



BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

FILED
08/14/20
04:59 PM

Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning.

Rulemaking 20-01-007

(Filed January 16, 2020)

COMMENTS OF THE INDICATED SHIPPERS IN RESPONSE TO JULY 31, 2020
ASSIGNED ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENTS

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August 14, 2020

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Pursuant to the July 31, 2020 *Assigned Administrative Law Judge's Ruling Seeking Comments* (Ruling), the Indicated Shippers¹ submit these comments responding to the questions in the Ruling.

I. INTRODUCTION

The Indicated Shippers appreciate the California Public Utilities Commission's (Commission or CPUC) collaborative process in developing the record for its consequential decisions on the short, mid- and long-term future of the natural gas system. In evaluating next steps, care must be taken to correctly identify both the problems to be solved, and red herring issues to be avoided. The Commission should focus on reasonable, pragmatic solutions in this time of long-term transition, and avoid seismic, unnecessary changes that could lead to stranded infrastructure, unintended consequences, or both. The pragmatic, reasonable solutions should include consideration of continued, appropriate use of Aliso Canyon.

¹ The Indicated Shippers represent the following companies in this proceeding: Aera Energy LLC, California Resources Corporation, Chevron U.S.A. Inc., ConocoPhillips, PBF Holding Company, Phillips 66 Company, and Tesoro Refining & Marketing Company LLC.

Critically, in the context of the gas and electric price spikes in the summer of 2018, evidence points to the constraints on SoCalGas's system, including limitations on Aliso Canyon and months-long pipeline outages, as significantly contributing to reduced system capacity. These reductions in capacity led to increased gas prices, which in turn led to increased electricity prices. In such a situation, not only are customers not receiving the service they are paying for, but the utility is not meeting standards for reliability. During the same time period, SoCalGas' shareholder earnings exceeded the authorized Return On Equity (ROE). In this context, it would be reasonable to consider one-way financial incentives for shareholders to encourage compliance with established standards. The utilities must be held accountable for meeting the reliability standards set by this Commission.

In addition, the question of costs, cost allocation, and cost recovery must also be addressed, carefully and thoughtfully. The Track 1 workshops and the Ruling do not directly address Scoping Ruling issue 2.1.5, "Will the updated reliability standards result in additional costs and if so what cost recovery and allocation mechanisms should be used?"² Yet cost allocation and recovery affect almost every proposal and question raised in this proceeding. Critical cost issues must be at the forefront of the Commission's consideration throughout Track 1 and Track 2, as well as pragmatic solutions that make reasonable use of existing infrastructure. As the California Council on Science and Technology (CCST) concludes, "replacing underground gas storage would be very expensive and nearly impossible to do in the near term."³

² *Assigned Commissioner's Scoping Memo and Ruling*, April 23, 2020, at 4.

³ Track 1B PowerPoint Presentation Materials: Market Structure and Regulations, July 21, 2020 (Track 1B Presentation) at 87 (CCST/Long).

II. RESPONSES TO QUESTIONS

1. *Cal Advocates, TURN, and other consumer advocate groups: Given the high gas and electricity costs incurred during tight conditions on the SoCalGas system in 2017 and 2018, what changes, if any, should be made to the existing reliability standards? (Track 1A, Scoping Memo Issues 1, 1a-c, 2 and 2a).*

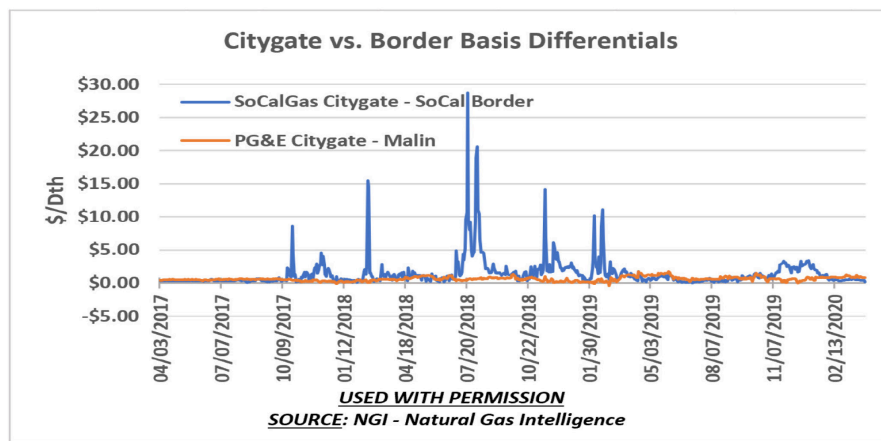
The high gas and electricity costs incurred during tight conditions on the SoCalGas system in 2017 and 2018 are concerning, but using those costs as a reason to change the current, long-standing reliability standards is questionable. In fact, none of the presenters at the Track 1A workshop observed a causal relationship between the reliability standards and the gas and electric price spikes. In considering how to prevent another price spike, reliability standards should not be the focal point of the Commission's scrutiny.

Rather, far more evidence points to the limited use of Aliso Canyon and concurrent pipeline outages on SoCalGas's system as the contributing factor.⁴ During the Track 1A workshop, Ms. Yap, on behalf of the Indicated Shippers and the Southern California Generation Coalition (SCGC), analyzed the differences between the market reactions in northern and southern California during the summer of 2018 "when demand exceeded flowing supplies." Ms. Yap's graphic shows the price differential, below.⁵

⁴ See *Aliso Canyon Working Gas Inventory, Production, Capacity, Injection Capacity, and Well Availability for Reliability, Summer 2018 Supplemental Report*, issued by the CPUC pursuant to Pub. Util. Code § 715, July 6, 2018, at 4; see also *Summer 2019 SoCalGas Conditions and Operations Report* issued by CPUC staff, July 20, 2020, at 12 and 15-16 (observing the impacts of major pipeline outages, including the significant outages on Lines 235, which started on October 1, 2017, and 4000 that reduced receipt point capacity and inventory).

⁵ Track 1A PowerPoint Presentation Materials: *Natural Gas Reliability Standards*, July 7, 2020 (Track 1A Presentation) at 134 (Indicated Shippers and SCGC/Yap).

What did we see in the summer of 2018 when demand exceeded flowing supplies?



