ATTACHMENT 2

California Gas Utility Reliability: Definition, Standards, and Measures

An Energy Division Staff White Paper

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Executive Summary

- The California Public Utilities Commission has not adopted a definition of reliability as it applies to California's gas utilities.
- There are multiple reliability standards used by the utilities. The standards apply to the physical delivery capacity of the system and to the amount of supply of natural gas. There are differences across the utilities in how the standards are defined and applied. The criteria used in defining the current standard is, in some circumstances, not readily apparent.
- The current reliability standards reflect the response to the energy crisis in California during the late 1990's and into the early 2000's. That crisis was driven by shortages in available gas supply. Additionally, they anticipated moderate and consistent growth in the demand for natural gas.
- Conditions regarding utility gas reliability have changed significantly since the energy crisis and the adoption of the current reliability standards. There is now an abundance of domestic natural gas supply and overall projected growth in demand is less than anticipated. However, natural gas has become increasingly important in supporting electric generation, in particular, during periods of peak demand.
- The gas utilities in California are operating with an aging infrastructure and have experienced significant outages, particularly over the last five years.

Introduction

Current measurements of reliability across California's utility gas system[1] are largely the outcome of a 2004 California Public Utilities Commission (CPUC) Rulemaking, (R.) 04-01-025. That rulemaking responded to a crisis of limited gas supply and resulted in two key decisions, Decision (D.) 04-09-022 and D.06-09-039. Several conditions have changed since the CPUC issued those decisions. Today, there is an abundance of gas commodity supply, and domestically produced gas is being exported. Additionally, a series of factors have led to new concerns regarding the future reliability of the utility gas system. These include: an aging infrastructure and coincident pipeline and storage field capacity restrictions; a system built largely to meet slowly growing baseload demand now being increasingly used to respond to short duration peak demands related to electric generation while baseload demand is declining; uncertainty about the role of natural gas given California's commitment to decarbonization; and concerns over the costs of maintaining infrastructure that could result in significant stranded assets. Addressing these concerns requires understanding the central issue of "reliability." Currently, there is no common definition of reliability, and it is measured by multiple differing standards across California's utilities. Ultimately, how reliability is defined and measured drives the what, how much, and how of the system.

The purpose of this report is to describe how utility gas reliability is currently measured, provide background on the origin and circumstances related to the adoption of those measures, and identify current and potential issues with the current measures.

I. Defining Reliability

There is no specific definition of reliability for California gas utilities. However, reliability is central to the purpose of the CPUC and the operations of the utilities. As noted on its website, the CPUC:

> "Regulates services and utilities, protects consumers, safeguards the environment, and *assures Californians' access to safe and* ***reliable*** *utility infrastructure and services."*[2]

However, the CPUC has not adopted a definition for "gas reliability." Neither have the California gas utilities. SoCalGas, the largest US gas utility[3] does not include reliability in its Rule 1 where it defines terms.[4] Nor does a SoCalGas reliability definition appear to be present in other company literature. PG&E defines electric reliability in its Resource encyclopedia but does not indicate whether the definition applies to its natural gas operations.

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[1] As referred herein the utility gas system includes the two primary utilities, Pacific Gas & Electric (PG&E) and Southern California Gas Company (SoCalGas). SoCalGas includes its subsidiary, San Diego Gas & Electric, and incorporates Southwest Gas' California operations, which rely on the SoCalGas transmission system.
[2] CPUC website, welcome page. Emphasis added.
[3] SoCalGas ranking based on gas revenues for 2018. See the American Gas Association website: https://www.aga.org/research/data/utility-rankings/.
[4] Southwest Gas, which operates in parts of California and relies on SoCalGas for much of its gas transmission, does not define reliability in its rules or on its website.

SoCalGas and PG&E are not unique—the broader gas utility industry and its industry associations also do not provide a reliability definition. A review the 10 largest gas utilities failed to surface a definition, and the American Gas Association does not provide a definition of reliability. Rather it references reliability in the context of performance noting that "…in 2016 fewer than 100,000 natural gas customers nationally experienced power outages" and comments that "…pipelines delivered 99.79% of 'firm' contractual commitments to firm transportation customers… firm pipeline transportation service historically is very reliable."[5]

As such, there is no common reference point for how the term reliability is applied. Rather, reliability is addressed in the context of specific standards applied to situations (e.g. winter/summer), customer type, and infrastructure or commodity supply. These standards differ across utility, customer class, and system as well as by whether they address the physical structure of the system or the supply of the gas commodity. The criteria underlying the choice of the standards is not readily apparent. Further, the standards are point-in-time focused and do not explicitly consider longer-term issues of the sustainability and resilience of the system. Given the current and likely future changes in the role of natural gas, the current standards may need to be examined. A definition of gas reliability could be a useful organizing tool for identifying what is included in, or excluded from, a given discussion. And, a common definition would provide a consistent framework within which reliability can be discussed, examined, measured, and evaluated.

A definition is a "Concise exact statement that sets the boundaries or limits of (circumscribes) the subject matter to *include* what belongs to it and *exclude* what does not. Its objective is to give the subject matter a distinctive identity and precise meaning to prevent conflict, confusion, or overlap."[6]

While gas reliability is not specifically defined, there are multiple definitions of electric reliability. PG&E defines electric reliability in its document, Resources, as "A measure of a system's ability to deliver uninterrupted service."[7] The Energy Information Agency (EIA) defines electric reliability in terms of supply coupled with the concept of security. According to the EIA it is "…the adequacy of supply and security of operations." The Department of Energy (DOE) defines electric reliability as "…the ability of the system or its components to withstand instability, uncontrolled events, cascading failures or unanticipated loss of system components." And the DOE introduces two companion concepts, 1) "Resilience: the ability of the system or its components to adapt to changing conditions and withstand and recover rapidly from disruptions; and 2) "Security: the ability of a system or its components to withstand attacks (including physical and cyber incidents) on its integrity and operations."

[5] AGA website, Mission Statement, https://www.aga.org/about/mission/.

[6] http://www.businessdirectionary.com/definition.definition.html.

[7] PG&E's definition appears in the context of electric system reliability and it is not clear if the definition is applied to gas reliability.

With minimal change, shown in italics below, the definition used by PG&E for electric reliability can be applied to gas reliability:

> "A measure of the *gas* system's *capacity and ability* to deliver uninterrupted service."

While concise, the definition does not clearly "set the boundaries or limits of the subject matter to include what belongs to it and exclude what does not…." Drawing largely on the DOE and EIA definitions that list could be extensive:

- Infrastructure: Physical system capacity to deliver the gas needed when it is needed;
- Supply: The availability of natural gas to meet demand;
- Security: Both physical and cyber;
- Stability: Or the ability to withstand instability;
- Resilience: The ability to adapt to change and recover from disruption;
- System Regimen: Rules, tariffs, procedures, and practices that govern how the system is managed and used.

Traditionally, within the CPUC's framework, reliability has focused primarily on infrastructure, supply, and the supporting system regimen.

While the CPUC has not expressly defined reliability, it did, in D.06-07-010, acknowledge a critical distinction between two of its central aspects: physical and supply reliability. The decision defined physical system reliability as pertaining to "the engineering design standard of the pipelines and related facilities that make up the transmission system. The physical system reliability of the transmission system is defined by the maximum volume of gas that can be transported over the system."[8] Supply reliability "is a function of the underlying gas market and relates to the ability of the end user to acquire sufficient supplies to meet its demand."[9]

Physical reliability applies to all the utility's customers, both core and noncore.[10] It is the ability to transport gas sufficient to meet total customer demand. As it is currently defined, supply reliability is, for the utility, confined to the amount of gas needed to meet *core* demand. For noncore customers, by definition, the supply obligation is their own responsibility not that of the utility. As discussed below, the distinction as currently applied may not effectively address the current reality of California's energy system.

