, Table 5.

project, ostensibly for the purpose of ensuring "reliable natural gas service" to customers who are connected to the so-called Southern System on SoCalGas' and SDG&E's natural gas pipeline network. Even if one accepts the reliability justification for the moment, Sempra should have conducted certain basic engineering cost evaluations to justify such a project. Sempra has failed miserably in this assessment. The Commission should dismiss the application without prejudice for this reason alone.

In several prior decisions the Commission has balanced policy objectives, such as safety, reliability or environmental goals, with the statutory requirement to adopt just and reasonable rates. The Commission has made clear that, notwithstanding the importance of such policy objectives, the utility must make a detailed showing that the costs of a proposed investment or program are reasonable and efficient. In particular, the Commission has required utilities to make two separate but related showings: (1) that there is a need for the proposed program or project, which usually requires a comparison of costs and benefits; and (2) that the proposed project or program is cost-effective, which requires a demonstration that the utility has considered reasonable alternatives and chosen the optimal solution.[3]

The Commission's 2010 decision on PG&E's "Cornerstone" application is especially instructive to the cost scrutiny that should be applied to Sempra's application. In its Cornerstone request, PG&E sought authorization for approximately $2 billion of additional spending to improve the reliability of its electric system. Notwithstanding the critical importance of electric reliability, the Commission found that PG&E had failed to demonstrate the need for its broad Cornerstone program, and instead approved a program of much reduced scope costing less than

[3] Decision (D.) 10-06-048 ("Cornerstone decision"), pp. 2-3.

$400 million – only 18% of PG&E's requested costs.[4] The Commission explained that the importance of electric reliability did not, by itself, justify huge spending increases:

> . . . our overarching policy is that PG&E must provide reliable electric service to its customers. However, that alone is insufficient reason for approving Cornerstone. We also have the obligation to ensure that rates are reasonable. Whether characterized as a policy or a basic ratemaking principle, for a capital program or project such as Cornerstone, there must be a compelling demonstration of need. A broad policy such as the desirability of maintaining or improving electric distribution reliability can only be implemented at the program or project level if there is demonstrated need for the particular programs or projects. PG&E has the burden to demonstrate such need for Cornerstone.[5]

Similarly, in the context of approving Smart Grid deployment plans required to modernize the electric grid pursuant to statutory directives, the Commission explained that where the proposed investment is needed to "achieve a policy requirement, then a least-cost analysis may be appropriate," showing that the utility is achieving the mandate in the least-cost, most cost-effective manner.[6]

Even in the context of investments designed to promote safety, the Commission voiced very similar standards for a utility showing:

> In evaluating PG&E's cost claims, we require that unless a work activity or program is mandated, the utility must demonstrate that the overall benefits justify the costs imposed on ratepayers. Although quantitative benefits may not necessarily exceed the costs, such benefits should be quantified as much as possible. Any qualitative benefits being relied upon should also be identified and explained. It is not enough to merely assert that safety would be compromised absent approval of a particular work effort.[7]
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> …

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[4] D.10-06-048, Finding of Fact 1, p. 47.
[5] D.10-06-048, p. 16.
[6] D.10-06-047 ("Smart Grid decision"), p. 2-3.
[7] D.14-08-032, p. 27-28.

> PG&E should demonstrate that it compared the cost of alternative approaches to performing the work activity and that the proposed approach is the most cost-effective. The burden is on PG&E to establish that its proposed work activities are necessary, and that it has prudently examined alternatives before receiving ratepayer funding.[8]

In this case, Sempra has failed to provide either a cost-benefit analysis, or a comparison of the cost-effectiveness of different options to ensure reliable flowing supplies delivered into the Southern System. Sempra has failed to quantify the potential reliability benefit of minimizing very low-probability *force majeure* events. As discussed in Section 5.2 below, the relevant analyses demonstrate that Sempra's proposed physical solution is much more costly than using various other tariff and operational solutions.

3 THERE IS NO PERSUASIVE EVIDENCE OF A NEED FOR THIS PROJECT

3.1 Summary of the Southern System Minimum Flow Requirement and Sempra's Justification for the North-South Pipeline

3.1.1 The Need for Minimum Flows into the Southern System

Any natural gas system must balance daily demand versus daily gas supplies. Gas operators perform this function by ensuring there is an appropriate mix of gas from pipelines and storage fields to reliably serve customers. SoCalGas receives gas from at least four main interstate pipelines, as well as a PG&E pipeline, at various receipt points on its system.[9] About 90% of the gas consumed in its service territory comes from supply basins located out of state, and is transported into the SoCalGas system by interstate pipelines.[10] The system has access to

[8] D.14-08-032, p. 28-29.
[9] Exh. SCG-6, p. 2.
[10] The main supply basins serving California are southwestern supplies (Permian, San Juan), Rocky Mountain basins, and Canadian basins. See, for example, Exh. SCG-6, p. 2.

several storage fields which connect to the Northern System north of the Los Angeles basin. None of the storage fields connect directly to the Southern System, and presently gas does not physically flow from storage into the Southern System.[11]

The Southern System includes demand in the Imperial Irrigation District and the San Diego service territory. Gas can be delivered into the Southern System through the South Mainline of the El Paso Natural Gas (EPNG) pipeline at Blythe,[12] as well as the North Baja or TGN pipeline at Otay Mesa.[13] Most of the gas to serve Southern System demand comes into the system at Blythe, with a receipt point capacity of 1,200 MMcfd. There is an additional 400 MMcfd of receipt capacity at Otay Mesa, and SoCalGas has the ability to move 200-300 MMcf/d from the Northern System to the Southern System via the Chino and Prado stations, and an additional 80 MMcfd via Line 6916.[14] Maximum daily flows from the northern system to the southern system are 400 to 650 MMcfd in each year.[15]

However, having adequate pipeline or storage capacity is only the first part of the equation. Capacity does nothing unless customers either bring gas in on the interstate system, or withdraw gas they have in storage. All gas pipelines have various operational rules to ensure that customers appropriately deliver gas supplies to match their gas consumption or face financial penalties.[16] Most interstate pipelines have daily balancing rules, meaning customers have to

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[11] 2 RT 244, SoCalGas, Marelli. The North South pipeline would allow physical flow from the Honor Rancho storage field. See, 5 RT 630, 756, SoCalGas, Bisi.
[12] Exh. EP-1. The Blythe receipt point is sometimes termed Ehrenburg. Both locations are just across the state line from each other, with Ehrenburg in Arizon and Blythe in California. E.g. 2 RT 278, Marelli, Sempra.
[13] Exh. SCG-6, p. 6-7.
[14] Exh. SCG-6, p. 6-7; 5 RT 703, SoCalGas, Bisi. Exh. TURN-1, p. 20.
[15] Exh. TURN-1, p. 9, Figure 2.
[16] A customer's gas consumption is also called gas burn, gas load or gas demand.

match daily use with daily deliveries up to a certain tolerance level.[17] SoCalGas has an extremely liberal monthly balancing provision, allowing customers to rely on the System Operator to balance the system on a daily basis.[18] If customer gas deliveries are so low compared to demand as to threaten the operational integrity of the system, the utility would have to curtail its customers' gas usage based on established curtailment priority rules.

The issue in this case involves reliable gas deliveries to customers served on the Southern System. Due to the fact that gas comes in primarily at Blythe, there needs to be a certain minimum amount of pressure in the pipeline system in order to ensure gas flow all the way into San Diego. This requires a certain amount of daily gas delivery at Blythe and Otay Mesa, depending on the forecast of total demand on the Southern System. SoCalGas has established so-called minimum flow requirements at the Blythe and Otay Mesa receipt points.[19] The Southern System minimum flow problem reflects the fact that on some days customers nominate too little gas into Blythe or Otay Mesa to provide that minimum pressure. In those situations, the SoCalGas system operator purchases and schedules gas into the Southern System in order to ensure adequate minimum pressures.[20]

3.1.2 Sempra's Justification for the North-South Pipeline

SoCalGas claims in this proceeding that the North-South pipeline is needed to meet the minimum flow requirements and ensure reliable service to customers in the Southern System.

[17] Exh. TURN-1, p. 14:29-31 and fn. 20.
[18] Exh. SCG-1, p. 2:4-7; Exh. TURN-1, p. 14.
[19] Exh. SCG-6, p. 6; Exh. SCG-2, p. 1-2.
[20] Exh. SCG-2, p. 2-3. Ms. Marelli explained that the System Operator took over responsibility for maintaining the minimum flow requirements as of April 1, 2009. Previously, Gas Acquisition assured minimum flows using core customer assets.

SoCalGas presented two primary arguments to support its position. Neither argument holds up to close scrutiny.

First, SoCalGas argues that low deliveries at Blythe require the System Operator to purchase supplies and incur so-called "support costs." SoCalGas alleges these costs are increasing, and will escalate in the future due to competition for supplies needed to meet increasing Mexican demand.[21] SoCalGas also alleges that supply shortages may result in the utility having to curtail customers' requirements.