Ms. Yap rightly concluded that this stark difference was caused by the fact that SoCalGas “had significant constraints on storage availability” where “PG&E had multiple storage fields on its system with unconstrained access.”⁶ Ms. Yap also observed that the California Independent System Operator’s Market Monitoring Department concluded that “the gas costs in SoCalGas’ service territory set electricity prices.”⁷ Her graphic demonstrating this point is shown below.⁸

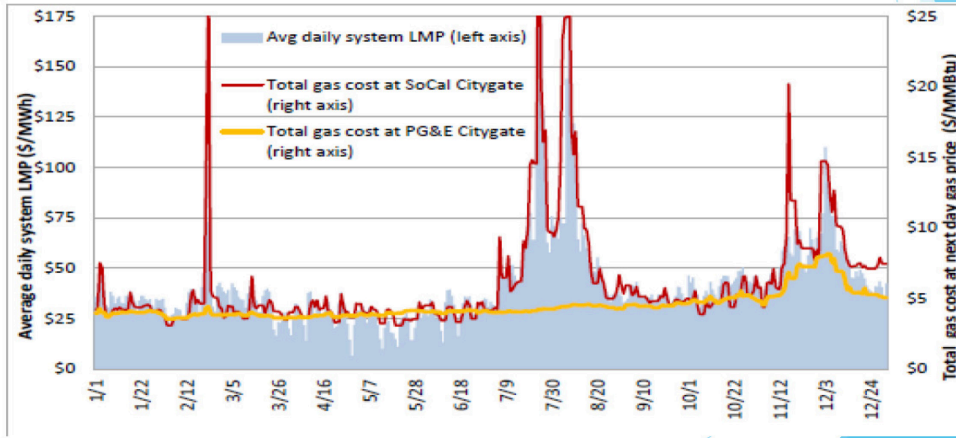
⁶ Track 1A Presentation at 137 (Indicated Shippers and SCGC/Yap).

⁷ *Id.* at 140 (Indicated Shippers and SCGC/Yap).

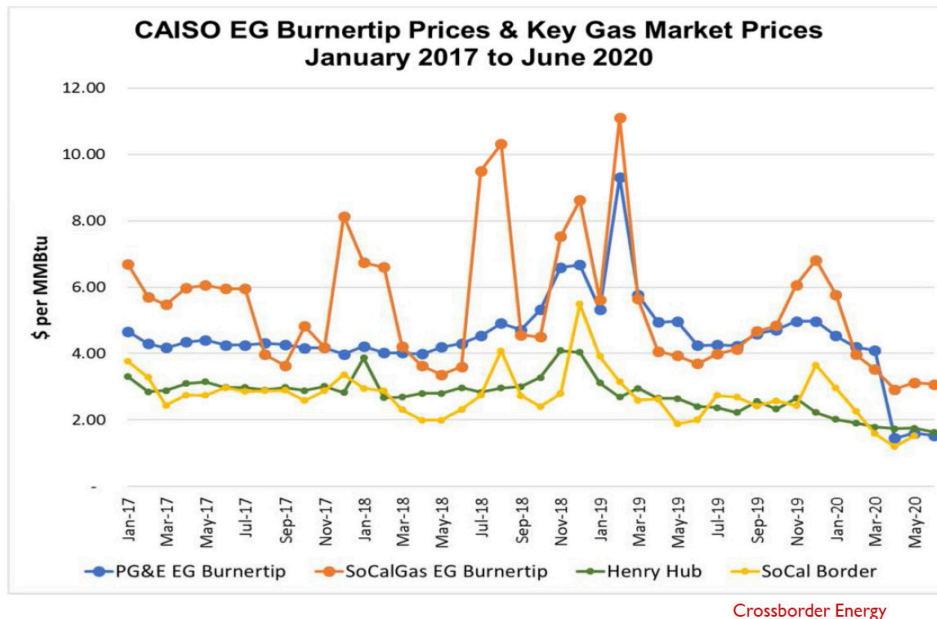
⁸ *Id.*

Electric customers statewide paid higher prices

- ▶ The CAISO's 2018 Market Monitoring Report (page 68) shows gas costs in SoCalGas' service territory set electricity prices



Similarly, Tom Beach, on behalf of Calpine, compared data on the Henry Hub, SoCalGas border, SoCalGas EG burner tip, and PG&E EG burner tip price.⁹ Mr. Beach's graphic is shown below:¹⁰



⁹ Track 1B Presentation at 33 (Calpine/Beach).

¹⁰ *Id.*

Mr. Beach concluded that during key periods, such as summer 2018, while there was no shortage of supply or interstate pipeline capacity, the SoCalGas burner tip price spiked upward.¹¹ This indicates that the problem of high prices in this instance stems not from issues with interstate capacity or supply, but rather from intrastate problems. The Independent Energy Producers (IEP) also showed that those intrastate problems are related to the well-documented pipeline outages and limited Aliso Canyon usage.¹² Responsible asset management by utilities to keep their system running is an integral aspect of reliable utility service. As demonstrated by the presentations and discussions at the Track 1 Workshops, the constraints on SoCalGas's system led to the ensuing electricity price impacts.

In considering how to prevent another occurrence, the Commission should clearly identify the root cause of price spikes. It would be a mistake to focus on reliability standards, which did not appear to have played a role in the electric price spikes – other than the fact that SoCalGas perhaps was not meeting the reliability standards. Changing the reliability standards now would likely not prevent a similar incident; rather, regulatory action should be undertaken to enforce the existing standards and incent compliance.

2. *Open to All Parties: Maurice Brubaker of Brubaker and Associates, Inc., spoke on behalf of the Indicated Shippers at the workshop, and provided several suggestions during his presentation on how the CPUC could respond to a utility's sustained failure to meet minimum design standards. One suggestion is to have a one-way financial incentive, such as utility shareholders sharing in the cost of repair or a reduction in the allowed return on equity. (Track 1A, Scoping Memo Issues 1, 1a-c, 2 and 2a).*

¹¹ Track 1B Presentation at 33 (Calpine/Beach).

¹² Track 1B Presentation at 64 (IEP/Smutney-Jones) (citing the CEC Summer 2019 Outlook Summary).

Over the past two years, while SoCalGas’s pipeline system suffered continual outages and customers received lesser service than they were paying for, shareholders reaped millions in earnings. Creating shareholder responsibility for a portion of the costs of repairing outages is important, because it creates an incentive for the utility to prioritize the repair over maximizing earnings. Long-lasting outages have had real world consequences, as described in the Question #1 response. The Indicated Shippers present the following methodology—composed of two sliding scales—for evaluating whether shareholders should be held responsible for future pipeline or other infrastructure outages that is centered on system reliability and customer harm.