[8] Decision 06-07-010, July 20, 2006. p.6, Footnote 3.

[9] Ibid., p. 6. Footnote 3.

[10] Core customers are defined as customers using less than 250,000 therms annually. (See D.86-12-009 and attached Glossary). Typically core customers are residential and small business customers. Noncore customers are typically large commercial and industrial customers.

Changes Impacting Gas Reliability

A combination of factors, most notably environmental concerns and legislation that electric generation become carbon free by 2045, has led to the growth in renewable energy sources. Coal- and oil-fired plants have been or are in the process of being replaced as a source of fuel for electric generation. That growth was accelerated by the closure of the San Onofre Nuclear Generating Station (SONGS). The timing mismatch between electric demand peaks and renewable generation combined with current technology-driven limitations on renewable energy storage has created an increased demand for, and dependency on, gas-fired electric generation. During weather extremes the supply mismatch can become critical, requiring increased, rapid response use of gas-fired peaker plants. In Southern California, the impact of the state mandate and the loss of SONGS have been amplified by pipeline outages and limitations on the use of the Aliso Canyon gas storage facility. These conditions contributed to electric curtailments and extremes in the prices paid for natural gas to fuel electric generation.

The increased reliance on natural gas for electric generation has caused the formally independent systems to become more intertwined. However, the rules by which the gas system operates did not anticipate the electric system's current level of reliance on the natural gas system to support California's overall energy system. In particular, the core/noncore customer distinction as it applies to supply reliability, especially in the case of electric generation has raised concerns in some quarters. The Western Interconnection Gas-Electric Interface Study comments on the rules and their consequences:

- "Virtually all generation on the local LDC [local distribution company] system is effectively unsupported by FT [Firm Transportation, i.e., contracts not subject to reduction or interruption] due to existing curtailment protocols; consequently, approximately 80% of capacity is essentially relying on IT-type [Interruptible Transportation] contracting for over 23 GW of gas-fired generation.
- The California intrastate systems are designed to be capable of meeting all demand (both core and non-core) under a 1-in-10 year cold weather event (though, with the reduced capability of Aliso Canyon, the current system may not meet these design criteria), but curtailment protocols classify electric generation as non-core end-use, meaning that utilities and generators would be the first to be impacted during curtailments."[11]

The report goes on to state that "…because generators are considered non-core customers, there is little value in holding FT further upstream on the interstate pipelines feeding into California. As a result, generators have already released or expressed intentions to release firm capacity from several pipeline systems."[12] As the report notes, this results in longer term ripple effects: "This lack of alignment of commercial incentives also makes it more challenging for pipeline operators to secure enough interest during open seasons for new expansions on their systems. These disincentives create

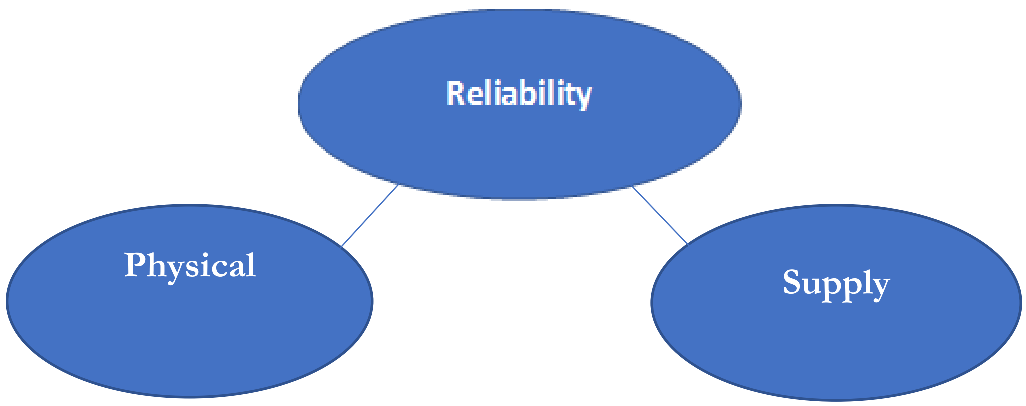
[11] Ibid., p.12.
[12] Ibid., p.12.

significant long-term reliability concerns as it ultimately reduces the ability of pipeline operators to invest in their system to increase reliability and deliverability for power generators."[13]

At the time of the two key decisions, D.04-09-022 and D.06-09-039, requirements for both physical and supply reliability standards for core customers but only physical reliability standards for noncore customers was consistent with the then-current needs and markets. However, the classification of electric generators as noncore, given their critical role in the stability of the overall energy system, may now increase reliability risk.

Independent of where the line is drawn between core and noncore, the two distinct aspects of reliability, physical and supply, suggests the following working definition or framework for gas reliability:

> **"Gas reliability is a measure of the gas system's capacity and ability to deliver uninterrupted service. It represents the ability to supply gas and the capacity to transport it in amounts sufficient to meet customer demand."**



As used above, *capacity* represents the quantity of gas the physical assets of the system can deliver (and it is typically an absolute measure); and, *ability* represents the utility's power, skill, or competence to deliver service (often a relative measure, which can include non-physical assets/rules/expertise/skills, etc.).

Physical Versus Supply Reliability

Using the framework presented in the prior section, "physical reliability" refers to the pipeline system infrastructure with its supporting assets such as compressor stations. When measuring physical reliability, a distinction is made between the backbone and local pipeline systems. Briefly

[13] Ibid., pp. 12-13.

stated, the backbone system is made up of relatively large capacity, high pressure intrastate transmission lines most of which connect to interstate pipelines. The interstate pipelines largely deliver gas from the out-of-state production basins that are the source of most of California's gas supply.[14] At the other end, the backbone system delivers gas into the local distribution system (or to a noncore customer's own line). The local distribution system if made up of smaller lines that distribute supply to mostly individual core and a more limited number of noncore customers.[15]

"Supply reliability" is a planning standard that addresses the amount of gas that the utility must provide to meet a defined level of demand. It focuses on interstate pipeline capacity and storage capacity and should include supply contracts and purchasing made by the utility's gas purchasing function.

Storage represents somewhat of a hybrid, combining aspects of both physical and supply reliability. In the case of SoCalGas, which owns all of its physical storage, the amount of gas held in storage on behalf of customers and the withdrawal rights associated with that gas is most similar to supply reliability while the physical asset and the infrastructure that supports injection and withdrawal capacity is closer to physical reliability.[16] Where storage is classified in the PG&E system is less clear. The storage PG&E owns shares the same hybrid characteristics as SoCalGas. However, its leased storage, which is held under the terms of negotiated contracts with independent storage providers, more closely resembles interstate pipeline capacity. Further complicating the issue is that the PG&E system includes long backbone lines that themselves as a form of storage through their "line-pack" or gas stored in the pipeline. Due to the way the SoCalGas system evolved, with five distinct regional systems that are somewhat isolated (and lacking the long lines that PG&E has), its linepack is less significant as an asset.

Note that the definitions of reliability are focused on the capacity to meet demand and do not address whether that capacity is successfully employed, nor do they address the consequences to the utility of not meeting the standard.

The following illustrates the elements of reliability as discussed in the previous paragraphs.

