FILED
10/14/21
04:21 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

ASSIGNED COMMISSIONER'S AMENDED SCOPING MEMO AND RULING

This Amended Scoping Memo and Ruling (Scoping Memo) sets forth the category, issues to be addressed, and schedule for Track 2 of the above proceeding pursuant to Public Utilities (Pub. Util.) Code § 1701.1 and Article 7 of the Commission's Rules of Practice and Procedure (Rules). The statutory deadline for this proceeding is extended to August 1, 2023.

1. Procedural Background

On January 16, 2020, the Commission issued an Order Instituting Rulemaking (OIR) to respond to past and prospective events that together require changes to certain policies, processes, and rules that govern the natural gas utilities in California. Past events include operational issues in southern California that prompted the Commission to reconsider the reliability and compliance standards for gas utilities. Prospective events include new state and municipal laws concerning greenhouse gas emissions that will result in the replacement of gas-fueled technologies and, in turn, reduce the demand for natural gas.

Track 1a of this proceeding addresses reliability standards that reflect the current and prospective operational challenges that face gas system operators. Track 1b addresses market structure and regulation. Track 1 issues have been the subject of numerous comments filed in response to rulings by the Administrative Law Judge (ALJ), workshop reports, staff proposals, and motions by various parties. On September 23, 2021, the ALJ issued a ruling denying motions for testimony and evidentiary hearings and granting motions for the filing of briefs on all Track 1 issues. Briefs are due October 15, 2021, and reply briefs are due on October 29, 2021.

Track 2 of this proceeding develops and implements a long-term planning strategy. It is divided into the three sub-tracks (Tracks 2a, 2b, and 2c) described below.

2. Scope of Issues in the Proceeding

2.1. Scope of Issues in Track 2a: Gas Infrastructure

How should the Commission determine the appropriate gas infrastructure portfolio for gas utilities that operate in California given the state's greenhouse gas reduction laws and the utilities' statutory obligation to serve customers within their service territories?

a. Should the Commission consider adopting a General Order (GO) analogous to GO 131-D for electric infrastructure projects, that would require site-specific approvals for gas infrastructure projects that exceed a certain size or cost?

b. What criteria should the Commission use to determine whether aging transmission infrastructure should be repaired or replaced when a gas utility requests ratepayer funds?

    i. Should the repair or replacement criteria be based on whether that piece of infrastructure is necessary to meet the utility's design standard as determined in Track 1?

ii. What other criteria might be considered?

iii. How should the cost to repair or replace the infrastructure be balanced against its reliability benefits?

c. What criteria should be used to determine when declining demand can enable transmission lines to be de-rated or decommissioned without harming reliability?

i. How should the Commission define a transmission pipeline vs. a distribution pipeline?

ii. What should the regulatory process be for de-rating a transmission pipeline to a distribution pipeline?

d. What criteria should the Commission use to determine whether aging distribution infrastructure should be repaired or replaced when a gas utility requests ratepayer funds?

i. What pipeline-related characteristics should be considered when determining whether to replace distribution infrastructure (*e.g.,* downstream impacts, pipeline's role in serving industrial (hard to electrify) load, type of customers served, customer density, age, safety condition, pipe material such as Aldyl-A)?

ii. What community characteristics, such as designation as a disadvantaged community (DAC), should be considered?

iii. What goals should be considered when using these characteristics (*e.g*., cost savings, pipeline safety, net greenhouse gas reductions, environmental justice)?

iv. What non-pipeline alternatives should be considered?

v. How should the cost of non-pipeline alternatives be compared to the cost of gas pipeline replacement or repair? For example, are there avoided operations and maintenance (O&M) and infrastructure replacement costs for retiring distribution pipelines that could be estimated and incorporated into cost-effectiveness analysis?

vi. If the Commission determines that a distribution pipeline should be decommissioned, what consideration should be given to customers who do not wish to stop their gas service?

e. What criteria should be used to determine which distribution lines should have the highest priority for proactive decommissioning?

i. What pipeline-related characteristics should be considered when prioritizing distribution lines for decommissioning (*e.g*., age, safety condition, pipeline's role in serving industrial (hard to electrify) load, extent to which it has been depreciated, location, customer density, pipe material such as Aldyl-A)?

ii. What community characteristics, such as designation as a DAC, should be considered?

iii. What goals should be considered when using these characteristics (*e.g.,* cost savings, pipeline safety, net greenhouse gas reductions, environmental justice)?

iv. What non-pipeline alternatives should be considered?

v. How should the direct and indirect costs of non-pipeline alternatives be compared to the cost of replacement? For example, are there avoided O&M and pipeline replacement costs for retiring distribution pipelines that could be estimated and incorporated into cost-effectiveness analysis?

