~~STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*~~

~~PUBLIC UTILITIES COMMISSION~~

~~505 VAN NESS AVENUE~~
~~SAN FRANCISCO, CA 94102-3298~~

~~July 5, 2019~~ **~~Agenda ID # 17561~~**
~~Quasi-Legislative~~

~~TO PARTIES OF RECORD IN RULEMAKING 15-01-008:~~

~~This is the proposed decision of Commissioner Clifford Rechtschaffen. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's August 15, 2019 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.~~

~~Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.~~

~~/s/ ANNE E. SIMON~~
~~Anne E. Simon~~
~~Chief Administrative Law Judge~~

~~AES:avs~~

~~Attachment~~COM/CR6/avs **PROPOSED DECISION** **Agenda ID #17561**

Quasi-Legislative
8/15/2019 Item 5

Decision **PROPOSED DECISION OF COMMISSIONER RECHTSCHAFFEN**
(Mailed 7/5/2019)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Adopt Rules and Procedures Governing	Rulemaking 15-01-008

Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371.

SECOND PHASE DECISION APPROVING NATURAL GAS LEAK ABATEMENT PROGRAM CONSISTENT WITH SENATE BILLS 1371 AND 1383

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SECOND PHASE DECISION APPROVING NATURAL GAS LEAK ABATEMENT PROGRAM CONSISTENT WITH SENATE BILLS 1371 AND 1383

Summary

This decision establishes additional policies and mechanisms for the California Public Utilities Commission (CPUC) and California Air Resources Board (CARB) Natural Gas Leakage Abatement Program pursuant to Senate Bills (SB) 1371 and 1383. This decision requires use of the Utility Proposed Cost-Effectiveness Methodology and two Cost-Benefit Analyses to provide useful information when evaluating proposed methane reduction measures and for evaluating the Biennial Methane Leaks Compliance Plans (Compliance Plans), while maintaining full discretion for the Commission to also consider qualitative factors and policy goals. Consistent with SB 1383 (2016) and SB 1371 (2014), this decision adopts a restriction on rate recovery beginning in 2025, for methane emissions greater than 20% below the 2015 baseline levels for Pacific Gas and Electric Company (PG&E) and Southern California Gas Company (SoCalGas) to ensure that expenditures authorized to implement their Compliance Plans achieve their intended methane emissions reductions. Except as provided above, both PG&E's and SoCalGas' rate recovery calculations continue to be subject to the factors approved in the utility's most recent General Rate Case or Cost Allocation Proceeding.

Within 60 days of the issuance of this decision, the Commission's Safety and Enforcement Division and Energy Division will convene two workshops:

1. In cooperation with the Technical Working Group, refine the scope and detail of the Compliance Plans and Tier 3 Advice Letters pertaining to cost-effectiveness and cost-benefit analysis and other elements as directed in Decision (D.) 17-06-015 and this decision; and

2. In consultation with CARB, develop a process that utilities can rely on prior to submittal of the next Compliance Plans in March 2020 to adjust Emission Factors used for annual reports to account for methane reduction measures that may be approved in Compliance Plans that will achieve reasonably quantifiable reductions.

This decision extends the timeframe from 2020 to 2021 for the CPUC's Safety and Enforcement Division and Energy Division Staff to complete a written program evaluation of the Natural Gas Leak Abatement Program after Commission approval of the second set of Compliance Plans in late 2020. All directives of D.17-06-015 remain in effect, unless they are superseded by directives and/or guidance provided by this decision.

Following submission of the second set of Best Practices Biennial Compliance Plans due March 2020 and the Natural Gas Leakage Abatement program evaluation in 2021, the Commission will determine the direction of the program moving forward. The CPUC and CARB will continue to consult and collaborate to determine the best management practices and other mitigation technologies for achieving greenhouse gas emissions reductions.[1]

Rulemaking R.15-01-008 is closed.

[1] *See* D.17-06-015 "Evolving Roles of ARB and CPUC" at 135-140.

1. Background

On January 22, 2015, the CPUC opened Rulemaking (R.) 15-01-008 to implement the provisions of Senate Bill (SB) 1371 (Statutes 2014, Chapter 525).[2] SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from CPUC-regulated natural gas pipeline facilities consistent with Public Utilities. Code § 961(d)[3], § 192.703(c) of Subpart M of Title 49 of the Code of Federal Regulation, the CPUC's General Order (GO) 112-F, and the state's goal of reducing greenhouse gas (GHG) emissions. SB 1371, which became effective January 1, 2015, added §§ 975, 977, and 978. Among other things, SB 1371 also requires gas corporations to file an annual report about their natural gas leaks, and their leak management practices.[4]

In Section 1(e) of SB 1371, the Legislature declared in part that "[r]educing methane emissions by promptly and effectively repairing or replacing the pipes and associated infrastructure that is responsible for these leaks advances both policy goals of natural gas pipeline safety and integrity and reducing emissions of greenhouse gases." SB 1371 directs the Commission to consult with the California Air Resources Board (CARB), to achieve the goals of the Rulemaking.

On June 15, 2017, the CPUC approved Decision (D.) 17-06-015 (First Phase Decision) to establish the Natural Gas Leak Abatement Program, which includes:

- Annual reporting that tracks methane emissions with emphasis on transparency of data to the public;
- Twenty-six best practices (26 Best Practices) for minimizing methane emissions that encompass gas meters, pipelines, storage facilities, compressors and other infrastructure; leak detection, leak repair, and leak prevention; and also

[2] *See* R.15-01-008 "Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage consistent with Senate Bill 1371," issued January 22, 2015, hereafter referred to as Rulemaking.

[3] Unless otherwise stated, all code section references are to the Public Utilities Code.

[4] Since 2015, utilities have filed five annual reports demonstrating progress toward emission redu ction objectives.

policies and procedures; recordkeeping; training; and experienced trained personnel.

- Biennial methane leak Compliance Plans (Compliance Plans) that must be incorporated into gas utility safety plans required by the Commission's GO 112-F;[5]
- "Soft" methane reduction targets to support California's statutory methane emissions reduction target of 40% below 2013 levels by 2030 (subject to review in a second phase of the proceeding). (SB 1383, Lara, Statutes 2016, Chapter 395,); and
- Preliminary cost recovery process to facilitate CPUC review and approval of incremental expenditures to implement best practices, Pilot Programs, and Research & Development (subject to review in a second phase of the proceeding).

The First Phase Decision directed the CPUC to conduct a follow up second phase to address issues that were not fully resolved due to lack of data and lack of experience with the new program. As directed in the First Phase Decision, Pacific Gas and Electric Company (PG&E), Southern California Gas Corporation (SoCalGas), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (Southwest Gas) submitted their first Compliance Plans setting forth proposed measures to implement the 26 Best Practices and associated revenue requirements for 2018-2019. The CPUC approved the Compliance Plans with modifications in Resolution G-3538 (issued October 12, 2018). The CPUC approved expenditures of $314.7 million to implement the Compliance Plans, as follows: $234 million for SoCalGas; $66 million for PG&E; $12.3 million for SDG&E; and $2.4 million for Southwest Gas.

2. Procedural Background

On July 21, 2017, the assigned Administrative Law Judge (ALJ) issued a ruling setting the Phase Two pre-hearing conference (PHC) for August 24, 2017.

[5] After the utility submission of initial compliance plans in March 2018, the next due date for submission is March 2020.

A PHC was held on August 24, 2017.