- Sliding Scale of shareholder contribution to the cost of repairs based upon (1) the amount of the cost of repair; and (2) the length of outage.
- Sliding Scale of basis point reductions to Return on Equity (ROE) with a threshold outage duration of 6 months triggering the initial reduction.

The advantage of using a sliding scale is that an outage with no customer impact would not result in shareholder payments or reduced ROE. Only outages that harm customers, as measured by the cost of repair and the length of outages, would lead to shareholder responsibility. Further detail and background on the development of the one-way financial incentives for shareholders are provided below in the response to Section 2(b) and 2(c).

a. What would constitute a “sustained” failure to meet the minimum design standard?

A “sustained” failure to meet the minimum design standard should include a factual evaluation of customer harm. It may be helpful to borrow the concept of the weighted equivalent availability factor for electric utility generation portfolios for these penalties. For example, the Commission could consider the potential capacity of the system or asset in

question over a certain time period, such as a month, compared to the historical capacity of the asset when in good working condition. If the capacity dips below 90%, the one-way financial incentives are determined and implemented.

By evaluating clear threshold metrics such as the weighted equivalent availability factor, the Commission can ensure that imposition of the one-way financial incentives in response to any failure to meet the minimum design standard is transparent and objective, while considering customer impact and harm. Customer impact and harm is an important component, as the one-way financial incentives for shareholders should not be imposed for minor outages (e.g., a spur line).¹³ One-way financial incentives should be imposed for sustained failures to meet minimum design standards where the impacts are broadly felt by customers, such as when critical assets planned to be available during high demand periods are not available.

b. Do parties agree that utility shareholders should share in the cost of repair if the utility does not maintain the minimum design standard? Why or why not?

Yes, shareholders should share in the cost of repair for not maintaining the minimum design standards, with the proportionate share based on the duration of the outage. This is because shareholder skin in the game creates the proper incentive to maintain their system to meet the minimum design standard. As the Commission has found, it is inappropriate for utility customers to pay full price for sub-standard service.¹⁴

¹³ Nor should the one-way financial incentives be implemented when the outage is due to a force majeure event over which the utility had no control.

¹⁴ See D. 20-02-045 at 105, Ordering Paragraph 14 (requiring SoCalGas to propose and implement a Backbone Transmission Service credit mechanism “that compensates Backbone Transmission Service customers for services they pay for but do not receive, for reasons beyond the control of the customer.”)

A fundamental tenet of regulation is that it should be a substitute for competition where competition is not feasible. The following observation in Bonbright encapsulates this tenet:

Regulation, it is said, is a substitute for competition. Hence, its objective should be to compel a regulated enterprise, despite its position of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation, but subject to the market forces of competition.¹⁵

This well-accepted principle is further supported by regulatory experts Alfred Kahn¹⁶ and Charles Phillips.¹⁷

Thus, it is well-established that, to the extent feasible, regulation should seek to emulate the results that would be achieved under competitive circumstances where alternative suppliers compete to provide services desired by consumers.

In a competitive market, supplier profit equals revenue from sales of goods and services minus costs to provide the goods and services. In utility regulation, the paradigm is somewhat different, in that the regulated price equals allowed cost to produce plus allowed profit. It is this latter component—i.e., the allowed profit—of the regulated price structure where adjustments can be made to more closely approximate the results that would be obtained in a competitive market.

¹⁵ *Principles of Public Utility Rates*, Second Edition, by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, Public Utilities Reports, Inc., Arlington, VA, Second Edition, March 1988, at 141.

¹⁶ *The Economics of Regulation: Principles and Institutions*, Volume 1, by Alfred Kahn, John Wiley & Sons, Inc. 1970, at 17; “...the single most widely accepted rule for the governance of the regulated industries is regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible.”

¹⁷ *The Regulation of Public Utilities, Theory and Practice*, by Charles F. Phillips, Jr., 1988 Public Utilities Reports, Inc. at 799, quoting Wilcox: “Taking the place of competition as the method of control, regulation should be expected to yield comparable results.”

In a competitive market, a supplier that provides inadequate or overpriced services would soon find that the discipline of the marketplace would result in lower revenues and correspondingly lower profits, because other entities would step in to provide the desired services under more acceptable prices and terms. For a regulated enterprise, the Commission should ensure that a similar outcome occurs. The result of sub-standard service quality should be a reduction in the allowable return on equity. This is a very effective means of communicating dissatisfaction with the utility to its upper management, board of directors and shareholders.

Recent Examples of ROE Adjustments as a
Response to Inefficiencies and Sub-Standard Service

Adjusting ROEs in response to sub-standard service has been used as a tool throughout utility commissions across the country. In a recent Maui Electric Company (“MECO”) rate case,¹⁸ the Hawaii Public Utilities Commission reviewed the adequacy of Maui Electric’s integration of renewable generation into its existing generation fleet, and further adjusted Maui Electric’s ROE (after having reduced it for improved market conditions) an additional 50 basis points. The Hawaii Public Utilities Commission stated at page 107:

The Commission finds it appropriate to adjust the Parties’ stipulated ROE another 50 basis points downward in light of apparent system inefficiencies which negatively impact MECO’s customers. For example, MECO appears unable to properly address known renewable energy curtailment issues.

¹⁸ *In the Matter of the Application of Maui Electric Company, Limited, For Approval of Rate Increases and Revised Rate Schedules and Rules*, Public Utilities Commission of the State of Hawaii, Docket No. 2011-0092, decision dated May 21, 2013, at 107-108.

In a recent order involving Central Maine Power Company,¹⁹ the Maine Public Utilities Commission determined that Central Main Power Company (“CMP”) was not adequately managing its system, and as a result, imposed a 100 basis point reduction to the otherwise allowable ROE:

This reduction exceeds any prior adjustment by the Commission to a transmission and distribution utility’s return on equity due to poor management and results in an allowed return considerably below the common-equity return of any other electric utility in the country. This reduction is supported by substantial evidence of failures by CMP’s management to provide reasonable and adequate customer service over recent years, and especially following the transition to its new billing system, which lead us to find that this service has been imprudent. This ROE reduction is directly tied to CMP’s service quality; the adjustment will remain in place until CMP improves its performance in several specified areas of customer service for a rolling period of 18 consecutive months (measured beginning March 1, 2020).

