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Staff Proposal on Gas Distribution Infrastructure Decommissioning Framework in Support of Climate Goals

California Public Utilities Commission Staff
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1 Contents

1 Executive Summary

Given California's climate goals and the California Public Utilities Commission's (CPUC's) mandate to ensure that utilities provide safe, reliable service at reasonable rates, the *Assigned Commissioner's Amended Scoping Memo and Ruling* (Scoping Memo) of the Long-Term Gas Planning Rulemaking (R.) 20-01-007 asks what factors should be considered to determine whether gas distribution infrastructure should be maintained or retired.[1] Specifically, the Scoping Memo presents the following questions under Track 2(a) of the proceeding:

- What criteria should the Commission use to determine whether aging distribution infrastructure should be repaired or replaced when a gas utility requests ratepayer funds?
- What criteria should be used to determine which distribution lines should have the highest priority for proactive decommissioning?[2]

Reflecting party input and CPUC staff (staff) research, this staff proposal suggests concepts and processes to guide gas distribution infrastructure decisions. Staff recommend that the Commission further refine the process discussed here in light of additional data analysis and party comments and utilize it in the planning process to be determined in Track 2.2.3 of this proceeding.[3]

Safety and reliability are key requirements for any infrastructure activities. Thus, gas utilities must continue to address hazardous leaks, and distribution pipelines should only be retired where hydraulically feasible, meaning that a pipeline segment can be retired without negatively impacting the rest of the system. Given these limits, staff recommend that distribution pipelines be prioritized for decommissioning by focusing on areas with the highest expected long-term benefits first. The following criteria are associated with higher expected benefits from decommissioning and should be prioritized:[4]

- higher pipeline risk;
- higher existing environmental health burden, including as reflected in the CalEnviroScreen scores, which underlie Disadvantaged Community designation;
- higher gas infrastructure cost savings;
- lower energy and community affordability, as reflected in measures like rent burden; and
- higher gas demand.

Staff recommend that these criteria, guided by data analysis, be used to classify all census tracts with distribution infrastructure into five tranches, ranging from those to be decommissioned early to

[1] Assigned Commissioner's Amended Scoping Memo and Ruling, R.20-01-007, January 5, 2022, Track 2(a) questions (d) and (e).
[2] "Decommissioning" refers to retirement of infrastructure. The CPUC has not specified whether the retired infrastructure must be removed or can be retired in place or what procedures may be necessary to make that safe.
[3] See footnote 1.
[4] These criteria are not listed in order of priority.

hard-to-electrify areas, using the approach detailed in this proposal. Non-emergency repair or replacement[5] of distribution infrastructure should be minimized unless mandated by other programs, such as the Natural Gas Leak Abatement Program.[6] Proactive decommissioning would occur tranche by tranche.

To implement these priorities, this proposal also suggests that utility non-emergency proposals to repair or replace gas infrastructure include cost estimates, timelines, impact on estimated risk, the location of the proposed work (which enables identification of the tranche in which it is located), and comparison with non-pipeline alternatives. These proposals would be evaluated by CPUC.

Throughout this proposal, staff pose specific questions for parties to consider to help refine these ideas. Utilities are directed to answer these questions, and other are parties encouraged to do so.

2 Background

R.20-01-007 covers many aspects of long-term gas infrastructure planning and related questions about gas transmission infrastructure, gas distribution infrastructure, and gas demand. Among other issues, R.20-01-007 is concerned with proactively planning a combination of maintenance and retirement of the gas distribution infrastructure. This planning question becomes increasingly timely in light of declining gas demand, California's goals to further reduce fossil fuel consumption, and increasing costs for remaining gas customers. Planning needs include considering criteria for decommissioning gas distribution infrastructure.

To advance these considerations, the January 5, 2022, Scoping Memo asked questions about two different scenarios related to gas distribution pipelines. In the first (Scoping Memo question 2.1(d)), a utility comes to the CPUC seeking funds for distribution work—for example, in an open general rate case (GRC)—and the Commission must decide whether to fund repair or replacement or to direct the utility to either take no action or decommission the pipelines.[7] The second scenario (Scoping Memo question 2.1(e)) considers which distribution pipelines should be considered for proactive decommissioning, outside of the context of a currently open proceeding.[8] The Scoping Memo asks a series of important policy and technical questions to inform the consideration of each scenario, listed under both (d) and (e) in the Scoping Memo.[9] The CPUC received extensive stakeholder comments on these questions.[10]

[5] Throughout this staff proposal, "replacement" refers to replacing existing gas infrastructure, typically pipelines, with new gas infrastructure, typically newer pipelines. If gas infrastructure is retired from use, that is referred to as "decommissioning" as noted in footnote 2. If electric or other alternatives are installed in order to provide replacement services, these are referred to as "non-pipeline alternatives."
[6] The Natural Gas Leak Abatement Program was put in place in accordance with Senate Bill 1371 by Decision (D.) 17-16-015 and D.19-08-020.
[7] See footnote 1.
[8] See footnote 1.
[9] The Scoping Memo includes sub-questions i-vii under question d, with the exclusion of "extent to which it has been depreciated," and i-x under question e.
[10] The CPUC received comments on these questions from gas and electric utilities Pacific Gas and Electric Company (PG&E), Southern California Gas Company and San Diego Gas & Electric Company (Sempra), and Southern California

<u>Scoping Memo Track 2(a) Questions "d" and "e:"</u>

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?

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 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, proximity to a source of renewable gas, extent to which it has been depreciated)?
    ii. What community characteristics, such as designation as a DAC, should be considered?
    iii. What other criteria, if any, should be considered?
    iv. What goals should be considered when using these characteristics (e.g., cost savings, minimizing stranded assets, pipeline safety, net greenhouse gas reductions, environmental justice)?
    v. What non-pipeline alternatives should be considered?
    vi. 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 [operations and maintenance] and pipeline replacement costs for retiring distribution pipelines that could be estimated and incorporated into cost-effectiveness analysis?
    vii. 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?
    viii. 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?
    ix. Are there health and safety issues that need to be addressed from decommissioned distribution lines?
    x. What procedural mechanism should be used to proactively decommission distribution pipelines?