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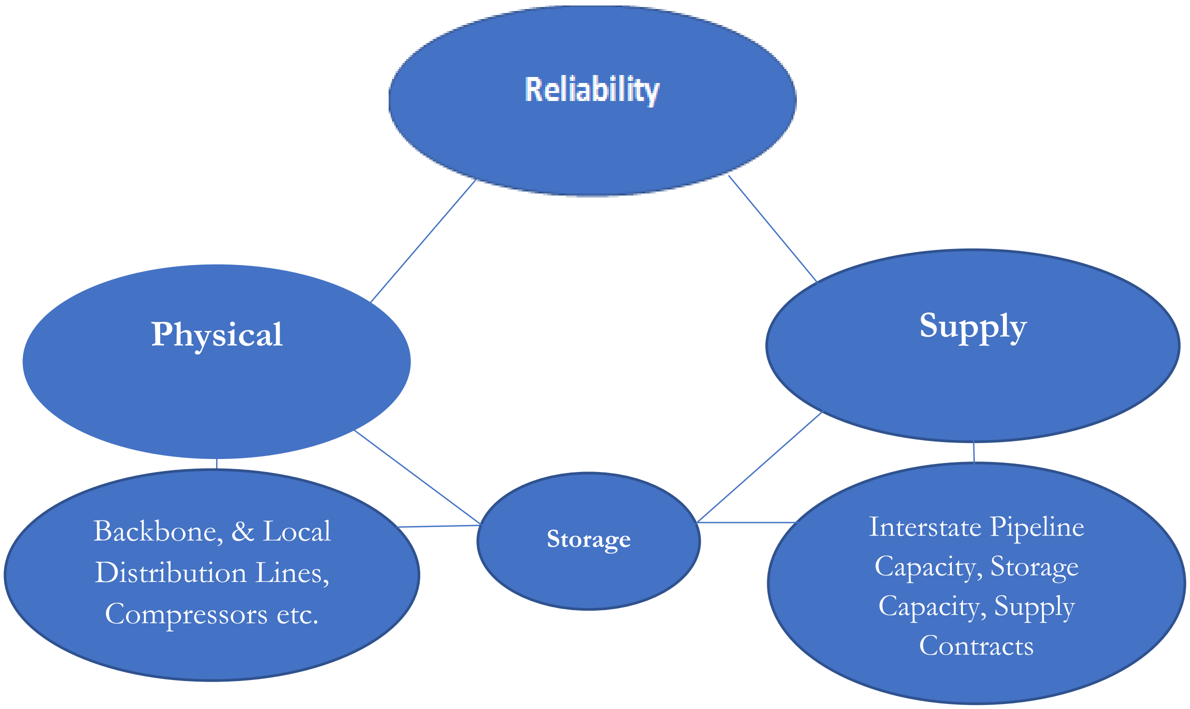
[14] A limited number of lines in the backbone system link to gathering systems within California's oil/gas supply basins, most of which are experiencing significant declines in production.

[15] The local distribution system as referred to herein includes what is sometimes called local transmission. This reflects a distinction made in certain cases between larger local lines that feed into smaller local lines. This is particularly true in the case of SDG&E. The SDG&E system 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. See also D.06-09-039 page 8 which references the SDG&E system.

[16] The distinction is made more complex given that the physical reliability aspect of injection and withdrawal capacity is highly dependent on the volume of gas in the storage facility.



II. Reliability Standards

Background

There are 13 standards related to components of reliability. The standards vary by utility, customer type, season, and finally, for physical reliability, by backbone or local distribution system. Table 1 following, presents the mix of standards currently in effect. The table does not include measures of slack capacity, which is discussed separately in the sections that follow.

The current standards are largely the result of a 2004 Order Instituting Rulemaking, (OIR), R.04-01-025.[17] The purpose of the rulemaking was "to ensure that California does not face a natural gas shortage in the future."[18] It was conducted "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."[19]

[17] D.02-11-073, an outcome of the OIR, established initial 1-in-10 and 1-in 35 standards for SoCalGas and SDG&E. See pps. 2 and 3. R.20-01-007 is revisiting several of the issues raised in R.04-01-025.
[18] D.04-09-022
[19] D.06-09-039 p. 4.

Table 1: Reliability Standards

CUSTOMER CLASS	RELIABILITY TYPE	RELIABILITY STANDARD	
		PG&E	**SoCalGas**
CORE	**PHYSICAL**		
	Backbone	1-in-10 Dry/Cold Year	1-in-35 Peak Day (Core Only) plus 1-in-10 Dry/Cold Year
	Local	1-in-90 Abnormal Peak Day*	1-in-35 Peak Day (Core Only) plus 1-in-10 Cold Day
	SUPPLY		
	Winter	Range from 962–1,058 MMcfd	Range from 100% to 120% of Average Winter Daily Demand
	Summer	Range from 746–1,058 MMcfd	Range from 100% to 120% of Average Summer Daily Demand
NONCORE	**PHYSICAL**		
	Backbone	1-in-10 Dry/Cold Year	1-in-10 Dry/Cold Year
	Local	1-in-2 Cold Winter Day**	1-in-10 Dry/Cold Year ***
	SUPPLY		
		NA	NA

* All core customers served; all noncore curtailed. **All Core and Noncore served. *** Previously 1-in-10 for firm noncore customers; firm noncore service discontinued.

Key objectives were ensuring that "there is sufficient firm interstate and intrastate pipeline capacity to serve California…[and that] the utilities and their customers would have access to natural gas supplies."[20]

The current reliability issues share a number of similarities to those addressed 16 years ago in

[20] Ibid., p. 4. One of the issues addressed was access to LNG facilities to import foreign natural gas to address shortages vs. the current focus on LNG facilities as an outlet for domestic oversupply.

R.04-01-025. The similarities include challenges to pipeline capacity and curtailments associated with aging infrastructure, as well as shifts in the nature of demand (i.e., the beginnings of issues which have now grown in magnitude concerning peaks associated with electric demand and heavily influenced by renewable output patterns). Significant differences relate to concerns regarding the anticipated growth in gas demand and declines in domestic supply. The 2004 California Gas Report projected average demand to have increased by 8.5 percent in 2020 from an average of 5,338 to 6,010 million cubic feet per day (MMcfd).[21] The projected growth has fallen significantly below the 2004 projections. The 2018 California Gas Report now projects 2020 average demand to be 5,564 MMcfd.[22] This projected demand represents an increase of less than half of a percent over actual demand and 446 MMcfd less than the 2004 report projected. In the meantime, concerns about constrained gas supply have disappeared as domestic supply has by 64 percent from 2004 to 2018.[23]

R.04-01-025 resulted in the CPUC adopting two decisions, D.04-09-022[24] which addressed supply reliability and D.06-09-039[25] which addressed physical reliability.

Supply Reliability Standards

The previous sections note the distinction between physical and supply reliability. In the case of supply reliability, the CPUC, in D.04-09-022 referred to the standard for supply reliability as a "capacity planning range." That same decision noted that the two major utilities use their own terminology for supply reliability standards. SoCalGas and SDG&E reference supply reliability as "Transportation Capacity Commitment Range." PG&E refers to it as the "Core Planning Standard." In this document the standard for supply reliability will be referred to as simply that, the supply reliability standard(s), independent of the differing terms used by the utilities and in the decisions.

D.04-09-022 notes that the underlying OIR and the decision supports a stated goal to:

> Ensure that adequate, reliable, and reasonably-priced electrical power and natural *gas supplies*, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers.[26]

The decision further states that, regarding supply reliability, "California utilities must rely upon firm transportation contracts with interstate pipelines… to preserve or provide for the infrastructure required to meet their core customers' annual demand."[27]

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[21] 2004 California Gas Report, Executive Summary, Consolidated Summary Tables, p.9.
[22] 2018 California Gas Report, Executive Summary, Statewide Consolidated Summary Tables, p. 17.
[23] EIA
[24] D.04-09-022: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/56349.PDF.
[25] D.06-09-039: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/60237.PDF
[26] D.04-09-022, p.2, emphasis added.
[27] Ibid., p.30.

