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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 PHASE 2 SCOPING MEMO AND RULING

This Phase 2 Scoping Memo sets forth the category, issues to be addressed, schedule, and other matters to be addressed in Phase 2 of this proceeding pursuant to Public Utilities (Pub. Util.) Code Section 1701.1 and Article 7 of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure (Rules). This ruling extends the statutory deadline for this proceeding to March 31, 2024.

1. General Background

On January 27, 2020, the Commission issued an Order Instituting Rulemaking (OIR) to respond to past and prospective events that require changes to certain policies, processes, and rules that govern the natural gas utilities in California. Past events include the Aliso Canyon gas leak in southern California as well as the rupture and prolonged outage of transmission

Line 235-2, which led to price spikes[1] and reliability problems,[2] prompting the Commission to reconsider reliability and compliance standards for gas utilities in Phase 1 of this proceeding.[3] Prospective events include the implementation of city, state, and regional policies, laws, and regulations that require or incentivize fuel substitution (from natural gas to electric appliances), as well as the prospect of changes in consumer choices, that collectively are projected to reduce demand for natural gas in California.

Since its peak in 2000, gas demand in California has declined by about 17 percent and is currently declining at the rate of about 1.1 percent annually.[4] Recent local and state policy developments make it likely that these trends will continue or accelerate over the next 10-20 years.[5]

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[1] Aliso Canyon Investigation (I.) 17-02-002 Phase 2 Results of Econometric Modeling Report, available as of July 26, 2023 at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/november-2-2020-results-of-econometric-modeling.pdf.

[2] Winter 2018-19 SoCalGas Conditions and Operations Report, available as of July 26, 2023 at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/conditions-and-operations-reports/winter2018-19lookbackreport-final-january2020.pdf.

[3] Decision (D.) 22-07-002 reaffirmed the existing reliability standards and implemented a citation program for a utility's failure to meet minimum transmission design standards.

[4] 2022 California Gas Report at 6, citing energy efficiency and fuel switching as primary drivers (as well as climate change, at 46). The report projects total statewide annual average rates of decreased demand in the residential, electric generation, and commercial sectors between 2022 and 2026 of 2.4 percent, 1.1 percent and 1.5 percent, respectively. While the report projects a decline in gas demand for the electricity generation sector in Northern California of one percent annually, demand in this sector in Southern California is projected to decrease 2.6 percent annually (*Id.* at 29 and 115). Available as of May 26, 2023 at: https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_Report_2022.pdf.

[5] The California Energy Commission (CEC) is undertaking work to improve gas demand forecasts as described in the docket for its Gas Decarbonization Proceeding, initiated on March 1, 2022. Available as of June 21, 2022 at: Order Instituting Informational Proceeding for

In addition to declining gas demand for retail use, gas used for electricity generation is also expected to decline. In particular, in 2018, Senate Bill (SB) 100 (De Leon, 2018) established an aggressive state renewable electricity goal that requires 100 percent of retail electricity to come from renewable energy and zero-carbon resources by 2045.[6] Interim targets set by SB 1020 (Laird, 2022) require 90 percent of retail electricity to come from renewable energy by 2035 and 95 percent by 2040. At present, about 900 gas-fired power plants consume about one-third of the gas used in California, with the highest power-producing facilities being the Dynegy Moss Landing and Delta Energy Center combined cycle power plants.[7] Implementation of SB 100, SB 1020, and other state and local drivers of fuel substitution from natural gas to electricity is expected to reduce the total demand for natural gas by electric generators and decrease the total amount of gas moving through California's pipeline system on an annual basis.

Taken together, these trends could dramatically impact natural gas costs and rates in the coming decades.[8] To the extent that natural gas pipeline system,

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Gas Decarbonization | California Energy Commission. (*See also* CEC, Final 2021 Integrated Energy Policy Report, Volume III: Decarbonizing the State's Gas System at 116.)

[6] Some 148,000 megawatts of new clean energy resources will be needed by 2045 to meet this goal. (*See* "Building the Electricity Grid of the Future: California's Clean Energy Transition Plan" (May 2023), available as of May 26, 2023 at: https://www.gov.ca.gov/2023/05/25/governor-newsom-updates-the-roadmap-to-californias-clean-energy-future/.)