This staff proposal addresses these Scoping Memo questions but does not seek to answer them exhaustively. Instead, staff propose here a framework of goals, criteria, and processes to help set a direction, provide guidance for future decision-making, and provide a starting point for further discussion, analysis, and party input in the proceeding. This staff proposal focuses on California's investor-owned gas utilities, PG&E, SoCalGas, SDG&E, and the Southwest Gas Company (Southwest Gas). Municipally owned gas utilities, which serve the cities of Long Beach, Palo Alto,

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Edison Company (SCE); residential, electrical and industrial gas customer groups, The Utility Consumers' Action Network (UCAN), The Utility Reform Network (TURN), the Southern California Generation Coalition (SCGC), Middle River Power, Indicated Shippers, and the Coalition for Renewable Natural Gas; labor organization, the Coalition of California Utility Employees (CUE); and environmental or other policy organizations, the Environmental Defense Fund (EDF), the Natural Resources Defense Council (EDF), the Rocky Mountain Institute (RMI), and the Center for Accessible Technology (CforAT).

and Vernon, are outside the jurisdiction of the CPUC. This staff proposal does not change or interpret gas utilities' obligation to serve customers in their service territories.

To provide some context, the table below summarizes the annual costs of California's current gas distribution system. Gas distribution system costs are shown as totals for each utility and as an average per service to provide a sense of scale.[11] Across these utilities, gas customers pay an average $283 per year to maintain the gas distribution system. These costs are only one factor in customer bills and do not reflect individual customer impacts.[12] The gas distribution system consists of the infrastructure that transports gas from the gas transmission system to the customer. The gas transmission system is not reflected in the table below and is not addressed in this proposal.

Table 1: Gas Distribution System Customers and Costs (Proposed by Utilities for 2023)

	PG&E	SoCalGas	SDG&E	Southwest Gas	Total or Average
(A) Services[13]	3,575,074	4,577,959	661,143	191,228	9,005,404
(B) Gas Distribution System Annual Costs (includes Capital and Expense Costs)	$1,823,325,380[14]	$578,576,000[15]	$100,400,000[16]	$47,871,769[17]	$2,550,173,149
Annual Distribution System Cost per Service (B / A)	$510	$126	$152	$250	$283

In this document, staff propose an approach to translate policy goals into geographic criteria and apply them to prioritizing where to repair, replace, or decommission gas distribution infrastructure.

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[11] Per 49 CFR 192.3: A service line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold: https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192/subpart-A/section-192.3.

[12] Gas customers' bills pay for the gas itself, the gas distribution system, the gas transmission and storage system, customer service, and public purpose programs.

[13] Calculated based on Long-Term Gas Planning Rulemaking (ca.gov), https://www.cpuc.ca.gov/industries-and-topics/natural-gas/long-term-gas-planning-rulemaking, "Gas System Census Tract Data" from each utility, column "Services," as submitted on November 4, 2022. This data was also submitted to the service list by each utility.

[14] Calculated based on Long-Term Gas Planning Rulemaking (ca.gov), "Gas System Summary Statistics – PGE" as submitted on November 4, 2022. See tab "Distribution Costs & Plans," row "Total gas distribution system costs per year," values reported for 2023, based on 2023 General Rate Case.

[15] Calculated based on Long-Term Gas Planning Rulemaking (ca.gov), "Gas System Summary Statistics - SoCalGas" as submitted on November 4, 2022. See tab "Distribution Costs & Plans," row "Total gas distribution system costs per year," values reported for 2023, based on 2024 General Rate Case.

[16] Calculated based on Long-Term Gas Planning Rulemaking (ca.gov), "Gas System Summary Statistics - SDGE" as submitted on November 4, 2022. See tab "Distribution Costs & Plans," row "Total gas distribution system costs per year," values reported for 2024 General Rate Case.

[17] Calculated based on Long-Term Gas Planning Rulemaking (ca.gov), "Gas System Summary Statistics – SW Gas" as submitted on November 4, 2022. See tab "Distribution Costs & Plans," row "Total gas distribution system costs per year," value reported as an "estimate" with year and source not specified.

Section 3 sets criteria for gas distribution system decisions and identifies specific pipeline-related, community, and other characteristics with data available at a census tract level. Section 4 describes how staff proposes these criteria should be used to assign census tracts[18] into five tranches in descending order of prioritization for proactive decommissioning of their gas distribution pipelines. In Section 5, staff outline a potential review process for gas distribution infrastructure projects, including both maintenance and decommissioning, which would utilize these tranches and other factors. Section 6 does not contain the level of detail of the other sections but discusses the opportunities and limitations posed by non-pipeline alternatives and the funding required to implement them. All sections contain questions designed to elicit alternatives and to help further refine this proposal.

3 Criteria and Goals

Distribution infrastructure repair, replacement, and decommissioning activities, as directed by the CPUC and implemented by gas utilities, should support several key goals:

1. Maintaining infrastructure safety;
2. Maintaining infrastructure reliability;
3. Reducing gas demand and gas distribution infrastructure every year until California's climate goals are achieved;
4. Maximizing community benefits, including health benefits and cost savings, by transitioning highest-need, highest-benefit areas first, and prioritizing areas with community champions among those; and
5. Supporting a smooth transition to a lower-gas-use society by saving the most costly or hard-to-decarbonize locations for last.

Substantial planning and investment will be required to achieve these goals. The following sections describe how these goals can be translated into criteria to inform gas distribution investment decisions.

3.1 Pipeline-Related Characteristics

Pipeline characteristics are currently used to assess risk and to inform infrastructure repair and replacement decisions. Pipeline-related information also forms the basis of hydraulic feasibility[19] and cost assessment for such investments. These characteristics should continue to play a role in repair, replacement, and decommissioning decisions, with further information needed, particularly regarding costs, as described below.

3.1.1 Safety and Investment

Safety must always be a primary goal of any energy system. Safety also interacts with investment decisions in that the highest-risk infrastructure, all else being equal, should be targeted for the

[18] In this staff proposal, "communities" is used as a synonym for "census tracts."