On September 20, 2017, the assigned Commissioner issued an Amended Scoping Memo and Ruling of the Assigned Commissioner (Amended Scoping Memo) which determined that the second phase of this proceeding would consider the following broad policy issues:

1) What data is necessary in order for the CPUC to consider a "cost-effectiveness" framework in this proceeding?
2) How should the CPUC's Annual Report Requirements and 26 Best Practices be harmonized with information or action required by other entities such as PHMSA (Pipeline and Hazardous Materials Safety Administration), DOGGR, (Division of Gas, Oil, and Geothermal Resources), CARB (California Air Resources Board), and local air quality management districts?
3) Pursuant to § 975(f), how should rules and procedures, including best practices and repair standards developed in this proceeding, be incorporated into the applicable general orders (*e.g.*, GO 112-F)?
4) How should ratemaking treatment for Lost & Unaccounted For Gas (LUAF) be structured and evaluated?

Workshops:

Consistent with Rulemaking directives and Scoping Memo objectives, Safety and Enforcement Division (SED) and Energy Division (ED) Staff conducted the following workshops in cooperation with CARB:

1. Workshop on Phase Two "Four" Scoping Memo Questions (November 16, 2018)
   - Cost Effectiveness;
   - Harmonization of 26 Best Practices with federal, state, and local regulations;
   - Potential Update to GO 112-F; and
   - How to Evaluate LUAF.

2. Workshop on Annual Report Template and Related Matters (January 17, 2019)

- Changes to the Annual Report Template and Updating Emission Factors (EFs);
- Retroactive 2015 Baseline Adjustments;
- MSA (Meter Set Assemblies) and M&R (Meter and Regulation) Station Leaks and Emissions Reporting (*e.g.*, "population-based" paradigm to actual leak rates or "event-based" reporting); and
- Review Wellhead EFs.

On November 30, 2018, the ALJ issued a ruling soliciting comments on the November 16, 2018 workshop. PG&E, SoCalGas/SDG&E, Southwest Gas, and EDF provided opening comments on January 22, 2019. PG&E, SoCalGas/SDG&E, EDF, and CUE provided reply comments on February 4, 2019.[6]

On January 25, 2019, the assigned ALJ issued a ruling soliciting comments on the January 17, 2019 workshop. PG&E, SoCalGas/SDG&E and EDF provided comments on February 15, 2019. PG&E and SD&E/SoCalGas and provided reply comments on February 22, 2019.

The First Phase Decision requires annual reports every June. On November 30, 2017, the assigned ALJ issued a ruling entering the CARB and CPUC 2017 Joint Staff Report analyzing the June 16, 2017 Utilities' Reports into the record and soliciting comments. PG&E, SoCalGas/SDG&E, Southwest Gas, EDF and CUE provided comments on December 12, 2017.

On November 20, 2018, the assigned ALJ issued a ruling entering the CARB and CPUC Joint Staff Report analyzing the June 15, 2018 Utilities' Reports into the record and soliciting comments. PG&E, SoCalGas/SDG&E, and Southwest Gas provided comments on December 5, 2018.

In response to comments, SED posted final versions of the CARB and CPUC Joint Staff Reports on the CPUC's website.

[6] Parties' comments were originally due December 14 and December 21, 2018. However, consistent with Rule 11.6 of the Commission's Rules of Practice and Procedure, on December 12, 2018, in cooperation with other parties, PG&E asked for an extension of time to file comments and the ALJ granted this request on December 13, 2018 via e-mail.

As appropriate, this decision references the findings and conclusions of the CARB and SED 2017 and 2018 annual report statistics. Based on the latest 2018 Joint Staff Report, parties generally agree that the report provides a credible assessment of trends regarding the natural gas emissions from leaks and vented emissions in transmission, distribution, and storage facilities in California.

3. Issues Before the Commission

As noted above, the Amended Scoping Ruling identified the following broad policy issues for the second phase of this proceeding:

1) What data is necessary in order for the CPUC to consider a "cost-effectiveness" framework in this proceeding?
2) How should the CPUC's Annual Report Requirements and 26 Best Practices be harmonized with information or action required by other entities such as PHMSA, DOGGR, CARB, and local air quality management districts?
3) Pursuant to § 975(f), how should rules and procedures, including best practices and repair standards developed in this proceeding, be incorporated into the applicable general orders (*e.g.*, GO 112-F)?
4) How should ratemaking treatment for LUAF be structured and evaluated?

Following is a brief discussion of the four original questions.[7]

First, during Phase One of this proceeding, parties had several opportunities to address various policy frameworks to address cost effectiveness.[8] However, in D.17-06-015 the Commission determined that there was not enough quantifiable information to establish a cost-effectiveness standard for the required Best Practices. Therefore, cost-effectiveness was only considered informally in the selection of Best Practices adopted in the First Phase Decision. Even in the absence of a specific framework, utilities were provided the discretion to focus on the most

[7] *See* Amended Scoping Memo at 5-6.
[8] *See* First Phase Decision at 10.

cost-effective means to reduce emissions (while meeting their requirements under all the Best Practices.)

Second, "harmonization" of the 26 Best Practices with other state and federal agencies (*e.g.*, DOGGR, CARB, United States Environmental Protection Agency (EPA) is an ongoing issue and it is appropriate to periodically review even if no action is taken. In the meantime, according to the First Phase Decision, if a Best Practice is included in a CARB, DOGGR, or local district rule, then those entities will have independent authority to inspect and enforce progress with that requirement.

Third, D.17-06-015 updated GO 112-F, Section 123-K Gas Safety Plan to reflect that each Utility Operator would submit a Gas Safety Plan consistent with SB 1371 and consistent with D.12-04-010 and D.17-06-015. However, it is possible that further refinements could be made to GO 112-F to reflect changing annual report requirements (Section 123, Annual Reports); leak survey cycles (Section 143.1 Distribution and Transmission Leakage Surveys and Procedures); and Leak Classification and Action Criteria Grade Definition of Priority of Leak Repair. Alternatively, methane emission reduction requirements that are not safety driven, could be incorporated into a separate GO in the future, for the sake of clarity.

Fourth, several parties raised the issue of re-evaluating ratemaking treatment for LUAF. This is also included in the scope of Phase Two. Section 977(b) requires the Commission to consider "Providing revenues for all activities identified and required pursuant to Section 975, *including any adjustment of allowance for lost and unaccounted for gas related to actual leakage volumes*." (Emphasis added.)

As the second phase of the proceeding progressed and we more clearly understand the various components of LUAF, and in accordance with the statutory reference to adjustments for "LUAF related to actual leakage volumes," we limit this discussion to "SB 1371" methane emissions, which represents a smaller subset of "total" LUAF. This is the portion of LUAF that is reported in the SB 1371 annual reports and is a listed as a line item in utilities' annual GO 112-F reports. Other GO 112-F non-methane emission components, including measurement, accounting, billing, theft, and other miscellaneous "non-study" components, are not directly addressed in this decision although they do provide important context. SED Staff, consistent with their PHMSA delegated authority,[9] is working with utilities to improve clarity and consistency of reporting of LUAF components, including methane emissions.

While associated implementation activities related to the Annual Report Template and ongoing revisions, Compliance Plan, and Technical Working Group are important, these activities proceeded without being included in the Phase Two scope. D.17-06-015 delegated relevant management oversight of these activities to SED and ED.[10]

As directed by D.17-06-015 and reiterated in the Amended Scoping Memo, SED staff, in consultation with CARB, will continue to hold workshops and technical working group meetings as necessary to discuss issues associated with Annual Reports for both large and small utilities, Compliance Plans (including Pilot and Research & Development activities), Emission Factors, and Technical Working Group activities (including direction on how to use new technology and scientific information toward emissions reductions, and best practices). In addition, ED, in cooperation with SED, is required to conduct necessary follow up workshops to resolve any outstanding cost recovery and cost allocation issues and provide guidance regarding the interaction of compliance filings and the utilities' future General Rate Cases.