This first argument is mostly a red-herring. The evidence is overwhelming that most of these supply shortages are caused by economic system-wide conditions. The shortages could be fixed more easily, and at a lower cost, by continuing and expanding the existing system operator tools to maintain reliable service, as discussed in Section 4.1, as well as by reforming SoCalGas's tariff rules to provide more incentives for customers to deliver gas at Blythe, as describe in Section 4.3.

Indeed, two of the most important potential changes – adoption of a low operational flow order ("Low OFO") regime and change to the monthly balancing tolerances – have only recently been authorized (Low OFO) or proposed (monthly balancing tolerance).[22] These recent and proposed tariff changes, together with other potential tariff or operational changes, will alleviate system supply shortages. At a minimum, the Commission should order SoCalGas to implement and assess these tools before investing huge amounts in a pipeline asset that is most likely unnecessary.

[21] Exh. SCG-2, p. 3-6.
[22] See, Section 4.2 in this opening brief.

Faced with considerable evidence regarding the lack of need for this pipeline in the testimonies of TURN,[23] SCGC,[24] and ORA, SoCalGas in rebuttal testimony retreated to its second argument – that gas reliability is enhanced by access to more than one pipeline, since relying primarily on one pipeline (EPNG) for gas delivery is inherently unreliable, and greater operational "flexibility" is provided by having multiple delivery sources.[25] SoCalGas explained that if a *force majeure* event disabled the southern system of the El Paso pipeline, it could jeopardize reliable deliveries.[26] SoCalGas also generally criticized relying on contracts with other pipelines for reliable service.[27]

TURN does not disagree that having multiple pipelines enhances reliability, though the evidence shows that only extremely low probability *force majeure* events could truly threaten reliable deliveries on the EPNG system. Thus, one of the main issues in this case is whether it is reasonable to spend $621 million to ensure against a *force majeure* event that might threaten reliability once every 20 to 30 years. In order to answer this question, SoCalGas should have analyzed the benefit of the reliability improvement and compared its costs with other alternative solutions. But in this case, SoCalGas has not even attempted such analyses.

3.2 Lack of Deliveries to the Southern System Are Caused Strictly by Economic Choices of Noncore Customers, Not by Any Physical Constraints or Limitations, and SoCalGas's Various Tariff Rules Promote Those Economic Choices

Even though SoCalGas claims there is a need for a physical pipeline expansion on the intrastate system, there is absolutely no lack of physical pipeline capacity that can flow gas into the

[23] Exh. TURN-1, the Testimony of Herb Emmrich.
[24] Exh. SCGC-1, the Testimony of Catherine Yap.
[25] Exh. SCG-10, pp. 3, 6. See, also, RT 95-96, 154, 229-230, Marelli, Sempra.
[26] 1 RT 155, Marelli, Sempra.
[27] Exh. SCG-10, Marelli rebuttal. See, also, RT 124, Marelli, Sempra.

Southern System. The delivery capacity at Blythe is 1,200 MMcfd, while actual average daily customer deliveries peaked in 2008 at 824 MDth/day.[28] Total customer demand on the Southern System exceeded 1,200 MMcfd on fifteen days during 2011-2014, peaking at 1290 MMcfd on January 15, 2013.[29] In other words, daily customer demand rarely exceeds the delivery capacity of the EPNG pipeline at Blythe. Moreover, total capacity into the Southern System is augmented by 400 MMcfd of delivery capacity at Otay Mesa[30] and the ability to flow 200-300 MMcfd from the Northern System at the Chino and Prado stations.

Thus, the potential inability of deliveries to meet Southern System minimum requirements is **not** a problem of physical delivery capacity into California. Rather, it is strictly an economic problem caused by the fact that at certain times it is more expensive to deliver gas at Blythe, and at those times many noncore customers choose to deliver gas into other less costly receipt points. Because SoCalGas has "postage stamp" rates, customers located on the Southern System do not pay any more in rates to bring gas into the Northern System at Needles, Topock or Wheeler Ridge, even though the gas has to either travel to the Southern System or be delivered through displacement.[31]

Ms. Marelli explained this problem in her direct testimony:

> It is frequently not in the economic interest of shippers to deliver supplies into the Southern System, even when they have the pipeline capacity to do so. The Commission does not require any of SoCalGas' customers to bring supplies into either Blythe or Otay Mesa, the two Southern System receipt points. As a result, SoCalGas frequently needs to provide flowing supplies for the Southern System in

[28] Exh. SCG-2, p. 5.
[29] Exh. NB-4, Sempra Response to SCGC DR 6.8.
[30] Exh. TURN-1, p. 20.
[31] Exh. SCG-01, p. 1-2; See, also, Exh. TURN-01, pp. 5-6, 12.

> order to meet the system minimums established by the SoCalGas Gas Control Department.[32]

SoCalGas's primary technical operational witness, Dave Bisi, agreed that the problem is actual customer behavior in not bringing in adequate supplies of gas on EPNG:

> Yes, and whether or not our customers will actually make use of those interstate pipelines. You know, the El Paso system I presume can still deliver 12, 10 million cubic feet per day to the Southern System, even with their proposed service expansion to Mexico. But if our customers aren't using it, then no gas shows up on SoCalGas' side of the meter.[33]

Noncore customers and their shippers historically have chosen not to bring gas into Blythe or Otay Mesa due to the higher cost of gas at those delivery points compared to other delivery points on SoCalGas' system.[34] The higher delivered price of gas at Blythe does not reflect a shortage of upstream pipeline capacity or supply, but rather reflects the higher total cost of basin supply and pipeline transportation to Blythe versus other receipt points.

The economic choice not to deliver gas at Blythe is facilitated by several "customer friendly" tariff provisions, such as postage stamp rates, liberal balancing rules, and until recently, no minimum flow requirements.[35] As discussed in detail in Section 4, changing these tariff rules and instituting other potential operational and tariff solutions would provide a less expensive means to ensure adequate flowing supplies at Blythe. These tariff changes should be implemented to evaluate whether the flow problems on the Southern System are ameliorated, prior to any expensive infrastructure solution. This is a common-sense "no regrets" strategy.

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[32] Exh. SCG-2, p. 2.
[33] 5 RT 761:16-24, Bisi, Sempra.
[34] Exh. TURN-1, Attachment 4, SoCalGas' Response to TURN DR 01-15.
[35] Exh. SCG-1, p. 1-2, Cho; Exh. TURN-01, p. 5-6, Emmrich.

If California noncore shippers purchased more capacity on EPNG's South Mainline system in order to deliver gas to Blythe, the minimum flow problem would largely disappear. EPNG (or another pipeline) would likely expand its capacity if increased demand, either east of California or to Blythe, warranted such expansions. Indeed, the recent announcement by Kinder Morgan of planned expansions on the El Paso system due to long-term contracts with Mexico illustrates exactly this type of market response.[36]

3.3 Sempra's Primary Evidence Concerning the Need for the Project is Based on Data Regarding Southern System Support Costs in 2012-2013, and Those Data Conflict with More Recent Evidence from 2014-2015

In discussing the "urgent" need for this project, Sempra's primary policy witness summarizes the evidence as follows:

> As explained by Ms. Marelli, Southern System support costs are increasing, deliveries from other customers are decreasing, and supply-related threats to Southern System reliability are on the rise. The quicker this project is put into service, the quicker we deal with these threats to reliability.[37]

The supporting testimony of Ms. Marelli presented data concerning support costs for the four-year period 2009-2013, and data concerning customer deliveries and minimum flow requirements for the period 2007-2013.[38] These data, especially when combined with more recent data for 2014 and 2015, do not support the conclusions reached by Sempra in this case, and fail to meet even a "reasonable evidence" standard, much less the applicable "substantial evidence" standard.

Ms. Marelli's data concerning support costs show that costs increased from $3.8 million to $9.1 million in 2011-2012, and then increased to $20 million in 2012-2013, largely related to

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[36] Exh. TURN-1, p. 4-5.
[37] Exh. SCG-1, p. 5.
[38] Exh. SCG-2, p. 4, Table 1 and p. 5, Figure 1.

increases in discounts paid to customers in order to flow gas through the Blythe receipt point. As explained in oral testimony, the increased costs in Sep. 2011- Aug. 2013 reflect at least in part increased electric generation demand on the Southern System due to the unanticipated shutdown of the SONGS nuclear power plant.[39] However, as documented in the testimony of SCGC witness Yap, support costs declined in 2014 to $15.9 million, and have declined even more significantly through the winter of 2014-2015.[40] Sempra's primary policy witness agrees that these costs have continued to decline in 2015.[41]

Similarly, the data on customer deliveries and southern system minimum requirements do not support SoCalGas' arguments. Ms. Marelli's data show that customer deliveries at Blythe increased significantly in 2008, then declined somewhat each following year, dipping below the 2007 level in 2012 and 2013.[42] However, customer deliveries subsequently increased and stayed above minimum flow requirements in 2014.[43]

In sum, SoCalGas' case is based on the assumption that two-years' worth of data represents some type of concerning trend, but more recent data do not support this conclusion. There is no basis for concluding that the long-term costs of having the system operator continue to backstop gas deliveries will increase.