[7] Large facilities listed at Energy Information Administration, California Electricity Profile, 2021, Table 2B, available as of July 24, 2023 at: https://www.eia.gov/electricity/state/california/state_tables.php.

[8] Energy and Environmental Economics, Inc., The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use, CEC-500-2019-055-F, available as of July 25, 2023 at: https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf; *see also*

maintenance, safety, repair, and replacement costs are assigned to fewer and fewer customers due to large numbers of gas customers exiting the system, remaining customers would be likely to face increased costs. A primary remaining task of this proceeding is to better assess this situation and potential mitigations, including identifying near term opportunities to reduce costs and emissions from the natural gas system.

Regarding Phase 2, if gas demand declines as projected in the coming years there may be opportunities for cost savings from derating pipelines from transmission to distribution pipelines. However, such opportunities must be carefully considered.

2. Procedural Background

On January 5, 2022, an Assigned Commissioner's Amended Scoping Memo and Ruling was issued regarding Track 2 issues (2022 Scoping Memo). The 2022 Scoping Memo updated and superseded an October 14, 2021 Amended Scoping Memo as well as the initial April 23, 2020 Scoping Memo and Ruling.

The Commission has so far adopted four decisions in this rulemaking. The first three decisions address reliability standards, market structure, and regulations.[9] D.22-12-021 adopts General Order (GO) 177, which applies to large

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Gridworks, California's Gas System in Transition: Equitable, Affordable, Decarbonized and Smaller, 2019, available as of July 25, 2023 at: https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

[9] D.21-11-021 established an Operational Flow Order structure for SoCalGas and San Diego Gas & Electric Company (SDG&E) (jointly, the Sempra Companies). D.22-04-042, extended the year-round SoCalGas Rule 30 Operational Flow Order winter non-compliance penalty structure and applied it to the Sempra Companies and Pacific Gas and Electric Company (PG&E). D.22-07-002, established a framework for a citation program when a utility fails to maintain adequate backbone capacity, amongst other matters. Resolution (Res.) UEB-013, issued on June 14, 2023, adopted a citation program to enforce compliance with natural gas utility minimum design standards in response to D.22-07-002.

gas infrastructure projects and gas infrastructure impacting sensitive populations.

On January 10, 2022, and January 24, 2022, Commission staff hosted two workshops. Workshop panels addressed 2022 Scoping Memo issues 2.1(b)-(k).[10] On March 1, 2022, the assigned Administrative Law Judge (ALJ) issued a ruling with the workshop report prepared by Commission staff summarizing the January 10, 2022 and January 24, 2022 workshops and inviting party comments. On March 15, 2022, parties filed comments on the workshop report.

On May 25, 2022, the assigned ALJ issued a ruling seeking party comments the 2022 Scoping Memo issues 2.1(b)-(k). On June 15, 2022, parties filed opening comments on the 2022 Scoping Memo issues 2.1(b)-(k).[11] Parties filed reply comments on issues 2.1(b)-(k) on June 27, 2022.[12]

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[10] Workshop panels addressed: Criteria for Repairing or Replacing Transmission Lines; Criteria for De-rating or Decommissioning Transmission Lines; Criteria for Repairing or Replacing Distribution Lines; Criteria for Decommissioning Distribution Lines; Meeting the Needs of Hard-to-Electrify Customers; The Role of Storage; Interpreting the Obligation to Serve; Milestones for Derating and Decommissioning; and Streamlined Approval of Zonal Electrification.

[11] Opening comments were filed by Green Hydrogen Coalition; Coalition for Renewable Natural Gas (CRNG); Rocky Mountain Institute (RMI); Natural Resources Defense Council (NRDC); Central Valley Gas Storage (Central Valley); The Utility Reform Network; Southern California Edison Company (SCE); the California Independent System Operator; the Center for Accessible Technology (CforAT); the Environmental Defense Fund (EDF); Independent Energy Producers Association; the Public Advocates Office of the California Public Utilities Commission; PG&E; Vistra; Southwest Gas Corporation; Lodi Gas Storage, LLC (Lodi Gas Storage); Wild Goose Storage LLC (Wild Goose Storage); Southern California Generation Coalition (SCGC); the Sempra Companies; Sierra Club; California Environmental Justice Alliance (CEJA); and Indicated Shippers (representing Aera Energy LLC, California Resources Corporation, Chevron U.S.A. Inc., ConocoPhillips, PBF Holding Company, Phillips 66 Company, and Tesoro Refining & Marketing Company LLC).