Immediately following that finding, the Maine Public Utilities Commission observed:

The Commission has a duty to approve utility rates that are just and reasonable. The Commission does not have unfettered discretion to set a utility’s rates or deny a rate increase. Maine’s Public Utility code, the U.S. Constitution, and long-established jurisprudence constrain the Commission’s discretion by requiring the approved rates be supported by substantial evidence in the record by prohibiting the Commission from confiscating private property without just compensation, and by requiring that the Commission balance the public’s interest in low rates with the utility’s interest in its continued operations needed to serve the public. That said, the Commission has broad authority to disallow costs or adjust rates when the Commission finds that a utility has not acted prudently. By this, we mean acted under a ‘course of conduct that a capably managed utility would have followed in light of existing and reasonably noble circumstances.’

As a legislative example, the Illinois Public Utilities Act (220 ILCS5)²⁰ provides for adjustments to

¹⁹ *Public Utilities Commission Investigation Into Rates and Revenue Requirements of Central Maine Power Company*, State of Maine Public Utilities Commission, Docket No. 2018-00194, Order issued February 19, 2020, at 1.

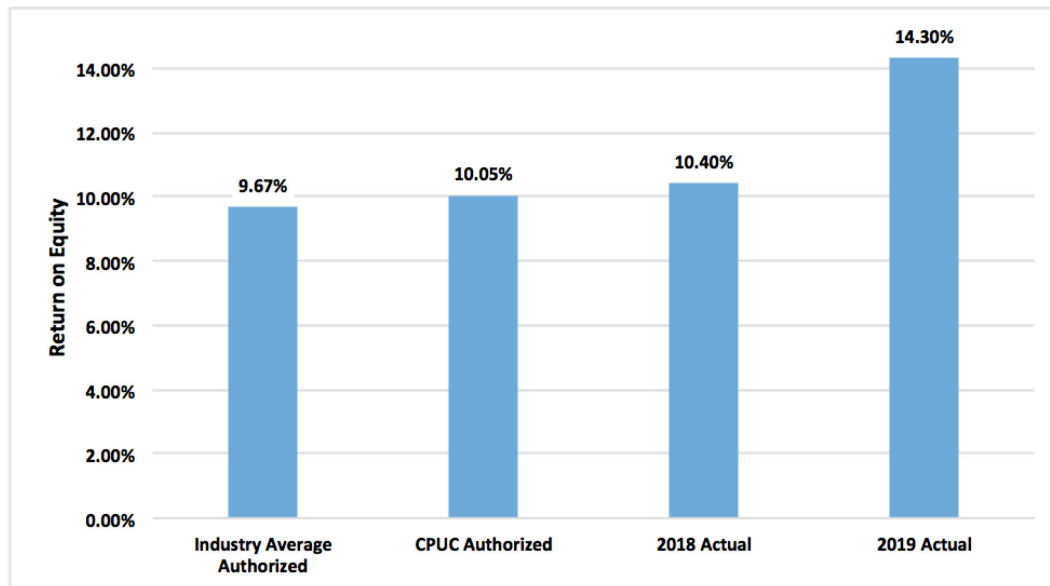
²⁰ Section 16-108.J (b-10) (f) and (f-5).

a utility's ROE in the event that it fails to improve service quality to the extent required by the statute (f-5).

c. Do parties agree that a utility's return on equity should be reduced if the utility does not maintain the minimum design standard? Why or why not?

Yes, a utility's ROE should be reduced if it does not maintain its system to meet the minimum design standard. In 2017 and 2018, SoCalGas reported profits that exceeded the ROE authorized by the Commission, as shown below.

SoCalGas Returns on Common Equity



Sources:

- ¹ S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions – January - June 2020, Table 2, July 22, 2020. Average Authorized Gas Returns for 2017 - 2019.
- ² Sempra Energy Investor Presentation, May 19, 2020 at 7 and 18 for CPUC Authorized and 2019 Actual, respectively.
- ³ Sempra Energy Investor Presentation, May 21, 2019 at 20 for 2018 actual.

In 2018, SoCalGas customers faced increased gas prices, and SCE's customers correspondingly faced a \$900 million undercollection to be recovered from electric rates.²¹ That same year, SoCalGas reported an ROE of 10.40%, in excess of the authorized ROE of 10.05%, as shown in the above table. In 2019, SoCalGas reported a 14.30% ROE compared to its authorized 10.05% ROE. Yet during this time, continuous outages severely disrupted the system.

As a threshold matter, the Commission should consider a reduction to an ROE when an outage continues for a 6-month period. This provides a reasonable time period (6 months) for the utility to repair its outages under the normal course. If a major outage extends beyond 6 months, then a temporary reduction on ROE should be implemented. Similar to the recommended sliding scale for the amount of shareholder contribution to the costs of repair based on the duration of the outage, the Indicated Shippers recommend a sliding scale for the ROE reduction based on the impact to customers. The temporary reduction to the ROE would be removed upon the full return to service of the asset(s).

d. Are there other measures or financial incentives the CPUC should consider to ensure that utilities meet minimum design standards?

Other measures or financial measures may not be necessary. Tying shareholder penalties and an ROE impact for maintenance on a system that has suffered consistent outage problems and considerable harm to customers should provide an effective tool.

3. Open to All Parties: A common set of temperature projections needs to be established in this proceeding. Energy Division staff proposes using California's Fourth Climate Change Assessment

²¹ See CPUC docket A.18-11-009 (where SCE sought authorization to collect a projected \$972.5 million (\$983.8 million including franchise fees and uncollectibles) in its Energy Resource Recovery Account's undercollection as of December 31, 2018 from its customers).

and the California Gas Report for such projections. (Track 1A, Scoping Memo Issue 2b).

a. Do parties have any concerns with using these sources?

The Indicated Shippers do not have concerns with using California’s Fourth Climate Change Assessment and the California Gas Report. That said, the most recent, vetted data and peer-reviewed, robust analysis should be used. Will there be an updated Climate Change Assessment for use in Track 2? The Fourth Climate Change Assessment was published in January 2019, and its key findings were published in August 2018. As California Energy Commission’s Susan Wilhelm cautions, in connection with the Fourth Climate Change Assessment, “It is important to use the wealth of climate projection data with care” and “Climate projections are not weather forecasts!”²² Further, the impact of weather on gas and electric demands is well known. Accordingly, while the 2020 Gas Report is delayed, it will be available soon, and it should be used once it is finally available.

b. Are there any other vetted projections, including peer-reviewed studies and projections produced by state agencies, on California’s climate that should be considered?

No comment.

4. CAISO: How does decreased snowpack impact the need for other baseload resources and/or gas-fired electric generation? (Track 1A, Scoping Memo Issue 2b).

No comment.