9 *See* D.15-06-044, Attachment A (GO 112-F, "Annual Reports," at 7, 123. Ref: 49 Code of Federal Regulations (CFR) Part 191, Sections 191.11, 191.12, 191.17.)

10 *See* D.17-06-015 OPs 2 and 6.

4. SB 1371 Cost-Effectiveness and Cost-Benefit Analysis Framework

4.1. Background

4.1.1. SB 1371 and Assembly Bill (AB) 197 Requirements

As stated in the First Phase Decision, several legislative provisions provide important context for Commission consideration of cost-effectiveness in implementing SB 1371.

According to § 975(e), the rules and procedures adopted...shall accomplish all of the following:

> (1) Provide for the maximum technologically feasible and **cost-effective** [emphasis added] avoidance, reduction, and repair of leaks and leaking components...
>
> (2) Provide for the repair of leaks as soon as reasonably possible after discovery, consistent with established safety requirements...and the climate change impacts of methane emissions.
>
> (4) Establish and require the use of best practices for leak surveys, patrols, leak survey technology, leak prevention and leak reduction...

According to § 977(d) the Commission shall consider "the impact on affordability of gas service for vulnerable customers as a result of incremental costs of compliance with the adopted rules or procedures."

SB 1371 required the CPUC to "adopt rules and procedures governing the operation, maintenance, repair, and replacement" of intrastate transmission lines to "reduce emissions of natural gas ... to the maximum extent feasible in order to advance the state's [GHG emissions reduction] goals" (§ 975 (b).) In doing so, "safety, reliability, and affordability of service" should be given priority, while giving "due consideration to the cost considerations of Section 977." (§ 975(b) and § 975(b)(2).)

4.1.2. Social Cost of Methane

Parties requested inclusion of the social cost of methane in the cost-effectiveness evaluation of methane reduction measures proposed in the gas utilities' Compliance Plans. We have consulted with CARB on this topic. Since this proceeding opened in January 2015, the California State Legislature approved AB 197 (Garcia, Statutes 2016, Chapter 250,) on September 8, 2016, which updates Health and Safety Code Section 38562.5 and directs that "When adopting rules and regulations …to achieve emissions reductions beyond the statewide greenhouse gas emissions limit and to protect the state's most impacted and disadvantaged communities, the state [Air Resources] board shall … consider the social costs of the emissions of greenhouse gases.."[11] AB 197 defines social costs as "an estimate of the economic damages, including, but not limited to, changes in net agricultural productivity; impacts to public health; climate adaptation impacts, such as property damages from increased flood risk; and changes in energy system costs, per metric ton of greenhouse gas emissions per year."[12] Health and Safety Code Section 38562(b)(6) also directs that, in adopting greenhouse gas emission reduction regulations, CARB "consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health."

As CARB shared with respondents at a Compliance Plan workshop on April 13, 2018, from 2009 to 2017, federal agencies (*e.g.,* EPA, Department of Transportation (DOT), Department of Energy (DOE)) incorporated the social cost

[11] As noted in D.17-06-015 at 43, footnote 32, following is the EPA Definition of "Social Cost": "From a regulatory standpoint, social cost represents the total burden a regulation will impose on the economy. It can be defined as the sum of all opportunity costs incurred as a result of the regulation. These opportunity costs consist of the value to society of all the goods and services that will not be produced and consumed if firms comply with the regulation and reallocate resources away from production activities and towards pollution abatement." (CARB November 3, 2016 Workshop Report at 7.)

[12] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB197; Health and Safety Code Section 38506.

of GHGs including carbon dioxide (CO2), methane (CH4), and nitrous oxide into regulatory impact assessment. In 2009, the United States Government Interagency Working Group (IWG) was convened to develop a methodology for estimating the social cost of carbon using standardized assumptions that could be used consistently when estimating the benefits of regulations across agencies. The IWG recommended use of values based on three Integrated Assessment Models (IAMs) developed over decades of peer-reviewed research. As stated previously, the social cost of methane for a given year is an estimate, of the present discounted value of future damage by a one metric ton increase in CH4 emissions into the atmosphere in that year, or equivalently, the benefits of reducing CH4 emissions by the same amount in that year. It provides a comprehensive measure of net damages—the monetized value of net impacts from global climate change that results from an additional ton of CH4.

Damages include:

- Changes in net agricultural productivity
- Energy use
- Human health impacts
- Property damage from increased flood risk
- Water availability
- Damages to coastal communities
- Biodiversity losses

IAMs combine models of the global economy and atmosphere to estimate the environmental damages from the release of a ton of greenhouse gas a given year in the future and discount the value of the damages back to the present. Such environmental damages increase over time as global emissions accumulate. The analysis is highly sensitive to discount rates that represent the present value placed on future environmental damages. A higher discount rate more sharply discounts the value placed on future damages. IWG provides values for the social cost of methane using a standardized discount rate used in economic models ranging from 2.5% to 5% through 2050, and an additional "high impact value" based on recent work indicating accelerated climate change as highlighted below:[13]

Social Cost of Methane (2007 $ per metric ton)[14]

	5%	**3%**	2.5%	High Impact
Year	Average	**Average**	Averag e	(3% 95th)
2010	370	**870**	1,200	2,400
2015	450	**1,000**	1,400	2,800
2020	540	**1,200**	1,600	3,200
2025	650	**1,400**	1,800	3,700
2030	760	**1,600**	2,000	4,200
2035	900	**1,800**	2,300	4,900
2040	1,000	**2,000**	2,600	5,500
2045	1,200	**2,300**	2,800	6,100
2050	1,300	**2,500**	3,100	6,700

The following table illustrates the social cost of methane in terms of volume of natural gas emissions, the IWG values calculated through 2050 are converted from metric tons to thousand standard cubic feet (MSCF) of natural gas. Please note the $/metric ton values are presented in equivalent terms of $/Mscf natural gas emission volumes, assuming a typical methane concentration in natural gas of 93.4 percent. The table above presents social cost of methane in terms of volume of natural gas emissions (thousand Standard Cubic Feet), assuming 93.4 percent methane concentration in commonly used in the CPUC/CARB annual emission inventory reports and for calculation of the Cost Effectiveness of proposed Best Practice programs. The conversion factor is 55.835 MSCF per metric ton CH4 [methane] at standard conditions of 1 atmosphere and 60 degrees Fahrenheit.

[13] Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide, August 2016, available at: https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf

[14] https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf

Social Cost of Methane Estimates

(in 2007 dollars per MSCF of Natural Gas)

	5%	**3%**	2.5%	High Impact
Year	Average	**Average**	Average	(3% 95th)
2010	$7	**$16**	$21	$43
2015	$8	**$18**	$25	$50
2020	$10	**$21**	$29	$57
2025	$12	**$25**	$32	$66
2030	$14	**$29**	$36	$75
2035	$16	**$32**	$41	$88
2040	$18	**$36**	$47	$99
2045	$21	**$41**	$50	$109
2050	$23	**$45**	$56	$120

In January 2017, the National Academies of Sciences, Engineering, and Medicine (NAS) released a report examining potential approaches for a comprehensive update to the IWG social cost methodology to ensure resulting cost estimates reflect the best available science. The NAS review did not modify the IWG values, but evaluated the models, assumptions, handling of uncertainty, and discounting used in estimating social costs. The report, titled "Valuating Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide," recommends near-term improvements related to the discount rate used in the existing IWG valuations as well as a long-term strategy for more comprehensive updates.[15] Until there is scientific and modeling consensus on new valuations that implement NAS recommendations and are based on the best available science, modeling, and data, CARB will rely on the existing IWG estimates.