vi. If the Commission determines that a distribution pipeline should be decommissioned, what consideration should be given to customers who do not wish to stop their gas service?

vii. What planning and procedures are necessary to ensure that there is sufficient local electric capacity available to reliably serve customers that move off the gas system?

viii. Are there health and safety issues that need to be addressed from decommissioned distribution lines?

ix. What procedural mechanism should be used to proactively decommission distribution pipelines?

f. What infrastructure is needed to fulfill the needs of customers who are likely to remain on the gas system the longest, such as electric generators or difficult-to-electrify industrial users?

g. What should be the role of existing natural gas storage facilities as a component of gas utilities' infrastructure portfolio?

h. How should the monopoly local distribution companies' "obligation to serve all customers who want service" (*see* D.15-10-050, at 18) be defined, given the state's decarbonization goals? What statutory and policy changes, if any, are needed to effectuate such a definition?

i. Should the Commission require the achievement of certain milestones (*e.g.,* replacement energy resources are built and operational) before a significant natural gas asset is derated or decommissioned to ensure energy reliability, equity, workforce planning, and other policy goals are maintained and/or achieved throughout this transition?

2.2. Scope of Issues in Track 2b: Safety; Data; Process

2.2.1. Safety

Gas utilities and independent storage providers must comply with all safety regulations established by national regulators such as the Pipeline and Hazardous Materials Safety Administration (PHMSA) and state regulators such as the Commission and the California Geologic Energy Management Division (CalGEM).

a. What factors should the Commission consider when balancing the need for pipeline safety with the need to avoid spending that will burden future gas ratepayers?

b. Can Commission rules on the Pipeline Safety Enhancement Plans (PSEP) be aligned with federal PHSMA rules? If so, should they be aligned?

c. How might the Commission consider achieving cost savings by de-rating or decommissioning infrastructure that has costly safety requirements?

2.2.2. Data

As noted in the OIR, this proceeding will evaluate demand scenarios that will materialize from state and local greenhouse gas-related laws and determine a long-term planning strategy to balance the impact that projected reductions in gas demand will have on the gas system.[1] It is relevant to examine analogs in the electricity system. Long-term planning for the electricity system in the Integrated Resource Plan and its predecessor proceedings[2] have a longstanding history of deferring to the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) demand forecast inputs, where available.[3] The 2021 IEPR Scoping Order states that the CEC will "assess the outlook for gas use in California both in the 10-year and 25-year planning horizons across key sectors through development and refinements to gas demand forecasts and scenarios, to accurately reflect the impacts of decarbonization policies and goals of the state" and it states "The CEC will also collaborate with the CPUC on their Long-Term Gas Planning Rulemaking and develop necessary assessments."[4]

a. What data is needed from the utilities to assist the Commission and stakeholders in long-term gas system planning?

---

1 OIR at 17.

2 The previous proceedings include the Long-term Procurement Plan proceedings.

3 D.07-12-052 at Finding of Fact 13.

4 2021 IEPR Scoping Orde, at 5.

b. The current design standard is based on forecasts of future weather and demand, so its accuracy depends on the accuracy of the assumptions used. What data inputs and outputs should the Commission require the utilities to integrate into their gas demand forecasts for each customer class on the gas utilities' backbone, local transmission, and distribution systems?

    i. Should the utilities develop more granular forecasts to better account for geographic differences and changes in demand?

    ii. Should the utilities be required to develop low, medium, and high demand forecasts?

    iii. How should system planning and utility design standards incorporate both robust historical weather data and the latest climate forecasts to generate demand forecasts?

c. In addition to the gas utilities preparing gas forecasts as part of the California Gas Report, please comment on the use of the CEC's IEPR average annual demand forecast for gas system planning, and peak gas demand forecasts, as available.

d. Should the Commission require the utilities to report granular data on the location, condition, depreciation schedule, and repair and replacement schedule of their transmission and distribution pipelines?

2.2.3. Process

a. Should the Commission require gas utilities to submit a decarbonization and reliability plan with a 10-year outlook in each general rate case (GRC) or via some other process that includes how the utility would address the following:

    i. Steps being taken to reduce their greenhouse gas emissions;

    ii. Coordinating with electricity providers to meet electric reliability needs;

iii. Cost-effectively maintaining aging infrastructure;

iv. Transitioning to renewable gas or hydrogen where feasible, safe, and cost effective; and

v. Plans for selectively decommissioning or "pruning" the distribution system and other gas infrastructure while maintaining safe and reliable gas service?

b. Should the Commission establish a process in which policy decisions made in this proceeding can be reevaluated over certain time intervals or in the face of changing conditions such as updated weather forecasts and new technologies?