5. Open to All Parties: Norman Pederson, who presented on behalf of the Southern California Generation Coalition, indicated that the winter peak day demand continues to exceed the summer peak day demand. Since the gas system is designed to meet the former, it will be able to continue meeting the latter without the

²² Track 1A Presentation at 27 (CEC/Wilhelm).

need for a summer reliability standard. However, this assertion does not consider the differences in supply availability during the winter and summer months. For example, SoCalGas depends on its storage capacity to meet both the summer and winter peak demand. A very cold winter may result in depleted inventory levels prior to the summer season, which may present difficulties in meeting summer peak demand. In addition, a daily demand assessment does not account for steep hourly ramping needs, which may further increase reliance on storage inventory. Is a winter reliability standard sufficient to ensure that a gas system can meet summer peak demand without the need for a summer reliability standard? (Track 1A, Scoping Memo Issue 2c).

Yes, a winter reliability standard is sufficient to ensure that a gas system can meet summer peak demand without the need for a summer reliability standard. First, as discussed above, the lessons of 2017-2018²³ need to be understood in the appropriate context: failed pipeline infrastructure and constrained Aliso Canyon usage. As CCST affirmed, “Without storage, California would be unable to consistently meet winter demand for gas.”²⁴ Second, SoCalGas/SDG&E is a winter peaking system.²⁵ PG&E is also a winter peaking system.²⁶ CCST also concluded that “all gas uses [are] expected to reduce somewhat in 2030, but timing of peaks will remain similar to today.”²⁷

Reasonable use of the existing storage infrastructure, specifically Aliso Canyon, should address concerns over potential difficulties in meeting summer peak demand after a cold winter with depleted inventories. Allowing reasonable injections (and subsequent withdrawals) should address the underlying concern with depleted inventory levels, particularly given the forecasts of

²³ Track 1A Presentation at 85 (CAISO/Hou).

²⁴ Track 1B Presentation at 87 (CCST/Long).

²⁵ Track 1A Presentation at 59 (SoCalGas/Bisi) and *id.* at 91 (SCGC/Pedersen).

²⁶ *Id.* at 91 (SCGC/Pedersen).

²⁷ Track 1B Presentation at 91 (CCST/Long).

decreasing summer daily demands. Notably, according to the 2018 California Gas Report, forecasts show that the trend of reduced summer daily demand will only continue. The 2018 California Gas Report forecast quantified the difference between the winter peak and the summer peak as 1,738 MMcfd for SoCalGas, and 2,000 MMcfd for PG&E.²⁸ While the 2020 California Gas Report has been delayed, it too can, and should be, taken into consideration once it is published. The Commission's determination should be informed by both the pending 2020 California Gas Report, as well as the impacts of its long-standing standards set in 2006, and the recently adopted decisions that address this issue for both PG&E and SoCalGas.

According to Tom Beach, current backbone reliability standards from the 2006 decision already incorporate summer peak requirements, because the standard includes a dry hydro year. As Mr. Beach explained, "Hydro conditions are the most important variable for summer gas demand."²⁹ The Indicated Shippers agree. Including hydroelectric conditions provides a strict reserve margin to the winter reliability standard.³⁰ Furthermore, consideration of a hydro year is one of the most important variables for summer demand.³¹ Mr. Beach further reiterated that the recent pipeline outages and issues with SoCalGas's existing infrastructure are the real

²⁸ Track 1A Presentation at 98-99(SCGC/Pedersen).

²⁹ Track 1A Presentation at 105 (Calpine/Beach)

³⁰ D.06-09-039 at 9-10 ("Florio further 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.") (emphasis added).

³¹ Track 1A Presentation at 105 (Calpine/Beach).

concern, not the lack of or possible need for a summer reliability standard.³² Ample evidence was presented on this point over the course of the two workshops.³³

Further, addressing the concern regarding increased ramping needs, within the past year the CPUC has issued decisions for both PG&E and SoCalGas that increased their respective balancing reserves and capabilities to specifically address the concerns over reserve capacity. First, the Commission adopted its PG&E GT&S decision, D.19-09-025, setting reserve capacity and expanding system balancing. Then, the Commission approved the SoCalGas TCAP decision, D.20-02-045, providing for more capacity for balancing, if available given Aliso Canyon's status. The Commission should recognize the impact of the inclusion of a dry hydro year in the standard as adopted in 2006 and "wait-and-see" the impacts of the two more recent decisions before rushing to change the rules. Equally important, the Commission should recognize that, pursuant to SB 100, summer EG gas demand will decline substantially over time.³⁴

Finally, there is real concern over increased costs that would be shouldered by ratepayers for a summer reliability standard. As shown below, the cumulative rate impacts on noncore customers alone from three recent rate cases result in an approximately 59 percent increase.³⁵

³² Track 1A Presentation at 106 (Calpine/Beach)

³³ See, Track 1A Presentation at 134-140 (Indicated Shippers and SCGC/Yap); see also Track 1B Presentation at 33 (Calpine/Beach) and *id.* at 64 (IEP/Smutney-Jones) (observing that the failure of the SoCalGas infrastructure as a source of price volatility).

³⁴ Track 1A Presentation at 108 (Calpine/Beach); see also *id.* at 94 (SCGC/Pedersen) ("Average summer daily gas demand is gradually decreasing due to California policy initiatives favoring the additional of renewable generation resources").

³⁵ These estimates are provided from the final decision for CPUC dockets the SoCalGas General Rate Case in A.17-10-008, the final decision for the SoCalGas TCAP in A.18-07-024, and the proposed impacts from the SoCalGas PSEP application in A.18-11-010.

Recent Rate Case Increases		
Application	Percent Increase	
	Total	Noncore
	(1)	(2)
A.17-10-008 (TY 2019 GRC)	25%	15%
A.18-07-024 (2020 TCAP)	---	28
A.18-11-010 (PSEP)	7	16
Total	32%	59%

While the Indicated Shippers do not believe a summer reliability standard is needed, any proposal to impose a new summer reliability standard should include an estimate of the cost impact on customers. As the seminal CCST study, Long-Term Viability of Underground Natural Gas Storage In California: An Independent Review of Scientific and Technical Information, explained, the Commission should be guided by affordability concerns. In the Track 1B workshop, Dr. Long concluded,

California needs natural gas and natural gas storage to meet winter demand and winter peak daily demand for heat. Pipelines do not have the capacity to meet these demands.

Replacing UGS [underground gas storage] would be very expensive and nearly impossible in the near term.³⁶

The Indicated Shippers agree.

