Decision **PROPOSED DECISION OF ALJ WEISSMAN (Mailed 8/8/2006)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California.	Rulemaking 04-01-025 (Filed January 22, 2004)

(See Appendix A (Service List) for Appearances.)

INTERIM PHASE 2 ORDER ADDRESSING INFRASTRUCTURE ADEQUACY & SLACK CAPACITY, INTERCONNECTION & OPERATIONAL BALANCING AGREEMENTS, AN INFRASTRUCTURE WORKING GROUP, NATURAL GAS SUPPLY AND INFRASTRUCTURE ADEQUACY FOR ELECTRIC GENERATORS, GAS QUALITY, AND OTHER MATTERS

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Summary

This decision is the culmination of a proceeding initiated by the Commission in January 2004 to assess the sufficiency of natural gas supplies and infrastructure in California. The Commission issued a Phase I decision in September 2004, specifically resolving some matters related to the anticipated introduction of gas supplies derived through liquefied natural gas (LNG). This order addresses the remaining issues in the proceeding. This order, among other things, does as follows:

1. Approves Interconnection Agreements and Operational Balancing Agreements for LNG providers (including gas arriving at Otay Mesa).
2. Directs the Pacific Gas and Electric Company (PG&E), the San Diego Gas & Electric Company (SDG&E), and the Southern California Gas Company (SoCalGas) to adopt, as a backbone transmission planning standard, one-in-ten cold and dry year average demand.
3. Approves an agreement between PG&E and independent storage providers for direct interconnection to storage customers.
4. Endorses the creation of an Infrastructure Working Group which will enable all participants and relevant state agencies to monitor system utilization and identify expansion needs.
5. Clarifies and expands policies related to receipt point expansion on the SoCalGas system.

6. Finds that no party has identified a specific example of inadequate infrastructure affecting the delivery of gas over the next few years.

7. Directs the utilities to make new system adequacy filings in a new proceeding, incorporating the requirements set forth in this order including the need to consider the probability of peak-period storage withdrawal, and the deliverability of withdrawn gas when assessing the adequacy of the entire system.

8. Directs the utilities to propose quantifiable slack capacity standards based on the specific characteristics of their respective natural gas delivery systems and the need to ensure adequate service in times of emergency.

9. Raises concerns about the adequacy and competitiveness of unbundled storage in the SoCalGas service territory and orders the utility to file tariffs creating a cost-based recourse rate for storage customers willing to make a multi-year commitment.

10. Rejects SoCalGas' proposed revisions to its rules affecting open seasons related to local transmission capacity. SoCalGas seeks to establish a requirement that customers seeking firm capacity commit to 5- or 10-year contracts. The order cites the Commission policy, as established in Decision (D.) 02-11-073, stating that the Commission will not consider the merits of imposing long-term contracts until SoCalGas has established an approved program for tradable firm rights.

11. Directs SDG&E and SoCalGas to plan more explicitly for appropriate system expansions outside of the open season process.

12. In reviewing current gas quality standards, the order requires the preservation of the status quo in terms of safety, reliability and air quality, by keeping in place the current SoCalGas Rule 30 requirements and ordering adherence to the current Air Resources Board (ARB) compressed natural gas vehicles standards. Parties are encouraged to develop an alternative

means for maintaining the status quo while the utilities and others complete studies necessary to ensure safe, reliable, and clean natural gas service under revised air quality standards. The additional studies will include compliance with the California Environmental Quality Act (CEQA).

13. Adopts various minor changes to PG&E's Rule 21 and SoCalGas' Rule 30 establishing gas quality standards, to make the two rules more consistent with each other, but forgive existing in-state producers from complying with the rule changes when delivering gas from existing fields.
14. Directs the Energy Division, in cooperation with the California Energy Commission, to convene a workshop to develop a detailed strategy for additional studies necessary to ensure that new gas quality specifications will preserve safe, reliable, and clean natural gas service.

Background

The Commission explained the purpose of this proceeding in D.04-09-022. The rulemaking docket was opened in response to new reports, recent Federal Energy Regulatory Commission (FERC) orders, and ongoing changes in the natural gas market, which indicated that there may not be sufficient natural gas supplies or infrastructure to meet the long-term needs of the state's residential and business consumers. The Commission concluded that it needed to act in 2004 to ensure that: (1) energy efficiency and renewable energy programs help moderate the potential future supply imbalance; (2) there is sufficient firm interstate and intrastate pipeline capacity to serve California; (3) storage facilities will be fully and beneficially utilized; and (4) the utilities and their customers would have access to new natural gas supplies.

The Commission determined that it needed to decide a number of issues in 2004, due to the long lead time needed to construct LNG facilities and due to certain deadlines in 2004 involving the expiration of existing interstate pipeline capacity contracts and open seasons for certain pipelines, including pipelines related to proposed LNG projects. The Commission considered LNG to be an important new source of natural gas supply.

Because of deadlines facing the utilities and other participants in the natural gas market, the Commission established two phases in this rulemaking. The initial rulemaking ordered the respondents utilities to file, by February 24, 2004, Phase I proposed guidelines prescribing how they would:

1. enter into contracts with interstate pipelines (whether new contracts or renewals of existing contracts) to meet core supply obligations;
2. provide access on intrastate pipelines to LNG supplies; and
3. provide access to interconnecting facilities with interstate pipelines to increase California's access to natural gas supplies.

The initial rulemaking identified the following as issues for Phase II:

1. how the designated utilities should provide emergency reserves consisting of slack intrastate pipeline capacity, contracts for additional firm interstate pipeline transportation rights, and supplies of natural gas in storage dedicated for emergency needs;
2. The process by which the utilities would keep the Commission informed about the infrastructure and services provided to noncore customers, and to propose a crediting mechanism in the event a noncore backstop recovery charge is adopted; and
3. new ratemaking policies that will be consistent with the goal of ensuring adequate and reliable long-term supplies of natural gas at reasonable rates to California.

The Commission resolved Phase I issues in D.04-09-022. After various rounds of proposals and comments, the Assigned Commissioners issued a

Scoping Memo on February 28, 2005, that identified the specific questions to be addressed in Phase II as follows:

- Should the natural gas quality specifications for California be revised, and if so, how?

- Should the Commission adopt a standardized operational balancing agreement or certain specific criteria for upstream pipelines connecting to the gas utility's transmission system?

- Can the California gas utilities' existing infrastructure and operations adequately protect California from short-term or long-term natural gas shortages caused by interruptions in natural gas supply?

- Should the Commission order the gas utilities to provide emergency reserves for California in the form of additional intrastate capacity or slack capacity, additional interstate capacity, and/or additional in-state natural gas storage?

- Should independent gas storage facilities be permitted to directly connect with other market participants such as California producers, electric generators, or other noncore customers, which Public Utilities Code sections are relevant to this issue, and should the Commission be concerned with bypass?

- Should the Commission form a working group to monitor the infrastructure and services provided to noncore customers and to keep the Commission informed about the situation so that the Commission can consider whether the utilities should provide a backstop function for noncore customers?

- Should the Commission order the utilities to provide a backstop function for noncore customers who fail to provide for their own gas supply needs?

- Should the Commission adopt a crediting mechanism or another mechanism so that noncore customers who procure their own supplies do not have to pay for any such backstop function?

- Should the cost allocation issues regarding emergency reserves or a backstop function be addressed now or deferred until such time the Commission decides whether or not to adopt emergency reserves or the backstop function?

- Should the Commission determine in this proceeding whether the gas utilities' backbone transmission capacity is sufficient to accept maximum withdrawals from all gas storage facilities during peak periods, if emergency gas storage reserves are authorized, or should the Commission defer this issue until such time as it decides whether or not to adopt an emergency gas storage reserve?

- Are the current at-risk ratemaking provisions consistent with the goal of ensuring adequate and reliable long term natural gas supplies, and should the at-risk provisions remain in place or be eliminated for the gas utilities?

- Should PG&E remain at risk for noncore throughput, while at-risk ratemaking is eliminated for SoCalGas and SDG&E?

- Should the Commission address whether a balancing account should be established for PG&E's core local transmission revenue requirement in this proceeding or should this issue be addressed in PG&E's 2008 gas market structure proceeding? If it is to be addressed here, should such an account be established?

In a revised scoping memo issued May 11, 2005, the assigned commissioners expanded the scope of Phase II to examine electric utility plans to supply, transport and store natural gas for electric generation in those plants for which the utility is responsible to provide the gas.

The Commission held hearings on infrastructure adequacy issues beginning June 22, 2005, and ending September 1, 2005. The Commission held hearings on gas quality issues beginning December 12, 2005, and ending

December 16, 2005. The administrative law judge (ALJ) declared Phase II of this proceeding submitted as of the receipt of reply briefs on February 1, 2006.

In this decision, we resolve all of these issues, with the exception of those related to gas quality, which were the subject of separate hearings after the submission of Phase II briefs. We will address that subject in a separate decision.

Discussion

I. Measuring Infrastructure Adequacy for Natural Gas Utilities

A. Backbone Capacity - Defining the Standard

How much backbone pipeline capacity is enough?

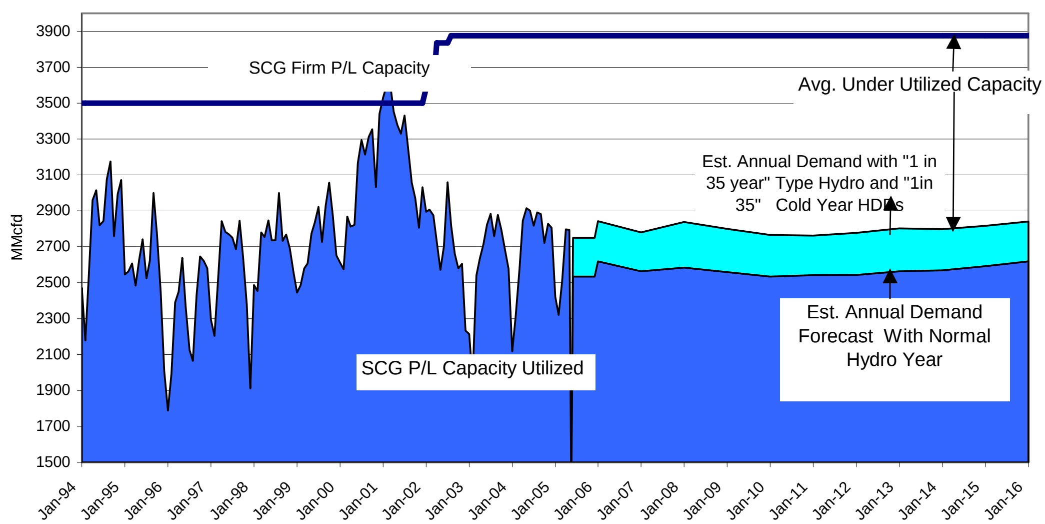
Most of the natural gas used in California comes from out-of-state natural gas basins. Natural gas from out-of-state production basins is delivered into California via the interstate natural gas pipeline system. The five major interstate pipelines that deliver out-of-state natural gas to California consumers are the Gas Transmission Northwest Pipeline, Kern River Pipeline, Transwestern Pipeline, El Paso Pipeline, and Mojave Pipeline. (Another pipeline, the North Baja Pipeline, takes gas off of the El Paso Pipeline at the California/Arizona border, and delivers that gas through California into Mexico.)

Most of the natural gas transported via the interstate pipelines, as well as some of the California-produced natural gas, is delivered into the PG&E and SoCalGas intrastate natural gas transmission pipeline systems (commonly referred to as California's "backbone" natural gas pipeline system). Natural gas on the utilities' backbone pipeline systems is then delivered into the local transmission and distribution pipeline systems, or to natural gas storage fields. The SDG&E system does not include storage, and does not interconnect directly with interstate pipelines. SDG&E refers to its largest pipelines as local transmission. Thus SDG&E does not consider itself as having a backbone pipeline system.

SoCalGas suggests that it should maintain total surplus capacity on its backbone system of 20-25% above average annual system total demand. PG&E proposes, and The Utility Reform Network (TURN) concurs, that the utilities should be required to maintain backbone transmission capacity sufficient to result in an 80%-90% utilization under cold temperature and dry hydroelectric conditions that have a one-in-ten-year likelihood of occurrence. This is the equivalent of an 11%-25% surplus capacity.

On TURN's behalf, Michael Florio asserts that PG&E's proposed guideline is generally consistent with historical reliability planning for electric service and should be sufficient to ensure both reliable natural gas service and a reasonable opportunity for price competition among competing supply sources. He notes that this would be somewhat stricter than what the Commission has endorsed in the past, in the sense that it takes into consideration the impact of adverse hydroelectric conditions on gas demand for electric generation, in addition to the traditional focus on the effects of colder-than-average temperatures on core gas demand. Florio argues that given the growing reliance on natural gas for electric generation, and the loss of alternative fuel capability in the electric sector, inclusion of dry hydroelectric conditions in the planning criteria is appropriate.

Southern California Edison Company (SCE) asks the Commission to reject SoCalGas and SDG&E's proposed slack capacity guideline, and adopt an alternative measure of infrastructure adequacy that takes into account peak period (stress) conditions, receipt point constraints, uncertainties in forecast loads and conditions, and other relevant factors. SCE offers a lengthy critique of the SoCalGas/SDG&E proposal. First, SCE argues that using average daily demand figures to determine slack capacity is wholly ineffective, particularly when considering the actual variability that occurs on SoCalGas and SDG&E's system during the year. System flows vary from day-to-day and month-to-month during the year, and do not adhere to simple flat annual averages. SCE points to Figure 1 in SoCalGas witness Jeffrey Hartman's testimony (Exhibit 8) to illustrate this point. This figure is duplicated below:



SCE points to the left side of the graph which shows the variability in the day-to-day and month-to-month capacity utilization on SoCalGas' system from 1994 to 2005, and argues that this variability highlights the flaw in using average annual flows to calculate the availability of capacity to meet system standards (as reflected on the right side of the graph). The question is: what would the peaks and valleys look like if the right side of the graph reflected actual demand? In other words, what might peak capacity utilization look like in future years, and how might that usage compare to the total available capacity?

SCE argues that the problem with the SoCalGas/SDG&E proposal is further exposed when considering peak conditions such as those that occurred in the course of the 2000-2001 energy crisis. As Hartman's Figure 1 shows, the SoCalGas/SDG&E system was highly constrained during 2000-2001. This is not immediately obvious from examining the average demand for the period June 1, 2000 through May 31, 2001, which was only 65% (3,410 MMcf/day[1]) of the peak send out of 5,210 MMcf/day on January 16, 2001.

Using data from the 2000 California Gas Report, Luis Pando, testifying for SCE, demonstrated that by looking only at averages, one would not have anticipated that problems were looming. He calculated that the annual average demand in mid-2000 yielded slack capacities of 24% on SoCalGas' system, and 59% for SDG&E's system, suggesting that there was more than adequate capacity at the time in both systems. Nonetheless, the SoCalGas backbone transmission system operated at peak capacity on several days. The SDG&E experience in 2000/2001 is similar. Despite the 59% slack capacity suggested by using averages based on the 2000 California Gas Report data, there were 17 days of curtailment on SDG&E's system between November 2000 and March 2001.

In short, using annual averages is ineffective when assessing the adequacy of the backbone transmission system during peak conditions.

SCE recommends that the Commission require SoCalGas to provide for the evidentiary record a peak-day capacity that SoCalGas is willing to stand by without qualification, or that the Commission complete an independent analysis

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[1] "MMcf/day" refers to "million cubic feet per day."

of the SoCalGas system to determine the peak-day capacity of the SoCalGas system.

SCE also questions the merits of SoCalGas' and SDG&E's planning approach, which uses different planning criteria for different parts of the system (for instance, there is one adequacy standard for the backbone system, and a different standard for local transmission). This can lead to contradictory conclusions concerning gas system infrastructure adequacy. Hartman's testimony suggests that when SDG&E's system is treated as if it were backbone transmission, it appears to have a very large slack capacity level (about 85%). However, Hartman then considers SDG&E's transmission system as local transmission, and concludes that SDG&E will need to expand its transmission capacity either by June 2007 or the winter of 2008/2009. SCE argues that using two different planning standards that produce inconsistent results makes no sense.

Another concern raised by SCE relates to the SoCalGas and SDG&E forecast of gas demand related to the generation of electricity. SCE argues that the gas forecast should consider the possibility that additional gas-fired generation could be needed if the San Onofre Nuclear Generating Station (SONGS) or the coal-fired Mohave Generating Station (Mohave) were to experience a prolonged outage or face retirement. Forecasting the gas demand for electric generation—although complex—is a threshold issue in determining the long-term reliability of gas transmission capacity. In addition, SoCalGas and SDG&E's proposed slack capacity measure does not quantify the strain put on the system by an extremely hot and dry summer or similar unusual load conditions over a five-month winter period. Existing criteria for local transmission do consider peak day deliveries, but these criteria do not explicitly cover system or backbone adequacy for peak day deliveries. Although summer constraints may not be a present concern on the SoCalGas system, higher electric demand in California and any corresponding increase in gas-fired generation to serve that demand could place a strain on SoCalGas and SDG&E's system in future years. SCE argues that SoCalGas and SDG&E's method of calculating slack capacity would be unable to detect such a constraint on their systems.

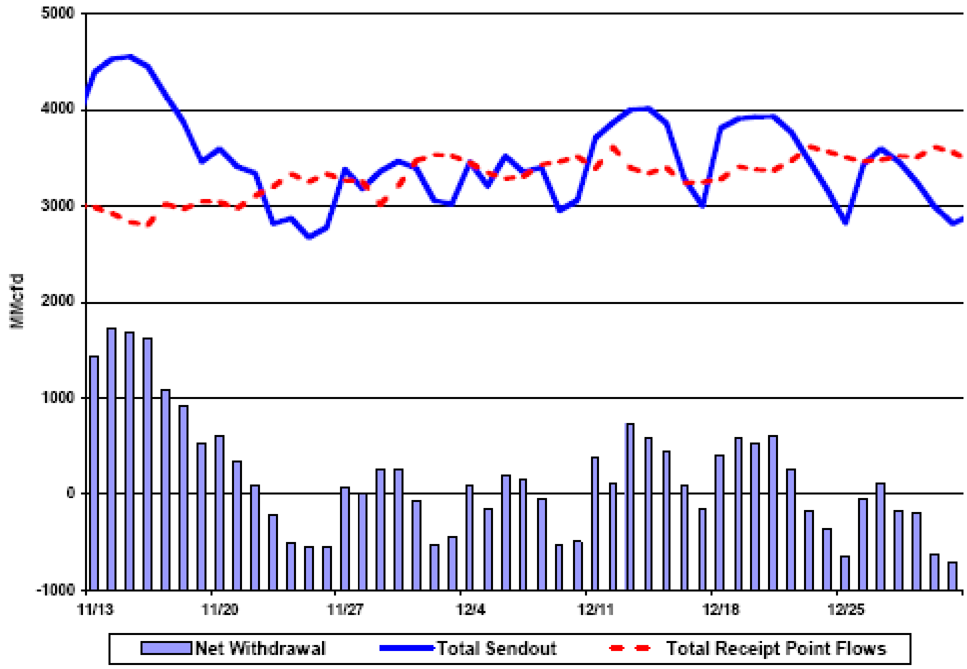
SoCalGas responds that its storage resources are sufficient to address these within-year swings in demand. When demand is lower than average annual levels, it can inject gas into storage, and when demand is higher than average annual levels, it can withdraw from its storage inventory to meet the load that exceeds the capacity of the backbone transmission system.

SCE argues that even if the total deliverable capacity on the SoCalGas and SDG&E system equals the sum of its backbone transmission capacity and its storage withdrawal capacity (including system draft), SoCalGas has the potential to substantially reduce the effective deliverability of the SoCalGas system because of its market discretion in procuring gas supplies for the core.

When a holder of withdrawal rights elects not to use them on any given day, but rather opts to import supplies, the capacity of the system to meet the needs of its customers is reduced. Currently, there is no requirement that the core use any or all of its storage withdrawal capacity when the system is constrained. SCE argues that if the core is not required to utilize its storage withdrawal rights on a peak-day, the calculation of slack capacity should not include that storage withdrawal capacity.

The effective slack capacity of the system is reduced when the core chooses not to withdraw from storage on a peak day. Figure II-1 from Pando's direct testimony (Exhibit 35) demonstrates what can happen when withdrawals change.

Figure II-1
Withdrawal, Sentout and Flows in Winter of 2000]



This graph shows SoCalGas system activity during a portion of the Energy Crisis in the Winter of 2000-2001. "Sendout" represents the amount of gas furnished to customers. The amount of flowing gas is represented by "Total Receipt Point Flows." Without questioning the reasonableness of the decisions underlying these activities, it is clear that when SoCalGas would stop withdrawing stored gas or reduce its withdrawals, the volumes of flowing gas would increase. This is not surprising, especially on those days when the withdrawals were less than zero, meaning that SoCalGas was injecting more gas while continuing to serve its customers entirely with flowing gas.

Pando testifies that if economic conditions do not motivate the core to use its storage capacity, what would otherwise be a 1,630 MMcf/day (37%) positive slack capacity could become a 305 MMcf/day (7%) shortfall. Under a one-in-ten cold year peak-day conditions, a decision by the core not to use its storage capacity on a peak day could mean the difference between a 735 MMcf/day (14%) surplus and 1,182 MMcf/day (23%) shortfall.

Finally, SCE asserts that the proposed backbone planning approach does not provide any insight into individual receipt point or transmission zone constraints. In fact, despite the fact that SoCalGas and SDG&E conclude that there is "adequate slack capacity" the utilities identify three areas of potential local transmission capacity constraint: the Imperial Valley, the San Joaquin Valley, and San Diego. Whether SoCalGas and SDG&E have identified all of the areas with potential capacity constraints is not clear at this time.

SCE urges the Commission to pursue this matter further. As illustrated in Figure II-2 in Pando's testimony, historical flows at SoCalGas receipt points demonstrate the receipt point constraint issue.

Figure II-2
Recorded Load Factor by Receipt Point

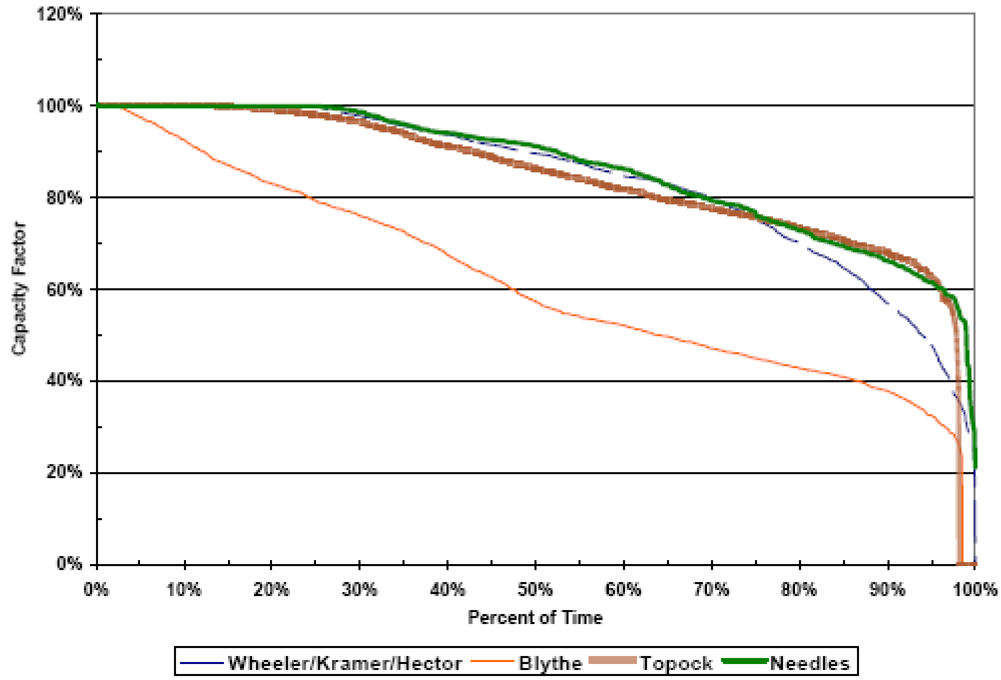


Figure II-2 shows the loading factor by receipt point using recorded available capacity and scheduled receipts. Receipt points such as Topock, Wheeler Ridge and Needles have shown little slack capacity a significant portion of the time, with Wheeler Ridge and Topock loaded about 80% a majority of the time. The Needles receipt point exhibits similar behavior. SCE argues that monitoring receipt point specific slack capacity is vital to assessing the need to expand receipt point capacity, and the adequacy of infrastructure generally.

B. Analysis

Before us in this part of the discussion are questions about the merits of maintaining slack, or reserve capacity on the backbone transmission system, and the appropriate standard to apply in determining whether and to what extent such a reserve exists. The Commission wanted to determine and apply the proper planning criteria for the utility backbone systems. It would be a mistake, however, to suggest that the backbone pipeline, or any other individual component of the utility storage and delivery system, can be viewed entirely in isolation. A pipeline is only sufficient if it works in harmony with the remaining infrastructure to provide relative assurance of meeting customers' needs.

The proposals offered by the utility are variations on a common theme—one with which we fundamentally agree: each utility can and should plan to ensure the overall adequacy of its storage and delivery system; however, since local constraints are largely the result of decisions made by individual shippers, it is incumbent on the utilities to work with individual shippers to determine their needs. A properly-administered "open season" process can be one tool to help the utilities make that determination. An open season is a public solicitation designed to secure commitments from shippers for the use of the pipeline. Although SCE is correct in suggesting that an adequate storage and delivery system is one that is free of local constraints, the utilities often can only plan to meet demand in the aggregate and to respond to individual constraints and expansion requirements as they arise.

The decision that launched this proceeding asked the utilities to propose "an emergency reserve for their systems consisting of excess intrastate pipeline and interstate pipeline capacity, as well as an additional reserve of natural gas in storage." The proposals were to specify "how much slack capacity should be available on their intrastate pipelines for emergencies…; whether or not PG&E's or SoCalGas' storage facilities should be expanded to help meet future California demand for natural gas; whether existing or new independent storage facilities should be expanded or constructed; and/or the extent to which expansion of intrastate pipelines may be necessary to enhance access to and flexibility in storage operations." (Rulemaking (R.) 04-01-025, *mimeo.*, p. 18.)

In order to determine the amount of slack capacity that should be available in the case of emergencies, it is necessary to identify, at least in a general sense, the nature of the emergencies against which the excess capacity would protect. SoCalGas and SDG&E did not offer an assessment of system adequacy as part of its Phase II proposals, filed April 23, 2004, nor did those companies discuss the applicable planning contingencies. PG&E did assess system adequacy as part of its Phase II proposals, and identified the following functions of emergency capacity:

1. To moderate gas prices through gas-on-gas competition
2. To ensure that gas customers do not become captive to a limited choice of supplies and rising prices during times of constraint
3. To ensure that gas at the California border is available to compete against any other supply source that might attempt to charge a commodity price higher than the otherwise available marginal supply
4. To guard against the impact of dry hydroelectric years on price and availability
5. To respond to increasing gas demand for electric generation
6. To moderate prices during some pipeline and storage facility emergency events (such as a sudden loss of capacity), as well as during periods of short-term variability of demand
7. To rely on long-term planning to avoid the high commodity prices that may result if the utility were to wait for the market to decide when there is a need for more capacity

In prepared testimony, SoCalGas and SDG&E do not address the scope of the emergency contingencies. Instead, those utilities discuss in a more general sense whether the customers will have all of the capacity they need. The need which they address is for enough backbone capacity to meet average demand.

The emergency concerns that easily come to mind include the failure of a major component of the delivery or storage system, an artificially-induced constraint on the flow of gas, a sudden or persistent loss of supply, an unpredicted and unplanned-for rapid increase in demand, or an excessive increase in the market price for gas. PG&E's description seems to envelop these concerns. What remains is to identify the characteristics that describe a system designed and built to protect against these contingencies and then use those criteria to assess the adequacy of the existing systems.

SCE was most conspicuous as it struggled with the SoCalGas/SDG&E proposed guidelines. Is it enough to plan for adequate pipeline capacity under average conditions? How will the utilities ensure that such infrastructure will serve demand under the most extreme circumstances? SoCalGas and SDG&E answer that it is most reasonable to rely on both stored and flowing gas to meet peak requirements—that a system developed to meet all peak requirements through flowing gas would, by definition, be overbuilt.

It is easy to endorse that proposition, as far it goes. This is a commodity that is easily stored for future use. We want to encourage a balanced reliance on stored gas because of the seasonal difference in gas demand and price, because there is a substantial storage capability, and because stored gas is an important physical hedge. The apparent problem comes from the manner in which the utilities treat storage withdrawal capacity for planning purposes. For instance, consider this table from the Prepared Testimony of Steven Watson on behalf of SDG&E and SoCalGas (Exhibit 11, p. 6):

Table 7: PG&E & SoCalGas Comparison

	SoCalGas MMcfd	PG&E MMcfd
Backbone Capacity	3875	3286
2003 Throughput	2608	2414
Annual Reserve Margin	49%	36%
Backbone Capacity	3875	3286
Firm Withdrawal Capacity	3175	2223
Theoretical Peak Service*	7050	5509
Peak-Day Demand 2006/7**	5578 (3414 Core 1-35) (2164 Noncore)	4755 (3255 Core 1-90) (1500 Noncore per 2004 CGR)
Peak-Day Reserve Margin	26%	16%

*Both systems have constraints that prevent them from simultaneously using all firm withdrawal in addition to all backbone capacities. Therefore, reserve margins on both systems are somewhat overestimated.

**SoCalGas has a 1-35 year peak-day planning criteria. PG&E's core planning criteria, APD, is 1-90. Neither utility plans to actually fully serve noncore under these conditions.

It is not enough to know that the combined available pipeline capacity and storage withdrawal rights[2] exceed peak demand by a certain amount. It is necessary to know that sufficient gas will be stored and that withdrawn gas can be delivered where it is needed when the system is most severely stressed.

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[2] For physical and economic reasons, not all of the gas in a storage reservoir can be withdrawn at any given time. A storage operator must determine its reliable withdrawal capacity and assign rights for individual customers to withdraw gas at any given time. These rights are referred to as withdrawal rights.

Watson acknowledges this concern, in the first footnote accompanying the table, without proposing a solution. In addition, the simple existence of storage and delivery capability does not ensure that each customer will actually choose to withdraw its full allotment of stored gas during peak periods. To the contrary, as SCE points out, sometimes, even utilities choose to inject gas during periods of high demand.

Without a demonstrated ability to deliver stored gas, and without an assurance that customers will rely on stored gas during system peak, it makes no sense to assume that the full storage withdrawal capacity represents a reliable resource for planning purposes. First, system planners must demonstrate that they will be able to deliver stored gas. If model runs under various scenarios demonstrate a substantial likelihood that some stored gas that might be delivered pursuant to firm withdrawal rights could not be effectively delivered during peak periods, then it is not reasonable to assume that the system can rely on all firm withdrawal quantities to serve peak demand. Further, planners must determine the probability that shippers will inject sufficient gas into the storage reservoir and the probable level of storage utilization at peak, and use those factors as part of the planning process. If it is only 70% likely that storage will be used at peak, then certainly no more than 70% of the storage should be included when calculating available capacity. There are arguments suggesting that the number should be even lower. Short of developing an appropriate and effective incentive for customers to utilize storage in a manner that benefits all customers, this is the reality under which the utilities must operate.

For planning purposes, PG&E, SDG&E and SoCalGas appear to have depended on shippers choosing to use storage fully at peak, and either assumed that stored gas could be delivered during peak conditions, or disregarded the issue. This may reflect an expectation, based on many past decisions, that core and noncore customers are basically on their own, in terms of establishing a storage strategy, and determining how to use stored gas. Stemming from this expectation is a sense that as long as there is sufficient capacity in the storage fields, it is up to the individual shippers to use it properly. This perspective is exemplified by SoCalGas' argument that there must be enough storage capacity on its system, because the noncore customers have not been fully subscribing to the storage rights available to them. This way of looking at the adequacy of the existing facilities does not sufficiently take into account the thrust of our inquiry in this proceeding. In the decision initiating this process, the Commission said:

> "In addition to procurement obligations for core customers, the California natural gas public utilities have public service obligations to all of their core and noncore customers in terms of how the utilities operate their systems. All four California natural gas public utilities are obligated to operate their natural gas distribution systems to meet the transportation needs of all of their core and noncore customers. In addition, PG&E and SoCalGas have storage facilities available to meet core and noncore needs, and both utilities also operate extensive intrastate pipelines, which provide access for core and noncore customers to supplies of natural gas from interstate pipelines, from in-state production of natural gas, to and from the utilities' own storage facilities, and, in the case of PG&E, to and from independent storage facilities.
>
> "In view of the future risk of California facing a natural gas shortage and much higher prices, the Commission proposes that the public service obligations of California natural gas public utilities, in their role as system operators, be expanded to include a requirement for maintaining "emergency reserves," which consist of: (1) slack capacity on the intrastate pipelines for maximum flexibility of access to storage and interconnecting pipeline facilities; (2) an emergency supply of natural gas in storage in California; and (3) a limited amount

> of additional interstate pipeline capacity subscribed to by the California utilities solely for the emergency needs of the utilities. In essence, we need insurance in the form of physical supplies that can be accessible to California in the event of an emergency. Even if utilities or some noncore customers enter into financial instruments that can hedge prices, the financial instruments provide inadequate protection to California, as a whole, if there is a physical limitation or supply interruption causing a shortage of natural gas supply for a short or long period of time. Natural gas is essential to provide heat and hot water in homes and businesses, for cooking food and drying clothes, and for fuel for many industries and electric generators. We therefore need access to and a supply of natural gas as a physical hedge to protect California in an emergency situation."[3]

In order to demonstrate this sort of system-wide ability to serve and to allow for the kind of flexibility needed to meet emergencies, it is not sufficient to demonstrate that the core customers have enough capacity for their purposes, and the noncore customers have as much as they are asking for. The critical questions go to the way the system operates as a whole. Enough capacity on the backbone system to satisfy demand on an average day is not adequate for system planning purposes if planners cannot depend on stored gas to make up the difference on the most severe peak day. That is what happens if customers do not reserve sufficient storage capacity, inject enough gas, and commit to make sufficient net withdrawals from storage during peak periods. The adequacy assessments submitted in this proceeding do not sufficiently take these considerations into account. For this reason alone, it is necessary for the utilities

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[3] R.04-01-025, *mimeo*., pp. 16-17.

to revise their plans. However, there are additional planning criteria that require our attention.