2.3. Scope of Issues in Track 2c: Gas Revenues and Rate Design; Workshop Issues

2.3.1. Gas Revenues and Rate Design

a. Do rate design changes or current cost allocation methods raise affordability and other economic concerns in light of gas system changes, especially for low-income customers and customers in disadvantaged communities? What criteria should the Commission apply when considering this issue? How can affordability issues be mitigated? Should the Commission reconsider gas rate design and cost allocation methods, such as fixed charges or marginal cost allocation methods versus embedded cost methodologies? If so, in which proceeding should these issues be addressed?

b. Will public purpose programs be impacted by any proposed rate design changes?

c. Should the Commission consider adopting or recommending financial mechanisms such as accelerated depreciation or securitization to balance costs between current and future ratepayers?

d. Are any measures needed to ensure that gas utilities remain financially viable and credit-worthy for as long as gas is necessary for energy reliability?

2.3.2. Workforce Issues

a. What utility workforce considerations are raised by a transition away from natural gas, and how should these be included in the long-term gas planning process?

b. How can any potential negative impacts on gas industry workers be mitigated?

   i. Which employees are likely to be at greatest risk of job loss from a transition away from natural gas? What are the characteristics of those jobs and work? What types of jobs could such workers transition to?

   ii. What share of the utility gas workforce at greatest risk of job loss is suitable for early retirement? Should utilities develop plans to support early retirement for affected employees?

   iii. What types of retraining should be made available to gas utility employees, including training necessary to provide high road employment? Who should pay for such retraining?

   iv. How can the Commission ensure that gas workers in disadvantaged or low-income communities have equitable access to retraining?

c. What are the potential costs associated with mitigation strategies? Who should be responsible for paying these costs?

d. Should the Commission create requirements for tracking data on implementation of mitigation measures, including retraining, job quality, and job access?

3. Workshops

A series of workshops will be held and facilitated by the Commission's Energy Division staff (Energy Division). The final schedule, agenda, goals/expectations and party/participant responsibilities will be determined by Energy Division. The purpose of these workshops will be to address the questions outlined in this Scoping Memo, gain a common understanding of the issues, gather information and facts, develop possible scenarios and resulting outcomes, seek feedback and input from stakeholders, and identify solutions. Energy Division will publish a workshop report resulting from this consensus building process. All parties will have the opportunity to provide comments on the workshop report. At the end of this workshop process, if there are disputed issues of fact within the final report, or additional necessary information to be considered, the assigned ALJ or Commissioner will consider other procedural pathways to resolve such discrepancies, including the need for evidentiary hearings and/or the need for testimony and briefs.

Meaningful public participation and stakeholder input is necessary to develop an effective long term gas planning strategy given that changes to the gas system will impact a variety of stakeholders. The Commission will make special efforts to solicit input from a broad range of stakeholders, particularly those representing disadvantaged communities, throughout this proceeding.

4. Need for Evidentiary Hearing

Examination of the issues in the proceeding to date does not demonstrate that evidentiary hearings are necessary at this point. However, because significant factual issues could be raised in the proceeding, and evidentiary hearings may be needed, potential hearing dates have been placed in the schedule in the event evidentiary hearings are found to be necessary and appropriate. The deadline to file a motion to request evidentiary hearings, serve testimony and file briefs is set forth in the below schedule.

5. Schedule

The following schedule for the remainder of Track 1, and for Tracks 2a and 2b is adopted here and may be modified by the assigned ALJ or Commissioner as required to promote an efficient and fair resolution of this OIR. A schedule for Track 2c will be addressed in a future ruling.

Activity	Time Period
TRACK 1	
Opening briefs, filed	October 15, 2021
Reply briefs, filed	October 29, 2021
Proposed Decision	December, 2021
TRACK 2	
Track 2 preliminary revised Scoping Memo and Tentative Schedule, issued	October 14, 2021
Opening Comments (limited to 20 pages), served and filed	November 2, 2021
Reply Comments (limited to 10 pages), served and filed	November 12, 2021
Revised Scoping Memo & Schedule, issued	November 29, 2021
TRACK 2a	
Conduct Track 2a Workshop on Gas Infrastructure, Scoping Document Question No. a-d	January 10, 2022
Conduct Track 2a Workshop on Gas Infrastructure, Scoping Document Questions e-i	January 24, 2022
Publish Track 2a Workshop Report	February 14, 2022
Comments on Track 2a Workshop Report, served and filed	February 28, 2022
TRACK 2a Scoping Document Question a	
Opening Briefs, filed	February, 2022