6. *SoCalGas/SDG&E, PG&E, Cal Advocates, TURN, IEP, CAISO, and SCGC: SoCalGas/SDG&E suggests that the core category should be redefined to include certain noncore customers, such as hospitals, refineries, and some gas-fired electric generation. With that change, SoCalGas/SDG&E suggests that the 1-in-10 cold day design standard be eliminated since the remaining noncore demand is interruptible at any time. Additionally, Eric Eyberg from Wood Mackenzie presented on the WECC Gas-*

³⁶ Track 1B Presentation at 87 (CCST/Long).

Electric Interface Study and discussed recommendations from the study on managing demand and providing fuel assurance. One recommendation from the study is to consider reclassifying some electric generators that are critical to grid reliability as core customers. (Track 1A, Scoping Memo Issues 1, 1a-c, 2 and 2a and Track 1B, Scoping Memo Issues 1-1a). Should the reliability standards be modified so that some noncore customers are reclassified as core customers and have access to firm storage rights? If so:

No; the reliability standards should not be modified so that some noncore customers are reclassified as core customers with access to firm storage rights. Changing the classification of certain customers from noncore to core, with a possible subsequent change to the noncore customers' level of service, is a consequential proposal with far-reaching repercussions. Evaluation of the reasonableness of this proposal for a profound transformation, if pursued, would require a deep, detailed factual investigation into current and forecast demand, usage, costs to make this change, and modeling to analyze possible consequences. If considered, this will necessitate testimony, discovery, and evidentiary hearings. Each of the proponents listed in this question appear to promote this sea change for different reasons. In evaluating next steps, the Commission should identify the exact problem it wants to solve.

If the Commission is focused on managing demand and fuel assurance, as indicated in the question, then its analysis should pragmatically consider reasonable solutions involving existing infrastructure that are being currently investigated. Specifically, an important first step in this evaluation is a determination to strategically, reasonably, and responsibly use the Aliso Canyon storage field. In a 2018 WECC Gas-Electric Interface Study, Mr. Eyberg from Wood Mackenzie reported that "Aliso Canyon at 30% of capacity fully mitigated" a major disruption.³⁷ As

³⁷ Track 1B Presentation at 12 (Wood Mackenzie & E3/Eyberg and Olson).

referenced above, an Aliso Canyon outage or retirement would have “ripple effects into neighboring regions.”³⁸ As emphasized by CCST, underground storage remains the *most affordable option* for California ratepayers.³⁹ Simply put, the appropriate and reasonable use of Aliso Canyon appears to be the clearest, most cost effective approach to managing demand and addressing fuel assurance. Further, appropriate and reasonable use of Aliso Canyon is less fraught with potential unintended consequences than reclassifying noncore and core customers.

a. Should the 1-in-10 cold day standard be eliminated so that remaining noncore demand is interruptible?

No, the 1-in-10 cold day standard should not be eliminated. First, none of the workshop presentations and discussion directly identified that existing reliability standard as either a cause of the historical reliability problems, or a solution to them (other than SoCalGas’ self-interested argument to eliminate a standard it fails to meet, discussed below). Reshaping both customer classification along with reliability standards for each class should not be undertaken. In addition, before the 1-in-10 cold day standard is changed, further factual investigation would need to be conducted on the efficacy of this approach to maintaining system reliability.

Second, it should not go unnoticed that SoCalGas proposes to eliminate the 1-in-10 Cold Day standard after acknowledging its failure to meet it.⁴⁰ SoCalGas attributes its inability to meet the Cold Day standard to “[i]nsufficient pipeline and storage capacity to meet the current demand forecast of 4.9 BCFD for core and noncore customers.”⁴¹ The problems with pipeline and storage capacity include: degraded withdrawal capacity, backbone pipeline outages and

³⁸ Track 1B Presentation at 13 (Wood Mackenzie & E3/Eyberg and Olson).

³⁹ *See id.* at 87.

⁴⁰ Track 1A Presentation at 62 (SoCalGas/Bisi).

⁴¹ *Id.*

operating limitations, and storage levels assumed for core reliability needs only.⁴² As described above, the Commission should address the utility's failure to maintain minimum design standards through one-way financial incentives for shareholders before eliminating the standards.

b. Would there be enough gas storage inventory to serve both the needs of historically noncore customers such as hospitals, refineries, and gas-fired electric generators and traditional core customers?

An accurate response to this question must be data-driven; it requires quantitative analysis, testimonial evidence detailing that analysis, as well as the assumptions and inputs that informed the analysis; the fact-finder should invoke the truth-seeking function of evidentiary hearings. Again, the sufficiency of gas storage inventory will also be greatly impacted by the future use of Aliso Canyon, which at this point is a significant unknown.

c. What policies should be put in place to ensure that there is enough storage capacity to accommodate peak electric demand in the summer while also allowing storage operators to prepare for residential heating demand in the winter?

It is reasonable for the Commission to be concerned with sufficient storage capacity to accommodate peak electric demand in the summer and consider appropriate policies to guard against inadequate storage capacity. Due to a cold 2018-2019 winter and resultant high core customer demand, SoCalGas observed that its storage levels for Honor Rancho and Playa del Ray neared their respective minimums for core reliability.⁴³ It is worth noting that to address this

⁴² Track 1A Presentation at 62 (SoCalGas/Bisi).

⁴³ See, Letter from SoCalGas to the CPUC titled *Winter 2018-2019 Lessons Learned*, February 26, 2019.

deficiency, SoCalGas recommended modifying the Aliso Canyon Withdrawal Protocol to allow SoCalGas to increase its system flexibility.⁴⁴ SoCalGas observed that it would need supply from the Aliso Canyon storage facility in its “worst case” supply assumption for the summer.⁴⁵

These facts support the conclusion that the policy to be put in place is a reasonable ability to continue to use the existing storage capacity in Aliso Canyon. As referenced throughout these comments, the Commission should strategically evaluate the ability to continue to reasonably use Aliso Canyon. Not only does Aliso Canyon provide significant stability during major disruptions, including fully mitigating a \$1 billion risk event due to a disruption on a major Desert Southwest pipeline, but Aliso Canyon also provides system flexibility.⁴⁶ Again, Aliso Canyon’s stabilizing impact is not isolated to California alone, but ripples throughout the western states.

- d. If it is determined that a subset of gas-fired electric generators should be designated as core customers, how should the CPUC determine that subset? What are the downsides or risks (if any) associated with such reclassification?*

No comment.