First, we must consider the choices made by the utilities concerning the type of day or year for which they would plan. To consider the adequacy of its backbone capacity, SDG&E and SoCalGas looked at average daily demand during a year with average weather conditions. For a similar purpose, PG&E looked at average daily demand assuming a year that is both the coldest and driest (least hydroelectric generation) one in ten years.[4] TURN endorses PG&E's approach.[5] The Division of Ratepayer Advocates (DRA)[6] does not offer an opinion concerning the standard that should apply.

There is nothing scientific about choosing a one-in-ten year standard, but there is something very logical about planning and maintaining a backbone system that can support an average day in a challenging year. It must be remembered that even in such a year, customers will often place significantly higher-than-average demand on each utility's gas supply system. Although SoCalGas and SDG&E propose a backbone planning standard that would focus on average consumption in an average year, those utilities have not offered a

[4] It is common for all three utilities to assume more severe service conditions when examining the adequacy of core resources.

[5] TURN also argues that if the system planning criteria are to take into account dry hydro conditions, then cost allocation to electric generation customers should be based on forecasted demand under the same dry hydro conditions that are used in system planning. While we note this concern, the issue is not before us in this proceeding.

[6] During the courses of the proceeding, after filing briefs on infrastructure adequacy, the Office of Ratepayer Advocates changed its name to the Division of Ratepayer Advocates.

strong justification for the adequacy of such an approach. The system must serve demand every year, not just during an average one. In our current era, with record high and low temperatures occurring almost every year, looking at severe weather conditions over a rolling ten-year period appears adequate. It is reasonable to require that each of the utilities plan for one-in-ten year cold and dry conditions, and we will direct them to do so.

Perhaps equally arbitrary is the particular percentage of slack capacity supported by various parties for planning purposes. When planning an electric system, there are well-understood benchmarks for the appropriate magnitude of system reserves. When planning generation reserves, it is prudent to ensure, at a minimum, that there is sufficient reserve to make up for the loss of the largest generating unit, or for a cluster of units dependent on a common transmission pathway. When planning a transmission system, it is important to plan for serving load even if the largest transmission line is suddenly removed from service. While these goals sometimes provide only a starting point for establishing electric reserve margins, they at least offer a common yardstick that can help guide utilities as they plan, and regulatory agencies as they set rules.

The proponents of various reserve margins, here, have not offered a quantifiable basis for establishing a specific backbone pipeline planning reserve. SDG&E and SoCalGas have declared that it is appropriate to maintain a 20-25% margin above the level of expected demand, but do not explain why. PG&E proposes an annual utilization of 80-90%, which is the equivalent of a reserve margin of 11-25%. PG&E argues that a reserve margin in this range will provide various benefits, but does not explain why its proposal represents the right numbers.

PG&E comes closer than the others to recognizing the importance of planning its system to meet certain contingencies. In her testimony (Exhibit 1, pp. 1-15), Halverson states, "even if there were a loss of 150 MMcf/day of on-system pipeline capacity over the year, annual capacity utilization still would be at 75 percent. Whether there would be shortages and price increases over some shorter period of time under such conditions would depend upon the size and timing of the loss and the level of available storage as well as any demand response to higher prices." Although this statement leaves many unanswered questions, it appropriately recognizes that the identification and assessment of contingencies such as the loss of pipeline capacity is an important aspect of system planning. It also provides a basis for quantifying a reasonable reserve margin, or slack capacity. By way of example, if the loss of the single largest backbone pipeline could reduce deliverability by more than 11%, then 11% may not be sufficiently high for the bottom of a slack capacity range.

Rather than declare the reasonableness of either of the slack capacity ranges offered by the utilities in this proceeding, we will direct the utilities to develop a quantifiable rationale for the adoption of a certain slack capacity standard, taking into account the goals of maintaining slack capacity as discussed above, planning contingencies reflecting potential physical constraints (both related to supply and transportation), and potential market problems. In addition, we will direct the utilities to estimate the costs and benefits associated with maintaining a particular slack capacity level. We will consider these proposals in a new rulemaking proceeding, which we will issue soon after issuing this decision.

C. Looking Specifically at Receipt Points - Management, Use and Expansion of Receipt Points

A receipt point designates the place on the delivery system where natural gas is transferred from one party to another. The nature of receipt points becomes an important factor in the context of this proceeding because SoCalGas manages its backbone pipelines by defining the maximum amount of flowing gas that the pipeline system can successfully receive and transport from any given receipt point along the backbone. The receipt point capacity is largely limited by downstream demand, the size of the backbone pipeline and the pressure of the flowing gas. These defined limits become a major point of contention between shippers who want the flexibility to introduce gas in the system at the place that provides the greatest economic benefit for them, and SoCalGas, which has an obligation to protect its ratepayers from excessive infrastructure investments.

Some parties have raised concerns related to the management and use of receipt points. Woodside Natural Gas advocates a specific way to allocate costs for receipt point expansions. We will address this issue later. The Kern River Gas Transmission Company (Kern River) shares SCE's concern for what it calls SoCalGas' lack of analysis of the adequacy of its receipt point capacity and a lack of clarity around its proposed framework for future receipt point expansions. SoCalGas submits that it "will construct additional facilities to increase transmission backbone receipt capacity if the Commission decides southern California needs additional capacity or … if other parties fund such expansion."[7]

SoCalGas continues:

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[7] Exh. 10 (SoCalGas –Hartman), p. 2, lines 8-11.

> "A more reasonable suggestion [for determination of the need of receipt point expansion] would be to monitor the utilization of SoCalGas receipt points. Then … consider expanding only those where shippers consistently seek access above the available capacity, despite an overall system wide excess reserve margin, if the receipt point can be expanded at a reasonable cost. If the Commission should find that the benefits of expansion outweigh the cost, the utility should expand the point's capacity. Alternatively, if the Commission does not find that the benefits outweigh the costs, shippers should be given the opportunity to fund the receipt point expansion. If shippers are willing to make such a commitment, the utility would undertake the construction."[8]

Kern River suggests that SoCalGas' proposed policy framework is comprised of three components: (1) monitor the utilization of the receipt points and consider expanding a point when shippers consistently seek access above available capacity; (2) perform a cost-benefit analysis to determine whether the benefits of the expansion outweigh the costs; and (3) where the Commission does not find that the benefits outweigh the costs, expand the system only if shippers are willing to fund it.

Kern River points out that under this proposal, monitoring the utilization of its receipt points is a critical event. The record is unclear, however, as to who would be doing the monitoring and how the data produced from the monitoring would be used to determine the need for receipt point expansions. Kern River asserts that in order for SoCalGas' proposal to work, the Commission must insist that SoCalGas better define the monitoring process—the Commission should

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[8] *Id.*, p. 4, lines 14-22.

place a specific obligation on SoCalGas to monitor the receipt points and report its findings to the Commission on a regular basis.

For Kern River, the next element of SoCalGas' proposed policy framework—the necessary cost-benefit analysis—is equally ill-defined.

SoCalGas has provided no concrete proposal on how such an analysis will be performed. Kern River offers that in order for SoCalGas' proposal to work, SoCalGas must establish, and the Commission must approve, a specific methodology to calculate the benefits of a proposed receipt point expansion.

Finally, we do not have before us reliable estimates of the costs of expanding SoCalGas' receipt point capacity. According to SDG&E and SoCalGas' witness Bisi, the cost estimates in his testimony are not detailed construction estimates and, as a result, are only generally accurate to plus or minus 30 percent—a significant margin of error. Further, in his testimony, Bisi offered cost estimates that he or his staff prepared in early 2004, and did not updated prior to SoCalGas' submission of testimony 18 months later.[9] During the hearings, he said, "If I were to prepare this testimony today, I would escalate all pipeline costs by approximately 30 percent."[10] He also agreed when asked if it would be very difficult to decide how to apply the 30 percent adder.[11] Another concern is the lack of clarity about how long the performance of a detailed

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[9] Tr. Vol. 3 (SoCalGas-Bisi), p. 279, line 27 to page 280, line 7. In a motion dated December 1, 2005, after the submission of reply briefs on this issue, SoCalGas offered updated cost data regarding some potential receipt point expansions. The motion is untimely and opposed. In addition, we do not need specific cost information for the purposes of this decision. For these reasons, the motion is denied.

[10] Tr. Vol. 2 (SoCalGas-Bisi), p. 235, lines 27-28.

[11] Tr. Vol. 3 (SoCalGas-Bisi) p. 282, line 22 to p. 283, line 2.

engineering construction estimate of a receipt point expansion would take. The record indicates that such an analysis could take six to eight months.[12] In order for the Commission to perform a cost benefit analysis of any proposed receipt point expansion, it must have a timely and accurate assessment of the costs.

Kern River argues that if the Commission adopts SoCalGas' proposed policy framework for determining the need for receipt point expansions, then it must provide some directives to make that framework effective. First, the Commission should require SoCalGas to monitor the use of the receipt points and to provide quarterly reports to the Commission clearly showing the extent to which shippers are (or are not) seeking access above available capacity. The Commission, with the assistance of interested parties, can then use this data to determine whether a cost benefit analysis of a particular receipt point expansion should be performed. Second, SoCalGas should be required to devise, and submit to the Commission within three months of the issuance of an order in this proceeding, a methodology for performing a cost benefit analysis for receipt point expansions. Parties should then be provided an opportunity to comment on the methodology. Finally, SoCalGas should be required to provide the Commission with usable cost estimates for receipt point expansions. Once having provided those estimates, SoCalGas should be required to update them on a periodic basis.

SDG&E and SoCalGas focused on their disagreement with the suggestion that the utilities should include specific receipt point capacity in their periodic resource adequacy assessments, citing the testimony of SDG&E/SoCalGas

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12 *See discussion*, Vol. 3, page 304, line 25 to page 305, line 13.

witness Hartman, and TURN witness Florio concerning the risk inherent in expanding specific receipt points in response to periodic demand.[13] Hartman offered his opinion that overall system capacity is a more reliable indication of infrastructure adequacy than capacity of particular receipt points, since demand at specific receipt points fluctuates over time.[14] Florio argued that heavy use of a particular receipt point does not necessarily justify expansion of that receipt point:

> "The mere fact that a particular receipt point may be constrained on occasion, or even over a fairly extended period, does not necessarily mean that an expansion is economically justified. As has often been observed in the context of electric resource planning, a certain level of congestion on the transmission system may in fact be economic, and new construction to relieve the constraint may not be cost-effective. This is especially true in an environment where the costs of different gas supply sources vary relative to each other over time. Just because the gas delivered at a particular receipt point is cheaper than other sources today does not necessarily mean that this condition will persist for a long enough period to justify the cost of system expansion."[15]

The utilities argue that heavy utilization of specific receipt points may not be a sign of system inadequacy, but may be the result of commodity pricing or other market factors that are subject to change.[16] Hartman stated that

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13 *See* SDG&E/SoCalGas Opening Brief, pp. 12-13.

14 SDG&E/SoCalGas/Hartman, Exh. 8, p. 9.

15 TURN/Florio, Exh. 43, pp. 1-2.

16 SDG&E/SoCalGas/Hartman, Tr. Vol. 1, pp. 61-65.

"utilization of commercially attractive receipt points can change over time."[17] He cited the example of the Topock receipt point, where receipts equaled or exceeded 90% of total firm capacity more than 75% of the time during the two storage cycles (April 1999-March 2001) coincident with the 2000-2001 energy crisis. During the past two years (May 2003-05), however, Topock receipts have declined significantly as the result of lower overall demand, and higher volumes both at the expanded Wheeler Ridge and the recently constructed Kramer Junction receipt points. As another example, PG&E expects decreased use of the Kern River Station receipt point for off-system deliveries to SoCalGas once LNG supplies flow into southern California.[18] Thus, SDG&E and SoCalGas argue, to the extent that expansion of a particular receipt point is prompted not by system reliability considerations, but rather by the desire to access supply on commercially favorable terms and conditions, it is wise to proceed cautiously.

This is a debate in which no one has to be proven wrong. Just as SDG&E and SoCalGas make a strong case for the complexity of receipt point planning, Kern River is persuasive when it asserts that the assessment of receipt point adequacy must be a disciplined part of overall system planning. It is conceivable that there could be more than enough capacity on the SoCalGas system as a whole, yet the system might be unable to deliver some of the potential flowing supply because of constraints at one or more receipt points.

To protect the integrity of the system and to ensure the ability to respond to emergencies, SoCalGas must track and document constraints, determine

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[17] SDG&E/SoCalGas/Hartman, Exh. 8, p. 9.

[18] PG&E Opening Brief, p. 7.

whether they are temporary or long-term, and respond accordingly. We agree with Kern River that SoCalGas has a specific obligation to monitor the receipt points and report its findings to the Commission on a regular basis. We are not persuaded by SDG&E/SoCalGas' concerns about reporting specific receipt point capacities. The suggestion behind their argument is that the Commission may be unreasonably influenced by what may be just a temporary constraint and order expansion that is not justified from a long-term perspective. This is not a necessary result. The utilities must report the numbers, but they also must report on their rationale for expanding or not expanding the capability of a particular receipt point. The burden is the utility's to make the case for the reasonableness of its planning decisions. We will adopt Kern River's recommendation of requiring SoCalGas to monitor the use of the receipt points and to provide quarterly reports to the Commission showing the extent to which shippers are (or are not) seeking access above available capacity. In addition, we will require SoCalGas to explain, in each report, why the company should or should not pursue receipt point expansion in response to existing or forecast constraints.

We also observe that the utility's analysis of the costs and benefits of a potential receipt point expansion could be a matter of significant controversy. Kern River suggests that we require SoCalGas to establish, and submit to us for approval, a specific methodology for calculating the benefits of a proposed receipt point expansion.

SDG&E/SoCalGas respond that in the Phase I decision, the Commission rejected their effort to establish a standard cost/benefit methodology and instead declared its intention to look at benefits and costs on an ad hoc basis. The utilities do not cite to a Commission decision to support this assertion. The Commission did not assess the merits of adopting a standard cost/benefit methodology and did not reach the conclusion that the utilities suggest. Rather, the Commission considered the utilities' generic proposal to allow for rolled-in rate treatment of LNG-related receipt point expansions. The Commission rejected this proposal, concluding that only once it is certain which LNG facilities will be constructed could the utilities or the Commission determine the true cost of system expansion. However, the Commission allowed that requests for rolled-in, or any alternative ratemaking treatment, could be filed as applications, with appropriate notice to customers. Those proposals, including the costs and cost recovery mechanisms, could then be evaluated on a case-by-case basis.[19] This is not a call for the use of an ad hoc approach for assessing benefits and costs, as SDG&E and SoCalGas conclude.

There are clear advantages to requiring the utilities to identify a cost/benefit methodology and submit it to the Commission for advance review. First, it would help ensure that the utilities take a consistent approach to considering the costs and benefits of various expansion proposals. Second, it could expedite future expansion efforts by eliminating the need to litigate the underlying methodology. Finally, it would help potential expansion proponents understand the cost-effectiveness of a potential receipt point expansion. For these reasons, we will direct SoCalGas to devise, and submit to the Commission within three months of the issuance of an order instituting a new proceeding, a methodology for performing a cost benefit analysis for receipt point expansions. We will provide parties an opportunity to comment on the methodology.

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[19] D.04-09-022, p. 68.

Kern River's third proposal—to require SoCalGas to prepare and regularly update cost estimates for receipt point expansions—presents a more difficult challenge. As the utilities point out, there are numerous variables affecting receipt point expansion including location, the size of the new demand, timing, and current downstream or upstream activities. SoCalGas could not, as a practical matter, model every likely permutation. In addition, such cost studies or updates take a lot of time and cost money. On the other hand, the lack of transparency related to expansion cost could hamper large shippers trying to make long-term supply decisions.

The appropriate balance is one where the utilities are not required to maintain and continually update the estimated cost of various expansion options, but are obligated to produce detailed cost estimates on request, in a reasonable amount of time, at a reasonable cost. SoCalGas stated on the record that cost estimates sometimes take six to eight months. This is not a reasonable timeframe for responding to a business request in this world of constantly fluctuating gas prices, even taking into account the iterative nature of the exercise. SoCalGas should take the steps necessary to respond more promptly to requests for cost estimates, whether this requires hiring additional personnel, having consultants on call, or both. We anticipate that customers will let us know if the company fails to meet this expectation.

D. Looking at Storage Adequacy and Practices - Is There Enough?

Storage service in PG&E's service territory consists of those facilities owned and operated by the utility, and those owned and operated by Wild Goose Gas Storage (Wild Goose) and Lodi Gas Storage (Lodi) (two independent storage providers). PG&E makes its case for the adequacy of the storage capability in its service territory by looking at potential usage from two perspectives: injection season and withdrawal season. In the months of April through October, there typically is a net injection of gas into storage. During this injection season, the system's ability to absorb a high demand or short supply event is relatively strong. For an example, PG&E discusses a major heat wave in the summer lasting five days that could result in as much as 300 MMcf/day of additional gas demand. This could be met with available pipeline capacity, or to the extent backbone transmission is flowing near capacity, with reduced storage injections. If, in this example, the demand initially was met entirely by reducing storage injections, then injections would fall behind by 1.5 billion cubic feet (Bcf). However, PG&E asserts that it would not be difficult to make up such a temporary shortfall in injections, by increasing injections by an average of 50 MMcf/day for 30 days, or 15 MMcf/day for 100 days, etc.

Similarly, during a winter cold snap, storage customers could increase withdrawals to cover the additional demand and replenish stored quantities during the injection season. In the Incremental Core Storage Application (Application (A.) 05-03-001), PG&E has proposed that PG&E's core customers hold backbone and storage capacity to meet a one-in-ten-year peak day demand.

Offering another example, P&GE discusses a major pipeline outage of an extended duration, causing loss of 600 MMcf/day of capacity for 30 days, that would result in a total loss of 18 Bcf of capacity. (PG&E notes that a pipeline outage of this magnitude is extremely unlikely.) In this example, there would be a need for 18 Bcf of additional supply and 600 MMcf/day of deliverability. Assuming 10 percent of the backbone capacity was available on PG&E's system (312 MMcf/day), and that 90 percent of this available capacity were used, 281 MMcf/day of supply could be delivered on the intrastate pipeline from supplies not interrupted by the outage. The remaining supply and deliverability in this instance could be met by using storage. The storage requirement would be 320 MMcf/day of deliveries for a total inventory of 9.6 Bcf. PG&E reports that during the injection season, there is a minimum of 1,100 MMcf/day of firm withdrawal capacity between PG&E, Wild Goose and Lodi Gas Storage. During the withdrawal season, the withdrawal capacity increases to over 2,000 MMcf/day. There is 79.2 Bcf of firm working gas storage inventory capacity.

PG&E presents these scenarios to support its contention that storage capacity on its system is adequate. Assuming that these hypothetical situations reflect the outward boundaries of likely contingencies (we note that PG&E has not asserted this to be the case), PG&E's contention would appear to be reasonable. Once again, the lingering question is whether PG&E would be able to deliver the gas to its customers, in the quantities represented by its firm withdrawal capacity, in the event that the backbone transmission system was otherwise constrained.[20]

SDG&E and SoCalGas face different circumstances related to storage. In southern California, SoCalGas is the only storage provider. Although SoCalGas asserts that there are other realistic storage options for southern California shippers due to the presence of Wild Goose and Lodi to the north, SoCalGas has

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[20] As part of a settlement between PG&E independent storage providers, to be discussed later, those parties stipulated that PG&E's backbone capacity is sufficient to deliver withdrawn gas during peak periods. While this stipulation may eliminate a potential dispute between those parties, it does not provide a factual basis for us to conclude that the backbone is adequate for this purpose as it relates to all of the storage customers on the PG&E system.

not offered sufficient evidence to support this contention. It has not demonstrated that southern California shippers could rely on the transmission capability necessary to move gas to storage in the north, or to take southern delivery of gas withdrawn from Wild Goose or Lodi storage facilities. Nor has it demonstrated that these facilities comprise an economically viable option in light of the added transportation costs involved in moving stored gas across the state. Neither has any other party proven that this contention is incorrect.

SoCalGas currently holds 122.1 Bcf of storage capacity, 3175 MMcfd of firm withdrawal capacity and 850 MMcfd of firm injection capacity.[21] SoCalGas' Watson asserts that SoCalGas' existing storage capacity is adequate to meet forecasted customer demand through 2016, observing:

> "Over the next several years, SoCalGas' existing storage facilities have sufficient capacity to meet customer needs. This can be demonstrated by (1) the fact that bundled core and balancing storage requirements can be accommodated with current storage facilities without significantly diminishing the size of the unbundled storage program, (2) the lack of long-term contracts for unbundled storage, (3) the modest level of market prices for short-term sales of SoCalGas' unbundled storage, and (4) the fact that there are many competitive alternatives to SoCalGas' unbundled storage service that can provide customers the same values as SoCalGas storage."[22]

He noted further that the total storage inventory and withdrawal capacity of SoCalGas significantly exceeds that of all northern California storage fields combined.

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[21] Injection and withdrawal capacity depends on physical inventory.

[22] SDG&E/SoCalGas/Watson, Exh. 11, p. 1.

The difficulty with this presentation is that it answers questions other than those posed in this portion of the proceeding. The relevant question is whether the storage capacity, injection rights, and withdrawal rights are sufficient to meet customer demand and provide a sufficient cushion to respond to emergencies. SoCalGas has answered other questions, instead. When SoCalGas states that bundled core and balancing storage requirements can be accommodated with current storage facilities without significantly diminishing the size of the unbundled storage program, it is saying little to address the issue of overall system adequacy. Instead, it is commenting on the sufficiency of storage to meet core demand without significantly reducing unbundled storage opportunity. These observations could be true even if there were too little storage, beyond the needs of core customers, to meet total noncore demand, maintain system reliability, and anticipate emergencies.

When SoCalGas remarks on the lack of long-term contracts for unbundled storage and the modest level of market prices for short-term sales of SoCalGas' unbundled storage, it is reflecting on its incentive, under current storage policy, to develop additional storage capability, regardless of the need. SoCalGas is not arguing that it is unable to sell its unbundled capacity, injection rights and withdrawal rights. To the contrary, unbundled capacity and injection rights have been oversubscribed in recent years, and withdrawal rights sales have hovered at about 80% of the total amount available. Neither is SoCalGas arguing that it is unable to recover its fixed and variable cost of unbundled storage service. To the contrary, it has been able, in recent years, to recover all of its variable and fixed costs and still have revenues that exceed fixed costs by 40%. What the gas company is saying is that it wants to see higher profits and a higher percentage of long-term sales before it would be willing to take on the risk associated with storage expansion. While this is an interesting commentary on current storage practices, it does not answer the question of whether there is enough storage.

We have already commented on SoCalGas' assertion that there are many competitive alternatives to SoCalGas storage. In this regard, the company has not made its case. Even if it had, the question would remain as to whether the SoCalGas system is adequate. For these other asserted opportunities to have an impact on that analysis, SoCalGas would not only have to demonstrate their practical availability, it would also have to quantify their impact on SoCalGas' system reliability. Simply alluding to potential alternatives to SoCalGas storage does not make that case.

Perhaps the most relevant portion of SoCalGas' analysis can be found in Table 7 in Watson's Direct Testimony (Exhibit 11, p. 6), which is replicated earlier in this decision. This table attempts to demonstrate that the utility has sufficient capacity to meet peak day demand, and sufficient reserve to secure against emergencies. This addresses the correct question. However, the answer remains deficient. While the numbers suggest the existence of a 26% cushion above peak day demand in 2006-2007 when one compares that forecast to the sum of total backbone pipeline capacity and total firm storage withdrawal capacity, Watson acknowledges that SoCalGas cannot simultaneously use all firm withdrawal and all backbone capacity, which means that its estimated cushion is overstated.

Based on the record before us, we cannot tell how overstated that estimate is. In addition, Watson's calculation does not reflect an assessment of the probability of injection and withdrawal by various shippers actually occurring, nor does he assess the deliverability of withdrawn gas over the local transmission system on a peak day. It is unrealistic to rely on the exercise of all withdrawal rights if customers are not required to inject enough gas or to exercise their withdrawal rights, or if SoCalGas cannot deliver all of the withdrawn gas to the customer. Each company must factor the likelihood of these occurrences into its assessment of system adequacy.

In addition, in assessing system adequacy, the utilities do not appear to consider the impact of a major change in the demand for gas to serve electric generation due to the extended loss of a nuclear unit, or the shutdown of another non-gas-fired generator such as the Mohave Generating Station (which closed after the completion of hearings in this phase of the proceeding as anticipated in D.04-12-016). SCE raised this issue in the context of the assessment of backbone adequacy. SDG&E and SoCalGas responded by arguing that:

> "SCE appears to believe that the [electric generation] forecast should take into account every potential occurrence that might affect demand. This approach to ensuring system reliability and meeting customer demand is ill-advised, however. Planning backbone transmission facilities to meet all extreme conditions that might occur would result in a needless build-up of capacity and unnecessarily high rates."[23]

PG&E made a similar point in its Opening Brief. There are two reasons that we cannot agree with the gas utilities' perspective on this point. First, the loss of Mohave was not like most other potential occurrences. As we took evidence in this proceeding, we were considering the potential loss of the Mohave plant in a separate docket. The facts surrounding that facility, and the looming potential of a shutdown, were well-known. SCE operates and owns the majority interest in the Mohave plant. It reminded SDG&E and SoCalGas of the

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[23] Reply Brief of SDG&E and SoCalGas, p. 27.

situation at Mohave through its participation in this proceeding. SDG&E and SoCalGas should have considered the loss of Mohave and the resulting impact on gas demand when assessing the adequacy of its infrastructure.

Second, just as it would be wrong for an electric utility to fail to plan for the potential loss of a nuclear unit, it is inadequate for the gas utilities to ignore this contingency. An electric utility must plan for the loss of a nuclear plant because it is the largest single source of electric generation. A gas utility must plan for such a loss because the alternative source of generation is likely to be gas-fired.

Considering the significant time needed to establish new storage capability, it is a matter of concern that the utilities have not planned for the possibility that demand for natural gas might grow at an unexpectedly high rate during the next few years. Nor have the utilities assessed system needs in the event of a dramatic change in supply from a particular source, such as Canadian or Rocky Mountain gas, or a sudden loss of gas from a major LNG facility due to a cataclysmic failure at a processing facility here or abroad, or a redirection of supply. Most significantly, the utility analysis does not consider the possible need for storage capacity to hold large shipments of imported gas.

SCE argues that a problem for electric ratepayers is what SCE characterizes as SoCalGas' market power over the sale of storage rights. SCE and the Southern California Generation Coalition assert that SoCalGas has a monopoly on natural gas storage in southern California and has unparalleled pricing flexibility in the sale of its storage services. While an interstate pipeline experiences flexibility in charging for pipeline services, including storage services, no interstate pipeline can charge an amount for a service that is greater than its cost of service cap for such services. For SoCalGas, under its G-TBS tariff, its price cap for any given service is the sum of the cost of all services under the tariff. It is the noncore customers, particularly electric generation customers, that bear the most of the burden of those charges. SCE argues, further, that as the backbone transmission system grows tighter and noncore gas-fired electric generation load swings get larger, SoCalGas' ability to price its storage services at well above cost-of-service levels will become more economically burdensome to electric ratepayers.

Testifying for the Southern California Generation Coalition, Catherine Yap argues that SoCalGas is making an extraordinary amount of money under its current ratemaking arrangement with a minimal amount of risk.

> "SoCalGas characterizes its unbundled storage revenues as $47.4 million of which it shares 50 percent or $23.7 with ratepayers. Watson Direct at Table 8. A copy of SoCalGas' Response to SCGC DR 4.20 has been attached to this testimony as Attachment C, which shows the annual revenues for SoCalGas' unbundled storage program from 2000 to 2004. SoCalGas only bears 50 percent of the risk of the $21 million dollars allocated to the unbundled storage program, or a total of $10.5 million. Therefore, SoCalGas is making a return of $23.7 million while risking only $10.5 million. This amounts to a return of 226 percent on top of the return that SoCalGas otherwise earns on its storage facilities in rate base. This sort of return doesn't seem very modest at all." (Exhibit 50, p. 5.)

In Watson's rebuttal testimony, SoCalGas responds that the excess returns in 2003 were $26.4 million, rather than the $23.7 million reported by Yap, and then went on to say:

> "Of the $26.4 million of 'excess returns' in 2003, half were refunded to ratepayers through the Noncore Storage Balancing Account. Therefore, in 2003 SoCalGas shareholders earned $13.2 million over and above a $21 million allocated cost, or a 63 percent above-normal pre-tax return."
> (Exhibit 12, p. 4.)

Even if Watson's way of calculating its net revenues were more accurate than Yap's, it would be difficult to characterize SoCalGas' net revenues from its unbundled storage sales as anything less than extraordinary. It must be remembered that these are revenues above-and-beyond a return on ratebase. The observation that ratepayers also receive a share of the net revenues does not change the fact that the unbundled storage business, in its current form, allows SoCalGas to realize a return that, in Yap's words, is "not very modest at all."

SCE finds SoCalGas' pricing discretion in the market for natural gas storage services particularly disturbing given its proposal, here, to transfer a proportion of its firm withdrawal rights from its "unbundled" storage program and system balancing to the core. According to Watson, SoCalGas proposes to reallocate its 3,175 MMcf/day of firm withdrawal capability as follows: the core's rights would increase from 1,935 MMcf/day to 2,289 MMcf/day, while the unbundled program's rights would decrease from 990 MMcf/day to 726 MMcf/day, and the system balancing figures would decrease from 250 MMcf/day to 160 MMcf/day. With less supply of unbundled withdrawal rights available to the market and less balancing flexibility for noncore transportation customers, SoCalGas would arguably be in a better position to increase prices for services under its G-TBS tariff.

SoCalGas also proposes to require noncore customers seeking an increase in firm storage withdrawal rights to commit to 15 year contracts. SCE argues that by transferring additional storage rights to the core, SoCalGas hastens the time when there will be no alternative to such a noncore commitment.

SDG&E and SoCalGas respond to SCE's market power concerns by stating that unbundled storage customers have many alternatives they can and do consider, including financial mechanisms to price-hedge, flowing supply alternatives to balancing supply and demand, and storage outside of the SoCalGas territory.

It is true that unbundled storage customers can consider financial hedges and flowing supply as procurement planning options. However, storage serves purposes far beyond price hedging, and provides certainty that cannot be matched by a reliance on flowing supply. Just as we would never approve a plan under which SoCalGas would surrender all of its core storage rights and rely exclusively on financial hedges, we would not expect prospective unbundled storage customers to consider financial hedges and storage to be equal and entirely interchangeable. Stretching a metaphor to make a point, storage and financial hedges are competitors much the same way that health care and life insurance are competitors. While it is true that insurance can provide financial compensation for loss of life, it is hard to argue that good life insurance and good health care are the same thing.

Similarly, neither SoCalGas nor its unbundled storage customers could rely exclusively on flowing supply in lieu of storage. In their Opening Brief, SDG&E and SoCalGas characterized flowing gas as a "near-perfect" substitute for unbundled storage. The essence of this argument is that electric generators, as the largest noncore customers, experience their highest gas demand in the summer, when there is most likely to be excess capacity available on the backbone system.

The Southern California Generation Coalition does not address this point directly, but argues that flowing supply is not a near-perfect substitute for an electric generator that needs to protect its native load customers from the results of constrained transmission capacity. In such circumstances, holding storage capacity rights downstream of a transmission constraint can ensure the supply of gas needed to meet demand. The Coalition argues that the alternative to storage in this situation would not be flowing supply. It would be to go out of balance and, in effect, commandeer storage services by taking supply off of the SoCalGas system and exceeding imbalance tolerances. Of course, Commission policy and SoCalGas tariffs strongly discourage this practice.

Storage and flowing gas both provide valuable services, but they are far from interchangeable. In addition, Hartman, on behalf of SDG&E and SoCalGas, acknowledges that by relying on flowing supply, the price of gas will be higher than it would be if one were to buy gas pro rata all through the year, inject it into storage in the summertime, and then withdraw it in the winter.[24]

Storage is a unique service. There is value to maintaining physical reserves that cannot be matched through paper transactions, or flowing supplies. SoCalGas understands that, and is seeking to set aside even more storage to protect its full-service customers. As we have said earlier, while SoCalGas argues that storage facilities outside of its service territory are worthy competitors, it has not supported its assertion with facts. Simply pointing to facilities in northern California does not make those facilities equal and full competitors.

In the abstract, it is logical that a firm that stands to receive greater profit when there is a perceived shortage of the service it provides might be motivated to keep the service in short supply. While all firms seek to maximize profits, economic theory suggests that there is not much that a firm in a competitive market can do to reach that result, other than to reduce costs and continue to

[24] Tr. 82.

expand its service until marginal revenue equals marginal cost. That is because a competitive firm is expected to be a price taker, not a price setter.

In its testimony, SoCalGas describes the process under which it seeks to maximize the revenue it receives from providing noncore storage service. When SoCalGas discusses the adequacy of its storage capacity, it does not suggest that it has reached that critical point where it could not achieve additional net revenues by providing more storage service. SoCalGas merely asserts that at the current level of profitability, it is not motivated to increase its storage capability. Clearly, unbundled storage revenues are sufficient to cover costs. Instead, SoCalGas states that the revenues are not as high as it would like, and the purchase commitments are not for as long as it would like. This is a perspective more associated with a price setter, than a price taker.

At a minimum, these circumstances support the conclusion that the utilities must do a more rigorous job of assessing the adequacy of current backbone and storage facilities. It is not enough to look only to the bidding behavior of potential buyers to determine whether resources are adequate. These conditions also suggest that the adequacy of the core storage set-aside should be reviewed not in a generic infrastructure adequacy context, but in a proceeding more directly focused on core service. Permission to increase the core set-aside must be based on a clear showing that it is the appropriate step to take as part of the overall core procurement effort. For these reasons, we will not rule on SoCalGas' core set-aside proposal in this proceeding.