On March 28, 2017, a Presidential Executive Order disbanded the IWG, withdrew the documents and valuations issued by the IWG.[16] The Executive Order's direction to disband the IWG and withdraw peer-reviewed and vetted

[15] https://www.nap.edu/catalog/24651

[16] https://www.whitehouse.gov/presidential-actions/presidential-executive-order-promoting-energy-independence-economic-growth/.

scientific documents does not call into question the validity and scientific integrity of the IWG's estimates nor the merit of independent scientific work. The Executive Order provided no economic or scientific rationale or defense of this withdrawal. CARB supports continued use of the IWG values and strongly suggests that other agencies support and promote the IWG social cost values for transparency and consistency of regulatory analyses.

CARB is currently using IWG values for identifying the social cost of GHG emissions, including methane, in the 2017 AB 32 Scoping Plan because "the IWG's work remains relevant, reliable, and appropriate for use…."[17] The CPUC has chosen to follow CARB's lead in this area when it issued D.19-05-019, "Decision Adopting Cost-Effectiveness Analysis Framework Policies For All Distributed Energy Resources," in R.14-10-003[18] that approves use (for information purposes) of an additional cost-effectiveness test using the social cost of carbon values published by the IWG.

4.1.3. SED and ED Authority to Approve Compliance Plans

In this section, we update the First Phase Decision evaluation of cost effectiveness strategies with knowledge and experience gained from the SED and ED Staff evaluation of Compliance Plans approved October 11, 2018 in Resolution G-3538, and in consideration of recent parties' comments. Ordering Paragraph (OP) 10 of the First Phase Decision required utilities to include the following in their Compliance Plans:[19]

a) The incremental direct costs associated with each individual Best Practice, Pilot Projects and Research &

[17] Final 2017 Scoping Plan, available at: https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm, at 39-42.

[18] *See* D.19-05-019 in R.14-10-003 "Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Energy Distributed Energy Resources."

[19] *See* Resolution G-3538 at 4.

Development (R&D), broken down by type of expenditure including capital, operations and maintenance, and administrative.

b) The justifications consistent with the criteria to evaluate Pilot Projects and R&D in Public Utilities Code § 740.1.

c) The proposed allocation methodology for amortization of the account and the corresponding CPUC decision authorizing the allocation methodology.

The First Phase Decision OP 11 authorized the Director of Energy Division to recommend a process for reviewing cost forecasts, including the development of cost limits, and the methods for cost recovery related to the incremental costs of Best Practices in two-way balancing accounts, and costs related to Pilot Projects and R&D recorded in the one-way balancing accounts. The First Phase Decision also directed SED and ED to convene working groups and workshops to refine the scope and detail of Compliance Plans and Tier 3 Advice Letter pertaining to forecasts, cost tracking and recovery.[20]

In essence, with CPUC approval of the First Phase Decision, SED has authority delegated by the CPUC to approve biennial compliance plans and disapprove any project it determines is not in the ratepayer's interest.[21] In this decision, we conclude that it is reasonable to keep this delegated authority intact to review and evaluate biennial compliance plans, while exploring the more narrow question regarding whether cost effectiveness analysis can be further improved, as discussed below.

4.2. Parties' Comments

On October 29, 2015, during the first phase of the proceeding, the ALJ requested comments on cost effectiveness considerations and parties provided

[20] *Ibid.*

[21] For example, in Resolution G-3538 at 9, given the relatively high costs to repair the entire Grade 3 leak backlog in PG&E's service territory, the CPUC limited PG&E's budget for Best Practice 21 to no more than half the requested ratepayer funding for its proposed Grade 3 leak backlog in the initial period.

comments on November 20, 2015 and December 4, 2015 [questions #2, a-e]. On December 1, 2016 the ALJ entered the November 3, 2016 cost effectiveness workshop documents into the record and parties provided initial and reply comments on December 9, 2016 and December 22, 2016, respectively.

Following the review of the first set of Compliance Plans,[22] on November 30, 2018, the ALJ requested a second set of comments on the same issues and parties provided initial and reply comments on January 22, 2019 and February 4, 2019. The following two sections summarize parties' most recent comments.

4.2.1. Necessary Data

A key Scoping Memo question asks what data that will be useful if the Commission continues to employ a qualitative cost-effectiveness evaluation of Best Practices.

In response to this question, some parties perceive that cost justification proposals presented in recent Compliance Plans provide adequate information with some room for needed improvements. Parties generally agree that methane emissions should be evaluated holistically to achieve the largest reductions at the lowest costs. Parties had mixed views regarding whether a quantitative "threshold" value should be used to ensure methane reduction programs achieve cost-effectiveness across the state. Other ideas that parties promote to improve evaluation of Compliance Plans include providing a more consistent assignment of costs and benefits in cost-effectiveness analysis, not disadvantaging programs that have higher startup costs and using net present value to properly account for long lives of programs. Some parties recommend that the CPUC broaden its evaluation of the program in comparison to other industry sector programs such as transportation, agriculture, and dairy, where large decreases in emissions are being sought.

[22] The first set of Compliance Plans were submitted to SED on March 15, 2018 and ratified by Resolution G-3538 issued on October 12, 2018.

"SoCalGas and SDG&E believe the current framework used to evaluate cost-effectiveness incorporates the necessary information, including the cost to customers for implementation, tangible cost benefits such as the cost of gas saved, and estimated emission reductions that will be realized from implementation." (SoCalGas/SDG&E January 22, 2019 Comments at 1.) They further opine that "cost effectiveness should not be considered in a vacuum. Methane emissions should be evaluated holistically to achieve the largest reductions at the lowest costs." (SoCalGas/SDG&E January 22, 2019 Comments at 2.) In terms of cost benchmarks, they recommend that the Commission consider the cost of other methane reduction activities in sectors that make up the large parts of the greenhouse gas inventory such as dairies or agriculture. According to SoCalGas/SDG&E, "[t]hese sectors may require much less cost to reduce methane than some best practices on the natural gas system." (SoCalGas/SDG&E January 22, 2019 Comments at 2.)

PG&E recommends that "the results from the first biennial Compliance Plan are necessary in order for the Commission to establish a cost-effectiveness framework in this proceeding." After completing the Compliance Plans, operators can offer useful data on the methane emissions reductions achieved in 2018-2019 and the cost of those reduction efforts to the Commission and other stakeholders. It emphasizes that "[t]his information can then be used to develop a cost effectiveness framework for evaluating proposed abatement measures in operators' future Compliance Plans." (PG&E January 22, 2019 Comments at 1-2.)

Southwest Gas believes that "the Commission must consider all costs to customers associated with Best Practices programs as well as individual program natural gas savings and estimated emission reductions. Southwest Gas suggests that a threshold cost level may be useful to ensure methane reductions are achieved in the most cost-effective manner across the state." (Southwest Gas January 22, 2019 Comments at 1.)

Similarly, EDF recommends that the CPUC should continue to follow the advice in the First Phase Decision by adopting a holistic approach to evaluating cost effectiveness while at the same time ensuring that utilities are selecting and implementing the most effective technologies. It observes the First Phase Decision did not adopt a specific metric for evaluating the cost effectiveness of methane reduction measures. "Instead, it acknowledged the importance of taking a comprehensive approach to evaluating the costs and benefits of methane reduction, while at the same time ensuring that the measures actually adopted would be effective and provide the 'biggest bang for the buck.'" (EDF January 22, 2019 Comments at 4 quoting D.17-06-015 at 50-51.)