[39] 2 RT 172, Marelli, Sempra.
[40] Exh. SCGC-2, Table 1, p. 6. The six-month costs from Sep. 2014-March 2015 were $4.0 million. Proportionally, this would result in an annual cost of $8 million, though typically support costs are disproportionally higher during the winter months, so the actual 2014-2015 costs should be even less.
[41] 1 RT 37:23-28, Sempra, Cho.
[42] Exh. SCG-1, Figure 1, p. 5.
[43] Exh. SCGC-2, p. 9, Figure 3. TURN does not dispute that there are still days when noncore customers do not flow in sufficient gas to meet minimum flow requirements.

3.4 All of the Historical Curtailments or Near Misses, Except for One Force Majeure Event, Were Due to System Supply Shortages and Would Not Have Been Solved by the North-South Pipeline

In her direct testimony witness Marelli describes one *force majeure* event and three "supply-related near misses" as examples of "some recent Southern System reliability problems" that have occurred because flowing supplies into the Southern System depend entirely on a single (EPNG) pipeline.[44] Apparently, these situations represent the type of flow events that could result in curtailments.[45]

However, in data responses SoCalGas admits that the North-South pipeline would not have solved any of those situations except for the single *force majeure* event. Except for that one event, the reliability problems all resulted from a system-wide gas supply shortage, so there was no gas to deliver from the northern system even if the North-South pipeline had been in place.[46] For example, regarding the December 2013 events, SoCalGas explains:

> With respect to the testimony on page 10, lines 9-16, SoCalGas and SDG&E do not believe that either the North-South Pipeline nor deliveries from Honor Rancho would have been able to support the Southern System on December 9, 2013. SoCalGas and SDG&E were short of supply across their entire system during that event, and there were no supplies available on its Northern System to transport to the Southern System.[47]

SCGC witness Yap evaluated in detail each of the daily events during these four periods of system stress and showed how, for each one, the North-South pipeline would by itself not have resolved the underlying supply issues.[48] **SoCalGas did not rebut this analysis**, and SoCalGas agreed that a pipeline joining the northern and southern system would do little to

[44] Exh. SCG-2, p. 8-11.
[45] Exh. SCG-2, p. 10, lines 20-21.
[46] Exh. TURN-1, p. 9:4 – 10:2.
[47] Exh. SCGC-1, p. 21 (citing Sempra Response to SCGC-DR-04-04.16).
[48] Exh. SCGC-1, pp. 18-22, 30-31.

resolve system-wide supply problems.[49] The Commission should closely consider this admission in evaluating the need for this project.

Indeed, what is most revealing is that tariff and operational changes that address the real underlying problem – the lack of an economic incentive to deliver gas into the overall system or into the Southern System specifically – may be much more effective than a pipeline located on SoCalGas' intrastate system. The recent approval of a system-wide low OFO regime will alleviate system-wide supply shortages,[50] and a similar low OFO regime for only the Southern System would provide similar benefits specifically for the Southern System. As discussed further in Section 6.1 below, the potential reliability problem due to a very unlikely *force majeure* event can likewise be addressed by solutions that are less expensive and more appropriate to a low-probability event.

3.5 There Is No Credible Evidence of Any Increase in Curtailment Threats, and the Curtailment Event of July 1, 2015 Had No Relationship to Southern System Minimum Flows

In addition to the inaccurate claims of an increase in support costs and a decrease in customer deliveries to the Southern System, Sempra vaguely alleges that "supply-related threats to Southern System reliability are on the rise."[51] Sempra provided no evidence in support of this statement in its written testimony. In response to questioning by the ALJ, Sempra could only point to the recent curtailment in the Los Angeles basin, as described in Advice Letter 4831.[52]

SoCalGas's reference to the July 1st curtailment is a red herring, since that curtailment event had little relationship to Southern System minimum flows and would have been unaffected

[49] For example, 2 RT 180-195, Sempra, Marelli.
[50] See discussion in Section 4.2.
[51] Exh. SCG-1, p. 5, lines 5-7 (Sempra/Cho).
[52] 1 RT 38, Sempra, Cho; Exh. ORA-4.

by a North-South pipeline. The curtailment was caused by high gas-fired electric power generation demand in the Lost Angeles basin that could not be met in a local area due to local transmission pipeline outages required for pipeline safety maintenance, repairs and testing.[53] If SoCalGas would have done a better job of planning this pipeline safety work in the shoulder months (April and May or October and November), instead of during the high peak electric power demand summer months, this curtailment would not have been required. This event was not a Southern System-related event, and does not provide any evidence of increased "reliability threats" due to lack of deliveries to the Southern System.

3.6 The Threat of Increased Mexican Demand Is Unfounded, Since Shippers Can Contract for Capacity to California and Interstate Pipelines Will Expand Capacity in Response to Increased Demand

SoCalGas argues that gas supply to the Southern System will be jeopardized by increased gas demand in Mexico, presumably because Mexico will contract for available pipeline capacity on the EPNG system, thus reducing the availability of flowing supplies to California.

The Commission should not succumb to this fear mongering. TURN does not disagree that there is a significant likelihood of increased demand in Mexico over the next few years. However, if increased demand for capacity materializes, such market demand will be met by expansions on the interstate pipeline systems, since this is exactly the way in which FERC-regulated pipelines have expanded and grown throughout the United States. Moreover, the California utilities have ample tools to contractually secure pipeline capacity for delivery to California.

[53] Exh. ORA-4.

In the longer term, there is evidence that Mexico may actually become a net exporter of gas as Mexico's enormous shale gas resources are developed. In that case, the North-South pipeline would prove to be entirely unnecessary because supplies delivered over El Paso's South Mainline to Blythe or Otay Mesa will increase.

3.6.1 Increased Mexican Demand Will be Met by Expansions in Interstate Pipeline Capacities Pursuant to Normal Market Dynamics and FERC Regulations

One of the key disputes in this proceeding concerns the expectation of how interstate pipelines, including the EPNG pipeline serving both Blythe and Topock, will respond to increased demand in Mexico. Mr. Chaudhury for Sempra fears that deliveries to Mexico will utilize capacity "which currently delivers supply to Ehrenberg" and will thus result in "lowering flowing supply at Ehrenberg."[54]

However, as demonstrated during evidentiary hearings, Mr. Chaudhury's testimony is based on the incorrect factual premise that interstate pipeline capacity is a zero sum game. This premise runs counter to the very nature of how gas pipeline transportation is constructed and expanded in the United States. FERC-regulated pipelines cannot abandon service or refuse to honor existing contracts. If EPNG wants to serve additional demand, it would have to hold an open season and sign firm long-term contracts with anchor tenants to support capacity expansion investments.[55] This is the way FERC-regulated interstate pipelines have expanded their system in this country, and it is the way in which they grow their business. The FERC has explicitly held

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[54] Exh. SCG-14, p. 3, lines 1-6. It is relevant to note that this issue primarily concerns interstate pipeline capacity. No one claims that there is inadequate gas commodity supply to serve demand. SoCalGas itself forecasts that natural gas demand on its system will decline in the future. Exh. TURN-1, p. 20:10-12 and Exh. TURN-8.

[55] Exh. SCGC-1, p. 12:23 – 13:3.

that El Paso cannot abandon, sell or divert pipeline capacities in a manner that degrades service to existing customers with firm capacity contracts.[56]

Indeed, pipeline expansions have occurred repeatedly over the past fifteen years to substantially increase pipeline delivery capacity into California through the Kern River and the Ruby Pipelines.[57] Presently, SoCalGas has about 6,725 MMcfd of delivery capacity from upstream pipelines at ten separate interconnections,[58] while SoCalGas' receipt point capacity is only 3,875 MMcfd.[59] SoCalGas thus already has a very significant surplus of interstate delivery capacity, so that disruptions from one or two individual sources do not necessarily threaten reliability.

The EPGN South Mainline already serves multiple customers east of California ("EOC"). El Paso has expanded its system in order to accommodate both California and EOC demand. Mr. Chaudhury admitted that EPNG already has constructed new laterals to flow about 200 MMcfd to Mexico.[60] Mr. Chaudhury further agreed that even though flows to Mexico via the EPNG South Mainline increased from an average of 637 MMcfd in 2012 to over 900 MMcfd in 2014, deliveries into SoCalGas' Southern System exceeded the Southern System minimum requirements in 2014.[61] Lastly, Mr. Chaudhury agreed that there are a number of proposed pipeline projects that would reverse gas flow so as to bring gas from the north into Texas, thus

[56] See, for example, 108 FERC ¶ 61, 024 (2004); See, also, 99 FERC 61,244 (2002).
[57] See, for example, D.08-11-032, p. 17.
[58] Exh. TURN-1, p. 20, Table 1. Three of those points flow into the Southern System.
[59] Exh. SCG-6, p. 1.
[60] 6 RT 848-850.
[61] 6 RT 853:4 – 855:27, SoCalGas, Chaudhury.

causing Permian Basin gas in Texas to flow west into the EPNG system and eventually supply Mexico.[62]

The announcement by Kinder Morgan of its long term contract with the Mexican Comision Federal de Electricidad explained that Kinder Morgan will expand its system by about 350 MMcfd and will use this expansion capacity and existing capacity to serve the contracted 550 MMcfd to Mexico.[63] The Kinder Morgan announcement illustrates exactly the type of market response that is to be expected, and thus casts considerable doubt on the fears expressed by Mr. Chaudhury and Sempra.