- 7. Cal Advocates, TURN, SoCalGas/SDG&E: Pages 35-36 of Commission Decision 19-09-025 discusses PG&E’s Reserve Capacity, which provides its system with emergency intraday supply of natural gas in case of a significant, unplanned equipment outage or other supply problem. Should a similar Reserve Capacity be considered for the SoCalGas system? Why or why not? (Track 1A, Scoping Memo Issue 3).*

⁴⁴ See, Letter from SoCalGas to the CPUC titled *Winter 2018-2019 Lessons Learned*, February 26, 2019 at 2-3.

⁴⁵ Letter from SoCalGas to CPUC titled *Summer Technical Assessment and System Reliability*, April 2, 2019, at 7.

⁴⁶ Track 1B Presentation at 13 (Wood Mackenzie & E3/Eyberg and Olson).

No, the Commission should not adopt a “Reserve Capacity” program such as PG&E’s for SoCalGas. First, as described in the response to Question 5, the ink is not yet dry on two CPUC decisions less than a year old that materially increased both PG&E’s and SoCalGas’s load balancing reserve and capacities. The Commission adopted the Reserve Capacity and Inventory Management program, two new storage services on PG&E’s system, in PG&E’s GT&S proceeding, D.19-09-025. Similarly, D.20-02-045 increased SoCalGas’s inventory allocated to the load balancing function from 8 BCF to 10 BCF.⁴⁷ This decision was adopted after litigation involving discovery, testimony, and hearings with cross-examination and briefing, thus based on a well-developed evidentiary record. It should be implemented and allowed to take effect, before contemplating further changes to SoCalGas’ system in response a workshop and comment process here.

In addition, further changes to SoCalGas’s inventory capacity are likely unnecessary given the revisions to the Aliso Canyon Withdrawal Protocol. The July 23, 2019 modification of the Aliso Canyon Withdrawal Protocol permitted revised withdrawal conditions with the purpose of improving short-term reliability and price stability.⁴⁸ The modification was touted as a success by multiple presenters during the Track 1A and Track 1B workshops, and by the CPUC staff in their *Summer 2019 SoCalGas Conditions and Operations Report*.⁴⁹

⁴⁷ D.20-02-045 at 96, Finding of Fact 98.

⁴⁸ July 23, 2019, Aliso Canyon Withdrawal Protocol:
https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf.

⁴⁹ *Summer 2019 SoCalGas Conditions and Operations Report*, by the CPUC, July 20, 2020, at 14 (“Generally, moderate weather, high production from out-of-state gas and oil wells, ample hydroelectric energy, and revisions to the Aliso Canyon Withdrawal Protocol contributed to a stabilizing of average gas prices.”).

Finally, as presented by multiple presenters during the workshops, the SoCalGas and PG&E system are simply different, both physically and operationally.⁵⁰ Due to these differences, a program designed for PG&E would not work as effectively for SoCalGas.

8. Open to All Parties: Should slack capacity include storage capacity? Why or why not? (Track 1A, Scoping Memo Issue 3).

Yes, slack capacity should include storage capacity. Cathy Yap, presenting on behalf of the Indicated Shippers and SCGC, observed the importance of taking storage components of the gas system into consideration. Slack capacity supports gas-on-gas competition, helping keep gas prices low for customers, but has been greatly reduced on the backbone transmission system by maintenance and repair requirements.⁵¹ Ms. Yap described that improved “access to storage withdrawal capacity would compensate for the reduced backbone capacity ensuring that we do not have a repeat of the high gas prices witnessed in 2018.”⁵²

In addition, in this time of transition, it is critically important to not overbuild the system, but recognize that the existing infrastructure is needed and should be used. As the CAISO explained, the current and forecast ramping needs are 15,639 MW in 2019 and 25,000 MW in 2030, slide excerpt shown below:⁵³

⁵⁰ See, e.g., Track 1B Presentation at 174 (PG&E/Graham) (In regard to OFO penalty structure: “PG&E’s physical pipeline constraints and operating conditions are different than SCG. . .”).

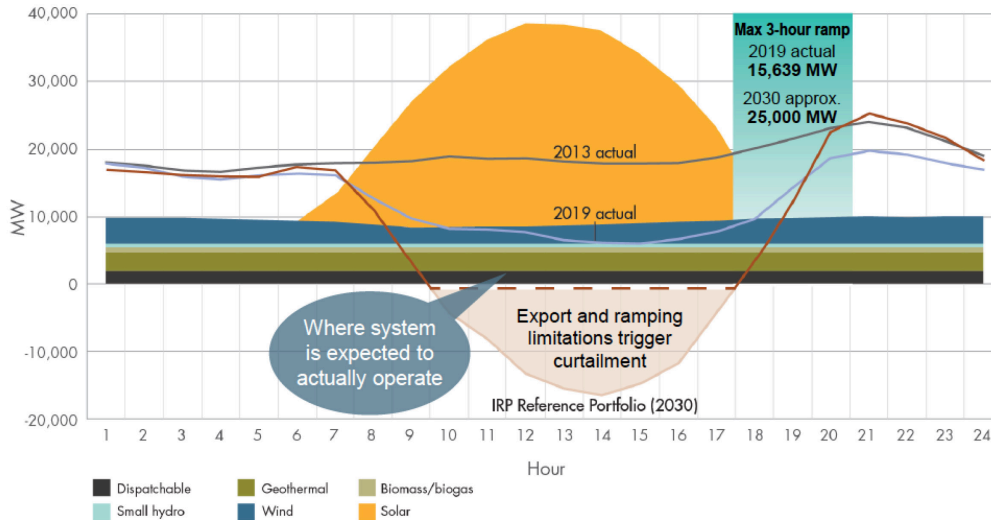
⁵¹ Track 1A Presentation at 126 (Indicated Shippers and SCGC/Yap).

⁵² *Id.* at 127 (Indicated Shippers and SCGC/Yap).

⁵³ *Id.* at 86 (CAISO/Hou).

By 2030, solar is expected to contribute to increasing ramping needs

- Actual and projected maximum three hour ramp



The CAISO forecasts show that gas contributes 2,805 MW to meet the ramp.⁵⁴ Again, the CCST conclusion emphasized by Dr. Long is on point:

With appropriate regulation and oversight, the risks associated with underground natural gas storage can be managed and mitigated. California’s energy system currently *needs* natural gas and gas storage to run reliably.⁵⁵

The Commission should heed Dr. Long’s blunt assessment, in large, bold, red text, that “without storage, California would be unable to consistently meet winter gas demand.”⁵⁶

9. SoCalGas/SDG&E: (Track 1A, Scoping Memo Issue 4).

- a. Please explain the representation on page 147 of the July 7, 2020 workshop slides from Paul Borkovich of SoCalGas/SDG&E that current El Paso Natural Gas (EPNG) Ehrenburg Delivery Capacity is 2.3 Bcf/d.