However, EDF notes some disparities when utilities assigned costs and associated emissions reductions. For example, EDF points out that "PG&E assigned an MCF [Thousand Cubic Feet] reduction figure to best practices 2-7 related to blowdown reduction, while neither SoCalGas nor SDG&E quantified methane emissions reductions for best practices 2-7. Evaluation of the comparative cost effectiveness of various practices requires consistent assignment of costs and benefits." (EDF January 22, 2019 Comments at 8.)

For this reason, EDF suggests that more data be included to evaluate cost-effectiveness across programs. (EDF January 22, 2019 Comments at 8.) EDF would require:

- Projected and actual methane reductions for each best practice and each element of the utilities plan to implement the best practice.
- Quantification to the extent possible of benefits of methane reduction, including the social cost of methane and avoided safety issues.

- Projected operational and capital costs for each best practice and each element of the utilities plan to implement the best practice, whether it was included in the GRC or the [SB] 1371 Plan;
- Actual operational and capital costs of implementing each best practice and each element of the utilities plan to implement the best practice.
- Analysis of technological advances that may make methane reduction more efficient.

4.2.2. **Consideration of Benefits**

This section addresses the related question regarding to what extent should benefits (*e.g.*, value of MCF avoided, environmental impact of avoided methane, system reliability, safety improvements, etc.) and other considerations be included to perform cost-effective analysis. (Parties were invited to comment on whether their positions have changed since they filed comments on this topic on December 9, 2016 and December 22, 2016).

In general, utilities recommend a more consistent and standardized approach and methodology to determine cost-effectiveness. They also recommend more uniform assumptions for performing such an analysis including established time periods for leveling expenses of fully loaded capital and operations and maintenance (O&M) expense, etc. over a useful life of the assets, compliance period, and from implementation to 2030. However, they warn that determining the dollar benefit of abated methane emissions can be problematic due to the need to consider multiple factors. For example, EDF claims that Compliance Plans focus too narrowly on the cost of avoided gas in their quantification of benefits and that analysis should be expanded to include the avoided SCM and safety benefits that result from more rapid detection and repair of major emitters. To ensure comparability across utility proposals, SoCalGas/SDG&E suggest that certain policies be adhered to in the development of any cost-effectiveness approach. CUE argues that the priority should be “finding and fixing leaks” rather than “misplaced focus” on the perceived value of different cost-effectiveness strategies.

Consistent with its December 22, 2016 comments filed after the Cost-Effectiveness Workshop, PG&E recommends that cost-effectiveness be measured by cost per unit of methane reduction. Similar to what other utilities propose, the components used to calculate the total implementation costs would include the fully loaded capital cost and associated O&M expenses, including ongoing O&M costs over the life of the capital asset, if applicable. For calculating the amount of abated methane emissions, PG&E would use methodologies consistent with its reporting for the Annual Leak Report in this proceeding.” (PG&E January 22, 2019 Comments at 2.)

However, it cautions that “[d]etermination of a dollar benefit for abated methane emissions is difficult because of the numerous factors that have to be considered, including social cost of methane emissions, the market value of gas, and the additional positive impact to safety and reliability of the gas system. These factors add substantial complexity to the calculation, but do not provide significant value when ranking programs.” (PG&E January 22, 2019 Comments at 2.) Despite the obvious complexity of assumptions, “PG&E is open to the concept of generating cost-benefit numbers and establishing a cost-effectiveness framework but proposes that the Commission standardize the calculation method for all utilities. (PG&E January 22, 2019 Comments at 2.) PG&E recommends that costs be expressed in terms of net present value (NPV) to properly account for long lives of some programs.” (PG&E January 22, 2019 Comments at 2-3.)

PG&E believes that assessment of individual programs is critical to evaluation process. However, it agrees with EDF that grouping together programs when evaluating cost effectiveness to test “interactions and synergies” among programs can be useful. However, it warns that “grouping programs may have the undesired effect of masking projects with poor cost-effectiveness. (PG&E January 22, 2019 Comments at 2-3.)

According to SoCalGas/SDG&E,

> SoCalGas and SDG&E recommend dividing the revenue requirement by the expected emissions reductions achieved by the proposed activity or asset. To evaluate cost-effectiveness in a more accurate and practical context, cost effectiveness must be evaluated over multiple time periods including the Compliance Plan period, from implementation to 2030, and the expected life of capital investments…For instance, a shorter evaluation period may artificially inflate costs because short term evaluations do not consider that the up-front costs of hiring and training new employees or purchasing new vehicles and equipment are incurred in the first 1-2 years, while reduction may not be realized until 2-3 years after the initial investment." (SoCalGas/SDG&E January 22, 2019 Comments at 2-3.)

More specifically, SoCalGas/SDG&E suggest specific evaluation methods for the Commission's consideration using various calculation formulas pertaining to compliance period, program and asset levels. (SoCalGas/SDG&E January 22, 2019 Comments at 3.)

In summary:

> To evaluate shorter time frames such as the Compliance Plan period, the average annual revenue requirement is generated by calculating the cumulative revenue requirement for activities that directly contribute to emissions reductions. The activity costs used to calculate the revenue requirement include the fully loaded and escalated capital investment and associated operation and maintenance (O&M), including on-going O&M over the useful life of the related capital asset, if applicable. The cumulative revenue requirement is then divided by the total years of useful life to generate an average annual revenue requirement. This annual revenue requirement can be multiplied by the number of years in the Compliance Plan period. The annual revenue can then be compared to the emissions reductions for the same number of years. (SoCalGas/SDG&E January 22, 2019 Comments at 3.)

SoCalGas/SDG&E observe that time frames can be expanded, and the annual revenue requirement can be multiplied by the number of years for the relevant evaluation period (*e.g.*, multiply by the number of years remaining until 2030 or the life of the asset) similar to the above. The revenue requirement can be compared to the emission reduction for the same period." (SoCalGas/SDG&E January 22, 2019 Comments at 3-4.)

In the adoption of any cost effectiveness strategy, SoCalGas/SDG&E recommend the following policies:

- All parties should calculate cost effectiveness in the same manner so that it can be compared equitably among activities and parties.
- Consistent with SB 1371, "nothing in this article shall compromise or deprioritize safety."[23] As such, system reliability and safety must be given priority in all implementation activities. If a proposed activity will compromise safety or reliability, it should not be considered as an option. Therefore, safety and reliability should not be a factor in determining cost effectiveness.

[23] SB 1371, Section 1(a).

- It may be premature to include a social cost of methane in cost effectiveness. There is currently no consensus method for calculating the social cost of methane. Affordability must also be at the forefront and a priority as required by SB 1371…Therefore, a measured and equitable approach must be taken when crafting a social cost of methane for use in this proceeding. (SoCalGas/SDG&E January 22, 2019 Comments at 4.)

Like other utilities, "Southwest Gas believes that the individual program revenue requirements should be levelized over the expected equipment life and then multiplied by the number of years being analyzed to ensure the analysis does not unfairly disadvantage programs that may have higher start-up costs relative to their near-term savings. The costs can then be divided by program savings over the analysis period to determine cost effectiveness." (Southwest Gas January 22, 2019 Comments at 2.) It emphasizes that any cost-effectiveness test should not deprioritize any safety related improvements. (Southwest Gas January 22, 2019 Comments at 2.)

EDF believes the CPUC should adopt an approach going forward that ensures the full range of benefits associated with reducing methane leaks are taken into account. It believes that Compliance Plans to date have focused too narrowly on the cost per MCF reduction in methane for each best practice. Therefore, utilities should make an effort to quantify other benefits, including: (EDF January 22, 2019 Comments at 5.)

- Avoided social costs of methane;
- Future reduced leak repair costs;
- Reduced gas lost to leakage;
- Shifting from emergency to planned work;
- Safety improvements;
- System reliability improvements; and
- Lower insurance costs.