[19] By "hydraulic feasibility," we mean whether it is feasible to isolate and stop using a given set of pipeline segment(s) while maintaining the usual flow of gas in surrounding pipelines to surrounding customers. Hydraulic modelling of gas flows and pressures within pipelines can be used to assess this. A pipeline decommissioning proposal is "hydraulically infeasible" if it would result in loss of existing gas flow to customers who are not planned to be part of the project.

earliest repair or replacement with new gas infrastructure or alternatives. Pipeline safety is assessed primarily in two related ways: existing leaks and risk assessment.

The federal Pipeline and Hazardous Materials Safety Administration (PHMSA) requires gas utilities to conduct leak surveys of their distribution pipelines on a regular basis and repair hazardous leaks, also known as Grade 1 leaks, in a timely manner, following procedures developed by each utility.[20] Leak abatement is further required per Senate Bill (SB) 1371 (Leno, 2014) and Decisions (D.) 17-06-015 and D.19-08-020, which incorporate leak abatement requirements into gas utilities' safety plans. Best Practice 21 of D.17-06-015 states: "Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, more than three (3) years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak." An example of an exception would be a small leak from an underground distribution pipe that would require expensive excavation to dig up and repair such that the cost per unit of emissions saved greatly exceeds the average for such repairs. Leak repair is a primary driver of pipeline repair and replacement.

In addition to leak repair, every gas utility has a Distribution Integrity Management Program (DIMP), which pre-emptively replaces distribution pipeline segments based on assessed risk. For older pipelines without hazardous leaks, gas utilities calculate a leak risk for each pipeline segment. These risk scores are used by utilities to identify which pipeline segments are highest risk and therefore should be replaced soonest. This risk calculation is based on utility-specific formulas using inputs such as soil conditions, nearby past leaks, pipeline material, and pipeline age. Therefore, these calculations of the probability of a leak per year, also known as the likelihood of failure,[21] are a more effective way to capture risk than just material or age. This assertion should be further examined using forthcoming data. For each such pipeline segment, utilities also calculate the probability of a serious safety *incident* given a leak, also known as consequence of failure. The product of the likelihood of failure and consequence of failure is the risk score of that segment.

Staff recommend that risk scores should be considered as a means to prioritize repairing, replacing, or decommissioning the riskiest pipelines. The CPUC may wish to consider partially or fully standardizing the approach across utilities and coordinating through the Risk-Based Decision-making Proceeding, R.20-07-013, which establishes risk assessment policy across utility activities.[22] When comparing the significance of distribution pipeline risks with other criteria for prioritizing decommissioning, the CPUC should continue to compare these risks with those posed by other energy infrastructure, since average distribution pipeline risk is low.

[20] Federal Code 49 CFR Sections 192.605, 192.703(b) & (c), 192.706, and 192.723.
[21] The likelihood of failure is sometimes also referred to as the "risk of failure."
[22] PG&E, SoCalGas, and SDG&E are required to file Risk Assessment Mitigation Phase (RAMP) reports pursuant to guidance adopted in D.22-12-027 and D.18-12-014 and the reports are also an input to the General Rate Case proceedings. RAMP filings have included risk-spend efficiency ratios calculated for diverse utility activities, including distribution infrastructure activities. Risk-spend efficiency ratios are calculated by dividing avoided risk by expenditures. In D.22-12-027 the CPUC replaced risk-spend efficiency ratios with a requirement that utilities calculate cost-benefit ratios that incorporate the monetary value of the avoided risk.

3.1.1.1 Questions for Parties

1) Do you recommend any changes to the five key goals proposed in Section 3?
2) Is *likelihood of failure* (reflecting the probability of failure) or risk score (*likelihood of failure* times *consequence of failure*, thereby reflecting the probability and size of the potential harm) a better way to reflect pipeline risk when prioritizing among communities?
3) Is there a level of risk at which it is not cost-effective or reasonable to replace distribution pipelines? If so, what is that level and by what method should it be assessed?

3.1.2 Feasibility

Hydraulic feasibility analysis will be necessary before commencing each decommissioning project. In areas served by gas, distribution main pipelines run under most streets. Valves at intersections or other locations can be closed to isolate an area for testing or maintenance. Thus, a city block or neighborhood between two or more valves can likely be feasibly isolated and decommissioned without major impacts to surrounding areas. In some cases, isolating an area in this way would also isolate a downstream area from gas access or substantially reduce pressure or reliability in surrounding areas. In these cases, a central distribution "artery" pipeline running through the target area may need to be exempted from decommissioning until it is no longer needed to support other areas. Systemwide hydraulic analysis would be time-consuming and is not necessary to prioritize among communities. Rather, when any given decommissioning project is proposed, the gas utility should conduct a hydraulic feasibility check and recommend any lines to be exempted for access or pressure support reasons.

3.1.2.1 Questions for Parties

4) Is there a need to conduct hydraulic feasibility analysis in order to inform statewide prioritization or can such modeling be postponed until individual projects are proposed?
5) If or when hydraulic feasibility is assessed, who should conduct that analysis?

3.1.3 Cost

The CPUC will need simple, consistent equations to estimate the costs of replacement and decommissioning. For example, the cost of a project affecting 10 miles of distribution main and service pipeline and repair of valves at one regulator station could be estimated by multiplying the pipeline mileage by a material cost per mile and an installation cost per mile and adding the specific regulator station repair estimate. However, labor costs per mile may vary substantially between urban and rural areas and among areas of similar density due to factors including prevailing wage norms as well as local scheduling and permitting requirements. In particular, using a standardized pipeline replacement cost per mile suggests that areas with fewer services per mile, such as rural areas, would net the most cost savings from decommissioning, but higher labor, permitting, and schedule-related costs in urban areas may suggest the opposite. Additional information is needed to reasonably compare costs across geography. Material costs may vary between steel and plastic and based on pipeline diameter or wall thicknesses or other characteristics. Therefore, the CPUC should collect cost information from the utilities that is sufficiently granular to account for these variations but sufficiently simplified to estimate future costs.