The Southern California Generation Coalition asks the Commission to go further by concluding that in the absence of meaningful competition, SoCalGas should be required to charge for its unbundled storage services based on the cost of service. In the alternative, the Coalition seeks price ceilings for storage inventory, injection, and withdrawal services. In that SoCalGas has failed to demonstrate the existence of effective storage competition, it is appropriate for the utility to offer a cost-based recourse rate for a fixed period of time. For instance, a three-year recourse contract featuring cost-based rates might protect customers from the potential exercise of market power, while enabling SoCalGas and its customers to negotiate shorter or longer term commitments on some other basis. We will direct to SoCalGas to file an application seeking the approval of such a recourse rate within the next 90 days.

While both PG&E and SoCalGas assert that there is currently more than enough storage capacity, Lodi argues that demand exists for additional gas storage, injection and withdrawal capacity. To support its position, Lodi points to evidence of the full utilization of Lodi's storage facility, Wild Goose's recent expansion of its storage facility, Lodi's application for further expansion of its storage facility, and both PG&E and SoCalGas' interest in increasing the core storage set-aside. Lodi does not offer its opinion as to what the Commission should do, if it finds Lodi's arguments to be persuasive.

None of these factors provides direct evidence of demand for capacity beyond that which already exists. The fact Wild Goose and Lodi are both willing to expand their facilities might suggest that those entities foresee unmet demand, although it also just might suggest that they see an opportunity to win over utility storage customers by offering a superior product or lower prices.

Our interest is to ensure that there is sufficient storage to meet the demand for storage and to work in concert with the pipeline system in a manner that ensures overall system reliability. For all of the reasons we have discussed, we cannot reach the conclusion Lodi seeks based on the record before us.

We take comfort in the fact that all parties (with the exception of Lodi) appear to support the contention that the current backbone pipeline and storage infrastructure are sufficient. However, we have yet to receive the kind of rigorous analysis that would allow us to share that conclusion. Perhaps more significantly, we are not persuaded that the utilities have in place an approach to planning that will ensure future system adequacy. We will direct the utilities to file new infrastructure assessments, consistent with this decision, in a new proceeding. As part of this process, we hope to be able to make a more informed determination of the adequacy of storage facilities and practices.

E. How Should the Gas Utilities Use Core Storage?

SCE points to events during the energy crisis of 2000-2001, when, it argues, SoCalGas withheld withdrawal capacity during several days in December 2000. SCE argues that the use of the storage system in this instance reflects a choice by core procurement to rely on flowing supplies that in turn constrained capacity at receipt points as they operated at above 90% capacity factor for the month of December, and that this choice had a direct impact on the high gas and electricity prices that severely impacted electric ratepayers.

Johannes Van Lierop, testifying for SoCalGas, points out that noncore customers, not just the core, injected gas and had decisions to make about withdrawal. SCE responds that any party that can control the greatest amount of storage withdrawal can control the amount of congestion and prices at the SoCalGas border, and that the Commission should require the party that controls significant withdrawal capacity to utilize that capacity to alleviate any receipt point congestion.

SoCalGas argues that SCE's proposal for such storage withdrawal guidelines would lead to an unfair subsidization of noncore customers by core customers. The utility noted that the Commission has previously addressed noncore customers' management of their own storage and reliability needs and has stated that it "never intended that SoCalGas would be a provider of last resort for gas shippers who did not wish to assume the risk associated with market price variability which occurs with the change in seasons," and expressly rejected the notion that the SoCalGas storage system should be available for the economic convenience of noncore customers."[25] DRA agrees with SoCalGas. SCE counters that the core receives preferential treatment in obtaining its storage withdrawal capacity, and that this results in a cost to noncore customers who are left to pay a steeper price for the remaining storage opportunities.

SCE raises an important concern: the effect that the failure to withdraw gas from storage during peak periods can have on all other customers. A failure to withdraw at such times may constrain the capacity of the backbone pipeline, and put upward pressure on gas prices at the California border. It reduces the capability of the intrastate system to respond to emergencies.

Our current rules and incentives do little to guard against this result. SCE would address the problem by creating a withdrawal obligation for SoCalGas on behalf of its core customers. Since SoCalGas controls by far the largest share of storage capacity on behalf of its customers, SCE's proposal is understandable. The problem is that it lacks symmetry. If SoCalGas should have an obligation to withdraw gas, why not place the same obligation on unbundled storage

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[25] D.97-11-070, at p. 12.

customers? Perhaps one reason is that such an obligation might discourage noncore customers from acquiring and using injection rights in the first place.

Under current practices, all customers, including core, are encouraged to act in their own best interest. This is the distinguishing characteristic of an increased reliance on market forces and economic signals. What SCE demonstrates is that when all customers have to rely on a single network of pipes and storage, self-interest is not always consistent with that of the greater body of customers. This is a problem that we cannot address without reconsidering the obligations of shipping customers and the way that economic incentives are applied. It is a problem beyond the stretch of this admittedly broad proceeding, but one that is worthy of our further attention.

F. Should New Storage Facilities Be Part of Rate Base?

It appeared, to several parties, that SDG&E and SoCalGas were proposing that new or expanded unbundled storage facilities be included in rate base. The utilities responded by stating that they are making no such proposal. Since this is the case, we will not address that issue here.

G. Planning and Expanding the Local Transmission System

In its showing, PG&E has not addressed its local transmission adequacy or planning approach in significant detail. SDG&E and SoCalGas, on the other hand, discussed these issues in detail and engendered a debate with some of the other active parties.

The Commission requires SDG&E and SoCalGas to apply the following planning criteria to their local transmission systems: the systems must be designed to provide service to core customers during a 1-in-35 year cold day event (one curtailment event in 35 years) and service to firm noncore customers during a one-in-ten year cold day event (one curtailment event in 10 years).[26] These utilities often use open seasons to measure the level of commitment of various customers to the use of local transmission capacity.

Hartman describes the current SDG&E/SoCalGas proposal as follows:

> "For non-constrained local transmission service areas, all noncore customers would be able to obtain firm transportation service by simply executing the standard two-year transportation agreement. For purposes of establishing the monthly contract quantity (MCQ), the following conditions would apply:
>
> "MCQs shall be derived from historical daily consumption data based on the most recent 24 months for which data is available. The MCQ may not exceed the highest recorded peak day usage for a particular month times the number of operating days.
>
> "Alternatively, customers may provide a forecast of consumption as the basis for their MCQ, provided those quantities do not exceed recorded historical usage.
>
> "Customers may request higher MCQs by submitting a letter attesting to changes in their operation or equipment warranting adjustments to historical peak day usage (i.e., pursuant to condition 1) and the schedule timing for these changes. A load survey will be required documenting the increase as a result of adding new equipment or increasing load.
>
> "Speculative or unsubstantiated requests for MCQ amounts will not be permitted.

[26] D.02-11-073, *supra* note 13 at *46, Conclusions of Law Nos. 1 and 10 at *68-70; SDG&E/SoCalGas/Bisi, Exh. 7, pp. 13-14.

> "SoCalGas believes that these existing mechanisms are workable in areas where there does not appear to be any potential constraint based on historical load and customer projections of future load."[27]

With regard to the overall adequacy of local transmission facilities, SDG&E and SoCalGas' Morrow observed:

> "SoCalGas and SDG&E are prepared to expand transmission facilities as needed to serve core needs and firm commitments of noncore customers. Due to the wide geographic distribution of our system, and the nature of customer loads, local areas of the system can become constrained where demand for firm capacity can exceed the available firm capacity. Although there is a limit on the firm capacity in these areas, so far the available capacity has been sufficient to meet customer requests in the most recent open seasons except for some minor prorations in the Imperial Valley."[28]

Although Morrow states that available capacity on the SDG&E and SoCalGas systems has generally been sufficient to meet customer demand, SDG&E and SoCalGas' witness Bisi identified three areas of potential local transmission constraint: the Imperial Valley,[29] the San Joaquin Valley[30] and San

[27] SDG&E/SoCalGas/Hartman, Exh. 8, p. 11.

[28] SDG&E/SoCalGas/Morrow, Exh. 4, pp. 7-8.

[29] During the most recent open season that concluded in March, 2005, the capacity of the Imperial Valley System was fully subscribed during the summer operating season, however excess capacity is available during the winter operating season. (SDG&E/SoCalGas/Bisi, Exh. 7, pp. 14-15.)

[30] During the most recent open season that concluded in March, 2005, the capacity of the San Joaquin System was undersubscribed during both the summer and winter operating seasons. (*Id*. at p. 15.)

Diego.[31] D.02-11-073 authorized SDG&E and SoCalGas to hold open seasons in these areas for purposes of allocating firm transmission capacity.[32] Under the open season approach adopted by the Commission in D.02-11-073, parties may bid for capacity on the basis of 24-month commitments, and are subject to take-or-pay obligations intended to "encourage customers to bid realistically and to prevent gaming on the system."[33] In the event that bidders oversubscribe to the available firm capacity, the utility prorates available capacity equally across the customer base.[34] To date, SoCalGas has concluded two open seasons in both the Imperial Valley and the San Joaquin Valley, and SDG&E has now concluded its second open season in San Diego. Morrow testified that the open seasons held in San Diego and in the Imperial and San Joaquin Valleys have proven to be useful in gauging customer needs and expectations.[35]

In D.02-11-073, the Commission was somewhat ambiguous as to the applicability of the one-in-ten year planning standard. It clearly applies to a determination of whether the local transmission facilities serving a firm customer are sufficiently reliable. What is less clear is whether the Commission intended to require that the utilities apply the one-in-ten year standard to the adequacy of

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[31] During the open season that concluded in May, 2005, the SDG&E system was fully subscribed during the winter operating season, while excess capacity was available during the summer operating season. (*Id*. at pp. 15-16.)

[32] D.02-11-073, *supra* note 13 at *20-22, 47-49.

[33] *Id*. at *21, 48-49.

[34] *Id*. at *22, 49.

[35] SDG&E/SoCalGas/Morrow, Tr. Vol. 2, pp. 161-162.

the system to serve all noncore customers, whether or not they have made a firm commitment to pay for transmission capacity. The Commission recognized in D.02-11-073 that "[o]pen seasons can test the need for further expansions beyond those indicated by application of the planning criteria," and further that reliability of demand estimates increases when customers are required to commit to the level of their bids and are made subject to take-or-pay provisions.[36] SDG&E and SoCalGas now propose a local transmission expansion policy that places even greater reliance on the result of an open season. As explained by Hartman:

We are proposing to modify the existing firm service provisions in the utility tariffs in the following manner to align long-term customer needs more closely with timeframes required for utility expansion of local transmission systems. In areas where we anticipate that requests for firm service exceed the capacity of the local system, either through a proration of existing capacity in a two-year open season, or specific information from customers that their firm service requirements are increasing, and the cost of the required expansion exceeds $5 million, SoCalGas and SDG&E would conduct an open season for long-term firm service needs. For that open season, we would estimate the needs for core customers over a ten year period, and then solicit binding bids for firm service by noncore customers for daily capacity based on the following segmentation:

Customers that have loads that have significant impacts on sizing of facilities would be provided the option of bidding for daily firm transportation

[36] D.02-11-073, *supra* note 13 at *48.

service for a 10-year term based on a [use-or-pay provision ("UOP")] as currently defined in utility tariffs.[37] That UOP is roughly comparable to a financial commitment for 60% of the value of firm transportation service. We propose that G-30 customers with peak usage of at least 20 MMcfd and EG Tier 2 customers would be eligible to obtain long-term firm service under this provision.

Customers with smaller peak loads, i.e., EG Tier 1 and G-30 customers less than 20 MMcfd, would be eligible to secure firm service under current full requirements tariff provisions (no UOP)[38] with three modifications:

The minimum term would be 5-years

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[37] If during any billing period, the customer's firm noncore usage is less than 75% of the customer's firm noncore MSQ, the customer will be assessed use-or-pay charges equal to 80% of the transmission charges multiplied by the difference between 75% of the customer's firm noncore MSQ and the customer's firm noncore usage for that month. (Special Condition 33, Rate Schedule GT-F).

[38] The three tariff conditions specifying Full Requirements Service are:

(1) Customers may elect full requirements service under this schedule. Full requirements customers are not required to contract for a stated annual quantity.

(2) Full requirements customers are prohibited from using alternate fuels or bypass pipeline service (1) except in the event of curtailment, (2) to test alternate fuel capability, or (3) where the Utility has provided prior written authorization for the use of alternate fuels or bypass for temporary periods.

(3) In the event of any unauthorized alternate fuel use or bypass, customers must provide the Utility written notice thereof quantifying the extent to which alternate fuel or bypass use occurred. Such notice must be provided prior to the end of the month in which the usage took place. Any unauthorized alternate fuel or bypass use will be subject to a use-or-pay charge equal to 80% of the applicable transmission charge. No other use-or-pay charges are applicable to full requirements service. (Special Conditions 10, 11 and 12, SoCalGas Rate Schedule GT-F.)

> The firm service reservation (i.e., monthly schedule quantity, or MSQ) would reflect demonstrated historical daily usage
>
> If a customer desired to increase its MCQ during the course of the 5-year term, the change would activate a new 5-year term commitment and the higher MCQ would take effect consistent with the timing of:

The amended contract (if no additional facility construction is required to provide the higher MCQ), or

Upon completion of any utility facilities required to provide additional firm transportation service.[39]

SDG&E and SoCalGas further propose to continue to treat these investments as common transmission facility costs and to include them in general ratebase. In addition, SDG&E and SoCalGas propose that any revenues received from use-or-pay charges be credited toward the same accounts in the same manner as all other intrastate transportation revenues.[40]

The proposal can be summarized as follows:

1. Where there is a potential for constraint in the local transmission system, EG Tier 1 and G-30 customers demanding less than 20 MMcf/day that want to ensure delivery must commit to a 5-year use-or-pay arrangement for a specified capacity.

2. Faced with a similar potential constraint, customers in these classes with larger demand must commit to a 10-year firm daily capacity user-or-pay arrangement.

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[39] SDG&E/SoCalGas/Hartman, Exh. 8, p. 13-14 (internal footnotes in original).

[40] *Id*. at p. 15.

3. In the absence of such commitments, the utilities will not expand the local transmission system.

4. Any resulting new investments would be treated as common transmission facility costs and included in general ratebase.

In discussing the rationale for this proposal, Hartman argued that the policy would permit each customer to self-select the level of firm transportation service appropriate to its needs, and that those decisions would ensure that the utility receives proper signals as to when it should expand its local transmission system. Hartman also discussed what he saw as the benefits of relying on open seasons to evaluate customer demand:

> "[O]pen seasons that require customers to make binding commitments for firm service are superior to the utility relying solely on its internal demand forecasting. Since the bids require that the customer commit to a use-or-pay (UOP) provision, the bidding process provides better assurance that customers will bid the amount of firm service they really need. Although the demand forecast sponsored by Mr. Emmrich represents the utilities' best estimate of demand, his testimony notes a number of factors that could alter actual usage. Also, the forecast is a single point estimate of total demand, unlike requests for firm service. Moreover, customers and potential customers frequently express an interest in taking additional gas service at various locations in our service area. If we built out our local transmission system based on those expressions of interest, it would likely entail significant investments for facilities that might not actually be needed, raising all customers' rates unnecessarily. We believe basing expansion decisions on customer commitments is a more cost-effective method to ensure that expansions of the

local transmission system meet customer requirements."[41] (Emphasis added.)

This proposal does not offer an opportunity, as Hartman characterizes it, to self-select the appropriate level of firm transmission service. Rather, any customer of a certain size would be forced to take one set of firm service terms, or none at all. To some customers, SDG&E and SoCalGas may be offering a Hobson's choice: commit to 5 or 10 year use-or-pay firm daily transportation payments or risk the utilities maintaining an undersized local transmission system.

While such an approach would likely ensure that the utilities did not overbuild, there are many countervailing considerations that we must weigh. Under such an approach, if an individual shipper could not predict its needs as much as 10 years in advance, then the utility would not commit to provide service. Shippers that are not privy to the detailed, area-specific demand information in the possession of the utility would be required nonetheless to determine the need for committing to a use-or-pay contract. Equipped with imperfect information, individual shippers are much more likely to make inefficient decisions.

This is a matter of great significance to ratepayers, who also buy electric power from many of the larger gas customers. Duke Energy argues that this proposal has the potential to require a customer to pay a large amount of money for transportation service that it may never use. Duke offers its South Bay power plant as a good illustration of the dilemma customers may face as they confront

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[41] *Id*. at p. 12.

the 10-year commitment. Duke operates the South Bay plant under a lease with the Port of San Diego. That lease expires at the end of 2009. The South Bay units are also subject to a Reliability Must-Run agreement with the California Independent System Operator (ISO), and Duke needs firm transportation service to South Bay because the RMR units are required to run when called on by the ISO. If Duke is required to make a 10-year commitment in order to obtain firm transportation service to South Bay, it could be stuck with making payment for several years after the lease expires, even though it might not need transportation service then. Duke points out that large industrial customers whose operations demand firm service, and who are considering moving to another location or who go out of business, face a similar problem.

On the other hand, TURN points out that if large noncore customers that demand system expansions to provide them with firm service are allowed to thereafter reduce or discontinue their usage without consequence, all other ratepayers would be stuck paying for idled facilities that were built to meet the demand of those customers. TURN suggests that a large noncore customer has better information regarding its future gas consumption than the serving utility, and more than the other ratepayers that would remain to pay for the unused capacity. It is unreasonable, TURN argues, to expect the general body of customers to pay for facilities that a specific large customer asks for and then fails to utilize. SDG&E also argues that Duke's concern just confirms that the utility should not expand its transmission system in reliance on Duke's plant continuing to place demands on the SDG&E transmission system beyond 2009.

In the proceeding that led to D.02-11-073, SDG&E proposed requiring long-term commitments much like those that SDG&E and SoCalGas propose here, although the terms would have been 5 or 15 years, depending on the level of demand. The Commission rejected that proposal because SDG&E did not offer a tradable rights program that would have helped protect customers unable to use all of their firm rights. The utilities asked for approval of a tradable firm rights mechanism in Phase I of this docket. In D.04-09-022, the Commission directed SDG&E and SoCalGas to file a new application (A.04-12-004) to consider issues related to SDG&E/SoCalGas system integration, tradable firm rights, and off-system sales. We are considering tradable rights in the second part of that proceeding, which is now underway. Thus, it is premature to consider the approval of a long-term commitment to firm access.

In addition, for other reasons, we are not persuaded that even the proper trading program would make it reasonable for the utilities to require the type of long-term contracts proposed here.

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

An over-reliance on firm contracts at the expense of other planning tools runs the risk of allowing a utility to take its eye off of the overall adequacy of its infrastructure. Although the Commission has allowed the utilities to make use of open seasons, it has not authorized them to abandon other means of forecasting and planning to meet demand.

The Southern California Generation Coalition raises this concern, and cites the Commission's description of the utilities' obligation to provide firm noncore service and to expand facilities as needed:

> "We authorize SDG&E to limit firm service to noncore customers to the firm capacity available, but, as discussed, we have also authorized a reliability standard of 1-in-10. This reliability standard, along with the service interruption credits, will serve as sufficient incentive to SDG&E to continue making investments in its system to meet the needs of its firm noncore customers and to avoid curtailments." (D.02-11-073 at 14.)

The Southern California Generation Coalition argues that while SDG&E may limit firm service on constrained local transmission systems as an interim measure, it must also expand constrained systems:

If a customer requests firm service, and SDG&E determines there is insufficient capacity on its system to ensure firm service, it must offer that customer interruptible service at an interruptible rate. However, SDG&E must also expand its gas transmission system so that it complies with the one-in-ten cold weather conditions, for firm noncore customer reliability standard adopted in this decision. (*Id*.)

The Commission also addressed SoCalGas' use of open seasons:

> "SoCalGas can plan the timing and location of capacity additions through a combination of various mechanisms including a thorough analysis of the subscriptions to its open season, adherence to a system planning criteria of 1 in 10 for noncore customers and 1 in 35 for core customers for location [sic] transmission, and nonbonding [sic] expressions of interest in long-term agreements in the event customer commitments exceed available capacity in any of the 24 months of the open season." (D.02-11-073 at 37-38.)

The Southern California Generation Coalition argues that this language obligates the utilities to go beyond the results of an open season and determine the adequacy of the transmission system for noncore customers in a more traditional way: through forecasts and the utility-initiated expansion projects that would result from those forecasts. We find this to be an overly expansive reading of what the Commission said in D.02-11-073. All that is clear from that order is that the utilities must use a one-in-ten year planning approach to ensure that its facilities to serve firm demand are sufficiently reliable. The Commission has not clearly stated a broader planning obligation.

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

Another concern is the apparently arbitrary nature of the proposed 5- and 10-year contract commitments. The record does not suggest why 5 years or 10 years would be the right period. At the same time, as discussed above, the record does provide evidence suggesting that 10 years might be too long.

The Southern California Generation Coalition also argues that requiring larger customers either to commit to a 10-year use-or-pay arrangement or face the inability to firm up any local transmission could encourage bypass.[42] While this assertion may be the product of conjecture, it has some logical support. It makes sense that a customer will be more determined in looking for service elsewhere as the utility shifts more of the market risk to that individual customer. SDG&E and SoCalGas respond by saying that such bypass would require choosing interstate transmission over local transmission. The record suggests that the interstate pipelines require 15-year commitments. The utilities argue that it is illogical to suggest that a customer would run away from a 10-year local transmission commitment in order to make a 15-year interstate pipeline commitment.

The utilities do not cite to the record for their suggestion that interstate pipelines provide the only bypass option. However, even if that is the case, it is not necessarily illogical to choose a longer commitment for transmission on an interstate line over a 10-year local transmission commitment. Perhaps interstate capacity might be more valuable because its use is less location-specific and it is more tradable. Because this line of reasoning was not developed for our consideration, we cannot reach a firm conclusion one way or another.

All of these factors militate against the utilities forgoing utility-planned expansion in favor of the commitments of individual shippers. They also support, at least for time being, the retention of the current practice of requiring no more than 2-year commitments from those seeking firm capacity through

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[42] Bypass refers to a customer electing to receive service from a provider other than the utility. In this instance, the service would be natural gas transmission.

open seasons in the absence of a well-developed trading mechanism and a more flexible menu of commitment terms. A commitment of 24 months does provide a measure of the earnestness of the request for firm capacity, but it does so without requiring the shipper to know what the world will look like in the year 2011 or 2016. And it does so, for example, without requiring the operator of an older generating facility to commit to paying for transmission during later years when its plant might most appropriately be out of service.

Shippers that want certainty of delivery in the face of future demand growth should be able to pay for and obtain that certainty. What concerns us is the coercive, all-or-nothing approach of requiring large customers to make 10-year commitments regardless of the underlying circumstances. While there is clear value (both to the utility and its other ratepayers) in requiring longer commitments, we do not know why 10 years would be more appropriate than any other term. In addition, we want the utilities to explore with their customers ways to structure longer and shorter commitments while still making economic sense. For instance, there may be ways to require tougher use-or-pay terms for shorter-term commitments, and more lenient terms for longer-term agreements. We look to the utilities and their largest customers to work out these terms together, and submit a proposal to us for our consideration. The price of firm service should relate to the cost of any incremental expansion necessary to provide dedicated capacity.

As requested by SDG&E and SoCalGas, it is appropriate to roll into general rates many expansions that are required as part of the one-in-ten year planning process. However, for those expansions required largely to serve individual projects, such as LNG terminals, the policy established in the Phase I decision (D.04-09-022) applies. In that decision, the Commission stated that it is presumed that LNG suppliers will pay the actual system infrastructure costs associated with their projects. However, requests for rolled-in, or any alternative ratemaking treatment, will be allowed through the application process and addressed on a case-by-case basis. LNG suppliers will also be responsible for the costs to interconnect with the utilities' pipelines.

In sum, we do not adopt SDG&E and SoCalGas' proposed changes to their rules for conducting open seasons on the local transmission system. In the near-term, the utilities shall conduct any approved open seasons in a manner consistent with existing tariffs. The one paragraph proposal contained in Hartman's rebutall testimony (Exh. 9) does not constitute a timely, sufficiently-detailed proposal for the adoption of a mechanism to allow for firm tradable rights on the local transmission system. If the Commission later approves such a mechanism, SDG&E and SoCalGas may file a new application seeking changes to its open season rules in a manner that answers the concerns we have raised above.

II. Measuring Gas Infrastructure Adequacy for Electric Utilities

Electric generators providing power to customers of California investor-owned utilities were expected to burn about 1,800MMcf/day of natural gas in 2005.[43] Currently, the California electric utilizes are responsible for supplying about one third of this gas, and expect to be responsible for about half of the generation-related supply within five years. This gas demand can be broken into three categories: utility-owned electric generation; gas tolling

[43] Based on responses to data requests submitted by the Commission's Energy Division to California electric utilities.

contracts under the California Department of Water and Power (DWR) electric contracts; and gas tolling contracts not under DWR electric contracts. The DWR tolling contracts represent the largest category, and the non-DWR tolling contracts represent the smallest. The utility-owned generation category is quite small, but will grow substantially in the next five years, as each of the major electric utilities begins to procure natural gas for new power plants in California.

In their May 11, 2005 ruling in R.04-01-025, the assigned commissioners included the following directive:

> … in order to more fully understand the adequacy of the California natural gas infrastructure and the impacts of current procurement practices, we have asked the Energy Division to examine electric utility plans to supply, transport and store natural gas for electric generation in those plants for which the utility is responsible to provide the gas. The Energy Division will then issue a report including any recommended actions for the Commission to take. The target date for release of the report is September 15, 2005. Comments on the report will be due October 17, 2005. The comments should address the merits of the Energy Division recommendations, and specifically identify any factual disputes related to the report that would suggest the need for evidentiary hearings prior to including the report in the record for this proceeding.

On September 13, 2005 the ALJ in R.04-01-025 granted an Energy Division request, and extended the due date for this report to October 6, 2005, with comments due November 4.

A. The Energy Division Report

The Energy Division report does not describe or critique the specific strategies that each electric utility employs in ensuring adequate natural gas supplies. The Energy Division offers very broad policy recommendations:

1) *secure firm transportation contracts for baseloaded electric generation gas supplies*:

   The electric utilities should consider assuring delivery of commodities purchased at the production basin by securing firm interstate capacity rights for the baseloaded utility-owned electric generation plants and for baseloaded plants under contract with DWR. Firm interstate pipeline capacity rights will ensure the reliable delivery of those supplies. Without such contracts, deliveries to California cannot be assured, even if the physical pipeline capacity to California exists.

2) *promote gas and electric end-use efficiency and conservation:*

   These investments will have significant impacts on electricity and gas consumption. In addition to ensuring diverse access to supplies, including new supplies, California needs to take, and is taking, measures to limit natural gas demand.

3) *promote efficient electricity generation from gas:*

   Since 2000, many old plants have been replaced with efficient new generators, resulting in a significant savings in gas use. This improvement is largely the result of plant owners seeking to become more cost competitive and has occurred without any mandates from governmental authorities.

4) *promote generation of electricity from non-gas resources:*

   The Commission has adopted the Renewable Portfolio Standard, which will ensure that no later than 2017 at least 20% of California's electricity will be generated by non-gas resources. The Public Utilities Commission and the California Energy Commission have also adopted Energy Action Plan II, which envisions a 33% renewable portfolio by 2020.

5) *continue to allow for and encourage hedging, storing, and long-term commodity procurement, where effective or necessary:*

These tools are currently in use by the electric utilities procuring gas for generation. The utilities should be encouraged to use these tools prudently, guided by the Customer Risk Tolerance and market signals to reduce costs. Natural gas volatility could give rise to higher seasonal spreads in prices, making storage more valuable as a means by which to manage natural gas costs. Of course, if storage is seen as more valuable, the price of storage may increase as well.

6) *consider introducing an incentive mechanism for Electric Generation gas procurement:*

The cost-minimizing advantages of Performance Based Ratemaking need to be weighed against their disadvantages, including the tendency to encourage all short-term market purchases and to discourage certain kinds of hedging activity. Prior to going down this road, these pros and cons should be evaluated, and ways of avoiding typical pitfalls should be envisioned.

7) *provide access to new supplies, including LNG supplies:*

In D.04-09-022 the Commission recognized that LNG could be an important future component of California's gas resource base. Indeed, one of the thrusts of R.04-01-025 is to facilitate access to this resource on an equitable and safe basis. The creation of open access tariffs and standardized agreements and the development of new gas quality standards are two aspects of this effort to facilitate importation of LNG and access to new supplies.

8) *monitor the potential for intrastate and interstate pipeline congestion:*

One of the recommendations of D.04-09-022 was to establish an advisory committee comprised of natural gas utilities state agency officials, and other parties who would monitor the interstate pipeline capacity situation to ensure sufficiency. This recommendation is being implemented. The first meeting of natural gas utilities and state agencies has already taken place, and an expanded meeting of this group with other interested parties will be scheduled shortly.

B. Parties' Comments

The Energy Division's recommendations are largely non-controversial since, with the exception of a procurement incentive mechanism and the acquisition of firm interstate transmission rights, the Commission and the utilities have already implemented each of the enumerated proposals. Comments largely focused on the firm transmission rights option.

PG&E, SDG&E, and SCE all express support for the option of acquiring firm interstate transmission rights, as needed. Not surprisingly, El Paso and Kern River (interstate pipeline operators) concur. TURN agrees that the utilities should consider acquiring firm interstate pipeline capacity, especially if they are able to negotiate contracts at less than full tariff rates.

However, TURN opposes a requirement that these utilities do so, arguing that any type of regulatory mandate would severely limit the utilities' bargaining power and could have the perverse effect of increasing ratepayer costs. Given that there currently appears to be a surplus of pipeline capacity available to California gas consumers, and the fact that electric generation tends to peak when core customer gas demand is lowest during the summer period, TURN argues that capacity availability may not be a major concern for the electric utilities. TURN also advocates that potential capacity arrangements be examined by the utilities on a case-by-case basis in consultation with their Procurement Review Groups (established a part of the broader electric resource procurement effort).

At the same time, TURN argues that gas storage, for both price and stability purposes, deserves consideration at least equal to that given to firm pipeline capacity. As a general matter, TURN believes that the utilities should keep, perhaps, a 10-day average winter gas burn supply in storage, but does not propose that the Commission impose a requirement to do this.

TURN also believes that this Commission must keep in mind that electric utilities own or contract for only a portion of the natural gas-fired electric generation in California. TURN expresses much more concern about the gas supply planning of non-utility generators. As the Energy Division report points out, the electric utilities operate under Customer Risk Tolerance guidelines that strongly encourage appropriate forward hedging arrangements. They also have an obligation to serve. But, TURN argues, California and other states across the country have experienced situations in which unregulated electric generators have sold off their gas supplies during peak gas demand periods because they can make more money selling the gas than using it to generate and sell electricity. TURN expresses concern that in 2005, some Qualifying Facilities (QFs) under fixed price contracts with the utilities have shut down their electric generation and sold their gas for higher profit instead. This type of behavior may be beyond this Commission's direct control, but it is a matter of concern nonetheless from an electric reliability standpoint. TURN proposes that the Commission consider requiring that any electric utility contracts for power supply (including future contracts with QFs) contain provisions sufficient to ensure that the generation does not suddenly "disappear" when gas prices rise and create other market opportunities for the generators. Electric resource adequacy cannot be achieved if the generating units that the state relies upon to meet its needs are free to cease operations in response to changes in fuel input prices.

PG&E states that it is a good idea to allow for firm interstate transportation contracts, but that there must be a Commission pre-approval process. PG&E also says that while an incentive mechanism may be helpful, it must be explored in a separate proceeding. SCE generally agrees, as does SDG&E, although the latter emphasizes that the current interstate capacity surplus is likely to grow.

C. Discussion

Electric generation facilities are usually the largest noncore natural gas transportation customers. It is logical that the failure of these customers to plan adequately could have repercussions for all natural gas customers. We agree with TURN that the need to ensure appropriate electric generator natural gas procurement planning goes beyond the regulated electric utilities and reaches to all gas-fired generators. We begin with consideration of the regulated electric companies because they are the most clearly subject to our jurisdiction in this regard. Securing needed firm interstate gas pipeline capacity rights is an important element of electric utility resource planning and an important factor in assuring the reliability of the natural gas delivery system.

Focusing on intrastate infrastructure, as generally we are in this proceeding, the importance of reliable delivery to the California border becomes clear. The natural gas utilities expect customers to rely on a combination of storage and flowing supply to meet demand. If these large noncore customers do not secure the delivery of supply to the border, then they may not be able to do their share to maintain flowing gas supplies.

We also agree with TURN that electric generators should do their part to fill storage fields, and to withdraw gas during times of system peak. Although the generators themselves will usually peak during the summer while gas demand is highest in the winter, the generators create significant gas demand throughout the year. To ensure uninterrupted generation capability and appropriately support the gas supply system, we would expect the electric generators to be active storage customers.

We expect the electric utilities to demonstrate, as part of the integrated resource planning process, that they have taken all necessary steps to ensure gas supply. As part of each planning cycle, they should actively consider the role of firm interstate capacity and report on their reasons for pursuing the strategy that they propose. We also expect the electric utilities to inject and withdraw gas consistently, as part of the annual fuel supply cycle. TURN offers one goal (maintaining a 10-winter-day supply in storage). As is true with other aspects of gas infrastructure and supply reserve, the electric utilities should define and work toward achieving a storage goal that is quantitatively related to the nature of their resource portfolios and the level of gas usage. This, too, should be developed and explained fully as part of each procurement plan.

We are not persuaded, at this point, that there are benefits in pursuing a performance incentive. We will leave it to parties to make a persuasive case for such an incentive in the general rate proceeding for each electric utility.

III. Creating an Infrastructure Working Group

Despite the utilities' primary obligation to ensure infrastructure adequacy, there appeared to be early consensus among the parties that it would be useful to establish an ongoing working group to monitor infrastructure adequacy. Parties disagreed somewhat as to the proper composition of the group. There is an existing body consisting of representatives of state agencies calling itself the Natural Gas Working Group, that meets periodically. That group offered to develop a proposal for expanding the process to include other interested parties.