It believes that "[t]hese benefits can often be quantified and, even when they are not, they often serve as the basis for approving utility expenditures, such as in a utility's general rate case." (EDF January 22, 2019 Comments at 5.) It refers to different examples of three-year leak cycles proposed in different GRCs with different results.

As an example, EDF observes:

> This overlap between measures included in a GRC and those included in this1371 proceeding demonstrates that there are multiple, overlapping benefits to reducing methane emissions. Therefore, the Commission should not evaluate cost-effectiveness based solely on the cost per MCF reduction in methane but should take into account the benefits associated with implementation of robust compliance plans, including the avoided social cost of methane and the safety benefits that result from more rapid detection and repair of major emitters. (EDF January 22, 2019 Comments at 6.)

EDF notes that the IWG (discussed in Section 4.1.2) has adopted a metric-referred to as the "Marten approach" for evaluating the social cost of methane. According to EDF, "this methodology has been applied in federal rulemakings and provides a conservative measure of cost effectiveness of reducing methane emissions." (EDF January 22, 2019 Comments at 6.) "EDF supports this approach, though notes that the approach might need to be updated to include methane's global warming value as determined in the 5th assessment report of the Intergovernmental Panel on Climate Change (IPCC)." (EDF January 22, 2019 Comments at 6.)[24]

EDF believes that both the total program and its individual components of best practices should both be looked at. EDF recommends that "[w]hen

[24] The IWG's "Addendum to Technical Support Document on Social Cost of Carbon" (August 2016) adopted estimates of social costs of methane from a published study by Marten et al. Available at: https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf The IWG used the Marten study to arrive at the above values.

evaluating the cost effectiveness of methane emissions, the Commission should not look at each best practice individually…it is imperative that the plans be evaluated as a whole, recognizing that some best practices may be cheaper than others, but a robust series of measures is necessary to move California towards its goal of reducing methane emissions by 40% (or more) by 2030." (EDF January 22, 2019 Comments at 7.)

CUE argues that the CPUC's current focus is misplaced. "The Commission took almost three years to adopt best practices to satisfy SB 1371. Now, more than four years after SB 1371 became law, the Commission is figuring out what it means to 'cost effectively' find and fix leaks rather than the simple mandate of SB 1371—finding and fixing leaks—is carried out." (CUE February 4, 2019 Comments at 3.) It warns that focusing on cost effectiveness again merely gives SoCalGas/SDG&E and its allies to relitigate best practices despite a strong record that demonstrates the "feasibility and affordability" of all of the adopted best practices. (EDF February 4, 2019 Comments at 3.) At the same time, it supports EDF's idea that any fair evaluation of best practices must consider the benefits of reducing gas leaks including those contained in the list that EDF provides above.

4.3. Discussion

4.3.1. Key Issues

We concur with PG&E that the central debate, based on the November 3, 2016 First Phase cost-effectiveness workshop and reiterated again through subsequent workshops and Second Phase comments, appears to be whether in implementing SB 1371, the CPUC should adopt a cost-effectiveness methodology for operators to evaluate and prioritize best practices, as proposed by the utilities and TURN, or develop a broader cost-benefit methodology as suggested by EDF and CARB that considers the social cost of methane. (PG&E December 9, 2016 Comments at 2.) Multiple parties recommend the adoption of a cost-effectiveness test, threshold, or ranking through which only Best Practices determined individually to be cost-effective, or most cost-effective, would be required or implemented. However, we agree with CUE that SB 1371 does not require fixed application of a specific cost-effectiveness threshold. (CUE May 20, 2016 Comments at 5.) But as a matter of CPUC policy, we are concerned about the reasonableness of rates; therefore, the cost of methane reduction measures must be considered.[25]

We agree that utilities should continue to calculate a proposed measure's costs per unit of methane reductions as they accomplished in recent Compliance Plans. At the same time, as parties observe, we acknowledge that such limited cost-effectiveness calculations may be too narrow as they do not include benefits such as the avoided social cost of methane, avoided cap and trade compliance costs, safety benefits that accrue due to more rapid detection of repair of super emitters and reliability improvements, for examples.

In addition to these comments on the adoption of cost-effectiveness methodologies, parties observe that utilities use inconsistent cost-effectiveness methodologies in Compliance Plans. Cost information across utilities has been presented in an "apples and oranges" format, that results in both difficulties in performing comprehensive evaluations and an inability to do meaningful comparisons across the utilities. Examples of problems include incomplete data, lack of net present value analysis to account for long lives of programs, inconsistent use of performance metrics and time frames for evaluation, and lack of compatibility of approaches with general rate case approaches.

In parties' protests to March 2018 Compliance Plans, parties shared similar themes. For example, as stated in Resolution G-3538, EDF reiterated its argument that SoCalGas and SDG&E did not provide enough details to evaluate cost

[25] *See* Pub. Util. Code § 451.

estimates associated with each Best Practice in the Compliance Plans.[26] In reply comments, SoCalGas mentioned that Supplemental Advice Letter filings provided better cost estimates and more accurate estimation methodologies and assumptions not yet available in previous filings.[27]

We address these concerns in the following sections pertaining to high level policy guidance and short-term and long-term cost effectiveness strategies.

4.3.2. SB 1371 Cost Effectiveness Policies

In D.17-06-015, the CPUC adopted four Technical Working Group (TWG) principles to guide the development of methane leak Best Practices including two directly related to the cost-effectiveness of methane leak abatement best practices:

> If we can use the most advanced, technologically feasible, cost-effective measures to further reduce methane emissions beyond established targets, we should.
>
> Improved methane detection by itself isn't enough; it should be coupled with better quantification and accurate categorization and matched with a plan/timetable for mitigation in manners that are cost effective in minimizing the release of methane. [28]

We generally agree with SoCalGas/SDG&E's proposed recommendations (with some slight modifications shown in italics) regarding cost-effectiveness analysis, as described below:

- All parties should calculate cost effectiveness in a same *or similar* [rather than just "same"] manner so that it can be compared equitably among activities and parties. *(Such approaches and associated formats should be compatible with those used in general rate cases and Natural Gas Leak Abatement Program Annual Reports.)*
- Consistent with SB 1371, nothing in this article shall compromise or deprioritize *safety*. If a proposed activity will compromise safety or reliability, it should not be

[26] *See* Resolution G-3538 at 6.
[27] *Ibid.*
[28] First Phase Decision at 58, OP 4 at 159.

considered as an option. If a measure has reasonably quantifiable safety or reliability benefits, those should be included in determining cost effectiveness.

- Cost-effectiveness of methane reduction measures shall be considered on an individual measure basis, or on an aggregate basis, if this is most appropriate considering the overlapping nature of benefits of each best practice.
- Although evaluation of Compliance Plans is slowly moving from a qualitative to a more quantitative framework over time, *flexibility* should be retained to consider a multitude of factors and subjective judgment in the evaluation and accomplishment of program goals.
- To ensure *transparency and consistency*, cost-benefit or cost-effectiveness metrics should continue to be vetted through *broad participation of parties* in public workshops and parties' comments in response to public workshops and submitted Compliance Plans.
- Natural Gas Leakage Program cost strategies should strive for *consistency* and *continuous improvement* and incorporate lessons learned from successive Annual Joint Staff Report and Compliance Plan cycles.

4.3.3. **Cost-Effectiveness Framework**

As stated above, we do not believe it is appropriate to adopt a numeric determination of cost-effectiveness as a "threshold" value.