If costs to repair, replace, or install pipelines can be avoided, the resulting savings can be substantial. PG&E reports a cost of approximately $40,000 per service to install or replace service pipelines and an additional $30,000 per service to replace the average amount of main pipelines associated with that service.[23] While SoCalGas reports lower costs per mile, approximately $15,000 for mains and services combined per affected service, they state that this estimate only includes "direct costs."[24] Insofar as infrastructure costs vary across geography, areas where non-pipeline alternatives are more affordable than repair or replacement should be prioritized for early decommissioning. The CPUC should consider costs and cost savings from a ratepayer and potentially a societal[25] perspective, including the gas infrastructure savings, other rate impacts, greenhouse gas (GHG) impacts, and costs borne by customers outside of utility rates. The ratio of gas vs. electric rates or costs should also be considered. Areas with higher residential energy costs, and higher gas-to-electric cost ratios, should be prioritized. In this way, areas with high electricity costs (but not high gas costs) will remain on the gas system longer. Costs will also be impacted by the selection of non-pipeline alternatives, discussed below.

Staff do not recommend direct consideration of depreciation costs when prioritizing among pipelines. Infrastructure costs are depreciated on an asset category basis, where a project entered into the category at a given time may affect many pipeline segments, with costs not parsed among segments. Therefore, it would be unnecessarily complex to determine the embedded depreciation costs of a given pipeline segment. Instead, staff proposes that the cost and safety metrics discussed above sufficiently represent the concepts intended by embedded depreciation costs in a manner that is easier to implement. These metrics include pipeline risk, which reflects the urgency of replacement, as well as forecast replacement costs.

Behind-the-meter costs of non-pipeline alternatives are discussed in the section "Non-Pipeline Alternatives and Funding," below.

3.1.3.1 Questions for Parties

6) What are the top 10 or fewer key cost input variables[26] necessary to estimate pipeline repair costs? For example, do they include pipeline mileage, pipeline material, city, county, or region in which the project is located, or number of known leaks?
   a) How should pipeline repair costs be estimated using these variables?
   b) Will using these variables capture at least 80 percent of the variation in costs?
7) What are the top 10 or fewer key cost input variables necessary to estimate pipeline replacement costs? For example, do they include pipeline mileage, pipeline material, pipeline diameter, city, county, or region in which the project is located?
   a) How should pipeline replacement costs be estimated using these variables?

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[23] See Long-Term Gas Planning Rulemaking (ca.gov), "Supplemental Data" for PG&E and SoCalGas, as submitted on November 4, 2022.
[24] Ibid.
[25] A societal cost approach is under consideration for distributed energy resources in proceeding R.22-11-003.
[26] "Variables" is meant to capture aspects which vary by project or geographic location. For example, if there are two common types of pipeline material, one of which costs $1/foot and another costs $2/foot, then "pipeline material" may be considered as one variable for the purposes of this question, and its costs may be calculated by multiplying the appropriate cost by pipeline mileage, which is a second variable.

   b) Will using these variables capture at least 80 percent of the variation in costs?
8) Is it most appropriate to estimate pipeline repair costs on a per mile basis, on a per mile basis plus a fixed cost per project, or by some other means?
9) What are the top 10 or fewer key cost input variables necessary to estimate regulator station repair or replacement costs? For example, do they include number and type of valves, regulators, flow meters and other equipment, and whether they are to be repaired vs. replaced, or city, county, or region where the station is located? If using, "type" of equipment, briefly identify each type and the cost differences among them.
   a) How should regulator station repair or replacement costs be estimated using these variables?
   b) Will using these variables capture at least 80 percent of the variation in costs?
10) Should valve repair or replacement costs also be considered as part of distribution infrastructure repair or replacement costs, for valves not located at regulator stations? If so, how should they be estimated?
11) What other costs, such as stub removal,[27] should be considered in decommissioning costs?
12) How should the incremental electric transmission or distribution infrastructure needs and costs associated with gas infrastructure decommissioning and associated electrification be considered?
   a) Is there a threshold electric demand increase below which electrification does not impact electric transmission or distribution infrastructure needs enough to merit consideration?
   b) What is the average per-home cost to the receiving electric utility to provide the in-front-of-the-meter infrastructure needed to support electrifying a home? What are the cost input variables, and how should they be estimated?
   c) How should the electric infrastructure implications of gas decommissioning be mapped to census tracts?

3.2 Community Characteristics

Staff recommend prioritizing community characteristics, which include existing environmental and health burdens, economic burden, affordability, and gas usage. Because of the way existing metrics are defined, some metrics, such as CalEnviroScreen scores, incorporate both health and economic burdens.

3.2.1 Community Benefits

Existing community environmental, economic, and health burdens should be a major consideration in prioritizing communities for potential decommissioning. The CalEnviroScreen (CES) is a key tool California uses to identify and prioritize burdened communities. CalEnviroScreen combines measures of pollution exposure, health impacts, health vulnerability, and economic inequity to form a standardized measure at the census tract level. Disadvantaged communities (DACs) are defined as those with CES scores in the top 25 percent (most DACs), as well as high-pollution-burden areas with no assigned overall CES scores due to missing data, DACs identified in 2017, and lands identified as under the control of federally recognized tribes. Gas decommissioning decision-making should take into account "raw" CES scores (which range from 1 to 100) to enable more detailed considerations beyond DAC designation. In addition to DACs, the CPUC's Environmental and Social Justice (ESJ Action Plan) defines ESJ Communities as low-income households and census

[27] Stub removal is the removal of pipeline end sections no longer in use.

tracts (below 80 percent of area mean income). DAC and ESJ Community areas (but not individual households, since the goal is to assess at the tract level) should be taken into consideration here.

Certain other variables merit particular consideration because of their relationship with gas or air quality. Asthma rates, a component of the CES calculation, should be considered since natural gas use may affect indoor air quality. Therefore, focusing on high asthma rate communities first may be appropriate. Ground-level ozone, also considered in CES, should also receive particular consideration because methane (i.e., natural gas) is the primary compound reacting with nitrous oxides (NOx) to create ground-level ozone, and ground-level ozone and particulate matter are the most widespread and health-impacting of the six criteria air pollutants.[28] For these reasons, areas with higher asthma rates and ozone levels may benefit most from reductions in natural gas use. Indoor air quality measures, if available, may also merit consideration given recent research on potential gas impacts on indoor air.