[12] Reply comments were filed by Middle River Power LLC (MRP), CforAT, Coalition of California Utility Employees (CCUE), EDF, SoCalGas/SDG&E, PG&E, SCE, CRNG, Sierra Club/NRDC/CEJA, Utility Consumers' Action Network (UCAN), SCGC, Indicated Shippers, and RMI.

On March 3, 2023, PG&E filed a motion to reopen the comment period on the 2022 Scoping Memo issue 2.1(c)(i), which the assigned ALJ granted on May 22, 2023. On June 13, 2023, PG&E filed a proposal to reclassify 600 miles of PG&E gas transmission pipelines and associated facilities as distribution mains (PG&E Proposal). On July 7, 2023, UCAN filed opening comments on PG&E's Proposal. On July 17, 2023, PG&E and UCAN filed reply comments regarding PG&E's Proposal.

3. Phase 2 Issues

Phase 2 of this proceeding addresses 2022 Scoping Memo issues 2.1(b)-(c) and issue 2.1(g) surrounding transmission pipelines and natural gas storage fields. This Phase 2 Scoping Memo reframes these issues as "tasks" below.

3.1. Task 1: Transmission Pipelines

A method to potentially reduce costs to the natural gas pipeline system is to identify transmission pipelines that can be derated to distribution pipelines or potentially decommissioned without compromising the safety or reliability of the rest of the system.

California's intrastate gas transmission system consists of wide-diameter pipes that deliver gas under high pressure and over long distances to distribution pipelines that operate at lower pressure and provide gas directly to most customers. Customers are divided between "core" residential and commercial customers and "noncore" customers, such as electric generation plants, petroleum refineries, and industrial gas users. Ninety percent of

California's supply is obtained out-of-state[13] and noncore customers consume about 65 percent of the natural gas delivered in-state.[14]

In 2021, some 10,987 miles of intrastate transmission pipeline existed in California. PG&E owns about 63 percent of the transmission pipeline system, consisting of 6,400 miles of backbone and local transmission pipelines, and the Sempra Companies own about 37 percent of California's intrastate transmission pipeline system. Southwest Gas is a wholesale customer of SoCalGas and owns and operates only distribution lines within California.[15]

Large volume noncore industrial and electric generator customers often take natural gas delivery directly off the high-pressure backbone transmission and local transmission pipeline systems. For PG&E, about 600 very large volume noncore customers account for about 93 percent of PG&E's noncore throughput and receive their gas directly from PG&E's backbone or local transmission systems.

[13] Natural gas from out-of-state production basins is delivered into California via the interstate natural gas pipeline system. The major interstate pipelines that deliver out-of-state natural gas from production facilities in Canada, Wyoming, New Mexico, and Texas to California gas utilities are Gas Transmission Northwest Pipeline, Kern River Pipeline, Transwestern Pipeline, El Paso Pipeline, Ruby Pipeline, Mojave Pipeline, and Tuscarora. Another pipeline, the North Baja-Baja Norte Pipeline takes gas off the El Paso Pipeline at the California/Arizona border and delivers that gas through California into Mexico. The Federal Energy Regulatory Commission regulates the transportation of natural gas on the interstate pipeline. Some 19 percent of 2018 natural gas consumption was delivered directly to California large volume customers via the interstate pipeline system. CPUC Natural Gas Overview webpage, available as of July 24, 2023 at: https://www.cpuc.ca.gov/natural_gas/.

[14] *Ibid.*

[15] Commission May 2023 Senate Bill 695 Report: Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Pub. Util. Code Section 913.1 (SB 695 Report) at 80, available as of June 22, 2023 at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2023/2023-sb-695-report---final.pdf.