A. The Proposal

Since the existing Natural Gas Working Group is chaired by a representative of the California Energy Commission (CEC), the CEC submitted the requested proposal on behalf of the group. All other parties were given an opportunity to comment on the proposal.

The stated purpose was to establish a working group that allows more frequent discussion and exchange of information on California's natural gas context, focusing on supply, infrastructure needs and operations, and emerging issues. The CEC described the objectives as follows:

- Monitor California and western United States natural gas demand,
- Monitor natural gas supply from instate and out of state sources,
- Monitor interstate natural gas pipeline operations,
- Monitor intrastate natural gas pipeline operations,
- Monitor instate and out of state natural gas storage operations,
- Monitor the adequacy of California's natural gas infrastructure,
- Monitor natural gas market prices important to California consumers,
- Identify emerging issues that could potentially affect the above,
- Ensure that Working Group members have a common information set on these issues,
- Seek additional viewpoints and information that could benefit Working Group participants and California consumers,
- Establish a reporting system that provides timely alerts on near term issues, as needed, and
- Establish working relationships that encourage an open and informal exchange of information and discussion between the participants.

The CEC proposed the following structure for this expanded group:

- Establish a California Natural Gas Infrastructure Stakeholders Working Group (NGWG+),
- Membership of the NGWG+ would be self-selected and composed of all stakeholders interested in California's natural gas supply and infrastructure,

The NGWG+ would:

- meet January and July of each year,
- hold its meetings in northern California and southern California on an alternating basis,
- keep its meetings open to any interested party with a stake in California's natural gas future,
- advertise its meetings on the CEC's and the California Public Utilities Commission's websites,
- conduct informal discussion only and issue no summary report,
- determine additional structure for the working group after its initial meeting.

The CEC proposes also to maintain the current the Natural Gas Working Group, but modify its practices in some respects. The smaller group would have the following members:

- California State Agencies
- California Air Resources Board
- California Energy Commission
- California Public Utilities Commission
- California State Lands Commission

- Department of Conservation, Division of Oil, Gas, and Geothermal Resources
- Department of General Services, Natural Gas Services Program
- Department of Water Resources, California Energy Resources Scheduling
- Office of Planning and Research

The smaller group would:

- Maintain the current monthly Natural Gas Working Group (NGWG) meetings ,
- Invite the California natural gas investor-owned utilities to attend the NGWG meetings on a quarterly basis,
- Hold these quarterly meetings in a month preceding each season in time to take last-minute action if needed to avert potential problems (e.g., April, July, October, and January),
- Keep the meetings informal and off-the-record,
- Use these meetings to explore possible problems with California's natural gas infrastructure and operations and potential solutions that benefit consumers,
- Establish a sunset date of July 2007, extendable as determined by the group, to consider the need to continue these meetings.
- The CEC offers to organize these new working groups and initially chair them, with the formal chair to be selected by each group on a permanent or rotating basis.

B. Comments on the Proposal

Transcanada's GTN and North Baja Systems, Indicated Producers, Lodi, PG&E, and SDG&E/SoCalGas filed comments.

While GTN states that it strongly supports the CEC's idea to allow all natural gas stakeholders to participate, in some form, in NGWG meetings, GTN does not see the need or rationale to segregate California natural gas investor-owned utilities and all other parties into two separate groups. GTN argues that the fact that, under CEC's proposal, "last minute actions to avert potential problems" could be made in the meetings that are limited to the NGWG and California utilities is problematic if not dangerous. Other non-California natural gas stakeholders, many of which are regulated entities that operate critical natural gas infrastructure both in and upstream of California, can provide valuable insights during these times of crisis. For this reason, GTN proposes that all interested parties with a stake in California's natural gas future meet with the NGWG on a quarterly basis. The format of these meetings would otherwise be consistent with the CEC's proposal.

Indicated Producers also support the proposal, but add that in addition to opening the NGWG membership to the investor-owned utilities, an invitation should be extended to a representative from the Governor's office, given the important issues at stake in California's electric and natural gas industries. Indicated Producers further argue that these quarterly meetings must also be open to the public with an opportunity for interested parties to provide public comments, because there may be instances in which issues must be addressed at the quarterly Natural Gas Working Group meeting instead of waiting for the biannual meeting of the California Natural Gas Infrastructure Stakeholders Working Group. Finally, Indicated Producers offer as a word of caution: the industry stakeholder group should not be placed in a position of monitoring the market and reviewing information that should be kept confidential. As noted in the proposal, the forums should be for the purpose of exploring possible problems and discussing potential solutions that will be brought before the appropriate regulatory bodies for consideration. Only open and informal exchanges will foster the desired objectives.

Lodi offers its support for the creation of the NGWG+ and its intention to participate actively. PG&E, SDG&E and SoCalGas concur, and add their enthusiastic support for the expansion of the NGWG to include utility representatives at quarterly meetings. PG&E objects to the proposals from GTN and Indicated Producers to open the NGWG meetings to more participants and public scrutiny. PG&E argues that there is a legitimate need for separate, confidential consultations between the gas utilities and the professional staffs of this Commission and the CEC, regarding issues of concern to gas consumers in California. PG&E adds that "these consultations should be allowed to occur without the prying eyes of suppliers, pipelines and other commercial operators, whose interests are not always aligned with the interests of the customers served by the utility companies."

The purpose of establishing regular meetings to discuss infrastructure adequacy is to add another source of information and feedback to the utilities' normal planning process. As such, we endorse this effort and encourage active participation. We agree with GTN and Indicated Producers that meetings between state agency representatives and utility representatives should generally be open to the general public, and ask that all meetings involving more than just state agency representatives be open to all participants. However, it may be necessary, at times, for the utilities to discuss confidential matters. When there is a legitimate confidential purpose to be served, they utilities may communicate that information to the Commission or the CEC staff, which can determine the best way to communicate the information to other NGWG members. We encourage the NGWG to err on the side of sunshine in its communications as a body with outside entities, and to function more privately only when necessary.

IV. Paying for and Gaining Access to New Facilities

A. Charging All Ratepayers vs. Charging the New Users

In Phase I, there was a lively debate on appropriateness of rolling into rates the cost of system expansions needed to serve LNG providers. In D.04-09-022, the Commission adopted a presumption that LNG suppliers will pay the actual system infrastructure costs associated with their projects. However, the utilities can file requests for rolled-in, or any alternative ratemaking treatment, through the application process, with appropriate notice to customers. Those proposals, including the costs and cost recovery mechanisms, can then be evaluated on a case-by-case basis. Several parties attempted to revisit this issue in Phase II. We see no need to deviate from the case-by-case approach adopted in D.04-09-022, and will not discuss the issue further, here.

B. The Woodside Natural Gas Proposal Concerning the Cost of Receipt Point Expansion

The cost of upgrading each receipt point varies substantially based on the scope of the expansion. For example, Center Road can be expanded to accommodate 800 MMcf/day of deliveries for approximately $27 million.[44] However, it would cost approximately $107 million more for the next supplier to

[44] SoCalGas/SDG&E Witness Bisi Exhibit 7 at 11, Table 5.

deliver 400 MMcf/day of gas to that receipt point.[45] Woodside Natural Gas argues that this provides the first supplier with a substantial competitive advantage over the subsequent supplier.

The additional $107 million might be sufficient to prevent that second supplier from seeking to supply California. The situation may be even more extreme when expansions at multiple receipt points are considered.

SoCalGas/SDG&E have indicated that if more than one receipt point is upgraded, the total costs will exceed the sum of the cost of expanding each receipt point individually.[46] For example, Salt Works Station can be upgraded to accommodate 800 MMcf/day on an expansion basis for approximately $78 million, and Otay Mesa can be upgraded to accommodate 600 MMcf/day of expansion capacity for approximately $206 million. However, if both receipt points are upgraded, the total cost of the expansion would be approximately $418 million; $134 million higher than the sum of the cost of upgrading each individual receipt point. Under a first-come, first-served policy, if the supplier seeking to upgrade Otay Mesa was first to be awarded a contract, it would pay $206 million. The second supplier, seeking to upgrade Salt Works Station, would see its costs climb from $78 million to $212 million. Conversely, if the supplier at Otay Mesa was second, it would experience a cost increase of $134 million.

Woodside argues that either situation could result in one supplier being unwilling to pay the increased costs, and California losing access to the relevant supply, based solely on timing. Woodside proposes that rather than simply

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[45] *Id.*

[46] *Id.* at 12:3-5.

relying on a "race to the contract," the Commission should establish a "more rational" process for allocating the costs of capacity expansions at individual receipt points and at multiple receipt points: identify suppliers interested in obtaining access to capacity expansions and allocate costs equally, on a dollars per MMcf/day basis, among all interested suppliers.

Woodside points out that SoCalGas has already used this type of process in determining whether capacity upgrades are required in certain constrained areas of its local distribution system.[47] Woodside asserts that it should not be difficult for the utilities to implement a similar policy when evaluating interest in receipt point and backbone transmission system capacity expansions. This would allow any potential supplier to be aware that expansions are being considered and give them the opportunity to participate in the expansion. Arguably, it could also increase the likelihood that more suppliers would connect with California because both the low-cost and more expensive upgrades would be allocated among all suppliers rather than simply requiring suppliers that come later to pay for the high-cost upgrades. Woodside argues that this would allocate cost responsibility in a fair, open and equitable manner, allowing suppliers to compete with each other based on the economics of their projects, rather than the timing of their receipt point requests.

Coral and Sempra LNG, proponents of an LNG project that may be closer to fruition than that supported by Woodside, strongly object to this proposal. Coral asserts that Woodside's proposal, if adopted, would undermine the ability of new gas suppliers to ascertain the terms and costs of access. Coral argues that a "first-come, first-served" incremental expansion approach for interconnecting new supplies serves the important purpose of providing cost certainty. Under this approach, sponsors of new supply sources would know what the costs of access would be, and they would be able to make rational economic choices on this basis. Coral concedes that the incremental nature of capacity expansion on a gas utility's integrated transmission system makes it likely that later expansion projects will be relatively more or less expensive than the expansion projects that preceded them, but argues that this does not make a first-come, first-served approach unfair. Rather, a first-come, first-served incremental cost allocation approach provides an incentive for shippers with new supply projects to assess the downstream expansion costs in conjunction with the timing of their supply projects. Coral concludes that the cost certainty that such an approach will assist all project sponsors in making economic decisions concerning their gas supply projects. Sempra LNG agrees, saying:

> "Adoption of Woodside's proposal could fundamentally undermine years of planning and investment in selecting the transportation routes, facilities and systems needed to move gas to market. In the case of the Energia Costa Azul facility in Baja, for example, some significant decisions have been made—and others must be made in the very near future—about how much gas to move via the Otay Mesa receipt point to the Southern California market versus how much gas to take east and north through the Bajanorte and North Baja pipelines. These decisions involve the design, permitting and construction of new transmission facilities in Mexico and the United States and necessarily have long lead times. Gas from the Energia Costa Azul facility is on schedule to begin to flow on or about January 1, 2008. If other projects in Baja come on line at a later time (whether one or two or three or more years later) and the Commission were to shift the costs of the

[47] SoCalGas/SDG&E Witness Hartman Tr. at 67:23-69:13.

> upgrades needed to permit gas to flow into Otay Mesa from those projects to the original sponsors of the expansion, this would fundamentally alter the economics of the original sponsors' business investments."[48]

Sempra LNG argued, in conclusion, that anything other than a clear rejection of Woodside's cost sharing proposal in this proceeding likely would inject significant additional uncertainty in the Commission's ultimate LNG access policies and may cause delays in getting gas from Mexico to the California market.

There is no disputing the fact that first-in-time cost allocation is a crude and, in some ways, unfair approach. Why should two customers situated in the same area, with potentially equal throughput demand, pay vastly different amounts for service? However, in some instances, the cure may be worse than the disease. One of the most significant reasons for imposing incremental expansion costs on the entity creating the demand is to enable the incremental customer to take those costs into account when siting its facilities, or when making a commitment to procure gas from a geographically-specific source. That economic signal may be diluted, if not destroyed, if the costs are subject to change over time. It is also easy to understand how a changeable allocation of expansion costs could discourage investment.

What is needed is an approach that allows for both fairness and certainty. There is no apparent reason that the utilities cannot provide for both. When a utility is considering a receipt point expansion for a particular customer, it can solicit firm expressions of interests from other customers. Where other

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[48] Sempra LNG Reply Brief, p. 5.

customers are willing to commit to supporting receipt point expansion to serve their needs, then the utility should plan its expansion to serve all of the identified customers, and apportion the expansion costs among all of the customers in an equitable manner. Customers that firm up their needs later in time will be required to shoulder the cost of any further expansion.

C. Gaining and Maintaining Access to New Facilities

Several parties have argued that if customers are required to pay for the construction of new facilities, they should have higher priority access to the use of those facilities. As a general proposition, this appears to be reasonable. We note that broader issues about access rights related to SDG&E and SoCalGas are currently before the Commission in A.04-12-004. In that proceeding, we will explore the appropriate means to provide higher priority access to such customers.

V. Interconnection and Operational Balancing Agreements

A. Background

In Phase 1, some parties representing potential LNG developers expressed the desire to ensure that all gas suppliers receive equal treatment in their relations with SoCalGas and SDG&E. In order to promote parity and transparency, the Commission provided notice that in Phase 2, the Commission would "establish a process to consider the adoption of standardized operational balancing agreements to connect all new upstream gas pipelines that interconnect with the pipeline systems of SDG&E and SoCalGas."[49] Such an

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[49] D.04-09-022, ordering paragraph 10.

agreement requires a shipper of natural gas to eliminate or mitigate operational imbalances created when the actual physical gas flow is different than the scheduled quantities.

On October 4, 2004, SDG&E, SoCalGas, and PG&E filed advice letters (1474-G, 3413, and 2577-G, respectively) proposing open access tariffs. On March 17, 2005, Resolution G-3376 approved PG&E's advice letter as filed, and ordered that SDG&E and SoCalGas re-file their open access tariffs with modifications, and also include drafts of four of the standardized contracts which were referred to in the proposed tariffs. On April 1, 2005, SDG&E and SoCalGas filed advice letters (1474-G-A and 3413-A, respectively) containing the revised open access tariffs (for both utilities, this is "Rule 39") along with the four proposed standardized contracts.[50] On September 22, 2005 in Resolution G-3382, the Commission approved the re-filed open access tariffs (Rule 39) and approved, with modifications, three of the agreements.[51] The fourth agreement, the Interconnect Collectible System Upgrade Agreement (ICSUA), was deferred to R.04-01-025, to be developed and approved alongside the Interconnection Agreement.

Meanwhile, on April 1, 2005, SDG&E and SoCalGas filed a proposed pro forma Interconnection and Operational Balancing Agreement (IOBA) in R.04-01-025. On April 21, 2005, the Commission issued an Assigned

[50] SDG&E and SoCalGas referred to an Interconnection and Operational Balancing Account in the open access tariffs but, in compliance with Resolution G-3376, did not include a draft agreement in these advice letters.

[51] On October 7, 2005, SDG&E and SoCalGas filed compliance advice letters 1474-G-B and 3413-B containing the approved Rule 39 and the three revised standardized tariffs. The Commission approved these as filed.

Commissioner Ruling in R.04-01-025 setting a schedule to explore further the issues related to the IOBA. The ruling called for comments to be filed by parties on May 2, 2005, followed by a workshop on May 11. Accordingly, parties filed comments and participated in the workshop. The Energy Division submitted a report on June 8, 2005, summarizing the written comments and the findings from the workshop, and providing recommendations.[52]

In addition to commenting on a number of specific terms and conditions in the proposed standardized contracts, the Energy Division offered recommendations concerning a number of "threshold" issues, which we discuss below.

Finally, the Energy Division report encouraged parties to pursue negotiations to narrow differences, and then report back to the Commission. Accordingly, on June 17, 2005, SoCalGas and SDG&E filed revised proposals for the Interconnection Agreement and the Operational Balancing Agreement, followed on June 24 by parties' comments.[53] In July and August, the parties met for further negotiations, and on August 16, 2005, SoCalGas and SDG&E filed

[52] In theory, the IOBA agreements (and successor agreements) could apply to all California gas utilities. But in actuality, their main practical purpose has been to address connection with new LNG facilities, and all of the new LNG facilities currently being considered for California would interconnect with the SoCalGas/SDG&E grid. For this reason, the agreements being developed now are meant to be effective only for SoCalGas and SDG&E.

[53] BHP Billiton, Coral Energy, El Paso, ExxonMobil, Independent Producers, Kern River, PG&E, SDG&E and SoCalGas, Sempra Global, Sound Energy Systems, Southern California Generation Coalition, and Transwestern filed comments on June 24, 2005.

another round of proposed standardized contracts, this time also including the ICSUA,[54] followed again by parties' comments on August 24, 2005.[55]

On November 22, 2005, SoCalGas and SDG&E filed a supplemental report on the negotiations. The companies reported that further engineering studies revealed the need for tighter operational constraints for gas being supplied into the SoCalGas/SDG&E grid from Baja California at Otay Mesa, and they filed a revised Operational Balancing Agreement reflecting these tighter constraints. Three parties filed comments on December 2, 2005.[56]

B. Discussion

Most parties expressing opinions on the disposition of the standardized contracts asked that the Commission issue a ruling without recourse to hearings. We agree that hearings are not necessary and will now rule on these contracts.

We believe that the recommendations offered by the Energy Division in its June 8, 2005 report on the "threshold" issues listed in the first five subsections below are reasonable and will adopt them, as discussed. Thereafter, we discuss issues that are still in contention.

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[54] The Energy Division had notified the utilities informally that the Commission was planning to defer the development of a standardized ICSUA to R.04-01-025. This was effectuated by Resolution G-3382.

[55] Coral Energy, Indicated Producers, Kern River, Sound Energy Systems, and Transwestern filed comments on August 24, 2005.

[56] Coral Energy Resources, Sempra Global, and Sound Energy Systems filed comments on December 2, 2005.

1. The IOBA Should Be Separated Into an Interconnection Agreement and an Operational Balancing Agreement.

The two agreements have traditionally been separate documents, dealing with separate issues. Furthermore, many have argued that separation is expeditious, as it allows parties to terminate one set of agreements while maintaining the other. All commenting parties supported this separation.

2. In-State Gas Suppliers Should Not Be Subject to These Contracts.

There is already an open proceeding that is addressing standardized contracts for in-state producers.[57] Furthermore, there appear to be significant differences between in-state producers and other suppliers. These include smaller average size of contract capacity, greater hour-to-hour flow fluctuations, and less control over those fluctuations.

3. The Contracts Should Not Affect Existing Agreements With Interstate Facilities and PG&E.

The existing interstate agreements and the agreement with PG&E appear to be working well. These entities have been operating in balance, and furthermore the distance of their interconnects from the SoCalGas load center make the SoCalGas and SDG&E's grid less sensitive to imbalances from the interstate pipelines. By contrast, new suppliers such as those utilizing Otay Mesa will need to adhere to the standardized agreements. These standardized

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[57] In A.04-08-018 the Commission is addressing the issue of standardized contracts for California-based gas suppliers.

agreements should be considered the standard template, with deviations obtained through the advice letter process.

4. Interconnect Collectible System Upgrade Agreement

No party raised any objection to the ICSUA version filed by SDG&E and SoCalGas on August 16, 2005, and we will approve it.

5. Issues Specific to the Interconnection Agreement and the Operational Balancing Agreement

The following is a discussion of the issues identified by parties as still subject to disagreement. The discussion will refer to the last versions filed (the Interconnection Agreement filed on August 16, 2005, and the Operational Balancing Agreement filed on November 22, 2005).

a) Hinshaw Exemption Is Protected

The Interconnection Agreement and the Operational Balancing Agreement contain the same clause (Sections 1.c. and 1.4.1., respectively) exempting SoCalGas from jurisdiction of the FERC under the Hinshaw Amendment to the Natural Gas Act, and allowing SoCalGas to refrain from any action that might possibly jeopardize this exemption.

In its August 24, 2005 comments, Sound Energy Solutions asks that the Commission include language stipulating that the Hinshaw Exemption clause of the contract "does not conflict with parties' rights to advocate for or utilize any off-system delivery rights authorized by the applicable state and federal agencies." Either in the standardized contracts, or in a settlement document accompanying adoption of the agreements, or in this decision. We decline to modify the proposed language in this clause, lest it jeopardize in any way the utility's Hinshaw Exemption.

b) Gas Quality Standards Will Reflect Current Realities Faced by Utilities

The Interconnection Agreement contains a clause (Section 4.a.i.) allowing SoCalGas/SDG&E to refuse delivery of gas not meeting certain specifications and a clause (Section 4.a.ii.) establishing the conditions under which the interconnecting entity can negotiate with SoCalGas/SDG&E to alter the gas quality specifications to which it is subject. The gas quality language of Paragraph 4.a.i. is of great concern to many parties.

Currently SDG&E and SoCalGas have tariffs (Rule 30) governing the quality of gas supplied to them. In their gas deliveries, the utilities are further constrained by gas quality standards established by the California Air Resources Board (ARB) that apply to mobile pollution sources (i.e., vehicles). These ARB standards are more stringent than the standards contained in the utilities' tariffs. Because the vast majority of gas supplied to SoCalGas/SDG&E by North American sources complies with ARB standards as well as the SoCalGas/SDG&E tariff standards, SoCalGas/SDG&E have been able to meet the ARB standards by blending the gas it receives from the different supply streams.

LNG supplies may be delivered to California, perhaps within the next few years, and while most LNG will probably meet existing SoCalGas/SDG&E tariff standards, it will likely not meet the current ARB standards. Faced with the impending arrival of much larger quantities of gas that will not meet ARB standards, SoCalGas/SDG&E are concerned that it will no longer be able to comply with the ARB standards.

In this proceeding we are working with ARB and other parties to reconsider the gas quality standards. Pending resolution of this issue, the utilities have proposed in earlier drafts contract language that states that incoming gas must meet the quality standards given in the utility tariffs, as well as standards established by other relevant government agencies. The interconnecting parties complain that they should be subject only to standards contained in the utility tariffs.

In their last Interconnection Agreement filing on August 16, 2005, the utilities propose to refrain from putting the new Interconnection Agreement and Operational Balancing Agreement into effect until the Commission issues new gas quality standards. Once the new uniform standards were issued, SoCalGas/SDG&E would put into effect the new standardized contracts with all reference to gas standards imposed by other entities removed.

In its August 24, 2005 comments, Coral objects to SoCalGas/SDG&E's assertion that it will not sign agreements with interconnecting parties until the Commission issues new gas quality standards. In its August 24, 2005 comments, the Indicated Producers argue that the replacement language offered by SoCalGas/SDG&E is unnecessarily vague about where the gas quality standards are contained. The Indicated Producers offer a proposed edit which clarifies that gas quality standards are contained in the utility tariffs. We agree that this specificity is an improvement, and order the utilities, when they file the new gas quality standards (Rule 30), to adopt the proposed language for the Interconnection Agreement.

The Indicated Producers also note that the language proposed by SoCalGas/SDG&E contains no protocol for determining whether a supplier is in compliance with the gas quality standard. At a minimum, they argue, the Commission should be certain that the gas standards are applied in a nondiscriminatory fashion. We are not certain that such a protocol would be sufficiently useful to merit adding so much detail to the tariff at such a late stage in the proceeding. Consequently, we will not require the company to file such a protocol at this time. Of course we expect and require that the utilities apply their gas quality standards in a nondiscriminatory fashion.

We make modest changes to the gas quality standards in this order, and those changes can be incorporated. However, we are not willing to hold up the signing of Interconnection Agreements and Operational Balancing Agreements until the Commission issues any subsequent new gas quality standards. We also will not place the utilities in a position of having to accept gas from interconnectors that they will not be able to deliver. For this reason, we will order that the utilities file an Interconnection Agreement containing the previously proposed references to other entities' quality standards (and including the language change proposed by the Indicated Producers). We believe that the presence of Section 4.a.ii. allows for any flexibility that may be required. Then, once the Commission issues any subsequent new gas quality standards, the utilities shall file a modified agreement containing the gas quality language referring only to SoCalGas/SDG&E tariffs.

c) Uniform Hourly Flow Requirements

SoCalGas/SDG&E's proposed Interconnection Agreement Section 4.b. requires that interconnecting entities supply uniform hourly deliveries, while allowing for intra-day schedule changes that may occur. Proposed remedies for noncompliance include suspended service and/or the installation of an automated flow control device, at the interconnecting entity's sole expense.

Coral characterizes the remedies proposed by SoCalGas/SDG&E as "unduly burdensome." Coral argues that under the utility proposal the utility could suspend service for even a ten percent deviation from uniform hourly flows. Instead, Coral offers language that provides more explicit and more lenient operational requirements.

Part of the problem we face is that the Uniform Hourly Flow clause requires that flows be "approximately" equal to the calculated hourly scheduled quantity, but provides no definition of "approximately". Coral offers a definition of +/- 20%, and SoCalGas/SDG&E have not responded to this proposal. We will accept the definition proposed by Coral, and order that SoCalGas/SDG&E insert this definition, applicable only to the measurement of hourly flows, into the clause. Aside from this addition, we will adopt the clause as proposed by SoCalGas/SDG&E.

d) Tighter Balancing Provisions Are Justified

Imbalances refer to differences between what a supplier schedules ahead of time with the utility and what the supplier actually delivers. Imbalances can result from either over- or under-deliveries. Once an imbalance occurs, SoCalGas/SDG&E's proposed Operational Balancing Agreement clause 2.3 provides for its elimination. This includes imbalances in hourly deliveries as defined in the IA.

Coral complains that SoCalGas/SDG&E improperly and confusingly address the issue of uniform hourly deliveries in the Operational Balancing Agreement, which is concerned rather with imbalances (which are daily and not hourly phenomena). We agree with Coral that discussion of uniform hourly deliveries in the Operational Balancing Agreement is confusing and unnecessary, and will order SoCalGas/SDG&E to remove reference to uniform hourly deliveries from Section 2.3 of the Operational Balancing Agreement.

Previous versions of the Operational Balancing Agreement's operational imbalance clause contained provisions for "cash-out" of imbalances, i.e., financial penalties for under- or over-deliveries to the SoCalGas/SDG&E grid. In response to complaints that these penalties were unduly harsh, SoCalGas/SDG&E now propose an operational imbalance clause that focuses on physical adjustments to rectify imbalances. The proposed clause allows for the utility and the interconnecting entity to work out a schedule to eliminate the imbalance over a 30-day period but, if no agreement can be worked out, allows the utility to demand that the imbalance be rectified within seven days.

Throughout negotiations, parties have complained that the payback period of seven days, which SoCalGas/SDG&E have proposed, is far more stringent than the payback period contained in the existing interstate contracts.[58] Coral and the Indicated Producers argue out that the payback period proposed by SoCalGas/SDG&E (up to 30 days, but with the default as seven) in the Operational Balancing Agreement is much shorter than those contained in existing interstate agreements, and thus violates Conclusion of Law 18 of D.04-09-022 which states that new gas supplies "should be allowed to compete on an equal footing with existing supplies."

We are sympathetic to the arguments raised and reaffirm the policy goal expressed in D.04-09-022. But we must also be mindful of other facts. SoCalGas/SDG&E have repeatedly explained that unforeseen fluctuations in supply volumes arriving from the new proposed LNG receipt points are more

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58 This fact was also observed in the Energy Division's report of June 8, 2005, which summarized many of the terms of the existing interstate contracts.

difficult to respond to effectively because of their proximity to the load centers.[59] This argument makes logical sense.

Finally, SoCalGas/SDG&E noted during the May 11 technical workshop that they have seen suppliers deviating from their flow schedules in order to take advantage of market price fluctuations, effectively placing higher costs on utility customers.[60] SoCalGas/SDG&E argue that the shorter imbalance payback period is needed to protect its customers from such abuse.

As a result of these considerations, we are willing to adopt the tighter operating guidelines proposed by SoCalGas/SDG&E. We are in fact treating the various supply streams in accordance with the same principles, and two of those principles are protection of customer service (i.e., system reliability) and protection of customer costs. The fact that the application of these uniform principles may result in different operating rules for specific interconnectors does not violate the fact that these supplies are being treated on an equal basis. There is no undue discrimination.

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[59] See SoCalGas/SDG&E May 2, 2005 pre-workshop comments, p.6. During the May 11 workshop, SoCalGas/SDG&E argued that proximity allows less time to dispatch gas from other sources and allows fewer intervening connections with major pipelines and storage fields which otherwise could mitigate the impact of the supply disruptions.

[60] SoCalGas/SDG&E noted during the May 11, 2005 technical workshop that they have seen this behavior especially from interconnecting entities that own the commodity they are supplying (these typically are California based suppliers), and have not observed this with the interstate entities, which typically do not own the commodity they are shipping.

e) New Special Provisions for Otay Mesa Are Justified, and Will Be Revisited

For each day's operation of the intrastate gas system, there are four nomination "cycles"—two occur the day before the flow day, and two occur during the flow day. Previous language in the Operational Balancing Agreement had allowed for interconnecting entities to change their nominations (i.e., statement of the amount they plan to flow) between Cycle 1 and Cycle 4 from the full capacity of the receipt point all the way down to zero. In October and November 2005, SoCalGas/SDG&E announced that based on the results of new engineering studies they had conducted, the utilities would revise language in the Operational Balancing Agreement to place much tighter operational constraints on supplies arriving into the utility grid at Otay Mesa. Under the new proposed constraints, the supplier at Otay Mesa would only be able to reduce its nominations between Cycle 1 and Cycle 4 by a total of 50 MMcf/day. Otay Mesa is expected to have an initial capacity of about 400 MMcf/day, so this is a significant constraint on operations.

The new constraints are contained in Section 2.2 of the proposed Operational Balancing Agreement. In addition, SoCalGas/SDG&E have added a new Section 2.4 which defines the penalties (i.e., "cash out") that would be imposed on a supplier at Otay Mesa whose under-deliveries exceed the 50 MMcf/day threshold. The proposed penalty is 150% of the current border spot gas price, applied to the amount of under-delivery exceeding 50 MMcf/day. Over-deliveries at Otay Mesa would not have cash out provisions and would be treated the same as imbalances at other receipt points.

Coral argues that SoCalGas/SDG&E have not provided sufficient information to explain the necessity of the stringent measures of Section 2.2, and raises the possibility of alternative operational responses to supply shortfalls at

Otay Mesa, such as increased flows from the SoCalGas backbone at Moreno Station. Coral suggests that reduced flows should be allowed at Otay Mesa in the event that demand by SDG&E customers were also to drop. Coral says that it simply wants more flexibility in the operational rules. Coral also complains that the immediate cash-out provisions of Section 2.4 are unjustified, unduly discriminatory, and punitive.

Sempra LNG argues that the rules SoCalGas/SDG&E are proposing for supplies arriving at Otay Mesa would apply to no other receipt point, and thus they would violate the mandate of D.04-09-022.[61] Sempra Global also questions the need to base operating constraints on the worst-case scenario.

It is important to apply the same principles to all sources of supply. However, the application of these principles may result in different operational rules for different receipt points, without resulting in undue discrimination. For the reasons discussed above, we will approve the new restrictions on Otay Mesa supplies as contained in the November 22, 2005 version of the Operational Balancing Agreement. We also agree with Sempra LNG that revisiting this issue one year after the beginning of operations could be useful, and will order the utilities to file a report to the Commission, one year after the beginning of gas flows from Baja Mexico at Otay Mesa, discussing their experience with the operational guidelines contained in the Operational Balancing Agreement, and offering recommendations on whether, and how, to modify them. The Commission may then choose to adopt the recommendations, convene a technical workshop, or take other action as appropriate.

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[61] Conclusion of Law 18.

f) New Operational Balancing Agreement Section 2.5 Protects System Integrity

In its November 22, 2005 revised Operational Balancing Agreement filing, SoCalGas/SDG&E have included a clause (Section 2.5) that allows the utility to reduce the capacity of a receipt point when necessary to maintain system integrity. In its comments, Coral supports the goal of system integrity, but questions the lack of constraint placed on utility discretion in this matter, and also reminds us of the need for the utility to avoid discriminatory behavior. Although we understand Coral's concern, the utility must remain accountable for system integrity and have the tools to ensure that this occurs. Of course, the utility is obligated to exercise this discretion in a reasonable manner. Consequently, we approve it, with the following modification.

In its comments, Sound Energy Solutions asks that the utilities insert language to this clause pledging that any capacity reduction would be announced prior to Cycle 1. We believe that such a notification requirement would be helpful to shippers managing their supplies, and so we agree to this modification.

g) Odorization Fees to be Paid by LNG Suppliers

Section 3.a of the Interconnection Agreement briefly discusses fees for operation and maintenance, and refers to the attached Exhibit C, which discusses in greater detail the methodology for calculating this fee. In addition, Section 4.h describes the process SoCalGas will take if it is required to odorize the delivered gas. When it is required, odorization comprises the lion's share of maintenance costs. In its August 24, 2005 progress report, SoCalGas estimates that odorizing incoming LNG supplies could cost $300,000 per year per Bcf/day, whereas continuing supplemental odorization of interstate supplies costs a nominal amount.

Kern River points out that FERC does not require interstate pipelines to odorize their gas supplies, but does require local distribution companies to do so. Kern River seeks to ensure that it does not have to pay odorization costs, as a result of this proceeding. As noted above in the discussion of "threshold" issues, the contracts with existing interconnecting entities, such as Kern River, are not affected by this decision. Coral points out that, by its own admission, SoCalGas "currently provides supplemental odorant facilities at existing interconnections with interstate pipelines," and that equal treatment requires that SoCalGas do the same for new LNG supplies.

There is more than one way to interpret the requirement of equal treatment. One could conclude that each supplier should pay the same amount. Since existing interstate gas suppliers pay little or nothing to odorize the gas, this interpretation would suggest that new LNG suppliers should also pay little or nothing. On the other, one could conclude that the utility should pay the same amount for odorization, regardless of the source of the gas. Since the utility pays little or nothing to odorize existing supplies, this approach suggests that it should also pay little or nothing to odorize new LNG supplies. Because of this ambivalence, the principle of equal treatment here provides no clear direction.