The Commission should not be persuaded by Sempra's fear-mongering. Sempra has provided no basis for assuming that normal pipeline expansions will not occur to meet Mexican demand. Of course, there are always some short-term capacity issues due to the lumpy nature of pipeline investments; however, such issues can be addressed either by requiring noncore customers to hold firm interstate pipeline capacity,[64] or by authorizing the System Operator or Gas Acquisition to continue to buy pipeline capacity on behalf of the noncore, as discussed in Section 4.1 below.

3.6.2 Mexico May Become a Source of Gas Into the United States, thus Stranding Any Pipeline Investment

While Mexico may increase its imports from the United States in the short to mid-term, there is a strong likelihood that such exports to Mexico will decline in the long run, as Mexico develops its own very substantial natural gas resources.

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[62] 6 RT 858:2 – 860:27, SoCalGas, Chaudhury.
[63] Exh. TURN-01, Attachment 2.
[64] Gas Acquisition is already required to hold firm pipeline capacity on behalf of core customers pursuant to D.04-09-022.

The same shale gas formations that have resulted in large increases in supply from the Permian basin in Texas also extend to Mexico. Analysts have projected huge reserves of shale gas in Mexico.[65] The only question is if and when will Mexico develop these resources and build pipelines to deliver the gas to domestic and foreign (i.e. United States) markets. Mexico amended its Constitution in December 2013, and implemented new laws in August 2014 that allow foreign companies to partner with Pemex, the Mexican National Petroleum Company, to invest in oil and gas exploration and production.[66]

While it will take some time for significant resource development to occur, the dramatic change in United States natural gas supply over the past five to eight years shows that shale gas development can happen extremely quickly.[67] The huge growth in shale gas transformed the United States from a potential importer of LNG, to a likely exporter of LNG. If such development occurs in Mexico, one can easily envision that Mexico could become a net exporter of natural gas to the United States. Such a market change may also require Sempra to increase receipt point capacity at Blythe or Otay Mesa to accommodate increased deliveries at those receipt points.

The historical experience with expansions on SoCalGas' system are highly instructive. In the early 2000's SoCalGas requested authority for ratepayer funding to expand receipt point

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[65] Exh. TURN-10 and Exh. TURN-4, p. 2.

[66] Exh. SCG-14, p. 7:15-19 (Sempra/Chaudhury). See, also, Exh. TURN-4, p. 2. See, also, Exh. TURN-10.

[67] The Commission can take judicial notice of widespread reporting concerning the increased shale gas supply in the U.S. Indeed, this increased supply is one of the underlying factors likely driving the North-South pipeline, since the parent company of the two Sempra utilities built the Costa Azul LNG import facility in Baja California, Mexico in 2008, and now hopes to convert that facility into an LNG export terminal, precisely due to the glut of gas in the U.S. market. Their problem is now how to transport gas to that facility from U.S. basins, rather than transporting it north to the San Diego demand center.

capacity at the Otay Mesa delivery point based on the assumption that there will be a significant need for LNG deliveries from Mexico.[68] Fortunately, the Commission did not authorize such spending and concluded that "it is appropriate to await further developments regarding permitting and construction of LNG terminals before deciding the extent, if any, to which backbone facility costs should be rolled-in to system-wide transportation rates." That was a fortuitous decision, as the gas market changed dramatically in the next few years, so that very little LNG gas has been delivered into the SoCalGas system. The North-South pipeline presents a similar situation. The Commission should likewise order SoCalGas to await further developments before investing in a pipeline.

3.6.3 SoCalGas Has Adequate Contractual Tools to Maintain Delivery Capacity to California

SoCalGas attempts to portray contracting with third parties for pipeline capacity as an unreliable means of securing long-term capacity for delivery to California, based on the notion that interstate pipelines could abandon service or convert gas pipelines to flow oil. SoCalGas supports this claim by relying on two examples of potential pipeline conversions.[69]

These two examples provide no support for SoCalGas' claim that EPNG could abandon contractual service while there is still customer demand for interstate pipeline capacity. Sempra cites to a FERC decision for the proposition that EPNG's service obligation changes "as its contracts are amended or expire."[70] But that is precisely the point. Interstate pipelines must honor contracts for pipeline capacity and cannot unilaterally choose to abandon service while the

[68] See, for example, D.04-09-022, p. 66-68.
[69] Exh. SCG-11, p. 5.
[70] Exh. SCG-11, p. 5, fn. 10.

contracts are in force.[71] In that very same decision cited by Sempra the FERC reiterated that capacity subject to an expiring contract cannot be sold if "a shipper with an expiring contract exercises a right of first refusal."[72]

The two examples provided by Ms. Marelli simply demonstrate that *when* there is limited demand for continuing pipeline service, then an interstate pipeline may abandon service, after FERC approval. However, no one is intimating that EPNG may be facing a lack of demand for its EPNG capacity. In fact, SoCalGas' entire case is premised on exactly the opposite conclusion, that EPNG capacity will be oversubscribed.

California obtains about 90% of its natural gas from out-of-state basins, and has always relied on interstate pipelines to deliver the gas to California. SoCalGas has contracted with EPNG for pipeline capacity since at least 1990, and SoCalGas "has typically been able to contract with EPNG for its desired capacity needs."[73] SoCalGas has not demonstrated that *if* Gas Acquisition or the System Operator contract for EPNG capacity to Blythe, such capacity could become unavailable.

Presently, shippers have contracts for 805 MDth/d of firm capacity rights for delivery at Blythe.[74] Such an amount is more than sufficient to meet minimum flowing requirements. TURN does not disagree that ensuring adequate contracting of firm EPNG capacity to Blythe is an integral element of preserving pipeline capacity for delivery to the Southern System, as discussed in Section 4 below.

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[71] There is apparently no dispute that an interstate pipeline must obtain FERC approval prior to abandoning or converting service.
[72] 105 FERC 61,201 at P 147 (2003).
[73] Exh. TURN-7. While SoCalGas' data response indicates a date of 1990, TURN presumes that SoCalGas contracted with EPNG even earlier.
[74] Exh. SCGC-1, p. 12.

3.7 Ironically, the Ultimate Goal of the North-South Pipeline May be to Increase Gas Flow to Mexico to Serve Sempra's Costa Azul LNG Terminal

Given the apparent lack of need for the North-South pipeline, one may well wonder why Sempra is pursuing this project. Ironically, the ultimate goal may well be to increase flows to Mexico so as to provide a reliable source of natural gas for Sempra's Costa Azul LNG terminal.

Sempra LNG completed the Costa Azul LNG import terminal in 2008. However, due to the unanticipated dramatic increase in domestic shale gas production, the terminal has been largely unused. This past February, 2015, Sempra Energy signed a Memorandum of Understanding with PEMEX "for the cooperation and coordination in developing a natural gas liquefaction project at the site of the Energia Costa Azul receipt terminal in Ensenada, Mexico."[75]

The potential conversion of the Costa Azul terminal into an export facility will require a reliable source of natural gas supply for the facility. SoCalGas had already proposed building a new 36-inch Line 3602 as a replacement for existing Line 1600 from Rainbow to Santee in the SDG&E service territory.[76] Both the North-South pipeline and Line 3602 are sized much larger than would be warranted by actual demand forecasts.[77] The addition of the North-South pipeline and Line 3602 provide a continuous 36-inch corridor from the Northern System down to Mexico.[78] It is difficult not to conclude that the ultimate goal of these two lines is to provide enough excess capacity so as to ensure the ability to flow a reliable amount of gas to supply Sempra's potential LNG export terminal.

[75] Exh. SCGC-2, p. 13:3-23.
[76] SCGC Response, February 23, 2015, p. 2-6.
[77] The North-South pipeline exceeds the "cold/dry year" design standard of D.06-09-039 by 344 MMcfd. Exh. SCGC-1, p. 5:27 – 6:22.
[78] 5 RT 738, SoCalGas, Bisi.

4 CONTINUATION AND EXPANSION OF EXISTING SUPPORT TOOLS, IMPLEMENTATION OF THE AUTHORIZED LOW OPERATIONAL FLOW ORDER REGIME, ADOPTION OF THE PROPOSED CHANGE TO MONTHLY BALANCING RULES, AND ADDITIONAL POTENTIAL OPERATIONAL CHANGES CAN ENSURE RELIABLE FLOWING SUPPLIES INTO BLYTHE AT A MUCH LOWER COST THAN A NEW PIPELINE

4.1 Existing System Operator and Gas Acquisition Support Methods Have Been Sufficient to Meet Southern System Minimum Flow Requirements and Could be Continued and Expanded to Ensure Reliable Flowing Supplies at Blythe

As discussed in Section 3.3, Sempra's allegation that support costs are increasing and warrant a large investment are not supported by convincing evidence, since the trend in 2012-2013 has reversed in 2014-2015. Thus, Sempra has made no *prima facie* case that reliability or economics warrant a change from the status quo, where Gas Acquisition delivers all of core Southern System needs on a daily basis pursuant to the Memorandum in Lieu of Contract ("MILC"), and the system operator backstops any shortages due to the lack of deliveries by noncore customers. These tools have worked adequately and could simply be continued without any change.