More than 80 percent of current transmission lines were installed before 1980. The expected physical lifetime of pipelines varies but is generally 70 to 75 years.[16] Numerous electric or natural gas turbine compressor stations along the transmission pipelines pressurize and pump the gas to enable its movement over long distances and elevation changes.[17]

In 2010, a PG&E transmission pipeline exploded in San Bruno, killing eight, injuring many others, and destroying neighborhoods, homes, and other infrastructure. In response to this event, the Commission moved to strengthen transmission pipeline safety requirements. In D.11-06-017, the Commission ordered all California transmission pipeline operators to prepare natural gas transmission pipeline comprehensive pressure testing implementation plans. PG&E and the Sempra Companies subsequently developed Pipeline Safety Enhancement Plans (PSEP) to pressure test or replace all segments of gas pipelines that were not pressure tested or lacked testing details.[18]

In 2019, PG&E completed its PSEP work, having spent $2.42 billion to test or replace 800 miles of pipeline, upgrade pipeline segments to allow in-line inspection (ILI), automate valves, and complete records collection and maximum allowable pressure validation. The Sempra Companies reported having spent

[16] CEC, Final 2021 Integrated Energy Policy Report, Volume III: Decarbonizing the State's Gas System at 92.

[17] Most PG&E compressors are gas-fueled and most SoCalGas compressors are electricity-fueled. CEC, June 2022. Presentation- Lead Commissioner Workshop to Launch Gas Decarbonization Proceeding at 10.

[18] The Commission in Res. L-410, adopted in 2011, found significant omissions in PG&E's pipeline records and Res. L-410 ordered PG&E and the Sempra Companies to locate complete records for transmission lines or undertake strength testing or pipeline replacement for line segments where full records could not be located.

$3.554 billion in PSEP implementation costs as of May 2023.[19] The Sempra Companies' PSEP work prioritized replacement of pre-1947 "nonpiggable" high-pressure transmission pipelines.[20]

Also in response to the San Bruno explosion, the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) revised its Transmission Integrity Management Program (TIMP) and its Distribution Integrity Management Program (DIMP) requirements for pipeline operators. TIMP requirements are more robust than those required under DIMP due to the operation of transmission pipelines at higher pressures. As a result, average costs to repair, replace or maintain transmission pipelines are higher than those for distribution pipelines.

PG&E's stated goal is to upgrade its gas transmission pipeline system to be capable of ILI for over 4,500 transmission pipeline miles by the end of 2036; if completed, this would amount to upgrading approximately 69 percent of PG&E's transmission pipeline miles. As of December 31, 2021, PG&E had upgraded 46 percent of its transmission pipeline system.[21] In March 2022, PG&E filed its 2022 Gas Safety Plan, which is reviewed and updated annually in accordance with GO 112-F Section 123.2(k) and Pub. Util. Code Section 961 and

[19] Sempra Companies' PSEP Status Report — May 2023, available as of July 25, 2023 at: https://www.socalgas.com/sites/default/files/2023-07/SoCalGas-SDGE_Monthly_PSEP_Status_Report_May%202023_Cov.pdf.

[20] *Id*. at 97-98. "Pigs" are devises used to clean or inspect pipelines in natural gas operations. Pipelines are defined as "nonpiggable" if they are difficult to inspect for a variety of reasons, such as the diameter of the pipe not supporting the size of the pig. Some older pipelines were not constructed in a way to support the use of a pig.

[21] 2022 California Gas Report at 89.

Section 963.1.[22] This report provides information about PG&E's safety activities and highlights specific gas safety work undertaken in 2021.

Although transmission lines comprise just five percent of the state's pipeline system, PG&E's revenue requirement request for its transmission system comprised 27 percent of its revenue requirement in 2023.[23] In the case of SoCalGas, transmission pipelines accounted for 11 percent of that company's total general rate case (GRC) gas revenue requirement request in 2023.[24] SDG&E's 2023 revenue requirement request for its transmission system in 2023 was $17 million, two percent of its gas revenue requirement.[25] These funds include capital, operations and maintenance (O&M), and administrative costs, including costs to implement the federally required TIMP as well as Commission-required PSEP programs.

Derating transmission pipelines to distribution pipelines, when hydraulically feasible, warranted and safe, can reduce transportation costs for all customers. For instance, PG&E has reported retiring 22 miles of transmission lines and avoiding 80 high pressure regulator rebuilds since 2018.[26] However,

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[22] *Id. at* 88.

[23] *Id.* at 83. PG&E's backbone and local transmission systems comprised eight percent ($468 million) and 19 percent ($1,052 million), respectively, of PG&E's total 2023 revenue requirement request.