Activity	Time Period
Reply Briefs, filed	March, 2022
Proposed Decision	May, 2022
Final Decision	No earlier than 30 days after the Proposed Decision has been issued
TRACK 2a Scoping Document Questions b-i	
Deadline to File a Motion to Serve Testimony and Hold Hearings	March 14, 2022
Opening Testimony (if determined to be needed), served	May 2022
Rebuttal Testimony (if determined to be needed), served	June 2022
Hearings (if determined to be needed)	June 2022
Opening Briefs, filed	July 2022 (earlier if no hearings)
Reply Briefs, filed	August 2022 (earlier if no hearings)
Proposed Decision	September 2022
Final Decision	No earlier than 30 days after the Proposed Decision has been issued
TRACK 2b	
Conduct Track 2b Workshop on Scoping Document Questions Nos. 1, 2, and 3 (**Safety, Data, and Process**)	October 2022 (possibly 2 days)
Publish Track 2b Workshop Report	December 2022
Comments on Track 2b Workshop Report, served and filed	January 2023
Opening Briefs (if determined to be needed), filed	February 2023
Reply Briefs (if determined to be needed), filed	March 2023
Proposed Decision, Track 2b, Natural Gas Safety, Data and Process	April 2023
Final Decision, Track 2b, Natural Gas Safety, Data and Process	No earlier than 30 days after the Proposed Decision has been issued

Each Track of this proceeding will stand submitted upon the filing of reply briefs, unless the administrative law judge directs otherwise. Based on the above schedule, this proceeding will not be resolved within 18 months as required by Pub. Util. Code § 1701.5 and the statutory deadline must be extended to August 1, 2023.

6. Category of Proceeding/*Ex Parte* Restrictions

This proceeding is characterized as ratesetting. Accordingly, *ex parte* communications are restricted and must be reported pursuant to Article 8 of the Commission's Rules.

7. Intervenor Compensation

Any eligible parties wishing to do so may file a new or revised Notice of Intent (NOI) to seek intervenor compensation related to work on Track 2. Section 1804 (a)(1) of the Public Utilities Code allows the Commission to determine an appropriate procedure for accepting new or revised NOIs if new issues emerge subsequent to the time originally set for filing of the NOI. The Track 2 issues specified in this Scoping Memo were identified subsequent to the original deadline for filing NOIs. This ruling allows parties to file new or revised NOIs to reflect their anticipated work on Track 2 issues no later than 30 days after issuance of this Scoping Memo.

8. Response to Public Comments

Parties may, but are not required to, respond to written comments received from the public. (*See* Pub. Util. Code § 1701.1(g).) Parties may do so by posting such response using the "Add Public Comment" button on the "Public Comment" tab of the docket card for the proceeding.

9. Public Advisor

Any person interested in participating in this proceeding who is unfamiliar with the Commission's procedures or has questions about the electronic filing procedures is encouraged to obtain more information at http://consumers.cpuc.ca.gov/pao/ or contact the Commission's Public Advisor at 866-849-8390 or 415-703-2074 or 866-836-7825 (TYY), or send an e-mail to public.advisor@cpuc.ca.gov.

10. Service of Documents on Commissioners and Their Personal Advisors

Rule 1.10 requires only electronic service on any person on the official service list. This will also include electronic service only to the assigned ALJ pursuant to Rule 1.10(e). When serving documents on commissioners or their personal advisors, whether or not they are on the official service list, parties must only provide electronic service. Parties must NOT send hard copies of documents to commissioners or their personal advisors unless specifically instructed to do so.

11. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Karl J. Bemesderfer is the assigned ALJ for the proceeding.

IT IS RULED that:

1. The scope of this proceeding is described above.
2. The schedule of this proceeding is as set forth above.
3. Evidentiary hearings are not needed at this time; however, potential hearing dates have been placed in the schedule in the event evidentiary hearings are determined to be necessary and appropriate.
4. The category of the proceeding is ratesetting.
5. Opening comments on this Scoping Memo are due November 2, 2021 and are limited to 20 pages.
6. Reply comments on this Scoping Memo are due November 12, 2021 and are limited to 10 pages.
7. The statutory deadline in this proceeding is extended to August 1, 2023.

8. Any eligible parties wishing to file a Notice of Intent to seek intervenor compensation related to work on Track 2 must do so no later than 30 days after issuance of this Scoping Memo.

9. Except as expressly set forth in this Scoping Memo, the terms of the previously issued Scoping Memo and Ruling remain unchanged.

Dated October 14, 2021, at San Francisco, California.

/s/ CLIFFORD RECHTSCHAFFEN
Clifford Rechtschaffen
Assigned Commissioner