High asthma rates and ground-level ozone rates should be given the highest priority among community characteristics prioritizing areas for early decommissioning. Consistent with the ESJ Action Plan and given historic disinvestment, Tribal lands should also be prioritized. Low-income tracts should be considered in the context of the affordability measures discussed below. The CPUC will continue to look into the overlap among these communities.

3.2.1.1 Questions for Parties

13) Do the variables discussed appropriately account for the potential community benefits from reduced gas use? Are there other community characteristics that should be considered?
14) Should indoor air quality be a consideration in prioritizing among communities? If so, what data should be used to represent variations in indoor air quality among census tracts?

3.2.2 Gas Demand and Affordability

Affordability, while included in some inputs to CalEnviroScreen scores, should also be considered as a distinct priority. The goal of affordability metrics for this purpose should be to capture a community's ability to afford energy; areas with lower affordability will benefit more from any reduction in energy costs. As customers leave the gas system, ongoing infrastructure costs will be covered by fewer customers, so rates are likely to increase for remaining gas customers. Given support from parties and workshop presenters and the potential to reduce long-term costs, low-affordability communities should be prioritized for proactive electrification or other non-pipeline alternatives. However, subsidies and/or rate reform may be necessary to avoid imposing increased energy costs on these communities in the short term; this topic should be addressed in the cost allocation portion of this proceeding, and in other ongoing proceedings, as appropriate.[29]

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[28] California Office of Environmental Health and Hazard Assessment, *CalEnviroScreen 4.0 Report*, October 2021, https://oehha.ca.gov/media/downloads/calenviroscreen/report/calenviroscreen40reportf2021.pdf#page=31, p. 31.
[29] Gas cost and rate proceedings include General Rate Cases (GRC), Triennial Cost Allocation Proceedings (TCAP), and Gas Transmission and Storage Cost Allocation and Rate Design (GT&S CARD) proceedings.

Metrics used to represent affordability may depend on data availability as well as relevance to gas demand. The CPUC has defined affordability and continues to address it via a dedicated rulemaking, R.18-07-006. The metrics used in that proceeding include the "Affordability Ratio," representing how much of a household's discretionary income is spent on utility service; the Socioeconomic Vulnerability Index, composed of metrics similar to some used in CalEnviroScreen; and Average Hours Worked at Minimum Wage. The Affordability Ratio, while relevant, is available only at the Public Utility Microdata Area (PUMA) level; each PUMA is composed of many census tracts. Related metrics available at the census tract level include gross rent and utility costs as a percentage of household income. Data available at the tract level should be favored in order to accurately reflect variations within larger areas.

Peak demand drives the amount of gas infrastructure needed and thus should be a consideration in prioritizing among communities. Although industrial customers constitute a substantial proportion of average gas demand, residential, commercial, and thermal electric generation gas use typically fluctuates more throughout the day and year. Where detailed peak demand data may be unavailable, residential and noncore commercial demand (as reported by utilities) or household gas costs (from utilities or census data) may be useful proxies for the local impact on systemwide peak demand for comparison among geographic areas. Gas-fired power plants' demand fluctuations should be considered for census tracts that contain such generation facilities. Weather information, particularly climate zones and heating and cooling degree days, may also merit continued consideration because they are major drivers of residential and commercial energy demand. Focusing on higher demand areas will enable greater gas use reductions. Climate zones are also used in rate-setting and therefore have cost implications.

Focusing on residential demand will typically enable the most reductions in gas distribution infrastructure costs, because most distribution infrastructure serves residential customers. However, more GHG emission reductions may be achievable by focusing on larger, non-residential gas customers. If electric alternatives are available, small commercial (non-industrial) operations may offer some of the most cost-effective electrification opportunities, as reflected in CEC analysis.[30] The CPUC should continue to consider how to address commercial gas demand in light of available technologies.

3.2.2.1 Questions for Parties

15) Do the variables discussed above appropriately represent affordability? Are there other affordability metrics that should be considered?
16) Should distribution pipeline decommissioning efforts focus primarily on residential customers? If so, why? If not, where should they focus?
17) How should non-residential, non-industrial gas demand be considered when prioritizing among communities?

[30] California Energy Commission, *California Building Decarbonization Assessment*, 2022, and associated data analysis, https://www.energy.ca.gov/publications/2021/california-building-decarbonization-assessment.

a) Should some sectors, such as restaurants, laundromats, schools, or hospitals, be prioritized for decommissioning, or alternatively, for maintaining gas infrastructure? If so, which ones and why?
b) What non-pipeline alternatives should be the focus for these sectors?

18) How should GHG impacts be considered when comparing among communities?
  a) Should GHG emissions from gas combustion, from gas leaks (methane release), and/or from non-gas GHG sources be used as a variable to compare among communities? If so, what data should be used to represent variations in these factors among census tracts?
  b) If yes to (a), how should this data be used when constructing the tranches discussed below?

3.3 Other Characteristics

In addition to pipeline information and community characteristics as defined above, the presence of community champions and hard-to-electrify facilities or sources of biomethane should be considered.

3.3.1 Community Champions

For early decommissioning programs such as pilots, the presence of community champions is an important consideration. The earliest decommissioning projects are likely to be the most challenging and expensive, with effectiveness and efficiency increasing with experience and technological development over time. An entity with significant community presence, whether a community-based organization such as a housing or environmental advocacy organization; a governmental entity such as a city, tribe, or public university; or a private corporation such as a landowner, developer, housing cooperative, or large commercial facility, may be able to facilitate outreach, support economies of scale, and help trouble-shoot other practical challenges to successful electrification. For example, PG&E has worked with California State University Monterey Bay to develop PG&E's Zonal Electrification Pilot Project Application (A.) 22-08-003, currently pending before the CPUC. Utilities planning electrification and decommissioning projects should look for community champions to partner with, and areas with self-identified community champions should be prioritized. Such entities may also be able to source non-ratepayer funds for electrification.