[24] *Id.* at 86. SoCalGas's backbone transmission and local transmission costs accounted for eight percent ($507 million) and three percent ($157 million) of SoCalGas's 2023 GRC revenue requirement request, respectively.

[25] SB 695 Report at 88.

[26] 2022 California Gas Report at 65.

PG&E has also stated it does not expect significant retirement of transmission assets during the 2023-2026 period.[27]

Federal pipeline safety code has no regulatory requirements for downrating as this generally reduces pressure, which reduces risks associated with operating pipelines at higher pressures, such as the potential for a rupture.[28] The Commission currently requires utilities to report when a transmission line is downrated but does not require Commission approval of this action. GO 112-F requires utilities to report when they lower the operating pressure of a pipeline to less than 20 percent of Specific Minimum Yield Strength. GO 112-F, Section 125, requires the utilities to file with the Commission a Proposed Installation Report under certain conditions.[29]

3.2. Task 2: Natural Gas Storage Fields

There are eleven natural gas storage fields in California. SoCalGas owns and operates four natural gas storage fields at Aliso Canyon, Honor Rancho, La Goleta, and Playa Del Rey. PG&E owns and operates natural gas storage fields at McDonald Island and Los Medanos.[30] Independent storage providers own and operate four other natural gas storage facilities in Northern California — Wild Goose Storage, Gill Ranch Storage,[31] Central Valley Storage and Lodi Gas Storage. PG&E is also in the process of trying to sell Pleasant Creek Storage.

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[27] CEC, Final 2021 Integrated Energy Policy Report, Volume III: Decarbonizing the State's Gas System at 97.

[28] PG&E, March 15, 2022 comments on March 1, 2022 workshop report.

[29] Southwest Gas March 15, 2022 comments on March 1, 2022 workshop report.

[30] PG&E announced the sale or its Pleasant Creek natural gas storage field in 2020.

[31] PG&E maintains a 25 percent ownership in this facility.

Storage plays an essential role in balancing energy supply and demand and achieving systemwide reliability, particularly in ensuring adequate gas supply during winter peak demand.[32] Natural gas is stored in storage facilities for later use during peak daily and seasonal gas demand, thereby also helping to hedge against price volatility in natural gas commodity markets. The utilities use storage as a physical hedge against potential future market volatility, buying, and storing gas when it is more favorably priced during low seasonal demand (*i.e.*, the spring and fall) for use during the winter heating season when demand is high. Storage has also played a role in addressing emergency situations, including extreme weather and wildfires.[33] Without storage, much more pipeline capacity would be needed to meet peak demand. The Commission requires gas utilities to hold set amounts of storage to provide reliability, resiliency, and price protection for core customers.[34]

In 2018, the California Geologic Energy Management Division (CalGEM) established fourteen new underground gas storage regulations. These include

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[32] Peak demand generally refers to the highest gas demand for a day, which usually occurs in the morning and evening. More specifically, the utilities design their gas systems to meet forecast peak demand during an extreme cold event likely to occur within a given number of years (*i.e.*, PG&E's peak day design standard is a one-in-90 year event for core customers and one-in-two year event for noncore customers; SoCalGas' peak day design standard is a one-in-35 year event for core customers and a one-in-10 year event for noncore customers). D.22-07-002 reaffirmed these standards for both utilities.

[33] California Council on Science and Technology, January 2018, Long-Term Viability of Underground Natural Gas Storage in California, An Independent Review of Scientific and Technical Information, Conclusion 2.5 at page 506 at: https://ccst.us/wp-content/uploads/Full-Technical-Report-v2_max.pdf.

[34] D.20-08-044 authorizes SoCalGas to allocate a set amount of storage (42.9-82.5 billion cubic feet [Bcf]) for core customers based on the inventory capacity at Aliso Canyon. D.19-09-025 requires PG&E to reserve five Bcf of PG&E-owned storage for core customers. For its Core Gas Supply, PG&E is further required to procure additional storage capacity from the Independent Storage Providers that is sufficient to meet one-in-10-year peak day demand (D.19-09-025 at Ordering Paragraph 19). The exact quantity to be procured is deemed confidential.

mechanical testing mandates that require each well to be taken out of service for inspection every 24 months, unless an alternative frequency is approved by CalGEM, and semiannual field shut in tests for inventory certification.[35] On March 13, 2020, a PHMSA Final Rule for Underground Storage regulation went into effect.[36]

Since October 23, 2015, when the Aliso Canyon leak occurred, this Commission has adopted a variety of restrictions on SoCalGas's use of Aliso Canyon.[37] In 2017, in response to SB 380 (Pavley, 2016), the Commission initiated I.17-02-002 to determine the feasibility of minimizing or eliminating use of the Aliso Canyon natural gas storage facility while maintaining energy and electric reliability and just and reasonable rates in California.[38] I.17-02-002 is ongoing as of the date of this scoping memo.