SoCalGas/SDG&E Supply Standards

In determining the appropriate supply standards for SoCalGas/SDG&E, the CPUC expressed its overriding concern for adequate interstate capacity. It noted that the cost of contracting for that capacity was small compared to the costs of purchasing gas on the spot market when supplies are tight. The decision determined that the amounts then being contracted for by SoCalGas/SDG&E could equal less than 100 percent of annual average daily demand and, as a result, did not meet the objective of adequacy. It commented that there was "little rationale" for targets that could result in reliance on the spot market for what could be between 10 and 20 percent of demand.

To address what was considered overreliance on the spot market, D.04-09-022 defined a range for SoCalGas that "set the minimum at the annual average daily amount and the maximum at 120 percent of the annual average daily amount…."[28] The range applies to both the winter and summer seasons. The average daily amount was to be based on the utility's forecasted average temperature year. The decision does not explain the choice of the specific maximum of 120 percent. The same range was adopted for SDG&E.

PG&E Supply Standards

D.04-09.022 rejected two standards proposed by PG&E, stating the company "failed to firmly establish the bases for either standard or explain how they are used to determine the target capacities." The decision noted that, unlike SoCalGas/SDG&E, which had proposed inadequately low standards, PG&E proposed levels that were above identified peak demand and failed to substantiate the need for standards that were higher than peak. In response, the decision first established a range for winter. That range was anchored by the company's then-existing interstate pipeline capacity. This capacity, 962 MMcfd, was already 116 percent of the projected average daily demand (and the decision noted that it did not make sense to change contracted capacity). To fix the other end of the range the decision increased the minimum of 962 by 10 percent, resulting in a maximum of 1,058 MMcfd. This maximum equated to 127 percent of the average daily demand. The decision noted that the top of this range was "close to PG&E's estimated cold winter average daily amount of 1,084 MMcfd." The decision adopted a lower bound for summer equal to 90 percent of the forecasted average demand and applied the winter maximum. This resulted in a summer range of 746 to 1,058 MMcfd.

Supply Standards—SoCalGas/SDG&E vs. PG&E

For comparison purposes Table 2 below summarizes and compares the supply reliability standards for both utilities required by D.04-09-022. For the comparison, the standards are expressed as a percent of average daily core demand. While the percentages are similar, they are not the same (differing in the beginning and end points as well as the spread between the points). The decision did not provide the logic for applying differing standards across the utilities nor does one appear to exist elsewhere. Further there does not appear to be any information concerning the actual impact, i.e.,

[28] Ibid., p.31.

whether the similarities in the standards produce similar results in the frequency of curtailments across the utilities.

Table 2: Supply Reliability Standards (% of avg. daily demand)

Supply Reliability Standards			
		% of Daily Avg. Core Demand	
		SoCalGas /SDG&E	**PG&E**
Winter	Minimum	100	116
	Maximum	120	127
Summer	Minimum	100	90
	Maximum	120	127

Physical Reliability Standards

Decision 06-09-039 provides the foundation for the current key standards for physical reliability.

Backbone Transmission Standards—PG&E and SoCalGas

D.06-09-039 begins with a discussion titled "Measuring Infrastructure Adequacy for Natural Gas Utilities." It first focuses on backbone capacity with the question "How much backbone pipeline capacity is enough?"[29] Ultimately the decision concludes that each utility should have physical capacity, through its backbone transmission system, to serve combined core and noncore customer demand on an "average day during a challenging year." A "challenging year" was considered to be one that combined specific temperature and wet vs. dry conditions. Temperature was considered to be the primary factor driving demand with wet vs. dry consideration determined by the availability of hydroelectric power—and the consequential need for gas to offset a decline in available hydroelectric power during a dry year. Specifically, both PG&E and SoCalGas were to have enough backbone transmission capacity to serve combined average core and noncore customer demand assuming a year that is "both the coldest and driest [least hydroelectric generation] one in ten years."[30]

The standards adopted were appropriate to existing conditions. However, given changes over time, the CPUC has determined that a reexamination of the standards is appropriate.[31] When the existing standards were adopted, there do not appear to have been analyses conducted or made explicit concerning the relative impacts of one standard versus another (e.g. economic or health impacts of curtailments, cost/benefit analyses, number of customers impacted, and the sensitivity of the

[29] D.06-09-039, p.8
[30] Ibid., p. 24. Note that in quantifying the standards the utilities comment that the cold/dry combination seldom occurs. As a result, they base the demand on a model combining data from a cold year and a dry year.
[31] R.20-01-007 is examining multiple issues related to reliability and reliability standards.

standards to those factors that may be able to demonstrate and allow for evaluation of the impact of adopting a 1-in-10 versus some alternative standard). In fact, the decision acknowledged that there was "nothing scientific about choosing a 1 in 10 year standard…"[32] The need for this analysis may be may be more relevant today given slower growth in demand, more frequent peak demand requirements, and potential impacts on gas infrastructure related to the state's decarbonization efforts.

Local Distribution Standards—SoCalGas/SDG&E

Local distribution standards for SoCalGas and SDG&E were defined in D.02-11-073. The decision was in response to "a gas transmission crisis in San Diego Gas and Electric Company's service territory that resulted in 17 days of curtailed service to firm noncore customers and threatened California's energy supply."[33] The crisis was driven by high gas demand on the SDG&E system during the summer of 2000 and curtailments of service to noncore customers during the winter of 2000-01. Ultimately for both SoCalGas and SDG&E the decision maintained the then-applicable local distribution standard for core customers of 1-in-35 cold year/peak day. The decision also required both SoCalGas and SDG&E to follow a 1-in-10 year cold year standard for noncore customers.[34, 35]

Local Distribution Standards—PG&E

In A.01-01-011, PG&E sought to mirror the local distribution standards adopted for SoCalGas and SDG&E in D.02-11-073. In response, the CPUC, in D.03-12-061, rejected the PG&E proposal for four reasons. First, the PG&E proposal relied primarily on the fact that the CPUC had approved the same standards for SoCalGas/SDG&E. In the words of the decision, "PG&E provided very little support to justify why a proceeding investigating a specific set of circumstances in Southern California should be applied equally to PG&E."[36] Second, replicating the standards across both core and noncore customers (as PG&E proposed) would require very significant investment. Third, PG&E was in bankruptcy court, and the court had not yet addressed the issue of whether the CPUC would continue to have jurisdiction over the utility's transmission system. Lacking clarity, the CPUC was reluctant to approve the expenditures that would be needed to meet the new standard. Finally, while it was certain that the magnitude of the expenditures would be significant, there was a high degree of uncertainty about how high those expenditures might become. Instead of adopting the proposal, the decision maintained the existing standards noting that "the current design criteria for PG&E's transmission system is to meet the more stringent of (a) core demand under APD [abnormal peak demand] conditions, which is a 1-in-90 year cold temperature event, or (b) 75 percent of core's APD demand plus all noncore demand, which is about a 1-in-3 year cold temperature event."[37]

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32 D.06-09-039, p.25.
33 D.02-11-073, p.2. The decision notes that the crisis of 2000 was confined to SDG&E and did not include SoCalGas.
34 Ibid., pp. 48-49 Ordering Paragraphs 1 and 10.
35 In a response dated May 30, 2019, to an Energy Division data request, SoCalGas elaborated on its standards stating that "SoCalGas and SDG&E plan its…distribution systems to meet two winter demand-based conditions. Service to all customers (core and noncore) is to be maintained under a 1-in-10 year cold day temperature condition, and service to core customers (with all noncore customers curtailed) is to be maintained under a 1-in-35 year peak day temperature condition."
36 D.03-02-061, p. 53.
37 Ibid., p. 54.