Another important principle is economic efficiency. Requiring each gas supplier to pay for odorization, rather than the utility, would provide a clearer indication of how much the gas from that source actually costs, and thus promotes more efficient resource allocation. As a corollary, a failure to charge new providers for odorization costs in excess of those related to odorizing gas from other sources would result in a subsidy to the new providers. Rather than ensuring equal treatment of new sources, it would provide special treatment. We will require those providing gas from new sources of supply to pay for any odorization costs in excess of those faced by the utility in treating gas from other sources.

h) Extra Equipment to be Specified in Notice

Proposed Interconnection Agreement Section 3.b allows the utilities to install additional equipment (e.g., odorizing and metering) needed to receive gas up to the full capacity of a receipt point, and to do so at the interconnecting entity's expense. In response to previous complaints, the utilities added language stating that the interconnecting entity would receive notice prior to installation. Sound Energy Solutions argues that this language still offers the utility too much latitude, and requests adding language to this clause that (a) requires that the notice include identification of the nature and the cost of the equipment to be installed and (b) allows for the interconnecting entity to challenge the utility's determination.

Requiring specification of the nature and/or cost of the equipment to be installed would provide reasonable additional protection to interconnecting entities, and we will direct the utilities to make this change. However, providing the opportunity to challenge the utility's determination could impede the ability of the utility to safely and efficiently provide service. It is also redundant, since interconnecting entities already have the ability to file complaints at the Commission, using both informal and formal channels. The utilities are under an obligation to only impose reasonable charges on interconnecting entities. For both of these reasons, we deny the request to add another avenue for challenge.

i) Language Is Clarified to Allow for Previously Installed Metering Equipment

The proposed Interconnection Agreement contains alternative sections covering situations where the metering equipment is owned by the interconnecting entity. Proposed Section 4.d, would require the installation of metering equipment. Transwestern notes that the current language incorrectly implies that the interconnecting entity has not already installed the equipment when it states the "Interconnector shall install equipment that meets all SoCalGas specifications and is necessary to measure deliveries to SoCalGas at the Interconnect Points." Transwestern suggests it be revised to read, "Interconnector has installed or shall install equipment that meets all SoCalGas specifications and is necessary to measure deliveries to SoCalGas at the Interconnect Points."

We find Transwestern's proposal helpful and adopt it.

j) Unilateral Termination Provisions Are Allowed

Conditions where unilateral termination of the agreement is allowed are discussed in Interconnection Agreement Sections 2.d, 4.i.i, and 4.i.ii and in Operational Balancing Agreement Sections 1.4.2, 1.4.3, and 3.2.

SoCalGas/SDG&E argue that these are necessary. Coral argues that parties should be able to terminate the agreements only with Commission approval.

Service suspension affects not only the interconnecting entity, but also utility customers. If the utility does take an action of this severity, it must be prepared to demonstrate to the Commission the necessity and prudence of this action, and to show that it was not unduly discriminatory. The fact that the utility is accountable to the Commission should serve to prevent it from undertaking such an extreme measure recklessly. With this cautionary note, we will not eliminate the right of either party to terminate the agreement unilaterally.

k) Dispute Resolution

The August 16, 2005 version of Section 9 in the Interconnection Agreement (as well as Section 6 of the Operational Balancing Agreement) contains language acknowledging that the Commission can resolve disagreements, but that disputes involving interconnecting entities regulated by the FERC would be resolved through binding arbitration. In the November 22, 2005 version of the Operational Balancing Agreement, only binding arbitration is allowed, regardless of the jurisdictional nature of the interconnecting entity. We will not impose binding arbitration requirements on parties in that this would unlawfully constrain their legal rights. Binding arbitration is only a fair and reasonable approach when all parties to an agreement freely agree to resolve disputes in that manner.

Interconnection Agreement Section 10.j and Operational Balancing Agreement Section 3.2 state that the agreements shall be subject to future actions that may be taken by the Commission to modify the terms. Transwestern argues that the statement is not true when the agreements are with FERC-regulated interconnecting entities, and asks that the language be changed to reflect this. We are not persuaded that we should make this change. The agreements apply to the interface between SoCalGas, which owns pipelines subject to the jurisdiction of this commission, and other entities. Whether those other entities are regulated by a federal agency, a state agency, or by no agency at all, the Commission has an obligation to ensure that the terms of these agreements are in the public interest. As part of our approval here, we require that those agreements continue to serve the public interest, and that the Commission remain able to influence the terms accordingly, in the unlikely event that this should be necessary.

l) "Regulatory Impairment" Clause Will Be Allowed to Stand As Is

The "regulatory impairment" clause, Section 3.2 of the Operational Balancing Agreement, allows for parties to terminate the agreement if the Commission should take actions that could render the agreement unacceptable. The Indicated Producers point out that the regulatory landscape surrounding these agreements—firm access rights, off-system deliveries, etc.—is still being developed, and asks for a statement by the Commission that changes in these areas will not be allowed to trigger contract termination under the regulatory impairment clause. We are not willing to tie the hands of the parties in this way, and decline to accept this suggestion.

VI. Independent Storage Provider Direct Interconnection With California Producers, As Well As Electric Generators and Other Noncore Customers

A. Background

The February 28, 2005, Scoping Ruling included two storage provider issues among those to be considered:

> "Should independent gas storage facilities be permitted to connect directly with other market participants such as California producers, electric generators, or other noncore customers, which Public Utilities Code sections are relevant to this issue, and should the Commission be concerned with bypass?
>
> "Should the Commission determine in this proceeding whether the gas utilities' backbone transmission capacity is

> sufficient to accept maximum withdrawals from all gas storage facilities during peak periods…?"

The issue of interconnections by independent storage providers was, in part, the result of a joint petition for rulemaking filed on October 15, 2003, by Wild Goose and the California Natural Gas Producers Association. That earlier petition preceded R.04-01-025 and requested that the Commission establish a rulemaking on storage provider interconnection issues. The second issue, regarding the adequacy of PG&E's backbone facilities to accept storage withdrawals, was left open in the Scoping Memo, in that it asked for comments on how to proceed in addressing this issue. However, the proposed settlement attempts to resolve this issue and not leave it to further comments or litigation.

By subsequent ruling issued April 21, 2005, the Assigned Commissioners established a Phase II schedule. Among other things, it allowed the parties 60 days to attempt to resolve the interconnection issues. At the request of the settling parties and based upon reports of progress in those settlement discussions, the assigned ALJ twice extended the deadline for reaching a settlement, with the final deadline being September 30, 2005.

The settling parties report that they participated in multiple settlement meetings and held regular phone discussions starting in May, and exchanged numerous settlement drafts. PG&E notified the entire service list of this process and invited all parties to participate. Parties that expressed an interest in participating in the settlement discussions, and agreed to be bound by Rule 51, were invited to the various settlement meetings and were provided drafts of the settlement documents. The primary parties to the negotiations were PG&E and the independent storage providers, although a number of other parties, representing a broad cross-section of the gas and electric industries, also attended the settlement meetings.

On September 12, 2005, PG&E notified all parties on the service list in R.04-01-025 of a formal Settlement Conference pursuant to Rule 51.1. The settling parties held a formal settlement conference at PG&E's offices on September 20, 2005.

The result was an uncontested settlement, which includes the pro forma tariffs and agreements needed to implement it. The agreement is attached to this decision as an appendix.

B. Description of the Settlement

Wild Goose is connected to PG&E Line 400 near Delevan and PG&E Line 167 near Gridley. Lodi is connected to PG&E Line 401 near Lodi and is proposing a nearby interconnection with Line 400 in A.05-07-018. The interconnections with these two independent storage providers are subject to Operating and Balancing Agreements. The terms and conditions of these Operational Balancing Agreements, which include many operating parameters such as pressure, gas quality, and balancing requirements, are not affected or modified by the Settlement.

The settlement prescribes the circumstances and requirements: (a) for an interconnection with an independent storage provider so that PG&E can provide service to a noncore or producer customer using the independent storage facilities and an exchange of gas with the independent storage provider (Exchange Service) or (b) for third-party interconnections with an independent storage provider so that it can provide that customer storage services, and nothing else (Direct Connect Storage Service). At a minimum, an independent storage provider offering Exchange Service to PG&E customer would provide storage services for balancing.

The following defines which PG&E customers would be eligible for Exchange Service (Exchange Service Customer):

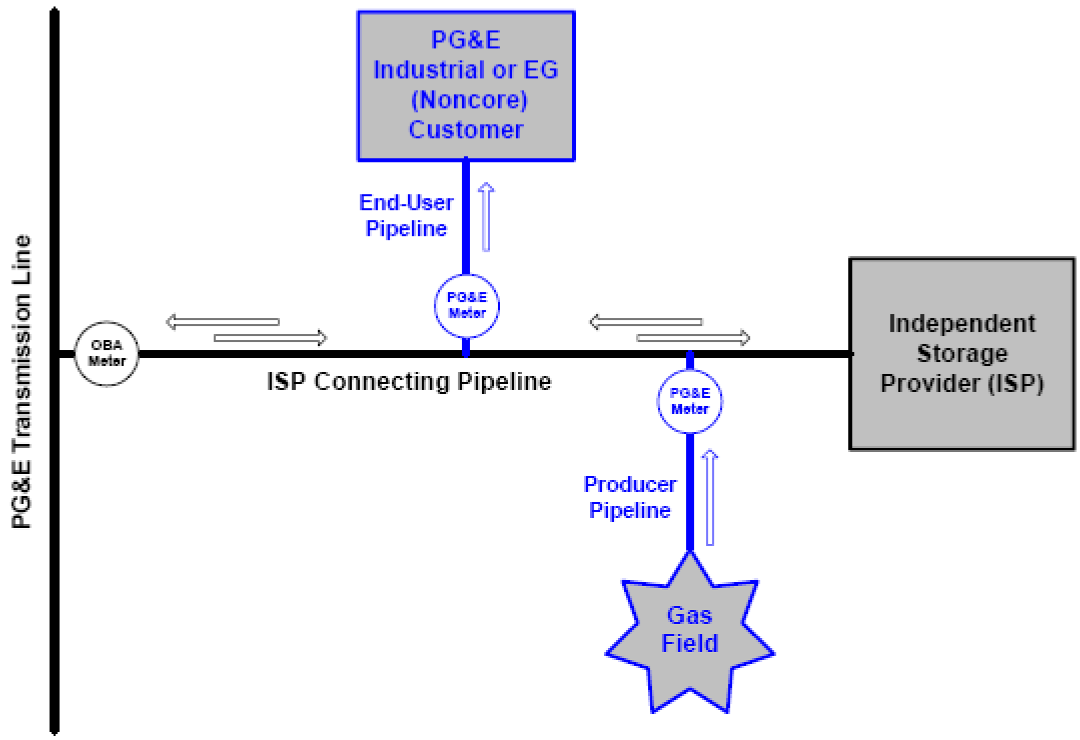
a. PG&E noncore end-use customer (industrial or electric generation facility) that is, or will be taking service under rate Schedules G-NT or G-EG, and is of a sufficient size as specified in the implementing agreements and tariffs. Other PG&E end-use customers would not be eligible.

b. A California gas producer, as defined in PG&E's gas Rule 1, which includes a gathering system operator acting on the producer's behalf.

c. Any PG&E customer that is already connected to an independent storage provider by a customer-owned pipeline.

For Exchange Service to an end-use customer, PG&E would deliver gas to the independent storage provider at a point of interconnection with PG&E, and the independent storage provider would deliver the gas through an exchange at a PG&E meter facility that is connected to the storage provider on one side and to the end-use customer on the other side. For Exchange Service to a California gas producer, the producer would deliver the gas through the PG&E meter facility directly connected to the storage provider, which would deliver the gas through an exchange to the point of interconnection with PG&E. PG&E would then deliver the gas either on-system or off-system under a Gas Transportation Service Agreement in the same way as if the gas were delivered directly to PG&E. In essence, gas to or from a PG&E customer would be exchanged with gas from the independent storage facilities, and that provider would receive an Exchange Fee for providing Exchange Service. The following diagram, from Appendix A of the settlement, shows these types of facility connections.

Schematic of Exchange Service Interconnections and Facilities



These new Exchange Service arrangements would require separate agreements between PG&E, the Exchange Service Customer and the independent storage provider, including new PG&E tariffs. The primary agreement would be an Exchange Agreement between the independent storage provider and PG&E. PG&E would also establish a new rate Schedule G-ESISP, "Exchange Service through [Independent Service Provider] Facilities." Schedule G-ESISP would be in addition to the otherwise applicable tariff requirements for the PG&E customer, and would allow PG&E to collect the Exchange Fee and provide for a self-balancing credit to the Exchange Service end-use customer, among other provisions. Associated with this new rate Schedule would be a G-ESISP Service Agreement (Service Agreement) signed by all three parties—the customer, the independent storage provider, and PG&E. The Service Agreement would require that all the other agreements and arrangements necessary to provide Exchange Service be in place before service would commence.

A PG&E Exchange Service Customer also would have the opportunity to enter into a contract with an independent provider for storage services. However, at a minimum, an Exchange Service Customer would be required to obtain storage services from the independent storage provider for purposes of balancing that customer's actual flows with its scheduled flows on the independent provider's system, so that the customer will continue to meet is operating and balancing obligations with PG&E.

For Direct Connect Storage Service, accounting and auditing procedures would be established to verify that storage is the only service being provided by the independent storage provider to the direct-connect customer, and that the customer is not bypassing PG&E's system and its Commission-approved tariffs and rules.

The settlement also includes pro forma agreements and tariffs consistent with terms of the settlement.

Further, the settlement declares that PG&E's current backbone capacity is adequate to ensure maximum withdrawals from the independent storage fields, and provides a mechanism for the independent storage providers to meet and confer with PG&E on this issue in the future.

C. Discussion

The primary question presented for our consideration is whether the terms of the settlement comply with Rule 51 of the Commission's Rules of Practice and Procedure. Only PG&E, Lodi, Wild Goose, and Calpine are signatories. However, no party opposes the settlement.

Under Rule 51.1(e), in order for a settlement to be approved by the Commission, the settlement must be: (1) reasonable in light of the whole record, (2) consistent with law, and (3) in the public interest.

First, the settlement is reasonable in light of the whole record. The theme focus of this proceeding is to ensure adequate infrastructure to deliver gas to customers under even the most severe conditions. As various parties have argued, a key to infrastructure adequacy is to maintain sufficient backbone and local transmission capacity, as well as sufficient storage capacity, and ensure that the utilities can use these facilities effectively to meet demand. By facilitating direct connections between independent storage providers and both large end-use customers and California gas producers, and by facilitating a more flexible working relationship between PG&E and the independent storage providers, there should be more ways to ensure that the gas delivery system supports demand, and greater likelihood that pipeline and storage will work together to ensure reliability.

Second, the settlement is consistent with the law. By its own terms, the settlement does not modify the Gas Accord market structure or associated services and rates as approved by the Commission in D.04-12-050. It furthers the goal of ensuring open access transmission and storage services on a non-discriminatory basis, and fully complies with Section 453(a) of the Public Utilities Code, which provides that: "No public utility shall, as to rates, charges, service, facilities, or in any other respect, make or grant any preference to any corporation or person or subject any corporation or person to any prejudice or disadvantage." The services and rates of Lodi, Wild Goose and PG&E are all subject to Commission jurisdiction and approval. The settlement merely allows PG&E to add certain new services that will increase the opportunities for customers to obtain cost-effective solutions to their needs in the context of the Commission-approved Gas Accord market structure and for subsequent or successor "Accords" or other market structures for the PG&E service area.

Third, the settlement is in the public interest. It provides for a reasonable disposition of the issues raised by the independent storage providers in this rulemaking proceeding. The settlement will save the parties considerable litigation costs and uncertainty. By avoiding what could have been extensive filing of testimony, evidentiary hearings and post-hearing briefing, the settlement also has the benefit of facilitating and expediting the Commission's review and approval of these new services. Also, the compliance process will be simplified by the fact that the settling parties have included detailed pro forma agreements, tariffs and forms as part of the settlement itself.

We note the stipulation among the settling parties to the capability of the backbone system to deliver gas withdrawn from storage during periods of peak demand. In approving this settlement, we are not expressing agreement or disagreement with this contention. As is true with all settlements under our rules, this one has no value as precedent. While the settling parties may be satisfied about the adequacy of the intrastate system for this purpose, this stipulation does not constitute a factual determination. We cannot find that infrastructure is either adequate or deficient based on an agreement of various parties. Our mission in this regard is not to resolve disputes, but to ensure that the delivery system is reliable, and sufficient to respond to emergencies. We must be persuaded of this fact based on data, analysis, and tested expert opinion—not based on a settlement which, according to its own terms, is the product of compromise.[62]

VII. Gas Quality

Each natural gas utility is accountable for the quality of the natural gas that it sells to its customers. Industry participants express gas quality in terms of the chemical composition and performance characteristics of natural gas. Gas quality is important because it directly affects air quality and the performance of machinery and appliances. The utilities define their gas quality standards through formal rules for the transportation of customer-owned gas,[63] and through adherence to the ARB's rules concerning the composition of gas sold for use in compressed natural gas vehicles. The ARB rules are in some ways more restrictive than Rules 21 and 30, and thus are a significant factor in maintaining the current relatively stable range of gas characteristics. As a result, the variations in the quality of currently delivered gas are less than would otherwise be allowed under Rules 21 and 30.

The anticipated introduction of LNG into the existing delivery system raises questions about the current standards. All participants expect that the quality of LNG supplies would differ significantly from that of the supplies the

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[62] Section 1.5 of the settlement reads as follows:

"This Settlement Agreement is a negotiated compromise of issues and is broadly supported or not opposed by parties to R.04-01-025 who are local distribution companies, gas producers, marketers, shippers, independent storage providers, wholesale and retail end-use customers, and regulatory representatives. Nothing contained herein will be deemed to constitute an admission or an acceptance by any Settlement Party of any fact, principle, or position contained herein…"

[63] PG&E's Rule 21 and SoCalGas' Rule 30.

state has traditionally imported. In addition to or as a result of compositional differences, LNG would almost certainly burn hotter than most domestic gas supplies, creating the potential for greater combustion-related nitrogen oxide (NOx) emissions and reduced reliability for gas-burning appliances and machinery. Among other things, NOx is an ozone smog precursor, leading to the possibility that hotter-burning gas could contribute to higher smog levels throughout the state, which contains significant non-attainment areas.[64] Some power-generating companies also raise a concern that compositional differences could affect powerplant performance in other ways.

An additional wrinkle is that LNG-derived supplies are likely to surge and recede with the periodic arrival and regasification of individual tanker shipments. Load centers relatively close to LNG terminals could experience dramatic swings in gas quality if LNG is not more closely matched to other flowing supplies. This makes it less likely that existing appliances and machinery could be recalibrated to adjust to the hotter-burning LNG supplies.[65]

The gas supplies delivered as LNG could be treated (either prior to shipment or upon arrival) by injecting inert gas (nitrogen) or extracting

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[64] A "nonattainment area" as a locality where air pollution levels persistently exceed national ambient air quality standards, or that contributes to ambient air quality in a nearby area that fails to meet standards.

[65] The size of the orifice or opening through which the gas must pass prior to combustion controls the flow of gas used by appliances and machinery. For most uses, less gas is needed when each increment creates a greater amount of heat. Unless the orifice in each appliance and machine is adjusted to match gas quality at any given time, the gas flow will remain constant and may repeatedly expose the apparatus to excess heat. One fear is that excess heat will cause an appliance or machine to "burn out," shortening its useful life.

components heavier than methane, such as ethane, to modify the quality of the gas. Some LNG project proponents state that they are prepared to meet any standard, and seek certainty in order to plan their physical plant and procurement strategies. Some are seeking a more relaxed standard than others, presumably to reduce treatment costs and maintain the greatest procurement flexibility.

If the utilities were to continue to insist on compliance with the current ARB rules, LNG suppliers would have to treat their gas prior to delivery to avoid most, if not all of these potential problems. However, LNG project proponents and others have placed considerable pressure on the ARB to significantly modify its compressed natural gas vehicle rules. Unless we act to narrow the scope of Rules 21 and 30, we face the likelihood that that the introduction of LNG will lead to gas supplies that are hotter-burning, and perhaps different from current supplies in other significant ways. These issues also raise concerns for in-state gas producers, which often require greater flexibility in quality standards in order to make their products acceptable for introduction to utility pipelines.

Most parties participating in the debate acknowledge a need to change the rules in anticipation of the new supplies. The exception is PG&E, which proposes only minor modifications to its Rule 21 to reduce the ways in which it differs from SoCalGas' Rule 30. At the time of its contribution on this issue, PG&E did not anticipate any near-term participation in LNG markets.

SDG&E/SoCalGas offer the following summary of the nature of current gas supplies and potential LNG supplies:[66]

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[66] Ex.107, Figure 1.

	System Average	California Production*	Potential LNGs
Heating Value Btu./scf	1020	1007-1150	1063-1166
Wobbe Index	1332	1283-1431	1373-1446
Carbon Dioxide	1.25%	0.09-3.00%	Trace
Air (N2, O2)	0.7%	0.12-3.15%	Trace
Total Inerts	1.95%	0.34-4.00%	Trace
Methane	95.4%	84-99%	83.2-91.2%
Ethane	2.1%	0.13-10%	4.3-13.2%
C3+	0.5%	0.02-7.1%	2.2-5.0%
C6+	Trace	Trace -.48%	Trace

* Acceptable under Rule 30 into SoCalGas System

A. Should the Commission Approve any Changes to the Existing Gas Quality Tariff Specifications of (1) PG&E; and (2) SDG&E and SoCalGas? If so, What Changes Should Be Approved?

1. Switching to a Standard Based on the Wobbe Index

a. SDG&E/SoCalGas Proposal

SDG&E/SoCalGas lead an effort to move away from the prescriptive or compositional nature of the existing rules toward an approach that focuses, instead, on the performance of the gas. One performance standard involves calculating the anticipated productivity of the gas based on its mass and heating value (Btu content).[67] Industry participants refer to the scale that is used to express this performance value as the Wobbe Index. SDG&E/SoCalGas propose replacing most of the existing rules with a Wobbe range having a low end of 1290 and a high end of 1400. This would allow for hotter-burning gas than the utilities usually receive now, but would be more restrictive than the range that could qualify under the existing utility rules. Since all parties anticipate that LNG providers will deliver gas at or near the top of whatever range the Commission adopts, the result would be that the average Wobbe number for flowing supplies would become higher, leading to hotter-burning gas, overall.

Potential LNG suppliers offering a position on this issue (BHP Billiton, Exxon Mobil, Sempra LNG, and Shell Trading) all support the SDG&E/SoCalGas proposal. BHP Billiton would also be comfortable maintaining the current rules. Sempra LNG would add a maximum butane content of 1.5% and a minimum methane content of 85% (the latter in response to SCE's concerns about powerplant performance). Indicated Producers, which represent in-state gas producers, also supports the SoCalGas proposal.

Most vocal in opposing this proposal is the South Coast Air Quality Management District (SCAQMD), the agency directly responsible for reversing the non-attainment status of the South Coast Air Basin. SCAQMD is undertaking an effort to reduce NOx emissions from all sources. Since hotter-burning gas could result in higher NOx emissions, SCAQMD finds the SoCalGas proposal to be entirely unacceptable. Instead, SCAQMD proposes

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[67] Another performance standard is a methane number (MN), which measures a gas' resistance to knock in an internal combustion engine, similar to an octane number for gasoline.

establishing a maximum Wobbe number of 1360, which more closely matches the current average Wobbe number in the SoCalGas service territory.[68] SCAQMD's intention is to ensure that the shift from a compositional standard to a performance standard does not lead to the introduction of hotter-burning gas in its air basin.

Calpine and SCE also oppose the SoCalGas proposal out of concern that a shift in gas quality could impair the performance of gas-fired power plants. These parties argue that there is insufficient information about the impact of hotter-burning gas on the performance and costs related to end-use equipment such as gas-fired turbines, and insufficient information about air quality impacts. Calpine recommends that the Commission adopt, as an interim standard, a Wobbe range of 1153-1391, with a maximum variation from historically-delivered gas quality of +/- 2%. SCE supports the SCAQMD proposal plus a minimum methane composition of 85%. In addition, Calpine and SCE would limit the rate-of-change in Wobbe value to two percent per minute.

No one, in this portion of the proceeding, spoke for the greater body of ratepayers that would face the consequences of any deterioration in the reliability of appliances and machinery that might result from the greater presence of hotter-burning gas.

SDG&E's and SoCalGas' proposed Wobbe Number minimum and maximum of 1290-1400 equates to a range of approximately +/- 4% from a

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[68] The system average Wobbe number for the SoCalGas service territory is 1332. The 1360 limit represents the higher end of a +/- 2% band around that average number.

midpoint of 1345.[69] The midpoint represents a national average Wobbe number. The average for SDG&E and SoCalGas is lower (1332). The 1290-1400 range is the same as an interim recommendation contained in a discussion paper prepared by a group that calls itself the Natural Gas Council NGC+ Interchangeability Standard Work Group (NGC+). SDG&E and SoCalGas place great reliance on the fact that their proposed Wobbe range was included in the paper prepared by that group and on that basis, conclude that their proposal has broad general support among stakeholders. They also refer to this proposed Wobbe range as "the consensus recommendation of the NGC+ Work Group."[70]

The NGC+ is a self-selected group of industry participants. In issuing its discussion paper, it took no votes. While the paper includes a list of participants, it does not state which of those participants endorsed its recommendation, or which were actually involved in reviewing it. The list includes the names of approximately 17 utility representatives from across the nation. Four of those representatives work for SoCalGas (two utilities have two representatives; all of the others have one.). Of the 75 people listed as participants, 15 represent LNG suppliers, including two from Sempra LNG, two from Shell, and one from ExxonMobil. At the end of its list of recommendations, the paper ambiguously states, "Alternative language was suggested as well…"[71] Other parties have noted that many organizations that

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[69] Ex. No. 107, at 10:25-27.

[70] Opening Brief of SDG&E and SoCalGas p. 18.

[71] Ex. 107, Attach. B, p. 23.

had representatives in the NGC+ group have filed comments before the FERC opposing the paper's interim recommendations.

Although the paper recommends adopting the specific Wobbe range for no more than three years, SDG&E/SoCalGas rely on that recommendation as the most prominent support for their proposal that this Commission adopt the same standard indefinitely.

SDG&E and SoCalGas argue that no additional research or data gathering is required to confirm the suitability of the proposed 1400 Wobbe index limit. Their sole support for this critically important statement is the observation that although the NGC+ paper proposed further data gathering, it did so only for the purpose of determining if a final standard should be even broader.

The NGC+ discussion paper is rich with unanswered questions about the appropriate standard to adopt. It discusses the kind of effects that varying natural gas composition "beyond acceptable limits" can have on combustion equipment:

> "a. In appliances, it can result in soot formation, elevated levels of carbon monoxide and pollutant emissions, and yellow tipping.[72] It can also shorten heat exchanger life, and cause nuisance shutdowns from extinguished pilots or tripping of safety switches.
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> b. In reciprocating engines, it can result in engine knock, negatively affect engine performance and decreased parts life.

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[72] "Yellow tipping" is defined by the American Gas Association (AGA) as the tendency of gases to burn with yellow tips at any given primary aeration that depends on their chemical composition. (Exh. 107.) It is an indication of incomplete combustion and soot generation.

c. In combustion turbines, it can result in an increase in emissions, reduced reliability/availability, and decreased parts life.

d. In appliances, flame stability issues including lifting are also a concern.

e. In industrial boilers, furnaces and heaters, it can result in degraded performance, damage to heat transfer equipment and noncompliance with emission requirements."[73]

The paper offered the following discussion about non-combustion-related applications:

"3.4.3 Varying gas compositions beyond acceptable limits can be problematic in noncombustion-related applications in which natural gas is used as a manufacturing feedstock or in peak shaving liquefaction plants, because historical gas compositions were used as the basis for process design and optimization of operating units. More specifically, domestic LNG peak shaving liquefaction plants will most likely require retrofits to continue operations utilizing regasified LNG as feedstock. Propane-air peak shaving operations will also likely require retrofits and/or additional controls to continue operations."[74]

In addition, the paper raises concerns about the affect of gas quality changes on gas utility infrastructure:

"22. Gas system infrastructure impacts must be considered when supply compositions change for extended periods of time. The impacts when shifting to a dry, leaner supply

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[73] Exh.107, Attach. B, p. 5.

[74] *Id*.

> source may include failure of certain gas transmission and distribution piping component seals and gaskets in valves, pipe clamps, joint sealants and other mechanical components. Additional infrastructure issues include impacts to custody transfer gas measurement techniques (thermal vs. volumetric billing) and related gas accounting issues."[75]

The paper also concludes that there are "several information gaps that must be addressed to better understand the overall impacts of gas interchangeability in North America."[76]

The solution that the paper suggests is to adopt an interim Wobbe cap of 1400 for a period of no more than three years, in the hopes that critical research can be completed within the next two-three years. The paper does not state that a significant concentration of 1400 Wobbe gas would successfully avoid any of the concerns listed above.

Further, SCE points out that SDG&E and SoCalGas have misapplied the paper's recommendation. First, the 1290 to 1400 Wobbe Index range recommended in the NGC+ paper, which equates to a range of approximately +/- 4% from a midpoint of 1345, is based on a national average and is offered as appropriate for those supplies with gas qualities close to this average. The paper also states that such limiting values should be calculated for individual market areas based on historical delivered gas supplies. It specifically states:

> "The 1992 'average' gas was characterized by a Wobbe Number of 1345 and gross Heating Value of 1035 Btu/scf. This 'average' gas is assumed to be a reasonable estimate for an average adjustment gas in the U.S. It is important to note

[75] *Ibid*., p. 19.

[76] *Ibid*., p. 22.

> that the limiting values in the interim guidelines simply serve to establish boundaries for market areas that have received historical gas supplies with gas quality close to the 1992 reported national mean and have experienced successful end use with these gas supplies."[77]

SoCalGas/SDG&E's historical average is 1332, not 1345.[78] Since the SoCalGas/SDG&E's system average Wobbe is 1332, a variation of 4% above that amount would result in a maximum Wobbe limit of 1385, not the 1400, that has been proposed. Second, SoCalGas/SDG&E's proposal is inconsistent with the Interim Guidelines recommended in the NGC+ paper, which provide that the Wobbe Index should be based on "local historical average gas" or "established adjustment or target gas for the service territory." The paper specifically states:

> "Interim Guidelines – A range of plus and minus 4% Wobbe Number Variation from Local Historical Average Gas or, alternatively, Established Adjustment or Target Gas for the service territory Subject to:
>
> Maximum Wobbe Number Limit: 1,400
>
> Maximum Heating Value Limit: 1,110 Btu/scf."[79]

With regard to the first part of the Interim Guidelines, i.e., a "range of plus and minus 4% Wobbe Number Variation from Local Historical Average Gas," SCE argues that the reference to "local historical average gas" should refer to SoCalGas/SDG&E's local Btu districts and not to SoCalGas/SDG&E's system-wide Wobbe Index average of 1332. An examination of the local Btu

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77 *Ibid*., p. 25.

78 Ex. 107, p. 4.

79 *Ibid*., p. 26.

districts demonstrates that the Btu districts in the South Coast Air Basin predominantly receive interstate gas (or have gas that is blended) and do not have experience with gas with a Wobbe index of 1400 or greater.[80]

SCE argues that the Commission should also consider the fact that the Wobbe Index for customers in SDG&E's service territory may be lower than the 1332 Wobbe historical system-wide average because these customers fall in Btu districts 11 and 12, which receive gas deliveries with the lowest Wobbe Index of all the Btu districts in the SoCalGas/SDG&E service territory.[81] This could be a significant factor, if a significant amount of LNG-derived gas is delivered at Otay Mesa.

With respect to the second part of the interim guidelines, "Established Adjustment or Target Gas for the service territory," SCE submits that it is unreasonable for SoCalGas/SDG&E to impute the limited experience SoCalGas has with two Btu districts in SoCalGas' service territory that have received gas at a Wobbe Index of 1400 or above to the remaining seven Btu Districts in SoCalGas' service territory. Moreover, with regard to the SDG&E' service territory, SoCalGas' attempt to impute its limited experience from SoCalGas' service territory to a different service territory (i.e., SDG&E's service territory) is contrary to the language of the interim guideline in the NGC+ paper.

SCAQMD underscores these concerns by stating that the 1400 Wobbe Index standard would radically alter the traditional pattern of gas use in the South Coast Air Basin. The District argues that in essence, the SoCalGas/SDG&E

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80 Ex. 140, p. 8 (unnumbered).

81 *Id*. and Tr. 1015-1016.

proposal is to act now and respond to the consequences later. For example, the testimony indicated that SoCalGas would follow a "rollout" approach that would largely rely on responding to difficulties encountered by sources after the introduction of the high Wobbe Index gas.[82]

The District asserts that this approach—introducing the gas and then confronting the consequences—is simply too risky from both an environmental and an operational standpoint. Too many questions remain unanswered about the environmental and other effects of importing LNG with a high Wobbe Index. The consequences to the public health of approving that gas require a cautious, measured approach to making that decision.

The District maintains that adoption of the proposal is unnecessary. Two parties that propose to import LNG into Southern California have expressly stated that they could meet a more narrow standard such as the 1360 Wobbe Index benchmark proposed by the District.[83] Only a third proposed importer, owned in part by SoCalGas' corporate affiliate Sempra, dissents. SCAQMD asserts that this importer apparently bases its opposition on two grounds: (1) it chose a facility location with no pipeline access, and thus cannot "strip" the

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[82] Tr. 1143, lines 5-10.

[83] Ex. 138 (letter from Sound Energy Systems) and Tr. 1042 (testimony of the District's witness Dr. Liu that "Sound Energy has indicated to the district for a long time they will achieve whatever we request them to do in terms of cleanup [of the gas]"); Ex. 143 *** (letter from BHP Billiton; Ex. 142 at p. 354 (testimony of BHP Billiton before the Commission).

natural gas;[84] and (2) part of the product of stripping is restricted under a legal monopoly in Mexico.[85]

SCAQMD further notes that while the record apparently does not clearly document the Wobbe Index value of the natural gas that the Sempra facility will transport, the plant is building a nitrogen injection facility that can lower the Wobbe Index content of the gas it does receive.