4.1.1 The System Operator Could Expand Contracting for Baseload Supplies to Include Multi-Year Annual Contracts

A key issue is the retention of pipeline capacity to Ehrenburg. Presently, SoCalGas's Gas Acquisition and nine other shippers hold about 805 Mdth/d of capacity for delivery to Ehrenberg.[79] In order to assure firm capacity for delivery at Ehrenberg, some combination of parties serving California load must maintain sufficient capacity rights to meet minimum flow requirements.

[79] Exh. SCGC-1, p. 11-12.

SCGC witness Cathy Yap described several possible options for modifying and expanding existing system support tools in order to ensure adequate pipeline capacity to Blythe at a lower cost than a new pipeline. The existing Memorandum in Lieu of Contract ("MILC") arrangement could be extended for a multi-year period, rather than the current one-year with evergreen.[80] This would provide sufficient capacity to meet core minimum flow requirements. To meet additional minimum flow requirements due to noncore demand, the Commission could authorize the continued use of baseload contracts by the System Operator, potentially with additional baseload contracts to cover the summer period.[81] Ms. Yap also recommended that contracting authority for the system operator could be extended to include multi-year baseload contracts.[82]

Ms. Yap also described an alternative where the system operator itself would procure firm pipeline capacity under three to five-year contracts, with a right of first refusal, as a means of securely ensuring the continued availability of pipeline capacity to Blythe.[83] Since the noncore portion of the minimum flow requirements varies daily, there would be excess capacity on many days.[84] SoCalGas could contract with an asset manager to manage the pipeline capacity. On days when the capacity exceeded the noncore portion of the minimum flow requirement, the manager would use the capacity to flow gas and sell it on the spot market at the border. Ms. Yap calculated that such alternative would have an annual net cost of about $17.5 million, assuming

[80] Exh. SCGC-1, p. 13.
[81] Exh. SCGC-1, p. 14.
[82] Exh. SCGC-1, p. 15.
[83] Exh. SCGC-1, p. 15-16.
[84] As explained by Ms. Yap, currently the System Operator contracts for 255 Mdth/d of baseload winter capacity. Exh. SCGC-1, p. 14:10-13.

revenues from spot market gas sales of about $51 million.[85] This would be considerably less expensive than a new pipeline.

4.1.2 The System Operator Could Purchase Gas Supplies, Though A Southern System Low OFO Tariff Is a Better Solution

TURN generally agrees with the thrust of the recommendations by SCGC. Contracting for pipeline capacity would help in most circumstances; however, it may not solve the underlying problem that customers might not deliver gas under extreme market circumstances, such as, for example, when prices spike dramatically in eastern markets. Ms. Yap suggests that the system operator could purchase both pipeline capacity and gas supplies, instead of using an asset manager.[86] TURN believes that a better solution, that provides the right incentives and does not require the SoCalGas system operator to become an expert in the gas commodity market, is simply to institute a Southern System-specific low operational flow order regime, as discussed in Section 4.3.1 below.

4.1.3 Cost Savings Could be Achieved by Having the Gas Acquisition Department, Rather than the System Operator, Manage Procurement Contracts

Total costs to support the southern system minimum flow requirements were about $3-4 million in 2006-2011, increased to above $9 million in 2011-2012, and then jumped significantly to $20 million in 2012- 2013.[87] The costs subsequently declined in 2014 and 2015, as detailed in Section 3.3.

Some of the cost increase starting in 2011 may reflect potential increases in support costs due to procurement by the System Operator, rather than by Gas Acquisition. The System

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[85] Exh. SCGC-1, p. 17:16-25.
[86] Exh. SCGC-1, p. 24:6-22.
[87] Exh. SCG-2, p. 3-4.

Operator took over the responsibility to purchase reliability supplies in April 2009.[88] The Core Gas Acquisition Department has more assets and staff under its control. These assets include pipeline capacity on multiple pipelines all the way back to the supply basins, huge storage assets and an effective gas planning, forecasting and purchasing staff that can use these assets to purchase, hedge and forecast reliability purchase requirements. [89] The System Operator has only two staff who procure pipeline capacity and gas supplies for Southern System support, in addition to their other responsibilities within system operations.[90] Procuring gas supply and transportation capacity is simply not the primary function of the System Operator, while it is one of the core functions of the Gas Acquisition department.

The System Operator currently does not have hedging authority. If the Commission were to decide to keep the current reliability purchases responsibility with the System Operator, the System Operator should be granted authority to hedge reliability purchase volumes equivalent to the hedging authority granted to the Core Gas Acquisition Department. Such hedging authority, should enable the System Operator to reduce reliability purchase costs when gas prices spike.

4.1.4 Continuing to Use Existing Tools Is Less Expensive than Building a Pipeline

SoCalGas alleges that support costs will rise, implying that these cost increases make a new pipeline a worthwhile investment.[91] SoCalGas did not perform any quantitative analysis to support this assertion, perhaps because this assertion is factually extremely suspect. Even if support costs continued at the highest level of about $20 million experienced during the 2012-

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[88] Exh. SCG-2, p. 3.
[89] Exh. TURN-1, p. 12:1-13; See, also, 1 RT 131-132, Marelli, Sempra. Ms. Marelli testified that Gas Operations has two staff who are responsible for procuring gas supplies, among other duties.
[90] 1 RT 130:28 – 131:16, SoCalGas, Marelli.
[91] Exh. SCG-2, p. 5:2 – 6:2.

2013 flow year, such a cost is only one-fifth of the annual revenue requirement for the North-South pipeline, which exceeds $100 million per year for twenty-five years.[92] Moreover, the annual revenue requirement of the North-South pipeline does not account for the fact that customers would additionally have to purchase gas commodity supplies. Those supplies would add another $6.75 to $11.1 million in annual costs.[93]

Even if one conservatively assumed that support costs *doubled* in the future, the North-South pipeline would still cost about $60 million more *each and every year* for twenty years. Sempra's entire showing on this case is limited to providing four-years' worth of recorded "support costs" and asserting that such costs are likely to increase in the future. The data absolutely disprove SoCalGas' assertions, and show that it would be much more cost effective to continue using existing tools to provide for minimum flow requirements at Blythe, rather than building the north-south pipeline.

4.2 The Impacts of the Recently Authorized Low OFO Regime and of SoCalGas' Proposed Change to Balancing Rules Should be Assessed Prior to Any Consideration of a Major Capital Investment that Could Result in Stranded Costs

SoCalGas readily admits that the primary goal of its request for a low operational flow order ("Low OFO") regime in Application 14-06-021 was to reduce the risk of curtailments due to system-wide supply shortages.[94] It was precisely these system-wide supply shortages that were responsible for the "near misses" described by SoCalGas witness Marelli. The Low OFO regime

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[92] Exh. TURN-1, p. 10:27 – 11:15.
[93] Exh. TURN-1, p. 11:11-15. Mr. Emmrich calculated an annual cost of $11.1 million assuming a gas price of $5.75/Dth. Assuming a much lower price of $3.50/Dth yields an annual cost of $6.75 million.
[94] 1 RT 28-31, SoCalGas, Cho; 1 RT 153-154, SoCalGas, Marelli. See, also, Exh. TURN-1, p. 16-18.

imposes penalties if customers do not deliver a fixed percentage of their daily gas requirement when forecast customer deliveries and storage withdrawals fall below a threshold level of 340 MMDth/d.[95]

The Commission granted SoCalGas' request for Low OFO authority just this past June, in Decision 15-06-004. Thus, we have not yet seen the impacts of this operational change. All of the Sempra witnesses in this case agree that the Low OFO regime will "minimize supply-related curtailment threats by ensuring that transportation customers do not use any more storage withdrawal than has been allocated for the purpose of balancing.[96]

Additionally, Mr. Cho explained that SoCalGas's "liberal balancing tolerances" contribute to the ability of customers not to deliver sufficient supplies to the system to meet daily burn requirements.[97] And in its current application 14-12-017, SoCalGas had actually proposed to reduce its monthly balancing tolerance from 10% to 5%.[98] SoCalGas agrees that if this proposal were adopted, it would help alleviate customer under-deliveries on a system-wide basis.[99] A recently proposed settlement in A.14-12-017 amends SoCalGas's proposal to implement a monthly balancing tolerance of 8%. While this represents a smaller change than proposed by SoCalGas, it will still help to alleviate under-deliveries.

These two future tariff revisions will significantly impact the economic incentives that presently facilitate the choice by noncore customers not to deliver gas sufficient to meet their

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[95] D.15-06-004, p. 22-24.
[96] Exh. TURN-5, p. 2 (testimony of SoCalGas witness Watson in A.14-06-021). 1 RT 28, SoCalGas, Cho; 5 RT 757:20-28, SoCalGas, Bisi. Mr. Bisi speculated that it will take about one year to see whether the system-side Low OFO will impact deliveries into the Southern System. 5 RT 744-746.
[97] Exh. SCG-1, p. 2 and 1 RT 32-33, SoCalGas, Cho.
[98] Exh. TURN-6, p. 9.
[99] 1 RT 33-35 (Sempra/Cho).

daily burn when gas prices are unfavorable. The Low OFO rules and lower monthly balancing tolerances will provide added economic incentives, through the operation of various compliance penalties, for customers to deliver gas into the SoCalGas system.[100] The Commission should dismiss the present application and order SoCalGas to evaluate the impact of these two changes on customer behavior before making significant capital investments that have large rate impacts.