Cold/Dry Year vis-à-vis Peak Day

D.06-07-039 adopted backbone transportation standards for a 1-in-10 cold/dry year. By itself this does not address the peaks that may occur within such a year, i.e., a challenging day in a challenging year. The decision recognized this and made "explicit that the utilities plan their backbone and storage so as to meet the peak day criteria already in place for their local transmission systems."[38] The decision repeated this requirement in the Findings of Fact numbers 5, 6, and 7:

5. 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.
6. It is reasonable to require that each of the utilities plan its backbone system to meet one-in-ten year cold and dry conditions.
7. It is reasonable to require that each of the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems.[39]

Slack Capacity

In addition to the 13 measures listed in Table 1, multiple decisions reference, and two decisions in particular discuss, the concept of "slack capacity."[40] Notably while the concept of slack capacity on a systemwide basis that would include storage was referenced, the decisions focused their discussions and ultimately their measures of slack solely on intrastate pipeline capacity. D.02-11-073, which addressed both backbone and local distribution requirements, also addressed the issue of slack capacity in the context of the curtailments of 2000. The decision references slack capacity as providing "capacity that is available to accommodate scheduled and unscheduled outages, higher than anticipated peak demands, and increases in new and existing customers' demands."[41] However, after discussing the concept of slack, D.02-11-073 declines to adopt mandatory slack capacity requirements for SDG&E and SoCalGas. Instead it required that the utilities meet 1-in-10 and 1-in-35-year backbone capacity requirements, noting that these would provide for slack capacity without resulting in "excess" slack capacity and the costs associated with excess.

The second decision, D.06-09-039 asked "how the designated utilities should provide emergency reserves consisting of *slack intrastate pipeline capacity…*"[42] The decision notes differences in the methodology used by the utilities to determine slack capacity. Specifically, it states that SoCalGas based its calculations of slack on average daily demand, while PG&E determines slack based on a 1-in-10

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[38] D.06-09-039, p. 27. The decision referenced those requirements in a footnote to that page which stated: For SoCalGas and SDG&E, this is one event in 35 years for core customers and one event in ten years for firm noncore customers. For PG&E, the standard is one event in 90 years for core customers and one event in three years for the noncore.
[39] Ibid., p. 171
[40] Slack capacity is discussed in D. 02-11-073 and more specifically in D.06-09-039.
[41] Ibid., p. 9.
[42] D.06-09-039, p. 5

cold/dry year. And, it notes its preference for basing the analyses on a 1-in-10 cold/dry year demand. However, the decision concludes that the differing methodologies ultimately yield essentially equivalent results.[43] Further, the decision did not require that a specific level of slack be maintained or targeted by the utilities, noting that the then-current slack capacity appeared sufficient. The decision did require that PG&E and SoCalGas file biennial advice letters indicating the current and projected level of slack.

The required advice letter filings eliminated the inconsistency in the measurement of system demand—both now use the average daily demand for a 1-in-10 cold dry year, and both rely on the California Gas Report (CGR) as the source of that data. However, PG&E calculates slack as the *percentage of total receipt capacity that would be used by demand in a 1-in-10 cold/dry year*. The calculation is the division of the average daily demand in a 1-in-10 cold/dry year by the total receipt capacity. The result is the average daily capacity demand expressed as a percent of the capacity available. SoCalGas in its calculation of slack uses what is essentially the inverse of the PG&E methodology. SoCalGas determines slack as the *amount of additional demand that could be accommodated by the system on in a 1-in-10 cod/dry year. It expresses this amount as a percent of the demand in a 1-in-10 cold/dry year.* Their result is calculated by subtracting the average daily demand in a 1-in-10 cold/dry year from receipt capacity and dividing the result by that same average daily demand.

The following Tables 3 and 4 and associated graphs show the results of applying the PG&E calculation methodology to both itself and SoCalGas and conversely applying the SoCalGas methodology to PG&E.

[43] Ibid., p. 26. The Decision comments that the target amounts of slack as differently measured ultimately end up approximating each other. SoCalGas reported a target level of slack at 20–25 percent above average annual demand in an average temp and hydro year. When these results were applied to a 1-in-10 cold, dry year they yield a slack capacity of between 11 and 16 percent. PG&E proposed an annual capacity utilization of 80 to 90 percent, which yields a slack capacity of between 11 and 16 percent when measured against a 1-in-10 cold dry year. The decision notes that, "Both proposals appear to be virtually equivalent."

Table 3: Slack Using PG&E's Methodology

	PG&E			**SCG**		
Report/ Demand Year	1in10 Cold Dry Yr Demand	PG&E Receipt Capacity	**Capacity Utilization**	1in10 Cold Dry Yr Demand	SCG Receipt Capacity	**Capacity Utilization**
2008/09	2341	3249	**72%**	2825	3875	**73%**
2010/11	2349	3223	**73%**	2673	3875	**69%**
2012/13	2266	3098	**73%**	2759	3875	**71%**
2014/15	2308	3130	**74%**	2899	3875	**75%**
2016/17	2040	3082	**66%**	2787	3875	**72%**
2018/19	2271	3103	**73%**	2715	3080	**88%**