3.3.1.1 Questions for Parties

19) Should the presence of community champions be an important consideration in prioritizing areas for decommissioning? Why or why not?

20) Please identify the key types (of those listed above, or others) of community champions and attributes for an effective community champion.

21) How should community champions be identified?
  a) What process should be used, by whom, and when?
  b) If possible, provide a list of any identified potential community champions by name, address and 11-digit census tract.

22) Should the CPUC promote community champions? Why or why not? And, if yes, how?

3.3.2 Industrial Facilities and Biomethane

The presence of hard-to-electrify gas users and sources of biomethane on a pipeline should lower its priority for decommissioning. Large industrial facilities are often connected to gas pipelines designed specifically to serve them. Many industrial facilities use gas to produce heat using boilers, for which medium-temperature electric versions are available but expensive. Some industrial facilities use gas to produce particularly high temperatures or as an input to chemical reactions, thus making their gas use difficult to replace with electricity. Accordingly, the California Air Resources Board's (CARB) 2022 Scoping Plan (Scoping Plan) identifies the following high-temperature and calcining industries as hard-to-electrify: steel, glass, lime, and cement production.[31] In considering future energy demand, the Scoping Plan also models that 15 percent of current fossil fuel extraction and refining will remain online in 2045, and some concrete production may be reduced by substitution with other materials per SB 596. These considerations and future CARB definitions should be taken into account in identifying "hard-to-electrify" facilities and their future size for the purposes of gas planning.

Biomethane is among the energy options for hard-to-electrify industries. Biomethane is produced at local sites—such as landfills, wastewater treatment plants, and dairies—that often depend on pipelines to bring their product to customers. In D.22-02-025, the CPUC ordered the gas utilities to procure 72.8 billion cubic feet (Bcf) of biomethane annually by 2030 for core customers to comply with SB 1440 (Hueso, 2018) and SB 1383 (Lara, 2016).[32] Since pipelines are needed to comply with this decision, pipelines that bring biomethane to market should not be prioritized for decommissioning.

Hydrogen is another energy option for hard-to-electrify industries, particularly those with processes that require higher-temperature heat. In CARB's Scoping Plan Scenario almost 90 percent of energy demand is electrified by 2045, and the remaining energy demand is met with combustion of hydrogen, biomethane, and fossil gas.[33] If hard-to-electrify industrial customers switch to hydrogen, that could be a factor in the decommissioning of a distribution line. The CPUC has not made a determination whether the hydrogen pipeline delivery services provided by investor-owned utilities would fall within the jurisdiction of the CPUC.[34]

3.3.2.1 Questions for Parties

23) Should the presence of hard-to-electrify gas users and sources of biomethane on a pipeline lower its priority for decommissioning? Why or why not?
    a) How should this affect decommissioning of transmission vs. distribution pipelines?
24) How should "hard-to-electrify" customers be defined?

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[31] California Air Resources Board, "2022 Scoping Plan for Achieving Carbon Neutrality," November 2022, https://ww2.arb.ca.gov/resources/documents/2022-scoping-plan-documents, p. 209.
[32] CPUC, Decision (D)22-02-025, pp. 60-61, Ordering Paragaraph 18.
[33] California Air Resources Board, "2022 Scoping Plan for Achieving Carbon Neutrality," November 2022 pg. 212-213
[34] CPUC proposed decision on SoCalGas' Angeles Link Memo Account application: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K339/498339407.pdf.

a) What characteristics should be considered, such as industry classification; boiler temperature; use of gas for chemical reactions; or average or peak, current or forecast gas demand?
b) What future demand forecasts for these industries should be used?
c) How should those forecasts be allocated among facilities or used to forecast facility-level demand?

25) How do the costs per dekatherm of electrifying industrial gas customers compare to the costs per dekatherm of electrifying residential or small commercial gas customers?
26) How should the presence of industrial gas customers in a census tract affect whether the residential customers in that community have their gas pipelines repaired, replaced, or decommissioned, if at all?
27) How should the CPUC identify the set of pipelines and gas customers that should be expected to stay on the gas system using biomethane or other non-fossil fuels?
28) Is there potential for any industrial gas customers in California to electrify within the next 10 years?
    a) If so, how should these facilities be identified?

4 Defining Tranches

Staff proposes dividing all areas served by gas distribution infrastructure in California into five tranches using the criteria described in this staff proposal. Each census tract should be assigned to a tranche. These tranches should be used to prioritize communities for pipeline decommissioning or maintenance of existing pipelines. Generally, decommissioning activities in a given tranche should be largely completed before pursuing decommissioning in the next tranche. Some exceptions may need to be made, especially for hard-to-electrify customers. Because the tranches are large and each one will take years to complete, activities within a tranche may vary over time. A utility may exercise discretion within each tranche. For example, it may choose to focus first on a certain subset of a given tranche. These tranches are intended to guide utility planning, not to limit individual customer decisions. For example, some customers may choose to electrify earlier than is implied by their census tract's tranche. Data provided to date in this proceeding and in response to this staff proposal, as well as public data, can be used in defining tranches.

Staff note that census tracts, since they are designed with mail routes in mind, are related to where roads are and thus are likely related to the location of distribution pipelines. Nevertheless, staff understand that individual pipeline projects should be based on pipeline geography and may be smaller than a single census tract or may cross census tract lines.

4.1.1 Tranche 1: High Benefits Early Adoption

Staff recommends that Tranche 1 represent the earliest areas targeted to fully electrify and be defined to constitute only 5 percent of census tracts currently served by each investor-owned gas utility. This tranche should focus on areas likely to see the highest benefits from decommissioning and the most immediate potential to decommission. The tranche should therefore include census tracts with the highest community burdens, as well as areas where decommissioning would result in the highest projected ratepayer cost savings. Asthma rates, ozone rates, CES scores, and ESJ community membership (including but not limited to high CES scores) should be used to identify areas with the highest community burden. High pipeline risk should be taken into consideration to reduce risk and avoid unnecessary expenditures on pipeline replacement. Areas with identified community champions should also be included in Tranche 1. Despite forecast long-term benefits, completing this tranche may require significant investment to achieve decommissioning. Areas with particularly high electricity-to-gas cost ratios may be exempted from Tranche 1 and placed in Tranche 2, unless funding is available to ameliorate potential ratepayer cost increases.