4.3 Additional Operational Changes Could Entirely Cure Any Minimum Flow Problems

In addition to continuing, modifying and expanding the existing baseload contracting authority of the system operator, SoCalGas could implement additional operational and tariff changes to help ensure delivery of flowing supplies. Most importantly, TURN recommends the implementation of the Southern System Low OFO regime as the most direct method of curing the distortions caused by market prices. Only after implementing and evaluating these options should Sempra refile an application for the North-South pipeline, if it still believes such a pipeline is warranted.

4.3.1 The Commission Should Order SoCalGas to Adopt a Southern System Specific Low Operational Flow Order to Motivate Noncore Customers to Deliver at Blythe

Ms. Marelli explained that SoCalGas proposed a Low OFO regime specific only to the Southern System in its 2008 BCAP application 08-02-001.[101] Under SoCalGas's proposal, all customers would have had to flow "up to 20% of their usage" into Blythe on days when SoCalGas called a Southern System OFO. Thus, given that SoCalGas has already devised a possible Southern System Low OFO tariff, it is apparent that there is no practical or operational

[100] Exh. TURN-1, p. 14-19.
[101] Exh. SCG-2, p. 19:18-29.

barrier to developing a Southern System specific Low OFO. However, apparently "a number of intervenors" objected to SoCalGas's proposal in 2008,[102] and SoCalGas dropped it as part of a settlement agreement in that case.

SoCalGas agrees that "there may be merit to requiring all end-use customers to bring some portion of their gas usage into the Southern System," but SoCalGas claims it would not ensure reliable service for customers on the Southern System.[103] However, SoCalGas' explanation for why Southern System delivery requirement would not solve the problem appears to be based on an erroneous premise. SoCalGas states that "If SoCalGas and SDG&E are not able to obtain flowing supplies at Blythe, then it is unlikely that our customers will be able to do so either, no matter how large the potential financial penalty for noncompliance."[104] However, there is no factual evidence that SoCalGas and SDG&E have been unable "to obtain flowing supplies at Blythe" using the MILC and tools available to the system operator. Those tools have worked, albeit the system operator has had "near misses," possibly due to the fact that it is required to address the minimum flow problems on its own during extreme events.[105] But there have been no curtailments of customers. It is thus highly likely that a Southern System delivery requirement, keyed towards operational flow conditions, may solve the minimum flow problems at Blythe. At the very least, this additional tariff tool should first be tried, if SoCalGas determines that implementation of the approved system Low OFO regime and the requested balancing tolerance reduction have not solved the minimum flow problem.

[102] Exh. SCG-2, p. 20:1-3.
[103] *Id.*, p. 20:4-10.
[104] *Id.*
[105] Exh. TURN-1, p. 19.

TURN assumes that the objections of noncore customer representatives in the last BCAP reflect the desire by those customers to have total flexibility to take advantage of SoCalGas's postage stamp rates. But the Commission must consider the broader public interest, rather than the narrow economic interest of some shippers. All customers will be better off with some minimum flow requirement during OFO conditions, as any additional customer costs would be smaller in total than the cost of paying for the North-South pipeline. Based on the testimony of Ms. Yap, it also appears that noncore customers are concerned about having to make individual procurement decisions, and would prefer to have the System Operator or Gas Acquisition responsible for meeting minimum flow requirements at Blythe.

While TURN suggests that a Southern System OFO requirement would be the optimal solution to the problem of inadequate minimum flows, if noncore customer shippers continue to object to such a solution, TURN recommends that the better alternative, rather than building the expensive North-South pipeline, would be to authorize Gas Acquisition to purchase reliability supplies for all customers and allocate the resulting costs equitably to all customers.

4.3.2 Firm Versus Interruptible Service

By its own admission, SoCalGas states that it has not provided more reliable service to customers that have selected firm service as compared to customers who are classified as interruptible under SoCalGas' Gas Rule 14. Since SoCalGas currently charges both firm and interruptible customers the same rate, there is no incentive for SoCalGas to actually follow its own tariff rules. Now, SoCalGas has filed application 15-06-020 to eliminate the firm and interruptible classification for non-core customers.

The Commission should look at this issue closely in the upcoming proceeding. Most interstate pipelines provide firm or interruptible service, with a higher rate for firm capacity. Differentiating service and reliability levels, and providing for lower rates for interruptible service, is another tool that could improve reliability for customers who are willing to pay for greater reliability. Historically, SoCalGas has not curtailed even interruptible customers.[106] It is possible that providing rate discounts in return for the potential of very infrequent curtailments could be another method of promoting reliability of service without an expensive new pipeline.

4.3.3 Reliable Service for Electric Generators Can Be Improved with Other Tariff Changes

The Southern System serves a number of gas-fired power plants located in the SDG&E service territory. As discussed by Sempra witnesses Cho and Marelli, natural gas use by these power plants has increased since the SONGS shutdown. SoCalGas is concerned that reliability problems on the Southern System could impact electric generation ("EG") customers.

As discussed by Sempra witness Cho, two primary factors contribute to supply uncertainty for EG customers. First, the Commission eliminated alternative fuel capability requirements for all noncore gas customers in 1993.[107] Today, most electric generation facilities in California do not have alternate fuel back-up due to a variety of air quality and global warming concerns. Second, electric generators are not allowed to elect core service, which provides much more reliable service.[108]

[106] Exh. TURN-1, p. 13.
[107] Exh. SCG-1, p. 3.
[108] Exh. SCG-1, p. 1.

To address these two underlying problems, the Commission could require SoCalGas to construct an above-ground LNG peak shaving facility, and/or could authorize EG customers to select core service status.[109]

4.3.3.1 Alternate Fuel Supply

One relatively simple and more cost-effective alternative would be to ensure that EG customers have 5 to 10 days' worth of alternate fuel back-up that would be used only during extreme weather conditions, most likely in winter months, when air quality concerns are minimal. Minimal use of alternate fuels on critical days would not endanger California's long-term environmental or air quality goals. Moreover, an alternative fuel supply composed of LNG would not impact air quality.

Ideally, the Commission should require major electric generators to maintain 10 days' worth of alternate fuel back-up in the form of jet fuel, propane or Liquefied Natural Gas (LNG) peak shaving plants. However, the Commission may not have authority to impose such a requirement in California's deregulated electric market. However, the Commission could impose a similar requirement upon SoCalGas, with the same ultimate impact.

LNG peak shaving plants are located all over the United States and are used cost-effectively by other pipeline companies. Atlanta Gas Light Resources owns and operates an LNG plant in Macon, Georgia, with the equivalent of about 1.5 Bcf of inventory capacity and capable of withdrawing up to 140,000 Dth/day.[110] TURN witness Emmrich estimated that a plant with 1.5 BCF of inventory capacity and 175 MMcfd withdrawal capacity would be able to deliver

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[109] These solutions are detailed in the testimony of TURN witness Emmrich. Exh. TURN-1, p. 21-23.

[110] Exh. TURN-1, p. 22:6-15.

enough natural gas for two 500 MW power plants in the San Diego area for about 9 days.[111] The Commission should require SoCalGas to provide a cost estimate of this alternative prior to approving the North-South project.

4.3.3.2 Core Status for Electric Generation Customers

Although it is correct that electric generators under current rules are not allowed to choose the more reliable and more valuable core service, this is a regulatory prohibition that could be changed by the Commission.[112] If electric generators were allowed to choose core service they would receive more reliable and more valuable service and pay the higher associated rates for that service. If EG customers chose core status, SoCalGas may have to plan system expansions in order to meet the more restrictive core service reliability standards with a greater forecast core load. It is not clear whether this would be a more cost effective solution, but SoCalGas should perform this analysis in order to meet the cost-effectiveness standards enunciated by this Commission.

5 A PHYSICAL PIPELINE SOLUTION DUE TO THE POTENTIAL RISK OF A *FORCE MAJEURE* EVENT ON THE EL PASO SOUTH MAINLINE ATTEMPTS TO MITIGATE A VERY UNLIKELY RISK AT A LARGE COST

5.1 Sempra's Only Defensible Argument for a "Physical Solution" Is the Concern that a Highly Infrequent *Force Majeure* Event Could Impact Delivery on a Single Pipeline

As explained above, the need for minimum flows into the Southern System can be adequately and less expensively assured through various "non-physical solutions." The alleged problem of "Mexican demand" sucking up pipeline capacity will be addressed by normal

[111] *Id.*
[112] There does not appear to be a bar under P.U. Code §§ 2771-2774 to allowing EG (other than certain cogeneration) customers to choose core service.

pipeline expansions pursuant to FERC regulations, as has already been demonstrated by Kinder Morgan's proposed expansion based on its long-term contract with the Mexico's CFE.