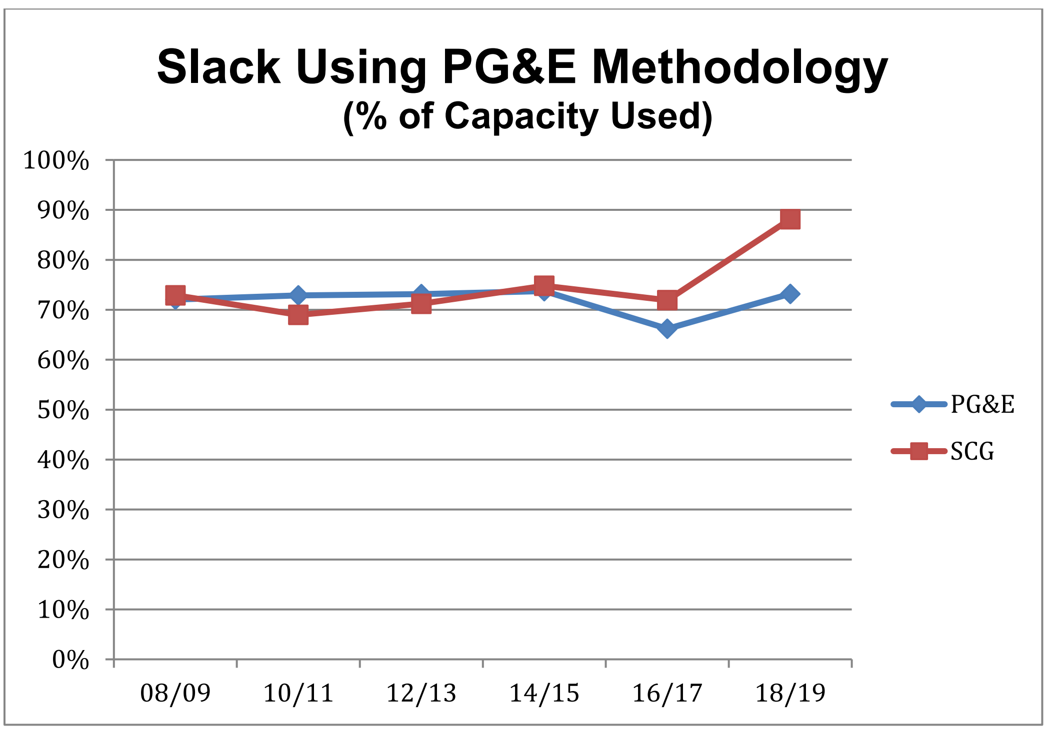
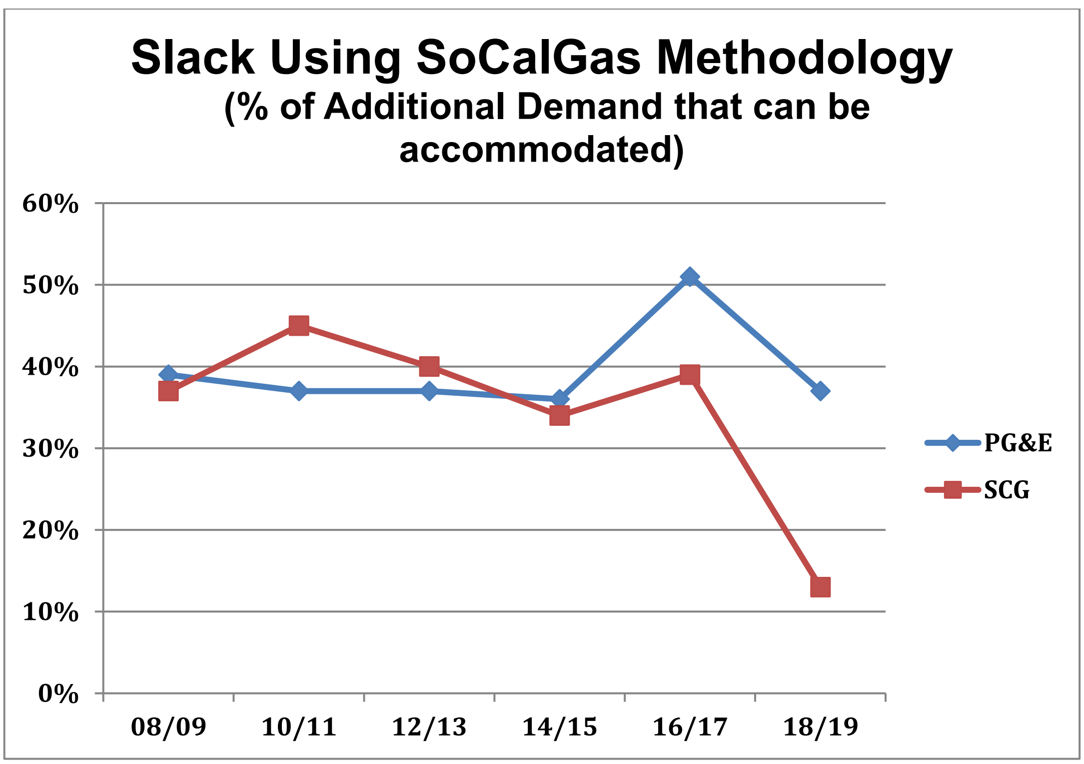


Table 4: Slack Using SoCalGas' Methodology

	PG&E			SCG		
Report/	1in10 Cold	PG&E		1in10 Cold	SCG	
Demand Year	Dry Yr Demand	Receipt Capacity	**% Addit'l Demand***	Dry Yr Demand	Receipt Capacity	**% Addit'l Demand***
2008/09	2341	3249	**39%**	2825	3875	**37%**
2010/11	2349	3223	**37%**	2673	3875	**45%**
2012/13	2266	3098	**37%**	2759	3875	**40%**
2014/15	2308	3130	**36%**	2899	3875	**34%**
2016/17	2040	3082	**51%**	2787	3875	**39%**
2018/19	2271	3103	**37%**	2715	3080	**13%**



Independent of the methodology used, the decision did not determine a defined level of slack that the utilities were to maintain. Further it stated that there was "no quantifiable basis upon which to decide the 'right' number."[44]

The concept of slack is essentially another way of looking at the utility's physical system capacity available to meet extreme days in a cold dry year. Conversely, it provides a way of understanding in a broad sense how much of the system's physical capacity could be out of service before it could not meet the 1-in-10 standard. However, the way in which slack is calculated and reported (every two years) is not dynamic and does not incorporate outages that occur in the interim period between reports. By way of example, significant sustained outages on the SoCalGas system that reduced capacity by 20 percent of what was reported in 2016 were not reflected until the 2018 report. Additionally, the current concept of slack does not capture the critical role of storage.

III. Summary: Defining and Measuring Reliability

Currently there is not a guiding definition of reliability for California's gas utilities. Rather, reliability is represented in 15 different standards applied across PG&E and SoCalGas/SDG&E. The standards apply separately to supply and infrastructure (and within infrastructure to backbone and distribution), customer group, and season and differ by utility. There are no clearly articulated empirical bases underlying a specific standard. The current standards originated during the energy crisis of the late 1990s and early 2000s. They have undergone what has largely been incremental change and, while not the subject of this paper, the system with these standards has been, in aggregate, functional. However, it is not clear whether these standards are adequate for conditions today. Additionally, more recent events (San Bruno, Aliso Canyon, SoCalGas pipeline outages, etc.) support a critical examination of the current standards.

[44] Ibid., p. 25.

Appendix A: Glossary of Reliability Decisions

D.86-12-009

Defines "Core Gas Customers"

Core Customers are defined by their annual/monthly natural gas usage. Core referred to any customers using less than 250,000 therms annually. The definition was based on a prior year decision, D.85-12-102, which set what was called a "transportation" rate. The rate was designed to encourage growth of the then-burgeoning enhanced oil recovery (EOR) industry. The CPUC determined that a rate beginning at the 250,000 threshold would increase competition between PG&E and SoCalGas to extend their pipelines into Kern County, thus providing natural gas transportation to these EOR firms, who could procure their own natural gas. The CPUC then applied the 250,000 therms as the new threshold of "core," which meant all residential and most small-commercial customers were characterized as "core," but the category also included some larger commercial and industrial customers.

Note: The utilities provide definitions of core and noncore customers in the California Gas Report. The definitions are consistent with the definition for core in D.86-12-009.

D.87-12-039

Defines "Cold Year" and Further Defines Core Customers

- **Cold Year** definition adopted by the decision *for cost allocation* is "Two standard deviations from the mean (One year in 35)." Noted that this is the definition of a cold year based on the testimony of the of the utilities and that it is consistent with the filings made with other state agencies such as the California Energy Commission. The decision states that "this definition is also more reasonable for system planning purposes." It notes that, "The definition will be consistent for all three utilities…".
- **Core Customer** was further defined as customers without the financial flexibility to purchase gas from other than the utility. (Note that other decisions state that gas is available to core customers only through utility-owned pipes).

D.90-09-099

Defines the Required *Interstate* Pipeline Capacity for SoCalGas

The required *interstate* pipeline capacity is that needed:

"(1) to serve 'cold year' requirements of core customers, and

(2) to provide a reasonable allowance for company use and lost and unaccounted for gas.

The calculation of the amount of capacity to be reserved for the core market shall also take into account the capacity needed to have sufficient gas in storage to serve core peak day and cold year winter season requirements."

This concept concerning the interstate pipeline capacity requirement is essentially the equivalent of **supply reliability** (vs. infrastructure reliability) or the core reliability planning standard later defined 16 years later in footnote 3 of D.06-07-010.