Funds to operate and maintain natural gas storage fields comprised two percent ($82 million), four percent ($245 million), and three percent ($30 million) of PG&E's, SoCalGas', and SDG&E's 2023 revenue requirement requests, respectively.[39] Storage costs include the capital and O&M costs of operating natural gas storage facilities, including biennial well testing in accordance with

[35] 2022 California Gas Report at 146.

[36] *Id.* at 146. The PHMSA Final Rule adopts American Petroleum Institute Recommended Practice 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, as published, modifies compliance timelines, formalizes integrity management practices, and clarifies the state's regulatory role.

[37] *Id.* at 144 for an overview of these restrictions.

[38] OIR for I.17-02-002 available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M176/K180/176180991.PDF.

[39] SB 695 Report at 82-83, 86, and 88.

CalGEM regulations and other aspects of the utilities' Storage Integrity Management Program (SIMP).[40]

3.3. Issues in Scope of Phase 2

Issues scoped into this proceeding regarding transmission infrastructure and storage include:

Task 1: Transmission Pipelines[41]

a. What criteria should the Commission use to determine whether aging transmission infrastructure should be repaired or replaced versus being de-rated or decommissioned when a gas utility requests ratepayer funds?

b. Should the criteria for whether to repair/replace or de-rate/decommission be based on whether that piece of infrastructure is necessary to meet the utility's design standard as determined in Track 1?

c. What other criteria might be considered?

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

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

f. How should the Commission define a transmission pipeline versus a distribution pipeline?

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

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[40] SIMP requirements are set by PHMSA and CalGEM under Title 49 Code of Federal Regulations (CFR) Part 192.12 and Title 14 CFR § 1726, respectively, and are intended to identify and manage threats to the functional integrity of storage wells and reservoirs. Operators must periodically reassess storage wells using proscribed methods, identify existing and potential threats, and remediate them.

[41] These issues were included in the 2022 Scoping Memo as issues 2.1(b)-(c).

Task 2: Natural Gas Storage Fields[42]

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

4. Phase 3 Issues

I intend to issue a ruling with questions (Ruling Seeking Comments) or a draft Phase 3 Scoping Memo for comment by March 31, 2024 — prior to finalizing the issues to be scoped in Phase 3 of this proceeding. The purpose of the Ruling Seeking Comments or draft Phase 3 Scoping Memo for comment will be to frame the outstanding pending issues from the 2022 Scoping Memo, such as those related to distribution pipelines, cost control and cost allocation issues, and data and gas infrastructure planning needs, as well as to discuss additional issues related to long-term gas planning. Working with staff and the assigned ALJ, I may also host one or more workshops focused on the presentation of relevant data and existing or ongoing analyses that could help inform issues in scope for Phase 3.

5. Need for Evidentiary Hearing

There are no presently identified contested, material issues of fact associated with this proceeding. Accordingly, evidentiary hearings are not needed for Phase 2 of this proceeding.

6. Schedule

The following schedule is adopted here and may be modified by the ALJ as required to promote the efficient and fair resolution of the rulemaking:

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[42] This issue was included in the 2022 Scoping Memo as issue 2.1(g).

EVENT	DATE
Proposed decision on Tasks 1-2	Q3 2023
Issuance of Ruling Seeking Comments or a draft Phase 3 Scoping Memo for comment	Prior to March 31, 2024
Issuance of Phase 3 Scoping Memo	Prior to March 31, 2024

Phase 2 of this proceeding was submitted on July 17, 2023, with the filing of reply comments on the PG&E proposal. In order to provide time for the development of a scope and schedule for Phase 3, however, the statutory deadline for this proceeding is extended to March 31, 2024.