The District argues that under these circumstances, it hardly makes sense to rush into adopting the SoCalGas proposal, a standard designed solely to meet the needs of its affiliated importer whose gas may be the least favorable from an environmental standpoint. SCAQMD further argues that Sempra LNG's choice of locating its facility in Mexico should not compel decisions affecting California's public health.

Sempra LNG responds by pointing out that it, too, has committed to conform to whatever rules the Commission adopts, although it continues to advocate adoption of the 1290-1400 Wobbe index range.

SCAQMD points out that the parties supporting the SoCalGas proposal of a 1400 Wobbe Index number characterize that proposal as "tightening" or "narrowing" the current standards. For example, SoCalGas argues that the Commission should "approve the proposed narrowing of their gas quality

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84 "Stripping" refers to treating a gas supply by removing one or more of its components. This is one of the two major ways that a gas supplier can reduce the heat rate or the Wobbe number of the gas supply. The other method involves adding an inert gas such as nitrogen.

85 Tr. 1275, 1277 (testimony of Dr. Kuipers for Shell, a partner in the Sempra facility).

standards…."[86] The District argues that such a characterization simply masks the actual effect of SoCalGas' proposal of a 1400 Wobbe Index and does not aid the Commission's decisionmaking.

The record is indisputable: the vast majority of gas users in the South Coast Air Basin have never used gas approaching the 1400 Wobbe Index range. To the contrary, the average gas used by SCE over the past five years had a Wobbe Index value of 1332. While some deliveries have been higher, such as Kern River's delivery of over 1360 Wobbe Index gas, these deliveries have been blended with lower-Wobbe Index supplies.[87] And while a small number of customers in the SoCalGas service area have used higher Wobbe Index gas, they are not located in the South Coast Air Basin.[88]

SoCalGas intends its proposal to authorize receipt of LNG shipments with Wobbe Index numbers far higher than users in the South Coast Air Basin have experienced. Furthermore, supporters of the proposal intend to propose further relaxation of the Wobbe Index limitation in the future. Shell, for example, states that after testing and experience the Commission may wish to relax the gas quality parameter. SCAQMD argues that framing the issue as a "tightening" or "narrowing" of standards, ignores the reality that SoCalGas seeks the Commission's permission to markedly change its historic gas supply practices.

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[86] SoCalGas Opening Brief at 9 (emphasis in original); see also WSPA Br. at 4 ("this change would represent a tightening of existing standards").

[87] SCE Opening Brief at 18.

[88] Tr. 1012 line 16 to Tr. 1013 line 4.

SCAQMD agrees with SCE that, even if the 1400 Wobbe Index figure might be useful as a general guide nationally, this does not dictate a conclusion that the figure is, per se, suitable for the South Coast Air Basin. The District sees one crucial fact distinguishing its basin from other areas of the country: its intractable air pollution problem. Congress has repeatedly recognized the extent of the public health problem that air pollution poses in this region. For example, it authorized more stringent emissions standards for vehicles sold in California than in the other 49 states. 42 U.S.C. § 7543(b) (authorizing the Environmental Protection Agency (EPA) to waive preemption on vehicle emission standards for California).

SCAQMD argues that the testimony often highlighted what was not known about the effects of a 1400 Wobbe Index, and the District discusses that testimony in later parts of this brief. As an example, the District cites one excerpt from the testimony of Shell's witness Dr. Kuipers. He first noted that the stationary sources in the South Coast Air Basin "could see an increase in NOx emissions with an increase in the Maximum Wobbe index." Dr. Kuipers then stated that to accurately quantify that increase, "one would need to break down the NOx emissions not only in source categories, as done by SCAQMD, but also in the various burner and fuel categories."[89] The District submits that information of this type is critical to an evaluation of the environmental effects of SoCalGas' proposal.

Calpine asserts that the determination of an appropriate, revised or new interchangeability standard is a difficult matter, and that the record is notable for

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[89] Ex. 158, p. 12, lines 13-17.

its lack of the solid empirical data necessary to establish the interchangeability requested by the LNG developers and utilities. The impact on many types of end-use equipment, particularly the Dry-Low NOx or Dry-Low Emissions (DLN/DLE) turbines used to supply a significant portion of power to California, is not known.

SCE witness Pando testified that General Electric Corporation (GE), one of the manufacturers of gas-fired turbines used in California, has stated that burning natural gas outside of its current specifications may require additional hardware and software modifications but that such a technical solution has not yet been developed and therefore, the capability of such equipment is unknown.[90]

PG&E witness Bronner also testified that insufficient information is available at this time. He stated that, "I have heard a lot of discussion about the need for research . . . here. I think we're coming to the conclusion that there is a lot of stuff that we don't know and a lot of answers we still need to make decisions."[91] Bronner agreed with the need for research on gas-fired turbines in light of the stated concerns of other witnesses. He also testified that the impacts of LNG and other gases on industrial and commercial equipment and burners, in particular appliances, are insufficiently understood at this time.[92]

Thus, three major power plant operators have expressed concern about the impact of the proposed 1290-1400 Wobbe range on plant operation. Only one

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[90] Tr. 735, line 26 to TR. 736, line 16.

[91] Tr. 771, lines 7-11.

[92] Tr. 771, lines 12-27.

power plant operator disagrees, and that operator is an affiliate of Sempra LNG. Testifying on behalf of SoCalGas/SDG&E, witness Baerman, who is responsible for operating and maintaining the new Palomar facility, stated that SDG&E is working with GE to ensure that Palomar will be able to operate safely, efficiently, and within emission limits using gas supplies within the range of specifications proposed by SoCalGas/SDG&E. He states that he does not believe that any hardware changes will be necessary for DLN and DLE gas turbines to operate safely using the proposed gas supply parameters. The record does not show, however, that all new GE plants are designed to run within the same Wobbe range.

SoCalGas tested the short-run affects of various different gas mixtures on one brand and model of each of 13 different types of appliances. These appliances were:

1. One forced-air furnace
2. One vapor ignition resistant residential water heater
3. One instantaneous residential water heater
4. One "legacy" residential water heater
5. One "legacy" floor furnace
6. One gravity built-in wall furnace
7. One pool heater
8. One commercial condensing hot water boiler
9. One commercial hot water boiler
10. One low NOx commercial steam boiler
11. One ultra low NOx commercial steam boiler
12. One deep fat fryer
13. One chain-driven char commercial boiler

SoCalGas tested these appliances to see how different gas blends affected safety (carbon monoxide emissions, and flame characteristics), and NOx emissions. The company used the four following gas types:

- Average SoCalGas system gas (1020 Btu, 1330 Wobbe number)
- Low Btu/Low Wobbe number (970 Btu, 1271 Wobbe number)
- High Btu & Wobbe number (1150 Btu, 1437 Wobbe number)
- High Btu/Low Wobbe number (1150 Btu, 1375 Wobbe numb)

The company also chose secondary blends to test any sensitivity observed while testing the primary gas blends. They did this by holding the Wobbe number constant at 1375 and lowering the heat rate to 1100 Btu, and by holding the heat rate at 1100 Btu while raising the Wobbe number to 1400. SoCalGas did not test gas with 1150 Btu and 1400 Wobbe number.

SoCalGas found that some of the appliances produced more NOx or more carbon monoxide when burning high Btu/High Wobbe number gas, and some did not. For twelve of the thirteen tested units, a change in gas composition led to a change in temperature. The company concluded that all tested units performed satisfactorily over a wide range of gas compositions and characteristics up to the 1150 Btu/1400 Wobbe number gas (although, again, it did not test gas with both 1150 Btu and 1400 Wobbe). The utility did not explain, in the report, what it meant by satisfactory performance.

SoCalGas did not test different models or vintages of the same category of appliance (such as different domestic water heaters, both old and new). Nor did it test more than one of each item (i.e., two water heaters of the same model from the same manufacturer). The company also did not test other common appliances, such as ovens or range tops, or other industrial equipment such as combustion turbines. SoCalGas did not assert that its study is statistically significant.

SoCalGas/SDG&E witness Hower explained that SoCalGas/SDG&E have not researched the long-term impact on the ability of natural gas appliances to function using a hotter gas supply. SoCalGas/SDG&E witness Sasadeusz testified about a similar unknown effect upon gas-fired turbines; in response to cross-examination by counsel for Calpine, witness Sasadeusz said that more data is needed regarding the affect of changes in gas quality on gas-fired turbines.[93] Sasadeusz also agreed, in response to cross-examination by counsel for Calpine, that the NGC+ paper confirmed the group's concern about the lack of empirical data for gas-fired turbines.[94]

Beyond the limited observations included in the SoCalGas study, there is a lack of information regarding the impact of "hotter" LNG on emissions, in particular NOx. Based on that limited study, SDG&E/SoCalGas witness Hower concluded that adoption of their proposal would lead to a very small increase in NOx emissions in the South Coast basin compared to emissions from all other sources. For this calculation, he assumed the replacement of either 0.5Bcf/day or 1 Bcf/day of natural gas with 1400 Wobbe number gas. This is the range of output for one large LNG terminal. He did not assume that there might be more LNG facilities delivering gas to Southern California. He apparently did not

[93] Tr. 1130, lines 16-17.

[94] Tr. 1137, line 28 to Tr. 1138, line 3.

consider the potential that providers other than those using LNG might provide more 1400 Wobbe gas, or that the introduction of a major new gas supply system might lead to higher overall demand for gas. In addition, for this calculation, Hower assumed no increase in NOx emissions from power plants, oil and gas production, petroleum refining, industrial and manufacturing facilities. This is because Hower assumed that all of these facilities already emit as much NOx as is allowed under air quality rules, and that in order to increase emissions, each and every such facility would have to purchase offset credits.

SCAQMD witness Lui testified that the influx of LNG into California, absent a narrowing of current tariff specifications, would disrupt the historical stability in the quality of delivered natural gas supply in California and could increase emissions. Accordingly, SCAQMD recommends that the Commission require at least four studies to ascertain the actual impact of an influx of LNG upon emissions. Lui said he could not present a quantitative analysis of the increase in NOx emissions because there is not enough information to address all the parameters and variables needed to perform the requisite calculations. Similarly, PG&E witness Bronner testified that the "air quality impacts associated with end-use equipment emissions when operated with LNG and other nontraditional supplies have not yet sufficiently been researched."[95]

Calpine argues that even if the impact on the operations of end-use equipment and emissions were known, the cost impact remains uncertain, and without this information it is impossible to determine the most economically efficient standard. SoCalGas/SDG&E assert that the impact of higher Wobbe

[95] Tr. 718, lines 25-28.

Index gas should be dealt with by individual end-users but three of SoCalGas/SDG&E's witnesses, Messrs. Steward, Baerman and Hower, each testified that the cost impact upon end users is not reliably quantified.

SoCalGas/SDG&E witness Steward acknowledged that SoCalGas/SDG&E have not conducted studies to determine what the associated costs for end-users would be.[96] Likewise, SoCalGas/SDG&E witness Baerman testified that he is uncertain that requiring end users, as opposed to the utilities themselves or LNG producers, to ameliorate emissions and gas quality issues at the burnertip is cost-effective.

Baerman testified that generators would need to add hardware to allow for the monitoring of gas quality and to make adjustments in real time and may need to resize the emissions control equipment, leading to increased cost.[97] However, in response to questioning, Baerman stated that he did not know the cost of such equipment and could only offer an estimate of between $100,000 and $300,000 per turbine, based upon data and/or information unavailable for public review.[98] Calpine witness So stated that Calpine's review of vendor cost information indicates that the cost would range from $250,000 to $1.5 million per turbine for equipment to control turbine dynamics.[99] The difference in these estimates suggest that as of now, we do not know with any accuracy the cost for

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96 Tr. 983, lines 2-23.

97 Tr. 848, lines 20-24.

98 Tr. 746, lines 6-16.

99 Tr. 712, lines 17-22.

the necessary equipment or whether these estimates are based on annual forecasts or the assumption of a one-time capital expenditure.

Hower states that he has not done a cost-effectiveness study of the impact of LNG on emissions.[100] However, he did state that the hotter gas will increase the costs of the largest emitters of NOx[101] and the changes in gas quality could increase labor costs and require new hardware, new software, monitoring equipment, and an advance warning system,[102] all of which would increase costs by some unknown amount.

Finally, Sempra witness Bamburg stated that no study has been introduced into evidence that projects the amount of LNG that will be brought into California and what customers would be affected.[103] Accordingly, the problem of determining cost impacts is compounded because the affected customer base is unknown. The Commission must better ascertain the true extent and nature of the cost impacts of the utilities' proposed interchangeability standards before adopting a new standard.

b. SCAQMD Proposal

SCAQMD proposes that the Commission adopt a Wobbe index range of 1332 +/- 2%. This would lead to a maximum Wobbe number of 1360. This proposal corresponds to the five-year average for Wobbe Index numbers experienced within the District's jurisdiction. The District's proposal preserves

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[100] Tr. 763, lines 16-18.

[101] Tr. 802, lines 1-16.

[102] Tr. 823, line 17 to Tr. 824, line 7.

[103] Tr. 1262, line 10 to Tr. 1264, line 5.

the status quo and is grounded on what it sees as the need for caution. SCAQMD argues numerous questions remain outstanding concerning the environmental and other effects of burning high Wobbe Index gas in the South Coast Air Basin. For example:

> -- The parties have undertaken no comprehensive testing of the environmental effects of LNG on large users of natural gas, such as turbines. At the same time, the testing carried out on smaller appliances by SoCalGas has been extremely limited. A SoCalGas witness admitted that its primary purpose was not to evaluate NOx emissions from burning higher Wobbe Index gas.[104]
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> -- The evidence indicates great uncertainty about the effects of high Wobbe Index gas on the reliability of electricity generation. The record contains no concrete assurances from turbine manufacturers that they will warrant the operation of the turbines if gas with a high Wobbe Index is introduced into Southern California. Outages of that equipment not only could profoundly affect the economy, they would likely result in significant air quality impacts.
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> -- The record is almost completely devoid of evidence on the variety of costs stemming from the use of high Wobbe Index gas. Consequently, the Commission has no basis upon which to make a fundamental choice posed by this proceeding: Whether end users should bear the costs of using a gas supply with a high Wobbe Index content, as SoCalGas proposes, or whether those companies importing the gas should bear those costs.
>
> -- Finally, no specific figures exist showing how the establishment of a Wobbe Index standard at various levels would affect LNG supply.

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104 Tr. 1152, lines 2-3, 15-17 (Statements of SoCalGas witness Sasadeusz).

Given this level of uncertainty, the District submits that the only prudent course is caution. The District's proposal is intended to retain the status quo for the period of time while necessary information is gathered.

SDG&E/SoCalGas, California producers, and all of the LNG proponents oppose this proposal.[105] SCE supports it. Calpine offers a related proposal, which we will discuss later.

SDG&E/SoCalGas argue that Commission approval of a Wobbe Number range of 1290-1400 for their service territories would do more to promote the District's air quality objectives than any measure that the District might adopt in the exercise of its jurisdiction, by making more supplies of reasonably priced natural gas available as a substitute for liquid petroleum based fuels throughout southern California. The utilities assert that the changes proposed by the District to the utilities' existing gas quality tariff specifications not only contradict the Commission's policy goals and determinations in this proceeding, but also contradict the SCAQMD's own goals to improve air quality.

Because of the nature of the utility service territories and the mandate to treat all types of gas suppliers in an evenhanded way, the District's proposed maximum Wobbe Number of 1360 would need to be a system-wide cap. Various parties argue that a cap at 1360 would be an extremely uneconomic and poor

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[105] In its Opening brief, SCAQMD argues that some potential LNG producers could comply with a 1360 Wobbe standard. On February 7, 2006, BHP Billiton filed a motion to clarify the record, objecting to this statement as misleading because Billiton now supports the 1400 Wobbe standard. SCAQMD responds that while it acknowledges Billiton's current position, Billiton has asserted its ability to meet the standard. Billiton's motion is denied.

energy policy choice for California.[106] SDG&E/SoCalGas assert that a 1360 cap would cut off access to the approximately 20% of interstate supplies currently delivered by Kern River to southern California.[107] The utilities argue that adoption of a maximum Wobbe Number of 1360 would elevate air quality concerns over all other factors the Commission must take into account.

SDG&E/SoCalGas argue that SCAQMD's proposed maximum Wobbe Number of 1360 is not supported by any scientific analysis of the estimated potential increase in NOx emissions from the volume-weighted SoCalGas system-wide five year average Wobbe Number of 1332, to the District's proposed maximum Wobbe Number of 1360.[108] Nor has the District presented any scientific analysis to attempt to estimate the potential increase in NOx emissions from a maximum Wobbe Number of 1360 to 1385; or to 1391; or to 1400.[109]

SDG&E and SoCalGas offer their belief that the potential impact on air quality from gas supplies with a maximum Wobbe Number of 1400 will be mitigated over time through re-tuning and adjustment of equipment, including commercial and industrial equipment operated under permits issued by the District, and by the development of improved emissions control and combustion technologies. They argue that these forward-looking mitigation measures will be

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106 Opening Briefs of SDG&E and SoCalGas, at pp. 10-16; Shell Trading Gas & Power ("Shell"), at pp. 5, 7-8,15-19, 26; BHP Billiton, at pp. 7-10; Sempra LNG, at pp. 5-9; Indicated Producers, at pp. 4-10; Exxon Mobil, at pp. 5-6; Kern River, at pp. 1, 5-7; PG&E, at p. 8.

107 Ex. No. 129; Tr. 1007:28-1008:1; 1026:11-18, 1046:15-1049:11.

108 Tr. 1065:6-26.

109 Tr. 1065:27-1066:15.

far more cost-effective in the long run than attempting to freeze the status quo and severely limiting potential new gas supplies to southern California. Other parties echo these arguments.

SCAQMD responds that these assertions reflect a misunderstanding of the proposal. The District proposes a 1360 Wobbe Index value maximum applicable to LNG supplies used in the South Coast Air Basin. The proposal is an interim step intended to prevent unacceptable environmental impacts while the Commission analyzes the effects of high Wobbe Index gas. That analysis would both clarify the impacts and identify mitigation measures to avoid any such impacts. Thus, SCAQMD asserts that contrary to these criticisms, all of SoCalGas' existing supplies would continue to be eligible for importation. In the meantime, use of Kern River gas would continue as it always has.

SDG&E/SoCalGas, Shell, and others accuse the District of not performing independent analysis to support its proposal. The District argues that this criticism ignores Dr. Liu's statement that a Wobbe cap of 1360 is intended to maintain the same level of emissions that is produced by gas fired end-use equipment with the current Wobbe average of 1332. SCAQMD argues that because its proposal conservatively protects the status quo, the assertion that the District failed to perform an "independent analysis" is a "straw man" argument.

Responding to a graph submitted by Shell on redirect in the last few minutes of the last day of hearings, those who oppose the SCAQMD proposal claim that it would preclude California from taking advantage of 80-90% of the world's supply of importable gas. This is a serious assertion, based on comments reportedly made to the witness by various unidentified people. The 80-90% figure was an off-the-cuff estimate offered by the witness without benefit of data or calculations. The graph suggested that some gas from Asian sources would fail to fall below a 1360 Wobbe number cap after a 3% injection of nitrogen. The graph does not take into account the option of stripping hotter-burning components from the gas, which might enable gas from all sources to qualify under the 1360 Wobbe cap. Stripping could occur during liquefaction in the country of origin, or after gasification upon arrival in the United States.

The District emphasized that the SoCalGas proposal would require the Commission to act before knowing the consequences of its action—to act now and respond to problems later. SCAQMD asserts that the arguments of the parties supporting the SoCalGas proposal expressly confirm this fact. SoCalGas first declares that it wants to implement the new high Wobbe Index number in June 2006. After that time, SoCalGas will "continue equipment testing and develop accommodation strategies in 2006 and 2007…."[110] The SoCalGas proponents then employ two strategies to avoid the inevitable conclusion that their suggested course of "act now, respond later" is illogical. First, they downplay the needed testing, asserting that the testing they propose to conduct after adoption of a high Wobbe Index "will be more of a confirmation than it is…a research effort."[111]

Second, the SoCalGas proponents accept the need for testing but suggest that the Commission can "re-address" the issues raised in this proceeding in future proceedings after testing is completed:

> "It is important to realize that the initial decision in this proceeding should not be delayed waiting for the completion of these or other studies. The Commission always has the

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110 SDG&E/SoCalGas Opening Brief at 47; see also Shell Opening Brief at 14.

111 Shell Opening Brief at 15 (citing Tr. 1201, statement of Sasadeusz of SoCalGas).

> option of re-addressing the issues if the results of the completed studies require the Commissioner's attention." (WSPA Opening Brief at 42.)

SCAQMD argues that this last statement illustrates the illogical and potentially dangerous thrust of the SoCalGas proposal. The District submits that, given the profound long-term impacts of this decision for California's economy, consumers, and natural environment, "acting first" and "re-addressing later" is not a sound strategy for the Commission's rulemaking.

c. Calpine Proposal

Because of the overwhelming lack of information as to the impact on operations of end-use equipment, emissions and cost to customers from the change in gas quality, Calpine argues that the Commission should take a more conservative approach to establishing interchangeability tariff standards than what has been proposed by SoCalGas/SDG&E. Unlike SoCalGas/SDG&E's proposal, Calpine's proposed standard is based on what is known, namely that gas-fired turbines were designed and constructed based on the quality of the historical gas supply. The turbine manufacturers provide operators with detailed fuel specifications upon which they guarantee operating capability within the required limits.

Calpine asserts that to go beyond the manufacturers' specifications without adequate information or research risks the operating capability of the generating facilities. Calpine proposes an interim interchangeability standard of a minimum Wobbe Index number of 1153 and a maximum Wobbe Index number of 1391, subject to a +/- 2% variation from historic deliveries. This proposal is based on the fuel specifications of the manufacturers whose turbines are extensively used in California, and therefore provide a prudent approach to establishing standards that will assure that California's system reliability is not harmed while the Commission further assesses the need for a final, revised interchangeability standard in light of empirical data.

Calpine witness Chancellor testified that this range will ensure that the gas will be acceptable to the turbine manufacturers as well as to the power producers that own and operate the DLN/DLE turbines. Chancellor stated that he developed this proposal after reviewing multiple turbine manufacturers' specifications. He explained that California has over 4,000 megawatts of Siemens DLN/DLE generating capacity that is either in operation, under construction or permitted, which is enough to power 2.6 million homes.

Calpine argues that California, should adopt an interim standard that ensures these plants can continue to safely and reliably operate. Similarly, the company asserts that Siemens' turbine specifications upon which Calpine bases its interim proposal incorporate the vast majority of gas-fired turbines that generate and supply power in California, again ensuring that the interim standard would maintain reliability and safety until the Commission has more complete information upon which to issue a final decision regarding a revised statewide specification.

Calpine states that its proposal would protect end-users to the maximum extent possible while still offering LNG as an economically viable solution for California's energy needs. In contrast, Calpine asserts, if the Commission adopts the gas-quality specifications proposed by SoCalGas/SDG&E (i.e., a maximum Wobbe Index number of 1400), the consequences will likely be negative. Calpine witness So testified that because the domestic gas sources differ so greatly when compared to LNG sources, the variability experienced with a 1400 Wobbe Index number would likely cause a host of operational issues in DLN/DLE gas turbines, such as lean-blowout, poor combustion dynamics, and an increase in emissions. While some effort can be made by the DLN/DLE operators to ameliorate these issues, the cost to do so is likely to be significant, and there is no guarantee by either GE or Siemens that "tuning" the equipment will completely eliminate the issue. Thus, Calpine asks the Commission to not go beyond GE and Siemens' fuel specifications at this time.

Calpine argues for a maximum Wobbe Number of 1391 based on the "lowest common denominator" of the fuel specifications of both GE and Siemens for DLN/DLE turbines.[112] As stated in the prepared direct testimony of Calpine witness Chancellor, the 1391 number is based on the Siemens specification.[113] However, SDG&E/SoCalGas point out that there are no Siemens DLN/DLE turbines currently served by those utilities,[114] and that Siemens itself has stated its support for the 1400 Wobbe Index maximum.[115] The utilities argue that Calpine's proposed limit of +/-2% variation from the Wobbe Number of historical supplies for its Siemens turbines is not based on the results of testing or on information received from Siemens, but rather is based on the fact that Calpine simply has no experience operating with gas supplies outside the +/-2% range.[116]

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112 Initial Brief of Calpine, at pp. 11-12.

113 Ex. No. 145 at 9:17-18.

114 See Ex. No. 106, Prepared Rebuttal Testimony of Lee M. Stewart, at 2:11-13; Ex. No. 114 (Calpine Data Response); Tr. 1222:4-7.

115 See Ex. No. 116, at Attachment C (letter dated June 8, 2005, from Siemens to FERC), p. 3.

116 Tr. 884:2-23.

Calpine responds that Siemens, in a June 8, 2005 letter to FERC, stated that, "the significant investments made in new combustion systems for end-users typically have much greater restrictive requirements." Siemens further cautioned FERC that, while it accepted a 1400 Wobbe as an "interim step," "[i]t may also be necessary to set a lower Wobbe Index limit; however, it may require extensive testing to evaluate this."[117] Calpine argues that clearly Siemens, which participated extensively in the NGC+ stakeholder process, did not envision the 1400 Wobbe Index number as some sort of floor, from which to only "go up." In addition, it appears that Siemens is not, at this point, endorsing the 1400 Wobbe index as a suitable long-term solution.

SDG&E/SoCalGas assert that, more importantly, the Wobbe number of a gas supply can be reduced by fuel pre-heating, as explained by Baerman:

> "The Wobbe number is essentially another measure of the heat content of fuel. Essentially when you heat the gas, all you are doing is expanding and increasing the volume so that less heat fits in the same amount of space. So essentially when you heat the gas you are lowering the Wobbe number by essentially injecting less combustible material in the same amount of volume."[118]

Calpine and SCE assert that their GE gas turbines in SDG&E's and SoCalGas' service territories cannot be operated with natural gas supplies that do not meet GE's fuel gas specification. The Indicated Producers assert that the needs of 4,000 megawatts of generation should not dictate the gas quality standards for the entire state. SDG&E/SoCalGas and Shell argue that even with

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[117] Exh. 145, Attach. A.

[118] Tr. 738:11-18.

1400 Wobbe gas, the generators could preheat the gas to effectively reduce the Wobbe number prior to combustion.

The GE specifications identified a Modified Wobbe Index number that sets the boundaries for acceptable gas performance. For a Frame 7FA (DLN/DLE) turbine, that number is 54. SoCalGas/SDG&E witness Baerman testified that although 1400 Wobbe gas equates to an Modified Wobbe Index number of 55-56 at a temperature of 60°F, a temperature increase to 100°F reduces that number to within the acceptable range for the GE turbines.[119] Shell concludes that if 1400 Wobbe gas is delivered to a GE Frame 7FA facility, therefore, the operator can raise the set points on the gas fuel heater in order to heat the gas to a temperature that will reduce the Wobbe number to a level that meets the Modified Wobbe Index of 54 within the GE specifications.[120] Baerman testified that the temperature range for the gas fuel heater at the Palomar plant (a GE Frame 7FA facility) is from a low of ambient temperature to a high of 365°F.[121] SCE witness Luis Pando testified that at the Mountainview plant, the gas is pre-heated to 365°F.[122] Pando acknowledges that with this preheating, 1400 Wobbe gas can meet the maximum Modified Wobbe index of 54, but cannot meet the specifications required for the Mountainview plant.[123]

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[119] Ex. 103 at p. 3; Tr. 854-55.

[120] Tr. 820 (Baerman); Tr. 1218 (Chancellor).

[121] Tr. 857.

[122] Tr. 1106-07.

[123] Tr. 1108.

Calpine's witness So testified that Calpine has gas fuel heaters at all of its GE turbines.[124] Although So noted that not all of Calpine's GE turbines have the capability to heat gas to 365°F,[125] So acknowledged that by heating 1400 Wobbe gas up to a temperature of 175°F, it is possible that the gas would meet the Modified Wobbe Index limit of 54 in the GE specifications. He went on to explain, however, that there are problems that develop as the fuel is heated; the gas turbine hardware may not function properly with the heated gas. "You've got valves that have fuel limits, you have designs of the nozzles that are based on a certain based temperature. So if you increase it [the temperature of the gas], you try to increase it, first of all your valves won't handle it because your dynamics will go up as your temperature goes up."[126]

Shell argues that Calpine's request for "interim" specifications and for more studies over the next two years improperly disregards the investment decisions that must be made today with respect to nitrogen injection facilities at the Energia Costa Azul LNG import terminal. Shell asserts that this argument also ignores the long-term supply commitments that must be made in the near future by Shell Mexico and others in order to ensure a reliable and California-compliant gas supply for the new facility.

d. PG&E's Position

PG&E's witness Bronner testified that PG&E's historical Wobbe Index range on its backbone transmission system is approximately 1300 to 1404, based

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[124] Tr. 891.

[125] Tr. 895.

[126] Tr. 736-737.

on a heating value range from 990 to 1080 Btu/scf.[127] In its Motion to Augment the Record dated January 27, 2006, PG&E declared it had revised its calculations. While this heating value range is accurate, the upper Wobbe Index value of 1404 is incorrect. Instead, the historical maximum Wobbe Index value of gas delivered on PG&E's backbone system is approximately 1370.[128] PG&E has confirmed that the historical lower Wobbe Index value on its backbone system is approximately 1300.

PG&E requested that the Commission permit PG&E to augment and correct the evidentiary record in the gas quality proceedings by admitting the Bronner Declaration into evidence. This motion is hereby granted.

PG&E strongly recommends that the Commission not impose a Wobbe Index specification as part of PG&E's Gas Rule 21 at this time. As explained by Bronner:

> "PG&E currently utilizes the methodology in American Gas Association (AGA) Bulletin 36 to determine interchangeability. PG&E is proposing no change to this policy.
>
> "PG&E strongly supports completing the research identified by the NGC+ as necessary to finalize a national gas interchangeability protocol. Once the research is complete, it may be possible and beneficial to alter this specification, particularly if it will accommodate a wider array of gas streams. However, until that work is done, PG&E believes it would be ill advised to move away from AGA 36.

[127] Ex. 102 (Bronner), p. 1, lines 26-28.

[128] Motion to Augment the Record dated January 27, 2006. (Bronner Decl., para. 3.)

> "SDG&E/SoCalGas have a different view on this specification, as described in their testimony. Both utilities agree that it may be possible, even likely, to settle upon a common interchangeability protocol based on the Wobbe index once more information is available."[129]

PG&E urges the Commission to await the results of research on an appropriate interchangeability protocol on the PG&E system before implementing any changes to PG&E's current interchangeability specification in Gas Rule 21. The utility adds that to the extent that research on the proposed NGC+ interchangeability protocol or other relevant research points to the need for a change in PG&E's specification, any change should be specific to PG&E's system, and not a statewide measure. The appears to be general agreement among the participants that it does not appear appropriate, at least at this time, to establish rules that are identical at all points throughout the state.

At the same time, PG&E and SDG&E/SoCalGas did work together extensively in an effort to determine where and how their rules should be changed to eliminate unnecessary differences. The result is that PG&E has proposed a number of mostly minor changes to its Rule 21.

The most substantive proposal from PG&E involves a proposal for which there is no current SoCalGas counterpart: the adoption of a Methane Number of 80. Currently, PG&E's rule contains no requirement for minimum methane content. As discussed below, the purpose of this proposal is to accommodate natural gas vehicles. Only SCE objects to this proposal. For purposes discussed below, it prefers the adoption of a methane minimum content level of 85%.

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[129] Ex. 101 (Bronner), p. 5, lines 17-29.

e. Discussion

The standard that we will apply in reviewing the proposed standards is as simple as this: Can we assure consumers, with a high level of confidence, that the gas delivered for their use will result in the safe and reliable operation of their appliances? PG&E's proposal, which does not include a Wobbe Index specification, and where the utility does not anticipate a near-term introduction of LNG, passes this test. Because of the state of appliance testing related to the Wobbe content of gas, we cannot offer that assurance for the Wobbe Index proposals. In addition, we cannot ensure that the standards proposed by any of the participants would avoid adverse environmental impacts. For these reasons, we reject the proposals currently before us and instead adopt an approach intended to preserve the status quo, pending the outcome of additional research.

All parties appear to accept the notion that SDG&E/SoCalGas should move from a largely compositional standard to one that relies on a Wobbe Index rating in order to ensure the interchangeability of natural gas from various supply sources. The record also makes it clear that with the anticipated importation of large quantities of offshore gas through liquefaction, the latitude provided by the standards incorporated in SoCalGas' Rule 30 is no longer acceptable. There is no reason to suspect that similar problems would not arise in PG&E's service territory as well, with the introduction of LNG-derived gas in large quantities.

While the current utility standards allow for using gas with a wide range of characteristics, the gas that SoCalGas delivers to its customers varies within a more limited range. A number of factors contribute to this result: the nature of North American gas supplies, the utility's efforts to uses in-state gas strategically and blend it with other supplies, and the existence of ARB rules affecting the content of gas delivered for use in compressed natural gas vehicles. The ARB rules are more restrictive than Rule 30. Since compressed natural gas vehicles might attempt to refuel anywhere in its service territory, SoCalGas requires all of its flowing supplies to be suitable for their use. The utility does this on its own—the Commission has never required it.

Although California producers would also like to sell more gas to the utilities, it is the anticipated arrival of very large quantities of offshore gas that is prompting this inquiry. Gas imported from overseas is expected to create more heat per therm (have a higher Btu rate) than most North American supplies. Because it would arrive in such large quantities, there is no practical capability to blend it with other gas. The result is that hotter-burning gas often would be delivered to end-use customers large and small. On a per-therm basis, hotter-burning gas produces more NOx, which is a smog precursor. It also raises concerns about the reliability and safe operation of end-use appliances and machinery.