D.02-06-023

Further Defines Core Customers

References core customers as "**those who lack alternatives to natural gas service** such as residential and small commercial customers." This is similar to the distinction made in D.87-12-039. The decision also, as part of the settlement regarding the gas cost incentive mechanism (GCIM), defined SoCalGas storage levels for core at 70 +/- 5 billion cubic feet (Bcf) by November 1.

D.02-11-073

Adopts System Planning Criteria and Reliability Standards for SDG&E and SoCalGas

References reliability in terms of the number of curtailments in a defined number of years. The decision declines to adopt a mandatory "slack capacity" requirement.
The decision also recaps the history of SDG&E reliability standards noting that D.97-04-082 required that SDG&E provide a noncore reliability standard for firm service customers that "reflects the level of service its system is able to provide." In response, SDG&E "filed a reliability report based on *1 curtailment in 5 years* (1-in-5) firm noncore reliability standard."

- The decision references SDG&E's newly adopted reliability standard for firm noncore service of 1-in-10, cold year conditions." P.8. Following on page 9, it references "SDG&E's *standard of one curtailment in every 10 years, normal weather conditions with each such curtailment lasting no longer than 3 days, (1-in-10)."*
- The CPUC states that SDG&E should adopt a 1-in-10 (one curtailment in ten years), cold year conditions reliability standard.
- The CPUC specifically does not adopt a mandatory slack capacity requirement. The decision states on page 9, regarding slack, " In balancing the concerns over who pays for this excess capacity against the increased reliability the excess provides, the Commission finds it is in the interest of all gas transmission users to adopt a 1 – in – 10 …, cold year conditions, reliability standard for SDG&E. With this standard, the Commission will not adopt a mandatory slack capacity requirement."
- The decision notes that "If SDG&E expands its system to meet a 1-in-10, cold year reliability standard, for even its firm noncore customers, SDG&E's transmission system infrastructure should be adequate to meet the needs of both its core and noncore customers." pp. 9-10.

- The decision adopts a Service Interruption Credit (SIC) aka curtailment credit to compensate customers if SDG&E fails to meet its service reliability requirements (SoCalGas had previously been subject to a SIC as part of Gas Rule 23).
- Decision determined that SDG&E will not charge the same for firm and interruptible service.
- Decision adopts "a system planning criteria for SoCalGas of 1-in-10 for noncore customers, and… maintain(s) a 1-in-35 for core customers for *local transmission*." The decision notes that this should ensure adequate transportation capacity without burdening any customers with the cost of excess slack capacity. Order number 10 reads, "The reliability standard of 1-in-35 for core customers, 1-in-10 for noncore customers, *and 1-in-35 for core local transmission customers is adopted for SoCalGas."*
- Decision also notes on pp. 37-38 that, "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…."

D.03-12-061

Maintains PG&E's Existing Reliability Standards for Local Distribution System.

This decision determined that PG&E did not provide sufficient reasons for changing its local reliability standards to mirror those of adopted for SoCalGas/SDG&E in D.02-11-073. Additionally, it noted that there was no assurance that the utility, then in bankruptcy, would remain under the jurisdiction of the CPUC and thus the CPUC should not approve changes that would result in significant costs. It also required that the then-current standards for local distribution be maintained, i.e., 1-in-90 cold year event for core customers.

D.04-09-022

Avoiding a Future Natural Gas Shortage

The rulemaking and decision are intended to further the goal of the Energy Action Plan to:

> "Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers."

The decision defines a "capacity planning range" (which corresponds to the concept of "supply reliability" in D.06-07-010*).* Supply reliability considers the amount of gas necessary to meet demand. The decision notes that "it is within these ranges that the utilities propose to establish their pipeline and storage capacity portfolios for core customers."

- For SoCalGas and SDG&E supply reliability is referred to as the "Transportation Capacity Commitment Range." The decision notes that "it is within these ranges that the utilities propose to establish their pipeline and storage capacity portfolios for core customers."
- The decision determined that SoCalGas and SDG&E should plan for a range of capacity for contracted interstate pipelines equal to the annual average daily amount of demand for a forecasted average temperature year at the minimum and 120% of the average at the maximum. This range would apply to both summer and winter months.
- For PG&E supply reliability is referred to as the "Core Planning Standard." The decision set, for winter months, a minimum above the forecasted average demand at 962 MMcfd (the minimum was already above the average and the CPUC declined to reduce it) and a maximum of 110% of the minimum. For the summer the minimum was set at 90% of the average daily demand.

D.06-07-010

Defines a Distinction Between Supply Reliability and Physical Reliability

The decision addresses Ordering Paragraph 5 of D.04-09-022.

- Supply reliability or the core reliability planning standard "addresses the amount of gas supply the utility (in this case PG&E) is to have available to meet core demand…. This reliability planning standard is a function of the underlying gas market and relates to the ability of the end user to acquire sufficient supplies to meet its demand." It includes factors such as firm capacity on interstate pipelines, storage withdrawal capacity and dedicated gas in storage
- "Physical system reliability pertains to the engineering design standard of the pipelines and related facilities that make up the transmission system. The physical system reliability of the transmission system is defined by the maximum volume of gas that can be transported over the system."

The decision focused on setting the reliability planning standard, i.e. the reliability of supply. It resulted in PG&E acquiring additional third-party storage capacity needed to meet the standard.
A 1-in-10 peak day core reliability standard was to be used to determine the level of intrastate pipeline capacity, firm storage withdrawal capacity, and incremental storage withdrawal capacity that the core should hold to meet peak day demand and to meet the local transmission capacity standards of Abnormal Peak Day and Cold Winter Day.

D.06-09-039

Establishes a Backbone Transmission Planning Standard and Finds Slack Capacity Adequate

This decision:

- Defined slack capacity (inferred from p. 26) as the margin above the level of expected annual average demand during an average temperature year and normal hydroelectric conditions.
- Accepted "slack" capacity ranges for backbone capacity as proposed.
- Found adequate SoCalGas' "slack" capacity on backbone system of 20-25% above average system total demand during an average temperature year and normal hydro conditions
- Found that PG&E's "slack" should be sufficient to result in 80-90 percent utilization factor under cold temperature and dry hydro conditions. This is equivalent "of an 11%-25% average surplus capacity during a cold and dry year"
- States the following with regard to the 1-in-10 standard (p. 25):
    - "There is nothing scientific about choosing a 1-in-10 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. The system must serve demand every year, not just during an average one. Looking at severe weather conditions over a rolling ten-year period appears adequate. It is reasonable to require that each of the utilities (PG&E, SoCalGas, and SDG&E) to plan for one-in-ten year cold and dry conditions, and we will direct them to do so."
- Notes that utilities say they maintain a 40%-50% level of slack and have taken different approaches in getting there (SCG & SDG&E use average annual demand; PG&E uses cold temp, dry hydro) and that the CPUC prefers PG&E's one-in-ten year cold and dry year.
- States the following about slack capacity: "While the slack capacity proposals appear reasonable and enjoy the support of many parties, we still have no quantifiable basis upon which to decide the 'right' number." p. 171 Finding of Fact 11.
- States on pps. 26-27: "We will direct the utilities to assure adequate backbone transmission capacity under one-in-ten year cold and dry conditions. We will also make explicit the requirement that the utilities plan their backbone and storage so as to meet the peak day criteria already in place for their local transmission systems." Footnote 20 references local transmission systems as "For SoCalGas and SDG&E, this is one in 35 years for core customers and one event in ten years for firm noncore customers. For PG&E, the standard is one event in 90 years for core customers and one event in three years for the noncore."
- States on pps. 49-50: "The Commission requires SDG&E and SoCalGas to apply the following planning criteria to their local transmission systems: the systems must be designed to provide service to core customers during a 1 – in – 35 year cold day event *(one curtailment event in 35 years)* and service to firm non-core customers during a 1 – in – 10 year cold day event *(one curtailment event in 10 years).*" This comes from D. 02-11-073.
- States that SoCalGas/SDG&E, "… must continue to study and report on the adequacy of their entire system, including local transmission, and act to ensure that it remains reliable." p. 61.