> *Electrification Zones:* The state should consider defining some or all of Tranche 1 communities as "Electrification Zones" and providing higher subsidies for electrification equipment and electric rates in these areas to prepare them for later decommissioning.

4.1.2 Tranche 2: Market Transition

This tranche should constitute the next 20 percent of census tracts and the next round of distribution pipeline decommissioning. Priority criteria including high community burdens, low affordability, high pipeline risk, high peak demand, high ratepayer cost savings, and feasibility should be combined to define this tranche. These characteristics should be represented by the variables discussed for Tranche 1. As a result, completing decommissioning of this tranche will increase the affordability and safety of the remaining gas system. This tranche may represent the transition of residential electrification from rare to common, increasing the convenience and feasibility of subsequent activities.

4.1.3 Tranche 3: Medium-Term Electrification

Tranche 3 represents the medium term and should be defined as the next 25 percent of communities using similar criteria to Tranche 2. These communities will therefore have medium-high community burdens, medium-low affordability, and/or medium-high pipeline risk, ratepayer cost savings, and peak demand levels. They should be feasible to electrify or supply with other non-pipeline alternatives. Thus, Tranches 1-3 together represent half of all areas served by gas utilities. Most DACs should fall into Tranches 1-3. Large industrial and electrical facilities and their immediate neighbors may be exempted from Tranches 1-3 even if their communities are in those tranches.

4.1.4 Tranche 4: Market Rate Electrification

This tranche is the next 25 percent, that is, the third quartile of communities. This tranche should reflect communities with lower-than-average expected need and benefits from decommissioning, based on community characteristics and cost forecasts. By the time this tranche is reached, customers should be able to electrify at market rates or with standardized approaches, reducing the cost of decommissioning. Areas with recently replaced pipelines are likely to fall into this tranche or Tranche 5, as described below.

4.1.5 Tranche 5: Difficult-to-Electrify Customers and Long-Term Electrification Areas

The final tranche should consist of those areas where community need and potential benefit from decommissioning pipelines is lowest. Most of this tranche will consist of the remaining communities not identified for Tranches 1-4. In addition, large hard-to-electrify customers and areas with high potential for biomethane should generally be included in this tranche.

4.1.5.1 Questions for Parties

29) What adjustments should be made to these tranche definitions?
30) How often and through what process should tranches be updated using recent data and analysis, given the potential to learn from past experience and new information, vs. the benefit of planning years in advance?

5 Process

These priorities should be incorporated into gas distribution infrastructure repair, replacement, and decommissioning processes as described below.

5.1 Repair or Replacement

Gas utilities must continue to identify and repair hazardous (Grade 1) leaks or replace the relevant pipeline segments on distribution pipelines per their current procedures and pursuant to federal code 49 CFR Part 192.723 and related requirements. Later, this proceeding may consider whether in some cases it may eventually become possible to provide streamlined approval and installation of non-pipeline alternatives on a timeline necessary to remove leaking pipelines within a year.

If not required within a year for safety reasons, or initiated by customers, staff recommends that a utility should be required to propose the gas distribution infrastructure repair, replacement, addition, electrification or decommissioning project to the CPUC for approval. This may occur as part of the utility's General Rate Case, a stand-alone application, an annual stand-alone process within a new pipeline replacement and decommissioning implementation oversight proceeding, compliance with the Gas General Order 177, or other venue to be proposed later in this proceeding (Track 2.2.3). This process may overlap with the requirements of the Gas General Order but is distinct given its focus on smaller distribution system projects. For pipeline repair or replacement, staff anticipate that the affected pipelines should be within the highest risk quartiles of the utility's distribution pipelines, given that remaining pipelines are likely to have much lower risk. Such repair or replacement of distribution infrastructure should be completed only if: the risk reduction is above a certain threshold and the CPUC deems the project in the long-term best interests of the ratepayers, or the project is necessary for reliability within the current GRC period, and the CPUC deems there are no feasible non-pipeline alternatives. The CPUC should consider this process an interim approach, to be replaced with a more standardized process by the time the subsequent rate cycle begins (four years).

When proposing a pipeline repair, replacement, addition, electrification, or decommissioning project, the utility should be required to provide the following information, so that CPUC staff may compare the project with the evaluation criteria. If the project proposal is part of a proceeding, the information should be served on the service list of the proceeding. The CPUC should review this information as described in the paragraph above.

1. Census tract(s) within which the project would be located
2. Tranche(s) in which the affected census tracts are located
3. Whether it is a repair, replacement, addition, electrification, or decommissioning project
4. How much infrastructure would be repaired, replaced, added, electrified, or decommissioned, including the following numeric values by census tract:
    a. Miles of main distribution pipeline, by diameter
    b. Miles of service distribution pipeline, by diameter
    c. Number of services in the project or connected to mains in the project
    d. Number of customers served by those services
    e. Number of main valves within the project area
    f. Number of any compressor stations, regulator stations, or other utility-owned infrastructure
5. Cost estimate for the project with supporting documentation. This may be an Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimate. It should include:
    a. Cost components including labor, non-labor, and utility-wide overhead
    b. Up to 10 key variables, such as region, pipeline length, pipeline diameter, or valve type, for each cost component are expected; more can be used at utility's discretion
6. Risk assessment of infrastructure to be repaired, replaced, added, electrified, or decommissioned, by census tract and for the whole project:
    a. Average calculated risk of failure and consequence of failure before and after the project
    b. Average calculated risk score (risk of failure times consequence of failure) before and after the project
7. Cost-benefit ratio (based on risk score, costs, and value of avoided risk)[35]
   Approximate cost estimate and cost-benefit ratio (based on risk score, costs, and value of avoided risk) for a non-pipeline alternative, if the project is not itself a non-pipeline alternative
8. Narrative and supporting documentation describing the reliability or other main benefits of the project, if its primary purpose is not risk reduction
9. Narrative describing the project and reasons for it
10. Narrative describing why the project should not be postponed for four years (next rate cycle)
11. Project timeline, including the following dates:
    a. Finalized project plan
    b. Project plan proposed to the CPUC
    c. Expected announcement to affected customers
    d. Expected commencement of project work