Without a change to the rules, industry participants generally expect that LNG importers would deliver gas that burns much hotter than the current average, and that would approach the top of the range allowed under Rule 30. The result would be a considerable increase in the heat range of flowing supplies and a commensurate increase in the average heat-producing capability of the gas. Adherence to the current ARB rules related to compressed natural gas vehicles would mitigate this result. However, in parallel with this proceeding, LNG proponents are seeking the repeal or radical change of the ARB rules. In addition, SoCalGas is under no obligation to make all supplies comply with the current ARB rules. No one contests the fact that if importers begin introducing offshore supplies, and the ARB loosens its rules or SoCalGas ceases to enforce them as broadly, it would be unacceptable for this Commission to do nothing to improve Rule 30. To do nothing would threaten air quality, safety, and the reliability of equipment that burns natural gas.

The chief benefit of hotter-burning gas is that it takes less of it to perform most heat-based functions. The challenge is that most appliances and machines will not automatically adjust to changes in gas quality. As a result, millions of end-use appliances and machines in Southern California would continue to consume natural gas at the same rate regardless of how hot that gas burns, creating the potential for all of the problems outlined in the NGC+ paper and cited earlier:

a. In appliances, it can result in soot formation, elevated levels of carbon monoxide and pollutant emissions, and yellow tipping. It can also shorten heat exchanger life, and cause nuisance shutdowns from extinguished pilots or tripping of safety switches.

b. In reciprocating engines, it can result in engine knock, negatively affect engine performance and decreased parts life.

c. In combustion turbines, it can result in an increase in emissions, reduced reliability/availability, and decreased parts life.

d. In appliances, flame stability issues including lifting are also a concern.

e. In industrial boilers, furnaces and heaters, it can result in degraded performance, damage to heat transfer equipment and noncompliance with emission requirements.

f. Varying gas compositions beyond acceptable limits can be problematic in noncombustion-related applications in which natural gas is used as a manufacturing feedstock or in peak shaving liquefaction plants, because historical gas compositions were used as the basis for process design and optimization of operating units. More specifically, domestic LNG peak shaving liquefaction plants will most likely require retrofits to continue operations utilizing regasified LNG as feedstock. Propane-air peak shaving operations will also likely require retrofits and/or additional controls to continue operations.

g. When shifting to a dry, leaner supply source such as offshore gas, the affects on utility natural gas infrastructure may include failure of certain gas transmission and distribution piping component seals and gaskets in valves, pipe clamps, joint sealants and other mechanical components. Additional infrastructure issues include impacts to custody transfer gas measurement techniques (thermal vs. volumetric billing) and related gas accounting issues.

We are obligated to make certain that Commission-approved rules do not create an unacceptable likelihood that some or all of these problems will arise.

In California, the utilities do not currently characterize gas quality standards in terms of a Wobbe Index. SoCalGas specifies a heating value range of 970 Btus to 1150 Btus. It now proposes to narrow that range a bit, by changing the minimum level from 970 Btus to 990 Btus. SDG&E would adopt the same range (it currently has no maximum). As noted earlier, SoCalGas' current average system heating value is 1020 Btus. SoCalGas asks to reduce its carbon dioxide (CO_2) specification from 3% to 2% by volume; and to reduce its oxygen (O_2) specification from 0.2% to 0.1% by volume. The Indicated Producers oppose these proposals, and we will discuss them later.

The utilities currently have no explicit Wobbe Index limitations in their tariffs. Since the Wobbe value is a product of the heating value and the specific gravity of the gas, it relates not only to BTU content, but to the composition of the gas. SoCalGas identifies the possible Wobbe Index values under its current rules as follows:

Test Gas Compositions Acceptable Under Rule 30[130]

Test Gas

Primary	METHANE	ETHANE	PROPANE	iso-BUTANE	n-BUTANE	iso-PENTANE	n-PENTANE	C6 plus	CARBON DIOXIDE	NITROGEN	MN	Wobbe#	HHV
1 Baseline, Line Gas	96.03	1.78	0.37	0.06	0.06	0.01		0.03	1.18	0.44	100	1338.9	1022
2 970 Btu Gas	96.00								3.00	1.00	108	1271	974
or 1000 Btu Gas	97.00	0.75	0.10						2.00	0.15	106	1315	1000
3 1150 Btu Gas, Hi Wobbe	87.03	9.23	2.76	0.99					0.00	0.00	75	1437	1150
4 1150 Btu Gas, Lo Wobbe	84.92	4.79	2.40	1.20	1.20	0.60	0.60	0.30	3.00	0.80	68	1375	1150
or 4 component mix	84.45		11.55						3.00	1.00	68	1375	1150
	84.92	4.79	2.40	1.20	1.20	0.60	0.60	0.30	0.00	4.00	68	1392	1150
Secondary													
If fails test gas 4													
5 1100 Btu Gas, Avg. Wobbe	88.88	5.28	2.61	0.34	0.50	0.11	0.06	0.06	1.40	0.75	79	1376	1100
or 4 component mix	90.85		7.00						1.40	0.75	79	1376	1099
Tertiary													
If passes test gas 5													
6 Increase BTU or Wobbe													
If fails test gas 5													
7 Decrease BTU or Wobbe													

As this table indicates, the current Rule 30 would allow a Wobbe range of 1271-1437. However, SoCalGas calculates its current average Wobbe number as 1332. Imported offshore gas could have a Wobbe number as high as 1445. In this proceeding, SoCalGas proposes to adopt a Wobbe Index range of 1290-1400. The utility would expect most LNG producers to deliver offshore gas at or near the maximum level—in this case, 1400. As a result, natural gas delivered under the SDG&E/SoCalGas proposed standard could burn significantly hotter, on average, than the gas the utility currently delivers to its customers.

In approving a standard for something as fundamental as the quality of the natural gas delivered to customers, we must be able to assure those customers that utility service will remain safe, that gas-fired equipment will remain reliable, and that environmental quality will be preserved. Based on the

130 Ex. 107 Figure 2.

information currently available, we cannot provide these assurances for the current rule, or for any of the specific new standards proposed for our adoption.

Without a massive effort to retune millions of pieces of end-use equipment, burning a large quantity of hotter gas may threaten safety, reliability and air quality. Prior to allowing for this change in practice, we need to know the magnitude of these threats and determine appropriate mitigation requirements.

No one contests the need to perform more tests and complete more studies in order to answer these concerns. Where parties differ is over what to do in the meantime. LNG project proponents, California gas producers, and SDG&E/SoCalGas (whose affiliate is constructing an LNG facility in Mexico) argue that the Commission can adopt the SDG&E/SoCalGas proposal while other studies are pending, roll out hotter-burning gas in phases, and make adjustments if problems arise. In other words, put any risks resulting from the unknown on consumers and the environment. Calpine and SCE argue that the Commission cannot allow gas with a Wobbe number as high as 1400 until turbine manufacturers have determined that it is safe to do so. In other words, LNG project proponents must remain open to the potential of tighter standards. The only party responsible for air quality management (SCAQMD) states that it is unacceptable to allow any changes that result in higher NOx emissions (in its air basin, which is non-attainment area), and proposes a Wobbe range intended to maintain the status quo until more information is at hand. PG&E, which at the time of record development in this proceeding did not foresee LNG supplies reaching its service territory in the near-term, agreed with the need for better information before adopting a Wobbe-based standard.

The policy trade-offs are clear. The Commission has stated its interest in welcoming appropriate LNG-based gas supplies. There is hope that this would put downward pressure on gas prices and ensure greater supply reliability. LNG proponents want to minimize the cost of delivering gas to California customers, and express concern that tight standards may limit their ability to buy gas from foreign sources. California producers raise similar objections. While air quality regulators express concern about increased impacts, others argue that any resulting air quality deterioration would be dwarfed by the anticipated economic benefits of new supply. Some parties also suggest that LNG imports create an opportunity for more natural gas use in the state, which might replace some use of more-polluting fuels.

Much of the growth in gas demand is driven by the introduction of new gas-fired power plants. As owners and operators of such plants, Calpine and SCE raise issues about the effects of fluctuating fuel quality on the reliability of electric service, another matter with which this Commission is vitally concerned. In addition, California law requires that agencies carefully study and then weigh the import of potential environmental impacts before making a choice of this type.

The Commission also has an obligation to ensure safety and end-use reliability. Natural gas consumers other than powerplant operators are not represented in this debate. We regret that TURN and DRA, which have been so active in other portions of the proceeding, have not contributed to the record on gas quality issues.

Here are some of the things we do not know yet:

1. **Whether, in the long-run, equipment will be less safe, reliable, or effective in the face of hotter-burning gas and greater fluctuations in quality.**

As discussed above, SoCalGas performed limited studies on 13 appliances. The study lacked statistical rigor, looked at a limited number of effects, only examined one model for each appliance type, and did not test some appliances at all. Nonetheless, the results were mixed. At some Wobbe levels, some equipment showed effects from the introduction of hotter-burning gas. Significantly, this study did not test for long-term impacts, such as a reduction in the useful life of the equipment.

2. **What the introduction of hotter-burning gas will do to air quality.** What is known is that hotter-burning gas increases NOx emissions. There are many unanswered questions about the magnitude of those increases and the affect of this change on ozone formation. SDG&E/SoCalGas offered testimony in an effort to quantify changes in NOx emissions, but that analysis relied on the limited SoCalGas study discussed above. There is inadequate information about other air quality affects, including indoor pollution, and any incomplete combustion that may result from using more fuel than necessary to produce the amount of heat required for the equipment. SDG&E/SoCalGas also argued that any increases in emissions of NOx would be minor in comparison to NOx emissions from other sources, implying that from a policy perspective, this Commission should just ignore those impacts. As SCAQMD points out, adoption of this perspective would lead to no air quality protection at all. For example, why should any individual car need a smog check when its contribution to emissions is so small when compared with society as a whole? Any change resulting from hotter-burning gas would be pervasive and would continue for a very long period of time. We need to better understand the magnitude of potential impacts, and the implications of choosing one Wobbe maximum over another.

3. **Whether it is more cost-beneficial to choose one particular standard over another**. If gas quality changes, owners and operators would have to retune or prematurely replace equipment large and small, but we do not know what that would cost. In the alternative, offshore and California-based producers could modify gas to meet historical norms, but we do not know those costs either. Identifying and comparing these costs is critical to choosing a path. As part of this inquiry, we need to understand how these incremental costs compare to the total cost faced by a particular entity and, in the case of gas producers, likely sales prices. A major unresolved issue is who should pay for the cost of transition to any new standard.

The NGC+ paper, upon which SDG&E/SoCalGas rely so heavily, recognizes the inadequacy of existing information, and proposes the adoption of interim standards for no more than three years. One problem is that the NGC+ paper does not even conclude that the proposed interim standards would avoid significant problems. To support the implication that the 1400 Wobbe maximum must be safe, reliable and clean, SDG&E/SoCalGas point to language in the paper suggesting that additional information might be used to expand the criteria in later years. However, this expression of intent does not make up for the lack of information demonstrating that the interim proposed standard would be safe and reliable, or that it would preserve current air quality. In addition, the NGC+ paper remains one of ambiguous authorship and support. It provides no assurance that adoption of the SDG&E/SoCalGas proposal, or anything that is less expansive, is an appropriate thing to do.

It is important to note the obvious problems with SDG&E/SoCalGas' suggestion that concerns about adverse effects from hotter-burning gas be resolved through a phased-in rollout. The suggestion is that the utilities could respond to problems as they occur, and make modifications as necessary. First, in light of the level of uncertainty we are facing at this point, we cannot approve of an approach that would use some conscripted portion of the customer base as test subjects. We must understand the risks and benefits prior to imposing a change on customers. Second, some of the impacts may only become evident over time. For example, suppose that a particular domestic water heater has an expected useful life of 15 years, and that long-term exposure to hotter-burning gas in the absence of a retuning of the appliance shortens its useful life by 20%. Without a controlled test, this problem would not come to light for up to 12 years. In addition, it is less than certain that consumers affected by this would understand or even notice what had happened. Third, LNG project proponents understandably want certainty and finality concerning the applicable rules. It is difficult to imagine that the utilities would pursue subsequent rules changes in the absence of dire problems. In addition, the rolled-out gas supplies have to come from somewhere. If they are part of a supply attached to a long-term contract, there might be major economic repercussions for the offshore gas providers or utility ratepayers if the rules were later tightened.

The Calpine proposal, which would allow for a Wobbe Index maximum of 1391, suffers from many of the same infirmities as the SDG&E/SoCalGas proposal. Even if gas of this quality would be adequate for Calpine's turbines, it would still result in the introduction of hotter-burning gas. We would still need to know what impact this fact would have on other gas users and on air quality.

SCAQMD intends its proposal to maintain the status quo in terms of air emissions, but it is not clear that this would be the case. Although the SCAQMD proposal is based on a current average Wobbe number of 1332, it would allow for the introduction of an unlimited amount of gas with numbers as high as 1360.

This could lead to a higher average Wobbe number, hotter-burning gas, and the resulting challenges to safety, reliability, performance, and air quality.

Perhaps more significantly, the record demonstrates that the SCAQMD proposal would not preserve the status quo in a key respect. Although the average rating for flowing gas now is 1332, SoCalGas gas currently receives some supplies at ratings higher than 1360. The SCAQMD proposal could restrict SoCalGas' access to current supplies.

Some of those who oppose this proposal also claim that it would eliminate access to gas from most foreign nations. This is based on hearsay evidence of questionable reliability in that it is not supported with records or data, and the sources of the information used are not identified. This evidence suggests that even with the injection of nitrogen up to 3% by volume, gas from most sources would still exceed 1360.

Even if we could rely on this evidence, it tells us only part of the story. While nitrogen injection is good way to reduce the Wobbe number of flowing gas, it is not the only way. At either the point of exportation or the point of importation, LNG suppliers could also strip hotter-burning components out of the gas to further reduce its Wobbe rating. For instance, Shell's witness Kuipers described its Sakhalin export project where gas will be stripped prior to liquefaction to produce a leaner product for the California market. Kuipers states that with 3% nitrogen injection, the resulting gas would approach the 1360 level.[131] The fact that Shell is preparing such gas for the California market shows that it can be done and suggests that it is economical to do so.

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131 TR. 1271-1272.

The record suggests that Sempra LNG would have difficulty in treating gas in this manner at its anticipated Costa Azul facility because of pipeline limitations and controls over participation in the gas stripping business. This does not suggest, however, that it would not be economical to do so, or that Sempra LNG or Shell would be unable to arrange for stripping prior to export. Based on the record before us, we do not conclude that a 1360 Wobbe number, or any other similar restriction, would eliminate significant opportunities to import offshore natural gas.

Later in this decision, we will discuss, in some detail, the types of studies that it appears necessary to complete before we could say, with confidence, that it is prudent to introduce significant quantities of hotter-burning gas and what Wobbe range is appropriate. We also will consider the legal arguments for and against the applicability of the CEQA to such a determination. At the current level of knowledge, however, the only prudent option is to maintain the status quo.

Although such was the stated goal of the SCAQMD proposal, we will not adopt the proposed 1360 maximum Wobbe number—both because it is not self-evident that this standard would maintain the status quo, and because it would likely reduce the amount of gas from current sources that would remain available. This is because the Wobbe number on some current flowing supplies exceeds 1360.

The goal is to preserve the current 1332 average Wobbe number during this period while we await complete test results and the preparation of an Environmental Impact Report, as discussed below. The most straightforward, although not necessarily the best way to approximate a retention of the status quo is to retain the current Rule 30 and the current ARB rules until the necessary additional studies have been completed. The combination of these two sets of rules has helped keep the average Wobbe number where it is. By using this approach, rather than establishing a lower cap as SCAQMD proposes, the utilities would still be able to receive higher-Wobbe gas in the current proportions and would maintain more flexibility to manage their systems. However, we invite SDG&E/SoCalGas and other parties to propose other ways to achieve this result.[132]

2. Requirements of CEQA

CEQA requires any California governmental agency approving a discretionary project to consider the environmental impacts of its decisions. (Pub. Res. Code at § 21080.) The definition of "project" includes any activity undertaken by a public agency that "may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment." (Pub. Res. Code at § 21065.) The term "project" has been interpreted to mean far more than the ordinary dictionary definition of the term (CEQA Guidelines Section 15002(d)), and includes the development of standards, rules, and regulations.[133]

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[132] PG&E faces similar challenges with the introduction of large quantities of LNG-derived gas. We have focused on SDG&E/SoCalGas because PG&E has asserted no near-term plans to introduce offshore gas. We need to preserve the status quo for PG&E as well. It should not receive large LNG shipments without proposing and receiving approval of changes to Rule 21 to accommodate those shipments.

[133] The language of the Act itself recognizes that this is the case. See, for instance, Pub. Res. Code § 20080.5(b)(2) that defines circumstances where CEQA applies to various types of rulemaking proceedings, but the statute allows for environmental information to be provided in another manner in lieu of an Environmental Impact Report. If CEQA did not apply to rulemaking, then this statute would be unnecessary.

Consistently and repeatedly, agencies and courts treat the development of rules and regulations as "projects" for the purposes of CEQA. Our consideration of gas quality standards, in this proceeding, involves the development or modification of rules—in this instance, PG&E's Rule 21 and SoCalGas' Rule 30. Shell and others are not persuasive when they argue that the development of a rule constitutes insufficient action to qualify as a project.

There is no comprehensive exemption for rulemaking, and no basis for concluding that rulemaking does not qualify as a "project." To the contrary, the CEQA guidelines expressly exempt legislation enacted by the State Legislature (CEQA Guidelines Section 15378(b)(1)). This exemption would make no sense if legislative acts, by their very nature, would not otherwise qualify as "projects." And by limiting the exemption to enactments by the State Legislature, the Guidelines make it clear that other legislative activities are not exempt, in the absence of another express provision. Administrative rulemaking is quasi-legislative in character, and regulations have the force and effect of law.[134] There are numerous court cases confirming the applicability of CEQA to local ordinances, and dozens of examples of the incorporation of environmental review in agency rulemaking. We take official notice of the ARB and SCAQMD websites, for instance, which list many proceedings where the agencies reportedly have conducted or are conducting environmental review of proposed new rules or rule changes.

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134 9 Witkin Cal. Proc. Admin Proc § 116. See, also, numerous California Supreme Court decisions, such as *Marine Forests Society* v. *California Coastal Commission,* 36 Cal.4th 1, 25 (2005); and *Green* v. *Ralee Engineering Co.,* 19 Cal. 4th 66, 82 (1998).

Further, SDG&E/SoCalGas are incorrect when they assert that matters which address policy are exempt from the definition of a "project" under CEQA. (Tit. 14 Cal. Code of Regulations, § 15378(b)(2).) First, that section of the guidelines applies to "continuing administrative or maintenance activities, such as purchases for supplies, personnel-related actions…" When it goes on to refer to "general policy and procedure making," it is in that context. Second, the applicability of CEQA to policy determinations is clear. See, for instance, Section 15385 of the CEQA Guidelines. That section discusses the rules related to "tiered" environmental impact reports (EIRs). In subsection (a), it states that tiering is appropriate when the sequence of EIRs is "From a general plan, policy, or program EIR to a program, plan, or policy EIR of lesser scope or to a site-specific EIR." Clearly, the guidelines anticipate that a policy determination can be a project. Otherwise, there would be no such thing as a policy EIR for the guidelines to discuss. As another example, Section 15168(b)(4) discusses the use of a program EIR to enable an agency to consider "broad policy alternatives." Third, even if Section 15378(b)(2) were read to affect policy determinations outside of the context of "continuing administrative and maintenance activities," the words of the section limit its application to "general policy." An effort to determine the appropriate composition or index to use in order to define the quality of natural gas could hardly be more specific. Finally, Section 15378(b)(2) does not apply if the policy determination could potentially have a significant direct or indirect impact on the environment.[135]

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[135] Section 15378(b)(2) states that it is not in effect "when applied to specific instances covered above. Those circumstances discussed earlier in the section include agency actions that have a potential for resulting in either a direct physical change in the

Footnote continued on next page

Various parties argue that even if a decision of this nature could otherwise constitute a project under CEQA, this one does not because there is no possibility that this decision could have a significant impact on the environment. The reasoning behind this argument is that each of the proposals under consideration would narrow the scope, and ultimately the range of possible environmental impacts resulting from Rule 30. In other words, with the introduction of LNG-derived gas into California, the air might be dirtier than it is now, but not as dirty as it would be without the rule change.

That the parties can even make this claim is a quirk resulting from the sequence of events and the limits of agency jurisdiction. The "narrowing" of Rule 30 proposed by SDG&E/SoCalGas would not be necessary to protect air quality unless the ARB subsequently retracts or eases its rules related to gas supplied for compressed natural gas vehicles, or SDG&E/SoCalGas elect to no longer apply those rules in the comprehensive manner that it currently does. The adoption of a Wobbe-based rule appears to be a condition precedent to achieving that result. When all is said and done, it appears that the rule change as proposed by SDG&E/SoCalGas would facilitate the introduction of hotter-burning offshore gas and could potentially result in significant environmental impacts.

SCAQMD posits that the "no potential for significant impacts" argument stems from a failure to apply the proper environmental baseline. The "environmental setting" of a project supplies the "environmental baseline" that a lead agency then employs in analyzing whether a proposed project will have a

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environment, or a reasonably foreseeable indirect physical change in the environment…" (Section 15378(a).)

significant environmental effect. (See CEQA Guidelines, 14 Cal. Code Regs. § 15125(a).) An accurate description of the real environmental baseline is critical to a fair and accurate determination of the potential impacts of a proposed project. Calibrating the "environmental baseline" too high (i.e., assuming more degradation in the present environment than actually exists) will cause an understatement of a project's actual significant impacts. SCAQMD argues such an artificial baseline is precisely what many of the proponents of the SDG&E/SoCalGas proposal urge upon the Commission. By considering the potential for even higher emissions under the current rules with the introduction of LNG, SDG&E/SoCalGas are clearly moving beyond existing conditions.

CEQA allows a lead agency to deviate from the normal baseline methodology in either of two instances: (1) when a different formulation will more accurately capture the actual potential environmental impacts of a proposed project; (2) when conditions and impacts assumed in the baseline were subject to prior CEQA review. The cases cited by SoCalGas and its proponents all fit within these narrow limitations. SCAQMD argues that in contrast, the present proposal by SoCalGas does not.

Courts have interpreted Guidelines Section 15125(a) to allow an alternative baseline where such a deviation from the standard practice would more accurately analyze the potential environmental impacts of a project.[136] In the current instance, it would be illogical to assume a continuation of current

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136 See *Save Our Peninsula Committee* v. *Monterey County Board of Supervisors,* 87 Cal.App.4th 99, 125-126 (2001) (approving an environmental baseline made up of historical water pumping data where the most recent actual conditions appeared to be abnormally high and would not result in a representative analysis).

condition if two things occur: 1) a significant amount of LNG is imported in Southern California, and 2) that gas would necessarily meet or exceed a Wobbe number of 1400. Interestingly, if either of these conditions does not apply, then the SDG&E/SoCalGas' proposal might make things worse, if it triggers a change in the ARB standard, or in the way that SDG&E/SoCalGas comply with that standard.

The problems with deviating from the existing baseline in this instance are two-fold. First, it is speculative as to whether a significant amount of LNG will be imported to Southern California and if such potential imports will, in fact, meet or exceed a Wobbe number of 1400. The record suggests that LNG imports are on the way, but that makes their arrival in large quantities something less than a certainty. The record also shows that imported gas could meet or exceed a Wobbe number of 1400, but that does not mean that it necessarily would. For instance, Shell testified that its Sakhalin project could deliver gas that, with nitrogen injections, would approach a Wobbe number of 1360. While a 1400 Wobbe maximum would put an upper limit on the index value for domestic and imported supplies, it may or may not be a limit that is too high. We must consider the impacts of gas at this limit in comparison with current conditions in order to understand the full import of approving such a change in the rules.

Second, regardless of what might be possible under the existing rules, the debate in this proceeding focuses on the choice between a 1360 Wobbe maximum, a 1391, or a 1400 Wobbe maximum. The record herein dwells on the potential environmental implications of that choice. The only air quality regulatory officials involved in this proceeding, those from SCAQMD, state that there is a potential that a choice within this range could result in significant environmental impacts. It is clear that the Commission's discretionary act in choosing among these options could have environmental implications.

In order to understand that possibility, we must compare the potential outcomes under the proposed new rules with current conditions. When the impact may be either adverse or beneficial, it is particularly important to apply CEQA which is carefully conceived for the purpose of increasing the likelihood that the environmental effects will be beneficial rather than adverse.[137] In *International Longshoremen's & Warehousemen's Union* v. *Board of Supervisors* 116 Cal.App.3d 265 (1981), the board of supervisors, acting as the governing board of the county air pollution control district, amended certain rules to raise the allowable levels of NOx emissions for certain facilities in the county. In adopting the rule change, the board determined that its action was categorically exempt from CEQA in that the action was taken for the protection of the environment and of natural resources. The Court of Appeal disagreed. Relying on *Wildlife Alive* v. *Chickering, supra*, it held that where there is a reasonable possibility that a project or activity may have a significant effect on the environment, an exemption is improper. In order to fully explore the implications of the alternatives and the range of mitigation options if potential impacts do prove to be significant, we are obligated to apply the procedural and substantive requirements of CEQA.

CEQA does not, however apply to specific actions necessary to prevent or mitigate an emergency. (Pub. Res. Code Section 2080 (a)(4).) The record suggests that the worst outcome, here, might be to do nothing. If there is a

[137] *Wildlife Alive* v. *Chickering*, 18 Cal. 3d 190, 206 (1976).

significant influx of LNG-derived imports, the current Rule 30 would not prevent an increase in the average Wobbe number in Southern California, which could lead to deteriorating air quality. CEQA would not apply to urgent actions we might take to preserve current air quality conditions while we await further studies and environmental impact analysis.

On this basis, both SCAQMD and Calpine argue that the Commission could adopt their respective proposals without preparing an EIR or Negative Declaration. This presumes that either option would preserve current air quality related to natural gas combustion. The record does not support this presumption. Either approach could lead to gas supplies with a higher average Wobbe number. It is not clear, without further analysis, that either approach would preserve the status quo. We can, however, take steps likely to preserve the environmental status quo without first undertaking complete review under CEQA, and that is what we have set forth above. If there is no significant change in potential gas quality because LNG shipments never arrive, then requiring continued adherence to Rule 30 and the current ARB rules should cause no concern. If there are LNG shipments of gas with high Wobbe numbers, then adherence to these rules should help maintain current air quality and gas performance.

B. If the Commission Approves Changes to the Existing Gas Quality Tariff Specifications, What Should Be the Timing for the Approved Changes?

All participating parties express an interest in earlier action on this subject, despite their disagreements as to what steps the Commission should actually take. SDG&E/SoCalGas, Sempra LNG, Shell, and ExxonMobile all ask for immediate adoption of the SDG&E/SoCalGas Wobbe proposal. BHP Billiton supports this proposal, as well, although it explicitly supports SDG&E/SoCalGas' proposal of conducting a phase rollout of higher Wobbe number gas. Calpine and SCAQMD argue that it is premature to adopt the SDG&E/SoCalGas' proposal because of the need for additional studies. SCAQMD and SCE advocate that the Commission act immediately to preserve the current composition of the gas in order to preserve reliability and air quality pending the results of further studies.

C. What Are the Appropriate Limits for the Specific Natural Gas Constituents and Other Parameters?

SDG&E and SoCalGas propose to keep the existing specifications (with minor wording changes) for the following constituents, and these recommendations are undisputed:

- Hydrogen Sulfide – 0.25 grains/100 scf, measured as hydrogen sulfide (4 parts per million (ppm))
- Mercaptan Sulfur – 0.3 grains/100 scf, measured as sulfur (5 ppm)
- Total Sulfur – 0.75 grains/100 scf, measured as sulfur (12.6 ppm)
- Water Vapor – Limit to 7 pounds per mmscf at 800 pounds per square inch gauge (psig) or less; dew point of 20° F if the gas is supplied at over 800 psig
- Hydrocarbon Dew Point – Limit to 45° F for gas delivered at 800 psig or less but measured at 400 psig, 20° F above 800 psig but measured at 400 psig
- Temperature – 50° F to 105° F
- Total Inert Substances – 4% by volume

SDG&E and SoCalGas propose changes or additions to the following specifications, which are undisputed:

- Liquids – The gas shall contain no liquids at or immediately downstream of the receipt point(s)
- Merchantability – No dust, sand, dirt, gums, oils, or other substances injurious to utility facilities or that would cause the gas to be unmarketable
- Landfill Gas – Gas from landfills will not be accepted or transported
- Biogas – Biogas refers to a gas made from anaerobic digestion of agricultural and/or animal waste. The gas is primarily a mixture of methane and carbon dioxide. Biogas must be free from bacteria, pathogens and any other substance injurious to utility facilities or that would cause the gas to be unmarketable and it shall conform to all gas quality specifications identified in this Rule.

SDG&E and SoCalGas are proposing changes to four specifications that are disputed by other parties:

- CO_2 – 2% by volume
- O_2 – 0.1% by volume
- Gas Interchangeability – Maximum Wobbe of 1400, Minimum Wobbe of 1290
- Heating Value – 990-1150 Btu/scf on a dry basis

SDG&E/SoCalGas say that they are seeking the proposed changes to the CO_2 and O_2 specifications to reduce the risk of internal corrosion to pipelines from new supplies and to continue to accept existing California production. For existing California production, it is proposed that the current 3% by volume CO_2

and 0.2% by volume O_2 limit remain in effect through a Commission-approved deviation process.

As stated in Dr. Oliver Moghissi's testimony "reducing the concentrations of CO_2 and O_2 will reduce corrosion rates and improve pipeline safety."[138] SDG&E/SoCalGas' proposed maximum for O_2, is the same as PG&E's current standard, and with respect to CO_2, the proposed limit is twice that currently imposed by PG&E's.

The deviation process, and the proposed 2% by volume CO_2 limit, reflect SoCalGas' and SDG&E's recognition that most in-state production in Southern California is associated gas, which has different properties or characteristics than dry gas production in Northern California. As stated in the testimony of Mr. Martini and Reheis-Boyd on behalf of independent producers, et al.:

> "In-state natural gas production can be defined in two categories: "associated" and "dry." Associated gas is produced in conjunction with oil and constitutes the majority of California's in-state natural gas supplies. Associated gas is found throughout the principle production areas in the Southern San Joaquin Valley, L.A. Basin, and South Central Coast. Dry gas is found primarily throughout the Sacramento Basin and primary production areas in Northern California."[139]

The primary difference in the properties of associated gas and dry gas is that: "associated gas contains significant concentrations of the heavier

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[138] Ex. No. 110, at 4:26-28.

[139] Ex. No. 117, at p. 3.

hydrocarbons, in addition to concentrations of CO_2 [and] O_2, … .”[140] SDG&E and SoCalGas assert that by having a deviation process and the 2% by volume CO_2 limit for new supplies, they will be better able to manage pipeline safety in a prudent manner while supporting in-state natural gas and oil production and resultant supply diversity.

The in-state gas producers contest this proposal. Slightly less than 75% of California’s native natural gas is associated gas—gas found underground with, and produced from the same reservoirs as, crude oil. In essence, natural gas consists of smaller and lighter molecules of the same varieties that, in larger form, make up liquid crude oil. Because associated gas is found with these heavier compounds, it is mixed with them, to some extent. The heavier compounds contribute to higher Wobbe numbers and Btu contents.

If it cannot be sold or otherwise consumed, gas recovered with the liquid crude oil must then be flared or injected back into the ground. Both of these options face significant air permitting hurdles.

The Indicated Producers support blending gas from different sources in order to bring out-of-specification gas into compliance. Such blending has historically taken place on both the SoCalGas and PG&E systems. As long as blending is thorough, and takes place before entry of gas into the pipeline system, there should be no issue. However, it is not always possible to ensure that the utilities can adequately blend gas in the pipeline.

CO_2 and O_2 can cause gradual corrosion in pipes and associated hardware in the presence of water. However, the in-state producers claim that the need for

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140 Ex. No. 117, at p. 3.

changes has not been substantiated. Indicated Producers assert that native gas is "dry" when it is introduced into the pipeline system, and that any corrosion results from exposure to water in the system. Therefore, any burden of corrosion prevention relating to oxygen, carbon dioxide, and water should fall squarely on the pipeline owners, who are responsible for keeping their own systems dry.

SDG&E/SoCalGas witness Sasadeusz testifies that water enters SoCalGas' pipeline system through its system of storage facilities.[141] Thus, the corrosion problem is as much related to the condition of the storage facilities as it is to the CO_2 and O_2 content of the gas when it enters the system.

SoCalGas adopted the existing minimum Btu value of 970 stated in the Heating Value specifications of Rule 30 in anticipation of accepting synthetic natural gas from coal gasification plants proposed during the energy crisis of the 1970's. None of those plants were built, and current receipts into the SoCalGas/SDG&E system are not below 990 Btu/Scf at an approximate 1290 Wobbe, which is the bottom of the utilities' proposed range. Therefore, SDG&E and SoCalGas recommend increasing the minimum Btu value from 970 to 990 in their existing specifications for Heating Value. California producers also oppose, characterizing it as lacking a clear rationale.

We will approve the proposed changes to CO_2 and O_2 content, as well as increasing the minimum Btu level from 970 to 990, as reasonable steps to improve the consistency of gas quality standards across the state. However, we do not see a benefit to requiring existing producers to now go through a deviation procedure. Instead, we will direct the utilities to "grandfather" (allow

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141 Tr. 1122.

the continued application of the historical CO_2, O_2, and Btu standards to) gas that in-state producers withdraw from existing fields. We will allow SoCalGas to utilize its proposed deviation process for gas from new sources.

SDG&E and SoCalGas are not proposing to introduce a Methane Number specification (which would specify the minimum percentage of the gas by weight that must be methane). They argue that the use of a Methane Number could produce inconsistent specifications with the proposed parameters for Wobbe Number and Heating Value. Additionally, as they see it, a Methane Number would be specific to a single end-use application, natural gas vehicles.