We do not consider it reasonable to adopt cost-effectiveness benchmarks that compare the results of this program versus those in other sectors such as transportation, agriculture, and dairy. Those other measures may receive significant subsidies, incentives and/or grants from ratepayers, taxpayers, and/or other sources,[29] and implement different statutory regimes, which would make an

[29] For example, six dairy biomethane pilot projects will receive $319 million in incentives funded by utility ratepayers pursuant to D.17-12-004 (December 3, 2018 Press Release, at: file:///C:/Users/SG8/AppData/Local/Microsoft/Windows/INetCache/IE/3H54LE43/246748640.pdf); in addition, the California Department of Food and Agriculture's Dairy Digester Research and Development Program awarded $174,288,365 in grants in 2018, $104,797,964 in grants in 2017, and its 2019 grant solicitation is pending. (See: https://www.cdfa.ca.gov/oefi/ddrdp/).

accurate comparison extremely difficult and not necessarily appropriate, and we have not attempted to create a record for such comparison in this proceeding. The CPUC may re-evaluate this in the future based on additional information.

Although we do not adopt a threshold value or official cost benchmarks, we require a more uniform approach using common assumptions to evaluate cost-effectiveness of emissions reductions projects. In this regard, at an October 2016 workshop, the four utilities offered a specific proposal that serves as a building block for quantification of benefits and costs:[30]

Utility Proposed Utility Cost Effectiveness Methodology

CAPITAL COSTS	• Determine Net Present Value of Best Practices Capital Costs; • May include cost of engines, portable compressors, vapor recovery systems, piping thermal oxidizers, over life of equipment
O&M COSTS	• Determine Net Present Value of Equipment and Labor, etc. • May include staff, supervision, clerical, monitoring, testing, lab work, analysis, recordkeeping systems, training, surveys, report preparation, etc.
GAS SAVINGS	• Estimate volume of Gas Reduced (MCF methane) and cost; • Note that Gas Flared/combusted cannot be monetized; • Recovered gas volumes can be monetized to reduce overall best practices costs
$/MCF GAS	• Divide combined capital and O&M Costs by volume of gas reduced to get $/MCF value; adjust for monetized gas savings if applicable.

In addition to gas cost savings, the avoided Cap-and-Trade costs discussed below represent savings to the utility that should be included when calculating the costs of methane reduction measures/MCF. Additional cost-effectiveness considerations shall include appropriate timeframe of analysis—over the life of the asset, compliance period, timeframe for incentive mechanism, etc. including time value of money, discounting, and capital recovery factor. We concur with the utilities that utilizing this approach will enable operators to target "low hanging

[30] *See* First Phase Decision at 45.

fruit" for emissions reductions and not disadvantage programs that may have high startup costs. In this regard, as stated in the First Phase Decision, it is worthwhile to continue to focus on implementing the "biggest bang for the buck" strategies in development and implementation of the 26 Best Practices. Such an approach would systematically balance tradeoffs between emissions reductions, safety, and affordability of gas service for a particular utility given its unique business model, operating conditions, and physical configuration of the gas system.

4.3.4. Cost-Benefit Analysis Including Avoided Social Cost of Methane

We also support, where practicable, utility documentation and quantification of miscellaneous other benefits of methane reduction initiatives in their Compliance Plans, as EDF proposes. Therefore, utilities should quantify other benefits, to the greatest extent practicable, including:

- Future reduced leak repair costs;
- Reduced gas lost to leakage;
- Shifting from emergency to planned work;
- Safety improvements;
- System reliability improvements; and
- Lower insurance costs.

Similarly, another benefit of reduced methane emissions is avoided reduced Cap-and-Trade compliance costs, which utilities incur for all LUAF (included methane emissions), issued by the CPUC in R.14-03-003:[31] Avoided Cap-and-Trade compliance costs are included as a benefit in the cost-effectiveness evaluations in the Compliance Plans. The amount of avoided costs are calculated based on volume of methane reductions estimated in the Plan, using the "Emissions Conversion Factor (MTCO2-e/MMcf)" and the "Proxy GHG Allowance Price"

[31] *See* D.15-10-032 "Decision Adopting Procedures Necessary for Natural Gas Corporations to Comply with the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Cap-And-Trade Program)" issued October 23, 2015. Pursuant to this decision, which implements CARB Regulations at 17, Cal. Code Regs., Sections 95851(b) and 95852(c), gas utilities submit an annual revenue requirement for their Cap-and-Trade obligations for gas sales, usage, and leaks/emissions.

used for the gas utilities' Cap-and-Trade forecast revenue requirements in R.14-03-003. These values in SoCalGas' 2018 Forecast Revenue Requirement were 54.64 for the Emissions Conversion Factor and $15.05 for the Proxy GHG Allowance Factor Price (Attachment C to Advice Letter 5293-A).[32]

After considering parties' comments and other recent Commission decisions on cost-effectiveness, we believe it is appropriate to require two methods to analyze cost-benefits in future Compliance Plans. These cost-benefit analyses will be used for information and comparison purposes.

The first method calculates the cost-benefits of individual proposed methane reduction measures, and the Compliance Plan as a whole, by determining the ratio of all reasonably quantifiable benefits to costs. In addition, methane reduction measures that together are intended to reduce one type of emission may be grouped together for purposes of the cost-effectiveness calculation, if this is most appropriate.

As discussed below, the second cost-effectiveness test mirrors the first test but includes as a benefit the avoided social costs of methane, using the IWG's average value with a 3 percent discount rate.

We agree with EDF that including the social cost of methane is important to the overall understanding of the avoided costs associated with emissions reduction practices, and should not be ignored. CARB supports use of specific social cost

[32] The costs paid by gas utilities in the Cap-and Trade program do not account for the full climate impact of methane emissions. The CO2-e (carbon dioxide equivalent) calculated for utilities' gas Cap-and-Trade compliance obligations assumes that all the gas is combusted, which is not the case for methane leaks. Thus, the costs are too low for the portion of LUAF that is represented by methane leaks (due to higher global warming potential of methane that is directly released to the atmosphere, compared to CO2 released when the methane is combusted). However, at this time, CARB has not accounted for this in its Rules, so the actual a voided cost to the utility remains the amount determined based on combustion.

valuations (as developed by the IWG [33] [34] and we agree. By considering best estimates of the social cost of methane, decision makers can benefit from better understanding discount rates, time horizons, and the global nature of IWG estimates. Without having access to this metric, we will have incomplete information and will not be making policy choices that optimize net social welfare over time. Utilizing the social cost of methane provides a comprehensive measure of the net damages—the monetized value of net impacts from global climate change that result from an additional ton of methane.

We therefore direct the utilities to include a second cost-effectiveness analysis in their Compliance Plans (for individual measures or aggregated related measures, and for the entire Plan) that considers the same reasonably quantifiable benefits and costs discussed above, but also includes the avoided social costs of methane as a benefit. The utilities shall use the values for avoided social cost of methane adopted by the IWG and set forth in the Tables at pages 15-16, using the average value with a 3% discount rate. In the context of the Natural Gas Leak Abatement Program, employing a cost-effectiveness test in Compliance Plans that considers the avoided social cost from methane abatement along with safety, reliability, ratepayer and other benefits, is in line with best available science and CARB recommendations. In California's 2017 Climate Change Scoping Plan (CARB Scoping Plan), at 39-40, CARB found that the IWG valuations are robust, reliable, and appropriate and should be considered as an aid to decision making.

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33 https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf and https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf

34 At a CPUC/CARB sponsored workshop on November 18, 2019, CARB provided the IWG definition of the social cost of methane: "The social cost of methane for a given year is an estimate, in dollar of the present discounted value of future damage by a one metric ton increase in methane emissions into the atmosphere in that year, or equivalently, the benefits of reducing methane emission by the same amount in that year."

CARB stated: "Along with SC-CO2 [social cost-carbon], the State also supports use of the SC-CH4 [social cost-methane] and SC-N2O [social cost-nitrous oxide] in monetizing the impacts of GHG emissions." (*Id.* at 41.)