Nevertheless, Sempra continues to argue that use of non-physical support tools "does not solve the reliability problem" and is only "a short-term fix to a long-term problem."[113] In trying to explain *why* those tools cannot fix the problem on a long-term basis, Sempra repeatedly falls back on the argument that "relying *on a single pipeline source* into the system is not a prudent long-term reliability solution."[114]

TURN does not disagree that having access to multiple supply sources can enhance supply reliability and gas price stability.[115] However, when the increased supply diversity can only be obtained at a very significant capital investment, the utility *must* quantify the potential benefits in order to justify the investment. Building a new pipeline is not at all the same as diversifying contracts with existing interstate pipelines, as has been done in the past.

Moreover, it is critical to understand what exactly is the "reliability" benefit of multiple pipeline delivery points. In her testimony, Ms. Marelli focuses on the potential dangers of pipeline abandonment and termination of contracted service.[116] However, this threat is a red-herring, given that interstate pipelines cannot simply walk away from contracts with ROFR rights, as explained in Section 3.6.3 above.

Thus, the only valid reliability concern due to reliance on a single pipeline is the potential impact of a *force majeure* event, which could disrupt delivery on the El Paso South Mainline,

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[113] Exh. SCG-11, p. 3-4. Oddly enough, the best summary of Sempra's position regarding project need is provided in Exhibit SCG-11, Ms. Marelli's rebuttal testimony "on ratesetting and safety."
[114] Exh. SCG-11, p. 7:18-20 (emphasis added).
[115] See, for example, D.04-09-022, p. 20.
[116] Exh. SCG-11, p. 5:5-18.

thus threatening supply reliability.[117] TURN does not disagree that such a *force majeure* event *might* present a reliability problem, depending on the severity of the event, the demand conditions at the time, and availability of supplies from Otay Mesa. It is critical to remember that a *force majeure* event is statistically a highly unusual event. The "freeze-off" of supply wells that occurred in February of 2011, resulting in the curtailment of about 200 MMcfd of load during the afternoon of February 3, 2011, has occurred only once in thirty years.[118] Other reported well-freeze ups in western production basins have not impacted gas supply flowing into California.[119]

The operational and tariff mechanisms discussed previously may not completely solve a reliability problem due to a *force majeure* event; however, they would certainly lessen, or even greatly alleviate, the impact of such an event. Some *force majeure* events, such as a pipeline break, may happen without warning and be difficult to address. However, the well freeze offs that occurred in February 2011 were caused by multi-day cold events. Calling a low flow OFO early during such an episode may well lessen the severity and extent of any eventual problems.

Moreover, the main way in which the North-South pipeline would help in the event of a *force majeure* loss of upstream capacity on the EPNG pipeline would be by physically flowing supplies from storage in the Northern System. As explained by SoCalGas witness Bisi, such a response would require at least eight hours of lead time, since it would take gas approximately eight hours to physically flow the distance from the storage fields to the Southern System.[120]

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[117] Sempra witness Marelli named a *force majeure* event as the one example of a problem that could not be solved by implementing a southern system low OFO regime. 1 RT 155-156.
[118] Exh. SCGC-1, p. 26:25 – 27:27.
[119] *Id.*
[120] 6 RT 822, SoCalGas, Bisi. This fact also nullifies any potential argument that the North-South pipeline is needed due to the intermittent nature of renewable power supplies. For example, if clouds were to suddenly reduce solar-based electric power supplies located in the Southern System, it would take 8 hours for gas to flow from the SoCalGas storage fields to the Southern

5.2 There Is no Evidence or Analysis that the Potential Benefit of Avoiding an Infrequent Force Majeure Event is Worth the High Cost of a New Pipeline

A key question, therefore, is whether the potential cost of curtailments on the Southern System due to *force majeure* events warrants investing about $620 million in a new pipeline, which will flow less than half full most of the time. When faced with similar issues concerning the cost effectiveness of investments addressing reliability concerns, the Commission has made clear that utilities should evaluate the relative costs and benefits of different alternatives, as explained in Section 2 above.

The Sempra utilities have done absolutely no analysis regarding the potential reliability dangers due to *force majeure* events, the potential costs of curtailments, or the costs of different strategies to minimize reliability threats. Even if one assumes that there is some reliability risk that could not be mitigated using other (non-physical) options, Sempra could have done a cost-benefit analysis of the reliability benefit of mitigating potential curtailments. For example, curtailment costs due to very infrequent *force majeure* events can be quantified based on the value of penalties, or assumed lost value of service. Sempra has failed to do such an evaluation.

5.3 There Are Less Expensive Alternatives to Address Even a *Force Majeure* Emergency Event on the El Paso Mainline

Moreover, there are at least three alternatives that can ameliorate even the impact of a *force majeure* event that disrupts flow into Blythe.

System to meet increased gas-fired electric generation gas demand, much too late to be an effective back-up electricity supply option.

First, the Commission could authorize SoCalGas to purchase LNG supplies from the Costa Azul plant.[121] Such procurement would still be much more economic than the new pipeline because SoCalGas would need to purchase LNG only very infrequently.[122]

Second, SoCalGas could increase the potential to deliver gas from the northern system on the existing connections. SoCalGas can flow approximately 280 MMcfd between the Northern and Southern systems, although maximum flows are much higher.[123] But the proposed Line 2001 looping project would provide greater certainty of being able to use that amount on a consistent basis.[124]

Third, SoCalGas should evaluate the potential to construct an above ground LNG peak shaving facility. As discussed in Section 4.3.3.1 above, TURN witness Emmrich estimated that a plant with 1.5 BCF of inventory capacity and 175 MMcfd withdrawal capacity would be able to deliver enough natural gas for two 500 MW power plants in the San Diego area for about 9 days.[125] SCGC witness Yap estimated the cost of an LNG facility with 2.0 Bcf of inventory and a 200 MMcf/d withdrawal rate at about $259 million.[126]

SoCalGas claims that an LNG plant would require an inventory capacity of 2 Bcf and a withdrawal capacity of 800 MMcf/d.[127] SoCalGas claims that TURN and SCGC's proposals for an LNG facility are not "practical" due to the cost and the long time for permitting and construction.

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[121] The Commission would have to explicitly authorize any Advice Letter for LNG contracts. See, D.04-09-022, p. 40.
[122] Exh. SCGC-1, p. 28:20 – 29:9.
[123] Exh. TURN-1, p. 9, Figure 2.
[124] Exh. SCGC-13 and 5 RT 710-711.
[125] Exh. TURN-1, p. 22:11-13.
[126] Exh. SCGC-1, p. 31:8-12.
[127] Exh. SCG-12, p. 11.

TURN does not disagree that an LNG facility may take a significant time to plan and construct. Such a criticism, however, does not make this physical alternative any less practical than the construction of a new pipeline. The permitting of a long-distance pipeline is at least as difficult and expensive as the permitting of a stationary facility, since the pipeline travels across a much larger linear land distance and thus entails more right-of-way issues.[128] SoCalGas apparently agrees with TURN and SCGC about the approximate inventory capacity necessary for an LNG facility. SoCalGas' claim that a withdrawal capacity of 800 MMcf/d is needed is unsubstantiated, as it is simply based on the proposed capacity of the north-south pipeline.[129] As discussed previously, that size of that pipeline is considerably more than the actual capacity necessary to ensure service reliability for the Southern System.

6 SHOULD THE COMMISSION DECIDE THAT A PIPELINE SOLUTION IS WARRANTED, IT SHOULD ORDER SEMPRA TO EVALUTE ADDITIONAL ALTERNATIVES AND TO HOLD AN OPEN SEASON FOR THIRD PARTY BIDS

6.1 The Commission Should Order Sempra to Evaluate Other Physical Solutions

Sempra evaluated two other locations for a new pipeline, including the River Route the Cross Desert route. Sempra dismissed the Cross Desert Route since it is the most costly physical option. The River Route is also more costly at $769 million, versus $621 million for the North-South project. SoCalGas does not provide a cost estimate for the purchase or lease of Line 1903. Since the cost of the River Route is $148 million more than the proposed route, it should not be considered as a viable alternative.

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128 SoCalGas explained that negotiating and permitting right-of-ways is a significant issue for any long-distance transmission pipeline.

129 3 RT 424, SoCalGas, Buczkowski.

Another option that the Commission should consider is for Sempra to purchase or lease the existing El Paso Line 1903. This pipeline crisscrosses the SoCalGas system from northwest to southeast and once connected to the SoCalGas system. It would therefore be a logical physical option to help support the Southern System. In the same vein, a looping of SoCalGas' line 6916, formerly the Questar Southern Trails Pipeline, should go a long way toward mitigating the Southern System flow problem.

Consistent with TURN's overall recommendation that Sempra should be required to perform adequate alternatives cost-effectiveness analyses, the Commission should require Sempra to evaluate these other physical options to determine if they are a better alternative to building a new pipeline.[130]

6.2 The Commission Should Order Sempra to Hold an Open Season

In this proceeding, representatives of interstate pipeline companies have testified that they could build new pipelines that would provide some, or all, of the alleged reliability benefits of the Sempra pipeline at a lower cost.[131]

If the Commission decides that a physical option should be pursued by Sempra or another entity, then it should require Sempra to conduct an open season for all of the proposed physical pipeline options. This should include the proposed North-South proposal, an expansion of the Havasu Crossover on the El Paso Pipeline system, the building of a Transwestern pipeline spur from Needles to Ehrenberg or Blythe, capacity from Energia Costa Azul via TGN to Otay Mesa, a doubling of line 6916 capacity and the lease or purchase of El Paso Line 1903.