7. Alternative Dispute Resolution Program and Settlements

The Commission's Alternative Dispute Resolution (ADR) program offers mediation, early neutral evaluation, and facilitation services, and uses ALJs who have been trained as neutrals. At the parties' request, the assigned ALJ can refer this proceeding to the Commission's ADR Coordinator. Additional ADR information is available on the Commission's website.[43]

Any settlement between parties, whether regarding all or some of the issues, shall comply with Article 12 of the Commission's Rules of Practice and Procedure and shall be served in writing. Such settlements shall include a complete explanation of the settlement and a complete explanation of why it is reasonable in light of the whole record, consistent with the law and in the public interest. The proposing parties bear the burden of proof as to whether the settlement should be adopted by the Commission.

[43] *See* D.07-05-062, Appendix A, § IV.O.

8. Category of Proceeding and *Ex Parte* Restrictions

This ruling confirms the 2022 Scoping Memo's determination that this is a ratesetting proceeding. Accordingly, ex parte communications are restricted and must be reported pursuant to Article 8 of the Commission's Rules of Practice and Procedure.

9. Public Outreach

Pursuant to Pub. Util. Code Section 1711(a), I hereby report that the Commission sought the participation of those likely to be affected by this matter by noticing it in the Commission's monthly newsletter that is served on communities and business that subscribe to it and posted on the Commission's website. In addition, the Commission served the OIR on R.04-01-025 and I.17-02-002.

10. Intervenor Compensation

Pursuant to Pub. Util. Code Section 1804(a)(1), a customer who intends to seek an award of compensation must have filed and served a notice of intent to claim compensation by April 23, 2020, 30 days after the prehearing conference was held on March 20, 2020.

11. Response to Public Comments

Parties may, but are not required to, respond to written comments received from the public. Parties may do so by posting such response using the "Add Public Comment" button on the "Public Comment" tab of the online docket card for the proceeding.

12. 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 866-836-7825 (TTY), or send an email to public.advisor@cpuc.ca.gov.

13. Filing, Service, and Service List

The official service list has been created and is on the Commission's website. Parties should confirm that their information on the service list is correct and serve notice of any errors on the Commission's Process office, the service list, and the ALJ. Persons may become a party pursuant to Rule 1.4.[44]

When serving any document, each party must ensure that it is using the current official service list on the Commission's website.

This proceeding will follow the electronic service protocol set forth in Rule 1.10, with the exception that the requirement to serve a paper copy of filed documents on the assigned ALJ is waived for Phase 2 of this proceeding. All parties to this proceeding shall serve documents and pleadings using electronic mail whenever possible, transmitted no later than 5:00 p.m. on the date scheduled for service to occur.

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.

Persons who are not parties but wish to receive electronic service of documents filed in the proceeding may contact the Process Office at

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[44] The form to request additions and changes to the Service list may be found at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/administrative-law-judge-division/documents/additiontoservicelisttranscriptordercompliant.pdf.

process_office@cpuc.ca.gov to request addition to the "Information Only" category of the official service list pursuant to Rule 1.9(f).

The Commission encourages those who seek information-only status on the service list to consider the Commission's subscription service as an alternative. The subscription service sends individual notifications to each subscriber of formal e-filings tendered and accepted by the Commission. Notices sent through subscription service are less likely to be flagged by spam or other filters. Notifications can be for a specific proceeding, a range of documents, and daily or weekly digests.

14. Receiving Electronic Service from the Commission

Parties and other persons on the service list are advised that it is the responsibility of each person or entity on the service list for Commission proceedings to ensure their ability to receive emails from the Commission. Please add "@cpuc.ca.gov" to your email safe sender list and update your email screening practices, settings, and filters to ensure receipt of emails from the Commission.

15. Assignment of Proceeding

Commissioner Karen Douglas is the assigned Commissioner and Cathleen A. Fogel is the assigned ALJ and presiding officer for the proceeding.

IT IS RULED that:

1. The scope of Phase 2 of this proceeding is described above and is adopted.
2. The schedule of Phase 2 of this proceeding is set forth above and is adopted.
3. Evidentiary hearing is not needed during Phase 2 of this proceeding.
4. The category of the proceeding is ratesetting.

5. The statutory deadline for this proceeding is extended to March 31, 2024.

Dated August 1, 2023, at San Francisco, California.

/s/ KAREN DOUGLAS
Karen Douglas
Assigned Commissioner