[35] For more on risk and cost-benefit calculations, see footnote 21.

e. Expected in-service date
f. Expected end date of the project's lifetime (e.g., 30 years later)

Staff recommends that gas-only utilities should not be required to provide electricity-related information, including assessments of non-pipeline alternatives and electricity-specific information on electrification projects. Instead, concurrent with their application submittal, they should submit a request for this information to the electric utility serving the affected area. If the electric utility is investor-owned, it should provide the electricity-related information to the gas utility and to the CPUC within 60 days of receiving the request. For electrification projects initiated by electric utilities, the electric utility may optionally request that gas utilities provide the gas-related information identified above for any decommissioning that may result from the project. In that case, the electric utility shall give the gas utility 60 days to provide the requested information to it and the CPUC.

The same categories of information, updated to include actual costs and timelines compared with previous estimates, should be required to be reported in the year after project completion. The updated information does not need to include non-pipeline alternatives if they were not adopted. This information will help CPUC track project timeliness and costs.

Projects consisting of the addition of new gas pipelines at customer request should be reported annually to the CPUC in the year after they occur, providing the information listed above. The CPUC should work with utilities to develop information to provide to customers describing the availability of non-pipeline alternatives. Utilities should be required to provide this information when customers request new gas pipelines.

5.1.1.1 Questions for Parties

31) Should distribution infrastructure projects that are not covered by the Commission's General Order 177 be considered within or separately from utility rate cases?
    a) If not addressed within rate cases, what scale of activity should be considered a single project?
    b) How should the topics covered by future rate cases and separately be defined to avoid duplicative review or expenditures for distribution infrastructure?
    c) What ratemaking/cost structures changes are possible to incentivize gas utilities to decommission distribution pipelines?
32) Are the proposed criteria appropriate for assessing distribution infrastructure projects? Why or why not?
33) How should the CPUC determine thresholds for approval?
34) What Commission review schedule is necessary so utilities can implement projects in a timely manner?
35) What process (e.g., advice letter; new ongoing proceeding which reviews all such projects; stand-alone application for each project; or other process) should be used to review this information?

5.2 Decommissioning

Staff propose that tranches form a basis for organizing the decommissioning process over time, as described below. Although the goal is decommissioning, the focus may initially be on electrification and other non-pipeline alternatives to enable subsequent decommissioning.

5.2.1 Pursuing Decommissioning Targets

Under this approach, utilities would pursue decommissioning most gas distribution pipelines in a given tranche, as described above, before pursuing the next tranche. Within each tranche, utilities would propose the timeline for which areas would be decommissioned and in what order. Planning could occur within rate cases or be undertaken separately. If possible after the completion of Tranche 1, the CPUC may consider setting timelines for the additional tranches if changes have been made to the obligation to serve. Timelines could be readjusted as needed based on updated forecasts and experience to date.

5.2.1.1 Questions for Utilities

36) How can electric and gas utilities best perform their respective roles to support cost-effective gas decommissioning?

6 Non-Pipeline Alternatives and Funding

Staff recommends consideration of all viable non-pipeline alternatives. Electric heat pump-based space and water heating, combined with electric stoves (induction models are generally more efficient than resistance), may be the most widely available options for residential and commercial use. Other options including passive design and community geothermal should continue to receive consideration. Insofar as some of these alternatives are already being discussed in R.19-01-011, that proceeding, and its building electrification strategy, may drive more detailed specification of alternatives. As noted in that proceeding, many local government initiatives and state building codes also discuss non-pipeline alternatives.[36] For larger commercial and industrial customers, additional information may be needed to identify preferred options.

Which alternatives are most viable and how they are pursued will also influence and be influenced by funding structures. For example, residential appliance purchase and installation costs may be dramatically reduced by direct-install programs that reach most or all homes on a given block, but such a program is only feasible if substantial funding is available for a concentrated geographic area and customers are willing to make the switch. If most, but not all, customers are willing, partial decommissioning may be possible although it will not achieve the same cost efficiencies. Mass outreach campaigns educating Californians about the individual health, safety, and potential cost benefits from electrification as well as the importance of meeting the state's GHG goals will be paramount. Community geothermal may have different cost implications depending on whether it is to be owned by the gas utility, electric utility, or another entity such as a municipality. Existing and

[36] CPUC, *R.19-01-011 Phase III Staff Proposal,* November 2021, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M423/K516/423516230.pdf.

future federal and state funding will shape these opportunities. Funding and ratemaking options should be explored later in this proceeding (Track 2b).

6.1.1.1 Questions for Parties

37) How should the identification and selection of non-pipeline alternatives be coordinated with other programs or proceedings?
38) What cost "rules-of-thumb" should be used to represent the behind-the-meter costs of implementing various non-pipeline alternatives? Responses should address the residential and small commercial sectors and, if possible, also address large commercial (e.g., refrigeration), industrial (boilers and other energy-using equipment) and electricity generation sectors.
    a) What are the average cost, cost range, and key cost input variables for each non-pipeline alternative that should be considered?
39) How should non-pipeline alternatives be paid for, both for customers of dual-fuel and single-fuel gas utilities?
40) Should non-pipeline alternatives to be pursued in coordination with decommissioning be identified by the CPUC, by gas utilities, a third party, or a hybrid approach?
41) How should the current conditions of the electric distribution grid be considered when determining non-pipeline alternatives?
42) Should criteria for prioritizing communities for decommissioning (defining tranches) be adjusted in light of the characteristics of non-pipeline alternatives? For example, should areas with colder weather be prioritized or de-prioritized for pipeline decommissioning given the capabilities of heat pumps or geothermal technology?

(End of Attachment)