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[130] Exh. TURN-1, p. 23:12-27.
[131] See, for example, Exhibits EP-1 (El Paso, Sanabria), TW-1 (Transwestern, Hearn) and NB-1 (TransCanada, Schoene).

7 IF THE COMMISSION DOES APPROVE CONSTRUCTION OF THE NORTH-SOUTH PIPELINE, WHICH TURN STRONGLY RECOMMENDS AGAINST, IT SHOULD MODIFY SEMPRA'S PROPOSED COST RECOVERY AND COST ALLOCATION

7.1 Cost Recovery

7.1.1 A Cost Cap Is Necessary Due to Extreme Uncertainty in Costs

TURN recommends that the Commission adopt a cost cap and a mechanism to hold shareholders responsible for any cost increases above the authorized funding limit. Such a cap is necessary due to the apparently high degree of uncertainty in program costs.

In its original application filed in December 2013, Sempra had forecast that the cost of the largest component of the project, the pipeline from Adelanto to Moreno, would cost $331.8 million. In its November 2014 update, Sempra forecast the cost to be $484.5 million, an increase of 46%, even though the planned pipeline length had increased only 5%.[132] Such an estimate is outside the supposed accuracy range of a Class 3 estimate, and even outside the accuracy range of a Class 4 estimate.[133]

SoCalGas explained that national construction costs increased by 5% from 2013 to 2014;[134] however, SoCalGas' construction cost forecast for the pipeline has increased by 50% in its update.[135] Mr. Buczkowski claims that the 5% increase in national construction costs reflects only the increase in labor costs, while the 50% increase in Sempra's construction forecast is due

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[132] Compare Exhibits SCG-21 and SCG-22, p. WP-2. See, also, 3 RT 359-360, SoCalGas, Buczkowski.
[133] 3 RT 357-360, Sempra, Buczkowski; See, also, Exh. SCG-3, p. 4; Exh. SCG-23, AACE 56R-08, p. 3.
[134] Exh. SCG-3, p. 3:10-13.
[135] 3 RT 348-349, SoCalGas, Buczkowski; See, also, Exh. SCG-3, p. 2.

to better project definition, greater understanding of soil conditions, and greater understanding of trenching requirements.[136]

The Commission cannot have faith in the accuracy of Sempra's cost forecasts. In order to protect ratepayers against significant cost overruns, and to provide proper incentives for the utility to manage costs, the Commission should adopt a hard cost cap for this project.

7.1.2 The Commission Should Not Authorize the North-South Project on a Stand-Alone Basis

SCGC witness Yap provided a comprehensive explanation of why the North-South project should not be authorized as a one-off project outside of the general rate case. Ms. Yap's primary recommendation was that Sempra should pursue this project as a market-based pipeline and recover costs through incremental rates paid by shippers who contract for pipeline capacity.[137] This ratemaking treatment has been applied previously to PG&E's line 401 expansion project and the Wheeler Ridge Expansion.[138] TURN fully agrees with this recommendation.

7.2 Cost Allocation

The data do not support SoCalGas' contention that there is a problem with gas delivery on the Southern System. However, to the extent that there are times when the system operator must use existing tools to buy gas to ensure sufficient flowing supplies, those times result from the fact that noncore customers are not delivering sufficient quantities of gas at the Blythe

[136] Exh. SCG-3, p. 3:4-10; 3 RT 349-350, Sempra, Buczkowski. Mr. Buczkowski first cited to the increased mileage, but then admitted that mileage only increased by 5%.
[137] Exh. SCGC-2, p. 12-13.
[138] Exh. SCGC-2, p. 13:24 – 14:8.

delivery point.[139] Noncore deliveries decline during peak demand periods when associated with higher gas prices.

TURN thus believes that core customers should pay none of the costs of the North-South pipeline, in the event that the Commission were to authorize construction of this pipeline. Not only has the core consistently flowed gas into Blythe, but also both core average and peak day demands are forecast to decline through 2035.[140]

Alternatively, as explained in the testimony of Mr. Emmrich, the core should be held responsible for no more than the amounts it has already paid in the past in order to meet its minimum flow requirements at Blythe. The core has incurred a "price premium" by purchasing more expensive gas at Blythe rather than less expensive gas for delivery into the Northern System, and this premium has averaged $6.1 million per year in 2009-2014.[141] TURN does not object having the core continue paying this amount for the revenue requirement associated with the North-South pipeline.[142]

SCGC witness Yap emphasizes that the noncore have contributed to historical support costs by paying the costs recorded in the System Reliability Memorandum Account.[143] However, non-core customers have relied on the core Gas Acquisition Department or the System Operator to procure supplies to meet non-core demand on the Southern System on a frequent basis when non-core customers failed to provide adequate supplies at Blythe. That should not be the

[139] See, for example, Exh. TURN-2, p. 3 and Exh. TURN-3.
[140] Exh. TURN-2, p. 3.
[141] Exh. TURN-2, p. 4 and Exh. TURN-3.
[142] The resulting allocation of the backbone transmission system rate is shown in Exh. TURN-2, p. 5.
[143] Exh. SCGC-3, p. 2.

responsibility of the System Operator except on an extreme emergency basis, not as a matter of routine due to price arbitrage.

7.3 Sempra Should be Required to Demonstrate the Cost of Using Electrical Compression for Its Project

Sempra proposes to upgrade the Adelanto Compressor Station by adding approximately 30,000 horsepower (HP) of compression at an estimated cost of $110.7 million.[144] The thermal efficiency of the proposed gas-fired compressors is 23% at a 50% load factor and only 33% efficient at a 100% load factor.[145] In comparison, a combined cycle power plant has a thermal efficiency of 51%.

The Commission should require Sempra to evaluate the potential costs and environmental benefits of using an equivalent electric option consisting of a 22.37 MW combined cycle power plant and associated electric motor-driven compressors before gas-fired compressors are authorized as part of this proposal. SoCalGas had the same gas versus electric option when replacing the old gas-fired compressors at the Aliso Canyon storage field, and SoCalGas chose electric motor-driven compressors for a variety of environmental and efficiency reasons.[146] Another alternative would be for Sempra to hook up electric motor-driven compressors to existing power lines to achieve the same environmental and efficiency benefits garnered at Aliso Canyon. Since Sempra states that the Adelanto compressors would operate over a wide range of capacity factors, electric motor-driven compressors would be suitable for variations in operational capacity factors.

[144] Exh. SCG-3 (Buczkowski), p. 7, Table 4.
[145] Exh. TURN-1, p. 24:8-10.
[146] Exh. TURN-1, p. 24:12-22. See, also, D.13-11-023, pp. 4, 17, 26.

Other electric alternatives are for Sempra to upgrade the Southwest Powerlink or upgrade power lines from the Los Angeles and Orange County area to San Diego County in order to transport more electric power from Los Angeles and Orange County power plants to reduce power production in San Diego County. Some of these upgrades were made when the San Onofre Nuclear Power Generating Station was taken off line.

SoCalGas explains that electric-driven compressors are inferior due to the reliability concern that the compressors could become inoperable during an electric curtailment event.[147] However, as SoCalGas acknowledges, this criticism is not relevant since TURN's primary proposal is for SoCalGas to construct a stand-alone combined cycle power plant to provide the electric service directly to the compressors. SoCalGas claims this proposal is not "well conceived," because a combined cycle power plant has certain minimum times for start-up.[148] Sempra alleges this shortcoming would not apply to gas-fired compressors.

Mr. Bisi's concerns are overblown. A combined cycle plant is highly reliable and is operated on a continuous basis. When excess power is produced, it would supply that electric power to the grid and therefore it is unlikely that a combined cycle power plant would ever start from a "cold start" unless it were shut down for scheduled maintenance.

8 CONCLUSION

The lack of economic incentives for noncore customers to deliver gas at Blythe results in the need for the SoCalGas System Operator to procure supplies on certain days to meet the minimum flow requirements. However, this reliability "problem" can be addressed by using

[147] Exh. SCG-17, p. 12:6-13.
[148] Exh. SCG-17, p. 12:18-22.

existing support tools, especially in combination with the recently authorized low OFO system, at a much lower cost than building a new pipeline.

TURN admits that relying on the EPNG pipeline for a significant amount of delivery could present a challenge during a *force majeure* event. However, SoCalGas has provided absolutely no data or analysis suggesting that the potential costs due to a very low probability *force majeure* event warrant spending $620 million on a new pipeline. And SoCalGas has failed to analyze alternatives that could provide gas supplies even when there is a disruption to El Paso's Mainline pipeline.

The Commission should thus dismiss Sempra's application without prejudice. The Commission should require Sempra to evaluate potential Southern System minimum flow issues after the implementation of the new low operational flow order system and reduced monthly balancing tolerances. If Sempra believes there is still a problem after implementing those changes for at least two years, it should first institute a Southern System specific Low OFO system before resubmitting the North-South pipeline application.

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Respectfully submitted,

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