- Comments on reliability of supply and infrastructure in Findings of Fact 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."
- Notes the role of storage in Findings of Fact 5: "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."
- States in Finding of Fact 6: "It is reasonable to require that each of the utilities plan its backbone system to meet one-in-10 year cold and dry conditions."
- States in Finding of Fact 7: "It is reasonable to require that each of the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems."
- States in Finding of Fact 18: "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."
- States in Finding of Fact 74: "The intrastate pipeline systems are complex, and the gas flows change constantly based on shifts in supply and demand."

D.06-10-029

Defines Summer and Winter Core Storage Requirements for SoCalGas

Decision approved a Joint Recommendation by the Division of Ratepayer Advocates (DRA, now Public Advocates), The Utility Reform Network (TURN), and SoCalGas regarding the use of storage capacity for core customers. "The Joint Recommendation requires more gas to enter storage during the summer for core customer winter heating season use." It set a July 1 storage target for SoCalGas core customers of 49 Bcf.

D.07-12-019

Defines Mid-Season Storage Targets for SoCalGas

Decision maintains use of mid-season storage targets consistent with D.06-10-029, setting minimum mid-season rather than monthly storage targets for core. Targets were set for the combined SoCalGas/SDG&E portfolio, including targets for injection and withdrawal capacity (see p. 26). The decision also:

- Required that SoCalGas obtain agreement from DRA and TURN "for mid-season core-purchased inventory targets which must be met…."
- Established core storage injection and withdrawal capacity of 369 MMcf/d and 2,225 MMcf/d respectively and a combined SoCalGas/SDG&E core storage inventory capacity of 79 Bcf;
- Combined the SoCalGas and SDG&E portfolios;

- Subjected all customers to imbalance requirements and Operational Flow Orders (OFOs);
- Reorganized the role of the System Operation.

D.15-10-050

Updates Supply Reliability Requirements and Bases Requirements on Mid-Season Demand

Decision "establishes a new core interstate pipeline capacity planning range." It updates the ranges set in D.06-10-029 and D.07-12-019. The targets were set for the combined SDG&E/SoCalGas portfolio including targets for gas storage injection and withdrawal capacity.

D.16-07-008

Ends the Distinction Between Firm and Interruptible Service for SoCalGas

Decision adopted the "Curtailment Procedures Settlement Agreement" that eliminated the distinction between firm and interruptible noncore service for SoCalGas' noncore customers as part of overall changes to the rules governing curtailments.

D.19-09-025

Incorporates Inventory Management and a "Reserve Capacity" for PG&E

Decision adopts PG&E's Natural Gas Storage Strategy (NGSS).

- The NGSS reduces overall storage capacity consistent with the declining need for storage as a price hedge and the increased cost of maintaining storage under new, stricter state regulations. Prior to adopting the NGSS, PG&E used core gas in storage on behalf of both core and noncore customers to help balance fluctuations in intraday gas demand and reduce the need for curtailments of noncore customers. Additionally, core capacity was used to respond to equipment outage-related supply issues. The storage costs were borne solely by core customers, and noncore customers bore none of the costs associated with this practice.
- As an outcome of the NGSS, core gas storage was reduced and no longer available for balancing. To compensate for this reduction, PG&E would, in order to meet its reliability standards, maintain an amount of storage capacity designated as Inventory Management. The costs of Inventory Management would be shared across core and noncore customers.
- The decision determined Inventory Management "…is a reasonable approach for PG&E to use to manage intra-day and day-ahead inventory fluctuations on its integrated gas pipeline and storage system. As part of the NGSS, the unused inventory, financed by core customers, that PG&E previously used to manage intraday inventory will no longer be available for that purpose. Thus, setting aside storage and pipeline capacity to provide that function is reasonable."[45]

[45] D.19.09.025, see pps. 23-24, 34 and 40.

- Additionally, the decision allows for "Reserve Capacity." Similar to Inventory Management, Reserve Capacity is designed to recognized that the reduction in storage capacity also reduced the ability to access "unused core inventory that PG&E previously used to resolve supply issues caused by equipment outages…."[46] The decision endorsed Reserve Capacity noting that "With the implementation of the NGSS, the unused core inventory that PG&E previously used to resolve unplanned supply shortages will no longer be available. Thus, setting aside storage capacity to resolve significant supply problems is reasonable."[47] As with the Inventory Management, what was previously a cost solely for core is now shared with noncore.
- The decision notes that to be reliable PG&E must "be able to meet load requirements for gas service on a day when there is a high customer demand for gas, a major system outage on its gas transmission system and a significant storage inventory imbalance." It states that the proposed inventory management and reserve capacity elements are necessary and consistent with meeting the 1-in-10 winter demand standard.
- The decision notes that PG&E should examine its curtailment process as an opportunity to help manage its reliability.

[46]Ibid., p.35.
[47] Ibid., p. 40

Reliability Topic Cross Reference

DECISION SUBJECT CROSS REFERENCE		
Subject Matter/Terms	**Decisions**	**Comment**
Core Customer Definition	D.86-12-009 D.87-12-039 D.02-06-023	
1-in-10 Year Standard	D.02-11-073 D.06-09-039	
Cold Year (1-in-35) Standard	D.87-12-039 D.87-12-039 D.02-11-073 D.06-09-039	
Average Temperature Year	D.04-09-022	
Abnormal Peak Day	D.06-07-010	
Cold Winter Day	D.06-07-010	
Dry Hydro Year	D.06-09-039	
Supply Reliability	D.87-12-039 D.04-09-022 D.06-07-010 D.15-10-050	“Core Planning Standard”

DECISION SUBJECT CROSS REFERENCE,	contd.	
Subject Matter/Terms	**Decisions**	**Comment**
Physical System Reliability	D.06-07-010	Physical System Reliability defined
Storage Levels	D.87-12-039 D.06-09-039 D.06-10-029 D.07-12-019 D.15-10-050	Injection and Withdrawal levels
Slack Capacity	D.02-11-073 D.06-09-039	
Backbone Capacity	D.06-09-039	

Reliability Related Resources

California Gas Report

- Region and utility specific review of gas supply and operations for most recent year and historical and forecast data. Published biennially (even years) and supplemented in off years.
- Definitions of core and noncore customers (2018 Glossary and prior year reports)
  - Core: SoCalGas/SDG&E: "All residential customers; all commercial and industrial customers with average usage less than 20,800 therms per month who typically cannot fuel switch. Also, those commercial and industrial customers (whose average usage is more than 20,800 therms per year) who elect to remain a core customer receiving bundled gas service from the LDC [local distribution company]."
    PG&E: "All customers with average usage less than 20,800 therms per month."
  - Noncore: "Commercial and industrial customers whose average usage exceeds 20,800 therms per month, including qualifying cogeneration and solar electric projects. Noncore customers assume gas procurement responsibilities and receive gas transportation from the utility under firm or interruptible intrastate transmission arrangements."

California's Natural Gas System: Regulatory Response to Market Changes

California Public Utilities Commission, Policy & Planning Division; Stephen St Marie, Ph.D., Maria Zafar, April 7, 2015. https://www.cpuc.ca.gov/General.aspx?id=6953

(END OF ATTACHMENT 2)