The ARB's compressed natural gas fuel specifications, are as follows:

Current CARB CNG Vehicle Specifications[142]

Hydrocarbons	
Methane (min.)	**88 mol%**
Ethane (max.)	6 mol%
C3 + higher (max.)	3 mol%
C6 + higher (max.)	0.2 mol%
Other Specs.	
Hydrogen	0.1 mol%
Carbon Dioxide	0.1 mol%
Oxygen	1.0 mol%
Inert Gases	1.5 – 4.5 mol%
Sulfur (max.)	16 ppmv
Water, Particulates, Odorant	

SCE supports adoption of an 85% minimum methane constituent level, which it sees as being consistent with the existing ARB minimum standard of 88% for natural gas vehicles.[143] Alternatively, a limitation on butane and heavy hydrocarbon components to less than one percent, as proposed by Calpine, accomplishes the same objective. SCE bases its recommendation on the following factors.

First, SCE operates the Mountainview Power Plant, which uses four GE Frame 7F gas turbines. SCE ratepayers receive the benefit from manufacturer guarantees on certain performance standards for the Mountainview power plant,

142 Exhibit 111, p. 6.

143 Exhibit 139. See also Exhibit 111, p. 6 (Direct Testimony of Pando, SCE).

including heat rate and emission levels, provided that the gas composition remains within levels described in the equipment specifications. This includes the air emission requirement that the plant emit no more than 2.5 parts per million of NOx. SCE argues that the Commission should adopt gas contents standards, such as those set forth in the ARB compressed natural gas specifications, because a minimum methane content specification is required to meet the specifications for GE frame 7F gas turbines, which are not only by the Mountainview power plant, but also the Otay Mesa and Palomar electric generating facilities. The GE specifications for these gas turbines contain the following constituent limits:

General Electric Fuel Specification

	MAX	MIN
Methane	**100%**	**85%**
Ethane	15%	0
Propane	15%	0
Butane + higher paraffins (C4+)	5%	0
Hydrogen	trace	0
Carbon Monoxide	trace	0
Oxygen	trace	0
Total Inerts (N2 + CO2 + Ar)	15%	0

As the table indicates, the GE specifications require a minimum methane content of 85%. SCE asserts that the absence of a minimum methane content standard could jeopardize SCE's ability to operate the Mountainview generating facility, negatively impact SCE's ability to meet air emission requirements, and risk damage to the gas turbines.[144] SCE reports that to date, GE has not been able to identify a solution that would allow Mountainview to deviate from the minimum methane content standards required in the specifications.

Calpine has indicated that Siemens, as well, specifically warned that the presence of heavier hydrocarbons in its turbines would affect emissions and operability.

Second, SCE argues that the imposition of gas constituent levels, such as those adopted by the ARB would result in gas being consistent with historical deliveries, which have had relatively high methane content. This has been especially true of gas delivered into the Los Angeles basin. According to SCE, SoCalGas/SDG&E's proposed gas quality standards, which lack a minimum methane content standard, would allow gas with lower methane content and higher ethane, propane and butane content, than historically delivered to Southern California.

Third, SCE asserts that adopting constituent levels, such as those set by ARB, will reduce potential gaming of gas quality standards since varying gas constituent levels can impact the Btu value of gas:

> "It depends on the gas composition. And while I would agree that the Wobbe number and the heating value are linked, it depends on the actual composition, the amount of the heavier hydrocarbons in the gas, the amount of the inerts, such as the nitrogen or something like that. So typically on our system, we have—the highest Wobbe number that we have seen is a 1404. And that's equivalent with the kind of gas we typically see, a 1038-Btu. It is possible to create a gas with heavier hydrocarbons that would still have a 1400 or a 1404 Wobbe

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144 Tr., Vol. 7, p. 722, line 26, through p. 723, line 2.

> number, but that would have instead a 1080 Btu, maybe an 1100, or something higher than that. So there is some variation depending on the gas composition."[145]

Apparently, different Btu limits can result in a wide range of Wobbe Index values, and vice-versa, depending on the amount of hydrocarbons (like methane) and inerts.

Finally, on the question of whether the ARB gas constituent levels be adopted, SCE asks, "Why not?" SCE argues that adoption of the ARB standards can only help (not hurt) end-users and air quality. SCE argues that it is only those who have a financial interest in the Sempra LNG facility who oppose the ARB standards because there are no pipelines that can transport the hydrocarbons to a nearby refinery. SCE submits that the lack of a local refinery or the means to transport the hydrocarbons is a matter that Sempra LNG should have been taken into account when it selected its site.

PG&E proposes adding a minimum methane requirement of 80% to its Rule 21. The utility asserts that this would be a good standard to facilitate favorable performance of natural gas vehicles.

Shell states that it does not oppose a minimum methane content of 85%, but it does oppose the broader adoption of the ARB compressed natural gas standards. Shell asserts, specifically, that the ARB's limits on ethane (6%) and C3 plus (3%) are incompatible with most, if not all Asia Pacific LNG supplies. Shell asserts that, like it or not, a Costa Azul facility would not have the option of stripping various products out of the gas. Similarly, Sempra LNG does not oppose the 85% minimum methane level, but argues that SCE has not stated why

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145 Tr., Vol. 7, p. 749, line 17 through p. 750, line 3 (SoCalGas/SDG&E, Baerman).

it would need both that requirement and the other ARB specifications. The Indicated Producers oppose the incorporation of the ARB standards into SoCalGas' Rule 30.

D. What Effect, If any, Would Commission Approval of Changes to Existing Gas Quality Tariff Specifications Have Upon Existing Interconnection Contracts or In-State Producer Contracts and/or Access Agreements?

Existing contractual language controls. If these agreements provide for incorporating the adopted rules by reference, then any adopted changes will apply. If the contract or agreement is in lieu of the tariff provisions, then the contractual standard applies. As always, it is the utility's obligation to ensure that it maintains overall gas quality.

E. What Process Should Be Employed for Approval of Deviations From the Utilities' Gas Quality Tariff Specifications?

PG&E, which relies on its Operational Balancing agreements to set special terms, does not foresee a need for a deviation process. SDG&E/SoCalGas, on the other hand, rely on advice letters to seek individual tariff deviations and propose continuing to use that process. The efficacy of these approaches is not in question here, and we will allow them to continue.

F. What Additional Research or Studies Should Be Undertaken at This Time?

Although most parties agree that there is a need for additional research into the effects of higher-Wobbe gas on the performance and reliability of end-use equipment as well as on air quality, the parties have been short on specifics. SoCalGas has conducted one- or two-hour tests on a limited number of appliances. The CEC has conducted research related to gas quality. Manufactures, such as GE, are conducting studies on some equipment.

SDG&E/SoCalGas report that there are several studies in progress on the local, state, and national levels concerning natural gas quality standards. At the national level, the United States Department of Energy (DOE) has agreed to take a leadership role in the investigation of national standards for gas quality and interchangeability.[146] SDG&E/SoCalGas make several other assertions about ongoing studies in their opening brief, but do not provide citations to the record to support those statements.

SCE and others recommend that the Commission direct the parties to hold a workshop to identify which studies have been completed or are in the process of being completed, and to identify those areas where studies are still needed. The Energy Division could then report back to the Commission on the state of existing research and the specific additional studies that appear to be required. The Commission could then consider that appropriate cost allocation and timeframe for further studies.

As an owner and operator of a large number of DLN/DLE gas turbines, Calpine addressed only the research and studies that it asserts should be undertaken related to that equipment. It offers that the DOE should conduct field-testing on Siemens and GE DLN/DLE units the next 12 to 18 months. Calpine proposes that the testing of the DLN/DLE gas turbines be performed in phases. Phase I would gather historical data on NOx emissions and operational and maintenance activities on the DLN/DLE units to use as a baseline for

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[146] See Ex. No. 145, Prepared Direct Testimony of Craig Chancellor, at Attachment A.

traditional domestic gas. Phase II would introduce varying degrees of hotter gas to the DLN/DLE units, up to the Wobbe Index limit proposed by SDG&E/SoCalGas utilities. Phase III would introduce test various compositional mixtures, including butanes+ in excess of the one percent advocated by Calpine. These particular compositional mixture studies should be sensitive to any changes to the gas turbines in terms of increased NOx emissions, auto ignition, burning velocity, lean blowout, flashback and combustion dynamics. Phases II and III should conduct testing both short-term and long-term to address any major issues that could arise but could be missed with short-term or incomplete testing parameters. Finally, Phase IV would identify the various operational and emissions issues that arose from running the hotter gas through the gas turbines, identify the various alternatives to correct the issues, and prepare a cost-benefit analysis of the various alternatives. A goal would be to determine the most economically efficient method of resolving the problems related to the use of hotter-burning gas.

Calpine states its belief that given the DOE's relatively advanced stage of handling the testing, including identifying the information "gaps" currently existing, it is only logical to piggy-back on to the work the DOE has performed and/or is about to perform.

Calpine states that it is aware that PG&E has requested the AGA write a new guidance document on interchangeability. Calpine does not express opposition to the AGA's efforts to address the interchangeability issue, but regardless of who actually performs the studies and provides the guidance, any testing should include the impact of hotter gas on DLN/DLE gas turbines.

Calpine argues that additional funding for field-work activities should come from the LNG suppliers, since it is they who are proposing to introduce the hotter-burning gas into the United States, and they who should be required to prove that their proposals will not harm end-user equipment or air quality.

SCAQMD suggests a number of studies that it asserts be undertaken:

- Emissions studies of the impacts of hot gas on combustion equipment, particularly larger combustion and power generation sources for which little data presently exists.
- Effects of inert gas addition on large and small equipment.
- Analysis of the regional air quality impacts from high-Btu LNG importation.
- Cost analysis of different mitigation measures, including gas treatment and end-use equipment modification.[147]

SCAQMD argues that the Commission should order the parties to agree on a testing process. In the alternative, the ALJ should order one. The testing should proceed concurrently with, and consistent with, the preparation of the EIR.

The Indicated Producers suggest that regional surveys should be compiled to itemize the "legacy" heavy-duty vehicles in the SCAQMD, south central coast, and San Joaquin Valley. The effort should include vehicle inventories by air district including engine types and usage. In addition, studies need to be updated with regard to interim vehicle fuel blending/engine replacement opportunities. Finally, an up-to-date summary of heavy-duty engine advancement available for commercial use should be compiled with an emphasis on the range of methane number variability.

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147 Exh. 115, page 8.

The Indicated Producers point out that each of these studies has been performed to some level of detail through a stakeholders process that has included the ARB, SoCalGas, the Western States Petroleum Association and its members, and the Engine Manufacturers Association and its members. The Indicated Producers assert that these studies can be completed in a 3- to 6-month timeframe.

Several parties have offered examples of the types of testing and study that are needed to improve our understanding of the implications of introducing hotter gas into California markets, but there is lacking the type of disciplined and detailed approach to designing a research strategy that we had hoped to receive. SCE and SCAQMD have offered sound suggestions for a way to proceed. We note that the CEC has demonstrated leadership in this area. We will direct our Energy Division to work with the CEC to convene a workshop to develop a research plan, identifying specific studies, timetables, and funding mechanisms. It would be helpful if the Energy Division and CEC could achieve DOE's involvement in this process.

There are several goals for this additional research:

1. To understand the implications of various gas quality standards in terms of the safety of gas service and the reliability of gas appliances and other equipment, both in the short-run and in the long-run.

2. To understand the potential impacts on air quality of various gas quality standards.

3. To understand the cost implications (for suppliers, utilities, and customers) of adopting various gas quality standards.

4. To support the completion of environmental review pursuant to CEQA of gas quality standards proposals.

These studies must be replicable and must provide statistically-significant results.

Time is of the essence in designing and completing this work. Several parties have mentioned the feasibility of completing needed studies in 12-18 months. This is a goal that we want to achieve. Toward that end, we direct Energy Division to convene the workshop within three weeks of the issuance of this decision, complete the workshop process within five weeks, and report back to us on the results within eight weeks. We intend to open a new rulemaking proceeding to receive this proposal, as well as other continuing matters related to this proceeding.

Conclusion

With this decision, R.04-01-025 is closed. The following order includes many requirements that will necessitate further Commission review. In the near-future, we anticipate establishing a new gas infrastructure rulemaking docket in which to undertake that further review.

Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Commission's Rules of Practice and Procedure. Comments were filed on ________________ and reply comments were filed on _______________.

Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Steven A. Weissman is the assigned ALJ in this proceeding.

Findings of Fact

1. Emergency concerns for which utility should plan include the failure of a major component of the delivery or storage system, an artificially induced

constraint on the flow of gas, a sudden or persistent loss of supply, an unpredicted and unplanned-for rapid increase in demand, or an excessive increase in the market price for gas.

2. We want to encourage a balanced reliance on stored gas because of the seasonal difference in gas demand and price, because there is a substantial storage capability, and because stored gas is an important physical hedge.

3. It is not enough to know that the combined available pipeline capacity and storage withdrawal rights exceed peak demand by a certain amount. It is necessary to know that sufficient gas will be stored and that withdrawn gas can be delivered where it is needed when the system is most severely stressed.

4. Without a demonstrated ability to deliver stored gas, and without an assurance that customers will rely on stored gas during system peak, it makes no sense to assume that the full storage withdrawal capacity represents a reliable resource for planning purposes.

5. For planning purposes, PG&E, SDG&E and SoCalGas appear to have depended on shippers choosing to use storage fully at peak, and either assumed that stored gas could be delivered during peak conditions, or disregarded the issue. This way of looking at the adequacy of the existing facilities does not sufficiently take into account the thrust of our inquiry in this proceeding.

6. Enough capacity on the backbone system to satisfy demand on an average day is not adequate for system planning purposes if planners cannot depend on stored gas to make up the difference on the most severe peak day.

7. It is reasonable to require that each of the utilities plan its backbone system to meet one-in-ten year cold and dry conditions.

8. The proponents of various reserve margins, here, have not offered a quantifiable basis for establishing a specific backbone pipeline planning reserve.

9. To protect the integrity of the system and to ensure the ability to respond to emergencies, SoCalGas must track and document receipt point constraints, determine whether they are temporary or long-term, and respond accordingly.

10. There are clear advantages to requiring the utilities to identify a cost/benefit methodology and submit it to the Commission for advance review. First, it would help ensure that the utilities take a consistent approach to considering the costs and benefits of various expansion proposals. Second, it could expedite future expansion efforts by eliminating the need to litigate the underlying methodology. Finally, it would help potential expansion proponents understand the cost-effectiveness of a potential receipt point expansion.

11. The appropriate balance is one where the utilities are not required to maintain and continually update the estimated cost of various expansion options, but are obligated to produce detailed cost estimates on request, in a reasonable amount of time, at a reasonable cost.

12. Six to eight months is not a reasonable timeframe for responding to a business request for a receipt expansion cost estimate in this world of constantly fluctuating gas prices, even taking into account the iterative nature of the exercise.

13. Assuming that PG&E's hypothetical situations reflect the outward boundaries of likely contingencies, PG&E's contention that its storage capacity is adequate would appear to be reasonable.

14. Although SoCalGas asserts that there are other realistic storage options for Southern California shippers due to the presence of Wild Goose and Lodi Storage to the north, SoCalGas has not offered sufficient evidence to support this contention.

15. SoCalGas' unbundled storage capacity and injection rights have been oversubscribed in recent years, and withdrawal rights sales have hovered at about 80% of the total amount available.

16. It is unrealistic to rely on the exercise of all withdrawal rights if customers are not required to inject enough gas or to exercise their withdrawal rights, or if SoCalGas cannot deliver all of the withdrawn gas to the customer.

17. In assessing system adequacy, the utilities do not appear to consider the impact of a major change in the demand for gas to serve electric generation due to the extended loss of a nuclear unit, or the shutdown of another non-gas-fired generator such as the Mohave Generating Station (which closed after the completion of hearings in this phase of the proceeding as anticipated in D.04-12-016).

18. An electric utility must plan for the loss of a nuclear plant because it is the largest single source of electric generation. A gas utility must plan for such a loss because the alternative source of generation is likely to be gas-fired.

19. Considering the significant time needed to establish new storage capability, it is a matter of concern that the utilities have not planned for the possibility that demand for natural gas might grow at an unexpectedly high rate during the next few years. Nor have the utilities assessed system needs in the event of a dramatic change in supply from a particular source, such as Canadian or Rocky Mountain gas, or a sudden loss of gas from a major LNG facility due to a cataclysmic failure at a processing facility here or abroad, or a redirection of supply. Most significantly, the utility analysis does not consider the possible need for storage capacity to hold large shipments of imported gas.

20. Storage serves purposes far beyond price hedging, and provides certainty that cannot be matched by a reliance on flowing supply.

21. Neither SoCalGas nor its unbundled storage customers could rely exclusively on flowing supply in lieu of storage.

22. It is appropriate for SoCalGas to offer a cost-based recourse unbundled storage rate for a fixed period of time.

23. All parties (with the exception of Lodi) appear to support the contention that the current backbone pipeline and storage infrastructure are sufficient. However, we have yet to receive the kind of rigorous analysis that would allow us to share that conclusion.

24. When all customers have to rely on a single network of pipes and storage, self-interest is not always consistent with that of the greater body of customers.

25. To some customers, SDG&E and SoCalGas, in their open season proposal, may be offering a Hobson's choice: commit to 5- or 10-year use-or-pay firm daily transportation payments or risk the utilities maintaining an undersized local transmission system.

26. In D.04-09-022, the Commission directed SDG&E and SoCalGas to file a new application (A.04-12-004) to consider issues related to SDG&E/SoCalGas system integration, tradable firm rights, and off-system sales. We are considering tradable rights in the second part of that proceeding, which is now underway. Thus, it is premature to consider the approval of a long-term commitment to firm access.

27. An exclusive reliance on long-term commitments to determine system adequacy would not do enough to ensure that the system would function well during emergencies, since an integrated system such as this must be planned and managed in an integrated way.

28. Although the Commission has allowed the utilities to make use of open seasons, it has not authorized them to abandon other means of forecasting and planning to meet demand.

29. Interstate capacity might be more valuable than local transmission capacity because its use is less location-specific and it is more tradable.

30. It is appropriate to roll into general rates many expansions that are required as part of the one-in-ten year planning process. However, for those expansions required largely to serve individual projects, such as LNG terminals, the policy established in the Phase I decision (D.04-09-022) applies.

31. Securing needed firm interstate gas pipeline capacity rights is an important element of electric utility resource planning and an important factor in assuring the reliability of the natural gas delivery system.

32. First-in-time cost allocation for receipt point expansion is a crude and, in some ways, unfair approach.

33. One of the most significant reasons for imposing incremental expansion costs on the entity creating the demand is to enable the incremental customer to take those costs into account when siting its facilities, or when making a commitment to procure gas from a geographically-specific source.

34. The standardized interconnection, and operational balancing agreements as described and modified in this decision are reasonable.

35. The proposed independent storage provider agreement described in this decision is reasonable in light of the entire record, consistent with the law, and consistent with the public interest.

36. The stipulation among the signatories to the independent storage provider agreement as to the capability of PG&E's backbone system to deliver withdrawn

storage gas during peak periods does not constitute a factual determination for our purposes.

37. LNG would likely burn hotter than most domestic gas supplies, creating the potential for greater combustion-related NOx emissions and reduced reliability for gas-burning appliances and machinery.

38. NOx is an ozone smog precursor, leading to the possibility that hotter-burning gas could contribute to higher smog levels throughout the state, which contains significant non-attainment areas.

39. Load centers relatively close to LNG terminals could experience dramatic swings in gas quality if LNG is not more closely matched to other flowing supplies.

40. Some LNG project proponents state that they are prepared to meet any gas quality standard, and seek certainty in order to plan their physical plant and procurement strategies.

41. Unless we act to narrow the scope of Rules 21 and 30, we face the likelihood that the introduction of LNG will lead to gas supplies that are hotter-burning, and perhaps different from current supplies in other significant ways.

42. Replacing some of the existing gas quality rules with a Wobbe range having a low end of 1290 and a high end of 1400 would allow for hotter-burning gas than the utilities usually receive now, but would be more restrictive than the range that could qualify under the existing utility rules. Since all parties anticipate that LNG providers will deliver gas at or near the top of whatever range the Commission adopts, the result would be that the average Wobbe number for flowing supplies would become higher, leading to hotter-burning gas, overall.

43. There is insufficient information about the impact of hotter-burning gas on the performance and costs related to end-use equipment such as gas-fired turbines, and insufficient information about air quality impacts.

44. No one in this proceeding spoke for the greater body of ratepayers that would face the consequences of any deterioration in the reliability of appliances and machinery that might result from the greater presence of hotter-burning gas.

45. The impact of the SDG&E/SoCalGas air quality proposal on many types of end-use equipment is not known.

46. There is a lack of information regarding the impact of "hotter" LNG on emissions, in particular NOx.

47. To do nothing to modify existing gas quality rules in anticipation of the importation of hotter-burning gas would threaten air quality, safety, and the reliability of equipment that burns natural gas.

48. Based on the information currently available, we cannot assure customers that under the current rule, or for any of the specific new standards proposed for our adoption, that utility service will remain safe, that gas-fired equipment will remain reliable, and that environmental quality will be preserved with the introduction of hotter-burning gas.

49. No one contests the need to perform more tests and complete more studies in order to answer these concerns.

50. Based on the record before us, we do not conclude that a 1360 Wobbe number, or any other similar restriction, would eliminate significant opportunities to import offshore natural gas.

51. The most straightforward, although not necessarily the best way to approximate a retention of the status quo is to retain the current Rule 30 and the current ARB rules until the necessary additional studies have been completed.

52. Approval of a new Wobbe-based gas quality standard is a discretionary act that has the potential to lend to significant environmental impacts.

53. It is clear that the Commission's discretionary act in choosing among the proposed gas quality options could have environmental implications.

54. CEQA does not apply to specific actions necessary to prevent or mitigate an emergency.

55. PG&E's proposed revisions to its Rule 21 are reasonable.

56. With the exception of the proposed Wobbe range, SoCalGas' proposed charges to its Rule 30 are reasonable.

57. SCE's proposed requirement of minimum methane content of 85% is reasonable, but unnecessary, as long as the ARB standard continues to apply.

58. It is necessary for the Energy Division to work with the CEC to convene a workshop to develop a research plan, identifying specific studies, timetables, and funding mechanisms needed to determine the safety, reliability, cost, and environmental implications of adopting a Wobbe-based gas quality standard at various levels.

Conclusions of Law

1. We should adopt a backbone adequacy standard of one-in-ten cold, and dry-hydroelectric year reliability.

2. System planners must demonstrate that they will be able to deliver stored gas.

3. Planners must determine the probability that shippers will inject sufficient gas into the storage reservoir and the probable level of storage utilization at peak, and use those factors as part of the planning process.

4. Rather than declare the reasonableness of either of the slack capacity ranges offered by the utilities in this proceeding, we should direct the utilities to

develop a quantifiable rationale for the adoption of a certain slack capacity standard, taking into account the goals of maintaining slack capacity as discussed above, planning contingencies reflecting potential physical constraints (both related to supply and transportation), and market problems. In addition, we should direct the utilities to estimate the costs and benefits associated with maintaining a particular slack capacity level.

5. We should adopt Kern River's recommendation of requiring SoCalGas to monitor the use of the receipt points and to provide quarterly reports to the Commission showing the extent to which shippers are (or are not) seeking access above available capacity. In addition, we should require SoCalGas to explain, in each report, why the company should or should not pursue receipt point expansion in response to existing or forecast constraints.

6. We will direct SoCalGas to devise, and submit to the Commission within three months of the issuance of an order in a new proceeding, a methodology for performing a cost benefit analysis for receipt point expansions. We will provide parties an opportunity to comment on the methodology.

7. SoCalGas should take the steps necessary to respond more promptly to requests for cost estimates, whether this requires hiring additional personnel, having consultants on call, or both.

8. The adequacy of the core storage set-aside should be reviewed not in a generic infrastructure adequacy context, but in a proceeding more directly focused on core service.

9. We will direct the utilities to file new infrastructure assessments, consistent with this decision, in a new proceeding. As part of this process, we hope to be able to make a more informed determination of the adequacy of storage facilities and practices.

10. Each utility must continue to study and report on the adequacy of its entire system, including local transmission, and act to ensure that it remains reliable.

11. SoCalGas should retain the current practice of requiring no more than 2-year commitments from those seeking firm capacity through open seasons in the absence of a well-developed trading mechanism and a more flexible menu of commitment terms.

12. The utilities should explore with their customers ways to structure longer and shorter firm local transmission commitments while still making economic sense. We look to the utilities and their largest customers to work out these terms together, and submit a proposal to us for our consideration.

13. We do not adopt SDG&E and SoCalGas' proposed changes to their rules for conducting open seasons on the local transmission system.

14. Electric generators should do their part to fill storage fields, and to withdraw gas during times of system peak.

15. When a utility is considering a receipt point expansion for a particular customer, it can solicit firm expressions of interests from other customers. Where other customers are willing to commit to supporting receipt point expansion to serve their needs, then the utility should plan its expansion to serve all of the identified customers, and apportion the expansion costs among all of the customers in an equitable manner. Customers that firm up their needs later in time will be required to shoulder the cost of any further expansion.

16. The proposed change to a Wobbe-based gas quality standard is a "project" under CEQA. A decision on this issue requires full compliance with CEQA.

17. In order to fully explore the implications of the alternatives and the range of mitigation options if potential impacts do prove to be significant, we are obligated to apply the procedural and substantive requirements of CEQA.

18. There is an insufficient factual basis to ensure that the adoption of a Wobbe Index standard such as proposed by SoCalGas, Calpine, or SCAQMD would adequately protect safety, reliability, and air quality.

19. Until the Commission can provide such assurance, PG&E, SDG&E, and SoCalGas should maintain current gas quality, even if the existing rules would allow for greater variation.

INTERIM ORDER

IT IS ORDERED that:

1. The Pacific Gas and Electric Company (PG&E) and the Southern California Gas Company (SoCalGas) shall plan and maintain intrastate natural gas backbone transmission systems sufficient to (1) serve, through flowing supplies, all system demand on an average day in a one-in-ten cold and dry-hydroelectric year, (2) allow for the delivery of all gas potentially withdrawn from storage during periods of peak demand, and (3) include a planning reserve, or slack capacity, sufficient to ensure uninterrupted gas service during emergencies, as defined below.

2. Emergency concerns include the failure or unavailability of a major component of the natural gas delivery or storage system, an artificially induced constraint on the flow of gas, a sudden or persistent loss of supply, an unpredicted and unplanned-for rapid increase in demand, or an excessive increase in the market price for gas.

3. PG&E and SoCalGas shall develop a quantifiable methodology for determining an appropriate level of slack capacity, as discussed in this order. This methodology shall take into account the potential for loss of major gas delivery or storage components, the loss of the largest available gas supply, the potential for sudden shifts in demand from events such as the loss of major non-gas-fired electric generation, and the potential for market manipulation. The determination of an appropriate level of slack capacity shall include a cost/benefit analysis.

4. SoCalGas shall monitor the use of the receipt points on its backbone system and provide quarterly reports to the Commission showing the extent to which shippers are (or are not) seeking access at levels above available capacity. In addition, we will require SoCalGas to explain, in each report, why the company should or should not pursue receipt point expansion in response to existing or forecast constraints. In addition to submitting these reports to the Commission's Executive Director 15 days after the end of each quarter, SoCalGas shall serve copies of the reports on any parties to this proceeding requesting service.

5. Within three months of the issuance of a new natural gas rulemaking proceeding, SoCalGas shall devise, and submit to the Commission in that new docket, a methodology for performing a cost benefit analysis for receipt point expansions. Other parties shall have an opportunity to comment on that methodology, and the Commission will determine whether or not the methodology is reasonable and should be adopted.

6. SoCalGas shall take the steps necessary to respond more promptly to requests for receipt point expansion cost estimates, whether this requires hiring

additional personnel, having consultants on call, or both. It is not reasonable to take six to eight months to prepare such estimates.

7. In assessing the adequacy of in-state infrastructure, the utilities shall consider the physical system as a whole (the interaction of backbone pipelines, storage, and local transmission) including the probability of storage withdrawal and the deliverability of withdrawn gas during periods of peak demand.

8. No later than 90 days after the issuance of this decision, SoCalGas shall file an application seeking the approval of a cost-based unbundled storage recourse rate for a fixed period of time, such as three years.

9. To facilitate a more informed determination of the adequacy of pipeline and storage facilities and practices, PG&E, SoCalGas, and the San Diego Gas & Electric Company (SDG&E) shall file new infrastructure assessments, consistent with this decision. We will establish the procedure and timetable for these new filings as part of a new rulemaking proceeding, which we will initiate soon after the issuance of this order.

10. SDG&E/SoCalGas' request for revisions to the open season process for expansion of local transmission facilities is denied.

11. In addition to the occasional use of open seasons to allocate access to constrained resources, SDG&E and SoCalGas shall include the expansion of local transmission facilities in their usual system planning process, and undertake expansion projects as needed to serve all types of customers.

12. In order to accommodate those noncore customers seeking firm commitments to transmission service, PG&E, SDG&E, and SoCalGas shall explore with their customers ways to structure longer and shorter commitments while still making economic sense. For instance, there may be ways to require tougher use-or-pay terms for shorter-term commitments, and more lenient terms

for longer-term agreements. We look to the utilities and their largest customers to work out these terms together, and submit a proposal to us for our consideration. The price of firm service should relate to the cost of any incremental expansion necessary to provide dedicated capacity.

13. We expect PG&E, SDG&E, and the Southern California Edison Company to demonstrate, as part of the integrated resource planning process, that they have taken all necessary steps to ensure gas supply. As part of each planning cycle, they shall actively consider the role of firm interstate capacity and report on their reasons for pursuing the strategy that they propose. We also expect the electric utilities to inject and withdraw storage gas consistently, as part of the annual fuel supply cycle. As is true with other aspects of gas infrastructure and supply reserve, the electric utilities should define and work toward achieving a storage goal that is quantitatively related to the nature of their resource portfolios and the level of gas usage. This, too, should be developed and explained fully as part of each procurement plan.

14. The Commission hereby endorses the effort to expand and encourage active participation in the Natural Gas Working Group. Meetings between state agency representatives and utility representatives should generally be open to the general public. The Commission asks that all meetings involving more than just state agency representatives be open to all participants. However, it may be necessary, at times, for the utilities to discuss confidential matters. When there is a legitimate confidential purpose to be served, the utilities may communicate that information to the Commission or the California Energy Commission staff, which can determine the best way to communicate the information to other Natural Gas Working Group members. We encourage the Group to err on the

side of sunshine in its communications as a body with outside entities, and to function more privately only when necessary.

15. When a utility is considering a receipt point expansion for a particular customer, it shall solicit firm expressions of interests from other customers. Where other customers are willing to commit to supporting receipt point expansion to serve their needs, then the utility shall plan its expansion to serve all of the identified customers, and apportion the expansion costs among all of the customers in an equitable manner. Customers that firm up their needs later in time will be required to shoulder the cost of any further expansion.

16. The standardized Interconnection Agreement and Operational Balancing Agreement described and modified in Section VII. of this decision are approved.

17. The settlement agreement between PG&E and independent storage providers concerning direct interconnection of those independent providers with California producers, as well as electric generators and other noncore customers is approved, subject to the clarification that the stipulation among the parties as to the adequacy of the PG&E backbone system to deliver withdrawn storage gas during peak periods is not a factual determination that is in any way binding on the Commission or other parties.

18. With the exception of the proposed gas interchangeability standard as proposed by SDG&E and SoCalGas, the changes to PG&E's Rule 21 and SoCalGas' Rule 30 as proposed by the utilities are approved.

19. Rules 21 and 30 shall also require that gas supplies have a minimum methane content of 85%.

20. SoCalGas' proposed method for seeking deviations from the requirements of Rule 30 is approved, with the exception that California producers are excused from compliance with the revisions to PG&E's Rule 21 and SoCalGas' Rule 30

adopted herein related to heat rate and content of CO_2 and O_2, to the extent that those producers offer gas from the same field from which they are currently furnishing gas to the utilities.

21. Until the Commission is satisfied that other proposed revisions to the gas quality standards will preserve current levels of safety, reliability, and air quality, PG&E and SoCalGas shall enforce Rules 21 and 30 (respectively) as modified in this decision, as well as the current Air Resources Board (ARB) compressed natural gas vehicle standards. The objective of this requirement is to preserve the status quo, in terms of safety, reliability, and air quality. The utilities are encouraged to work with other stakeholders to explore other means of preserving the status quo while additional research is underway.

22. When submitting new proposed revisions to Rule 21 or Rule 30 involving a deviation from current ARB compressed natural gas vehicle standards, the moving party shall also submit a Proponent's Environmental Assessment consistent with Rule 17.1 of the Commission's Rules of Practice and Procedure.

23. In the near-term, SDG&E and SoCalGas shall conduct any approved open seasons in a manner consistent with existing tariffs. Soon, in Application 04-12-004, the Commission will consider proposals for the adoption of a mechanism to allow for firm tradable rights on the backbone and local transmission systems. If the Commission approves such a mechanism, SDG&E and SoCalGas may file a new application seeking changes to their open season rules in a manner that answers the concerns we have raised above.

24. We direct the Energy Division to pursue additional research related to gas quality with the following goals in mind:

a. To understand the implications of various gas quality standards in terms of the safety of gas service and the reliability of gas appliances and other equipment, both in the short-run and in the long-run.

b. To understand the potential impacts on air quality of various gas quality standards.

c. To understand the cost implications (for suppliers, utilities, and customers) of adopting various gas quality standards.

d. To support the completion of environmental review pursuant to the California Environmental Quality Act of gas quality standards proposals.

These studies must be replicable and must provide statistically-significant results.

Time is of the essence in designing and completing this work. Several parties have mentioned the feasibility of completing needed studies in 12-18 months. This is a goal that we want to achieve. Toward that end, we direct Energy Division to convene the workshop within three weeks of the issuance of this decision, complete workshop process within five weeks, and report back to us on the results within eight weeks. We intend to open a new rulemaking proceeding to receive this proposal, as well as other continuing matters related to this proceeding.

25. Rulemaking 04-01-025 is closed.

This order is effective today.

Dated _______________, at San Francisco, California.

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(END OF APPENDIX A)