⁵⁴ Track 1A Presentation at 87 (CAISO/Hou).

⁵⁵ Track 1B Presentation at 103 (CCST/Long)(emphasis in original).

⁵⁶ *Id.* at 76 (CCST/Long).

- b. *On page 147 of the July 7, 2020 workshop slides, SoCalGas acknowledged that the North Baja XPress Project “would take away an additional 0.48 Bcf/d.” With respect to pages 159-161 of the July 7, 2020 workshop slides, “Southern System: Scheduled Quantities vs. Minimum (Dth/d) April 2017 – March 2018, April 2018 - March 2019, & April 2019 - March 2020,” how would a reduction of 0.48 bcf/d have impacted the ability of the SoCalGas System Operator to meet the Southern System Minimums, particularly on those days where the minimums were above 0.7 Bcf/d?*
- c. *List how many days in those three years where the Southern System Minimums were above 0.7 Bdf/d, and for each day provide temperature data, use by various customer classes (core and non-core), whether there were any curtailments requested and implemented, and any other relevant factors impacting daily usage and available capacity.*
- d. *Provide an analysis starting with April 2022 - March 2023 and going forward through March 2025 of how anticipated flows on North Baja to serve loads in Baja California and LNG Exports at Energía Costa Azul would impact maximum available Southern System scheduled quantities.*
- e. *On page 15 of its Opening Comments, SoCalGas/SDG&E said: “To the extent there may be potential reliability and price impacts for SoCalGas’ and SDG&E’s service territories from an expanded North Baja pipeline, SoCalGas and SDG&E look forward to discussing potential measures that could address these impacts.” Please provide an assessment of how an expanded North Baja pipeline could have potential reliability and price impacts for SoCalGas’ and SDG&E’s service territories. Besides SCG/SDG&E constructing additional intrastate facilities, what potential measures could address those impacts?*

No comment.

- 10. *SCGC: Please explain your representation on page 47 of the slide deck for the July 21, 2020 workshop that EPNG Delivery Capacity to Ehrenburg is 2.985 Bcf/d. (Track 1A, Scoping Memo Issue 4).*

No comment.

11. *Open to All Parties: SoCalGas stated that their system was generally designed around core customers. However, the increased amount of intermittent generation resources in the electric portfolio has resulted in gas-fired electric generators regularly exceeding their ratable supply (on a 1/24-hour basis). Furthermore, SoCalGas indicated that gas-fired electric generator ramp downs and volatility frequently contribute to over-pressurization. Are there policy changes the CPUC should consider that would help manage the changing use of the gas infrastructure? (Track 1B, Scoping Memo Issue 2).*

No Comment.

12. *Open to All Parties: IEP, speaking on behalf of several electric generators, stated that gas-fired electric generators should not be required to hold firm interstate contracts. They also forecast that gas-fired electric generators will play a role in California through 2030 and possibly 2045. Jonathan Peress, from SoCalGas/SDG&E, spoke about the system impacts of electric generator ramp ups and downs and the projected decrease in gas-fired electric generation, but continued increase in intraday ramping volatility. To capture the value provided to the electric system by the gas system, and absent firm interstate contracts, SoCalGas/SDG&E suggested a new tariff to internalize the value of the gas system and the flexible capacity offered. (Track 1B, Scoping Memo Issue 2).*

- a. *What are the benefits and costs of a renewable balancing tariff, as suggested by SoCalGas?*
- b. *What should such a tariff include or exclude?*

No Comment.

13. *Open to All Parties: Should PG&E's Operational Flow Order (OFO) penalty structure be changed so that it aligns with SoCalGas' winter OFO penalty structure? Why or why not? (Track 1B, Scoping Memo Issue 3).*

No, PG&E's OFO penalty should not be changed so that it aligns with SoCalGas's winter OFO penalty structure. As unanimously agreed upon by the Track 1B presenters, given the differences between the PG&E and SoCalGas system, different rules should continue. In

addition, PG&E's and SoCalGas's protocols were separately litigated with active customers and should not be changed without a full record and compelling reasons.

14. Open to All Parties: Should SoCalGas' winter OFO penalty structure be adopted year-round? Are there any risks in allowing the revised OFO penalty structure (D. 19-05-030) to expire in October 2021 and allowing the prior OFO penalty structure (D.15-06-004 and D. 16-06-039) to continue? (Track 1B, Scoping Memo Issue 3).

At this juncture, the Indicated Shippers recognize that the current penalty structure will remain in place until October 30, 2021, unless modified by a subsequent Commission decision, pursuant to D.19-05-030.⁵⁷

In D.19-05-030, the Commission adopted a bifurcated OFO penalty structure, distinguishing winter vs. summer penalties. For the winter season, the decision adopted an eight-stage OFO structure submitted by a settlement comprised of joint parties, including the Indicated Shippers.⁵⁸ Settling parties supported the eight-stage penalty structure as an effective tool for the SoCalGas System Operator to manage the system under stressed conditions. In addition, the eight-stage penalty structure provided teeth for the tools used to avoid pipeline service interruptions, a concern especially in the Los Angeles Basin.

For the summer season, the decision rejected the eight-stage penalty structure proposed by the settling parties, and instead adopted the penalty structure supported by SCE. The summer season penalty structure reduced the Stage 4 and Stage 5 penalties to \$5/dth, plus the daily balancing standby rate in Stage 5.⁵⁹

⁵⁷ D.19-05-030 at 28.

⁵⁸ Settling parties included the Indicated Shippers, SoCalGas/SDG&E, SCGC, NRG, and Western Power Trading Forum.

⁵⁹ D.19-05-030 at 35, Ordering Paragraph 3.

Since the decision was adopted, California has not experienced a high demand summer season to evaluate the efficacy of the summer season alteration. The Indicated Shippers understand that this issue will be evaluated throughout the summer 2020 season.⁶⁰

III. CONCLUSION

The Indicated Shippers appreciate this opportunity to respond to the questions posed in the Ruling.

Respectfully submitted,



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August 14, 2020

⁶⁰ D.19-05-030 at 36, Ordering Paragraph 9 (“The Commission reserves the right to revisit the Operational Flow Order penalties before summer 2020, using data collected during summer 2019.”).