In addition, the CPUC recently adopted D.19-05-019 (issued May 21, 2019) in R.14-10-003, that requires use of a Societal Cost Test that includes the social cost of carbon determined by the IWG for informational purposes in evaluating cost-effectiveness of electricity investments in the Integrated Resources Planning proceeding (R.16-02-007).[35] Although D.19-05-019 only addresses cost-effectiveness tests for electricity planning, it shows the direction that the CPUC is taking, and that information about social cost of GHG emissions is useful for evaluation of proposed utility investments. D.19-05-019 requires use of the social cost of carbon with the average value using a three percent discount rate (3 percent average value), and we likewise require the social cost of carbon using the 3 percent average value.[36] D.19-05-019 also requires use of an additional value for the social cost of carbon – the "high impact value."[37] But to avoid added complexity in evaluating current proposals, we will only require use of the value for social cost of methane adopted by the IWG for the average value using the 3 percent average value.[38] Pursuant to D.19-05-019 (OP 8), the ED will conduct an evaluation of the Societal Cost Test including the social cost of carbon in 2021 and recommend how to use it in future decision-making, including whether to use the IWG social cost of carbon 3% average value, or the high impact value. The Commission may consider modifications to the social cost of methane value approved for use in this Decision based on that evaluation.

[35] *See* D.19-05-019 "Decision Adopting Cost-Effectiveness Analysis Framework Policies for all Distributed Energy Resources" issued May 21, 2019 in R.14-10-003, at OP 4.

[36] *See* D.19-05-019, OP 5.

[37] We note that there is considerable scientific evidence that the "high impact value" would more accurately reflect the accelerated climate change impacts that are occurring in California and elsewhere. (*See* D.19-05-019 at 39-41; CARB Scoping Plan at 41.)

[38] D.19-05-019, OP 5.

These two required cost-benefit analyses will provide relevant information for the CPUC to consider during evaluation of proposed measures to implement Best Practices. However, we do not adopt a requirement that all measures, or the Compliance Plans in their entirety, must show a positive benefit to cost ratio under either methodology. The CPUC retains full discretion to evaluate measures proposed in the Compliance Plans considering cost-effectiveness along with other qualitative factors and policy goals.

4.3.5. **Next Steps**

In the short-term, consistent with the directives in the First Phase Decision, within 60 days of this decision, SED and ED shall convene a TWG and conduct a workshop to refine the scope and detail and ensure consistency in the Compliance Plans and Tier 3 Advice Letters pertaining to cost-effectiveness and cost-benefit analysis and other elements as directed in the First Phase Decsion and required by this decision. This workshop may also address any other refinements to cost tracking and cost recovery mechanisms.

By September 15, 2019, and in cooperation with SED, the TWG shall submit recommended changes for the next Compliance Plans due March 2020, consistent with the content and format of Compliance Plans established in the First Phase Decision, OP 6.

SED and ED Staff have the authority to convene the TWG every two years to consider updates to the Compliance Plan, and to make clarifying changes to Compliance Plan templates and requirements for filing Compliance Plans, as approved in the First Phase Decision and consistent with policy direction provided in this decision.

5. LUAF Ratemaking Treatment and Financial Incentives

This scoping memo question relates to current ratemaking methods to recover LUAF costs and how financial incentives can be aligned to eliminate methane leaks from the gas system. For the sake of analysis, we provide a common definition of LUAF below and an overview of the LUAF accounting systems that must be understood before any cost recovery strategy or rate treatment can be addressed for the methane emissions component of LUAF. As stated in Section 3, "Issues Before the Commission," we consider the methane emissions component of LUAF only. EDF's initial proposal in comments was that recovery for *all* components of LUAF for utilities be disallowed. All of the IOUs filed comments opposing this, as summarized below.

Two legislative actions provide important context for CPUC implementation of Pub. Util. Code § 975. SB 1383 directs CARB to implement a comprehensive short-lived climate pollutant strategy to achieve a 40% reduction in the statewide emissions of methane below 2013 levels by 2030. SB 32 sets a statewide 2030 greenhouse gas reduction target of 40% below 1990 levels.[39]

5.0.1. Definition of LUAF

PHMSA has the provided the following definition of LUAF, of which methane emissions is a sub-component:

> Unaccounted for gas" is gas lost; that is, gas that the operator cannot account for as usage or through appropriate adjustment. Adjustments are appropriately made for such factors as variations in temperature, pressure, meter-reading cycles, or heat content; calculable losses from construction, purging, line breaks, etc., where specific data are available to

[39] First Phase Decision, COL 42 at 148.

allow reasonable calculation or estimate; or other similar factors.[40]

5.0.2. Current LUAF Accounting Systems

The IOUs similarly define and calculate LUAF by means of a material balance but differ in methods of cost recovery. Whether LUAF is collected in kind through shrinkage allowances (PG&E), or in dollars through rates (SoCalGas, SDG&E), each of the major California gas IOUs operate a true-up mechanism through which they recover (or return) under- (or over-) collections of LUAF from previous periods. The utilities' cost recovery mechanisms and the gas rate calculation are determined in the utilities' cost allocation proceedings. Currently, PG&E, SoCalGas and SDG&E recover LUAF costs through annual Advice Letter filings.

For Southwest Gas residential and small commercial customers, LUAF is recovered monthly through its core gas cost adjustment advice letter included in its Purchased Gas Cost Adjustment Balancing Account. For transportation customers, a LUAF percentage factor is approved in each Southwest Gas GRC that is developed on a 5-year average of LUAF. Similar to PG&E, the shrinkage rate is equal to a LUAF percentage factor times the current effective monthly gas procurement rate. (Southwest Gas workshop presentation, November 16, 2018.)

These different accounting approaches are sufficiently consistent for purposes of defining, identifying, and accounting for LUAF, especially the methane emissions leakage component that is a subset of the total aggregated LUAF. As parties agree, LUAF is first and foremost an accounting tool used by IOUs to manage inventory and not a proxy for gas emissions. Methane emissions a

[40] *See* Instructions for Completing Form PHMSA F 7100.1-1, Annual Report, Gas Distribution System, Part G - Percent of Unaccounted For Gas. This definition is compatible with what was adopted in D.86-12-091: Unaccounted for gas is the difference between: (1) recorded gas purchase volumes and net changes in underground storage and pipeline inventory and (2) recorded gas sales to customers.

focus of this proceeding, represent approximately 30 percent of total LUAF, for the large four utilities based on 2017 data.[41] The other components of LUAF are presumably unrelated to methane leaks or emissions and include measurement error, accounting and billing error, gas theft, utility usage (*e.g.*, compressor stations, etc.) and "non-study" or "unclassified" components that we do not address here. (For an explanation of definitions of each of these categories see PG&E January 22, 2019 comments at 7-8.) Utilities argue that these non-emissions components are varied and complex and exist for reasons that either utilities cannot or should not control.

However, SED is taking steps to ensure a more rigorous and consistent LUAF reporting framework consistent with SED's authority to provide direction to utilities, in conformance with current federal (PHMSA), state (CPUC GO 112-F) regulations, and SB 1371 requirements. In particular, we encourage SED Staff to take steps to investigate and categorize LUAF currently classified as "unidentified" or "non-study components," which could conceivably contain a methane emissions component.

5.1. Parties' Comments

In general, utilities support the existing system in which they are able to recover the costs of LUAF (of which methane emissions is a subset of total LUAF volumes). They strongly argue that LUAF is not a result of utility mismanagement and recommend specific criteria be adhered to in order to create financial incentives. ~~In contrast, EDF initially recommended~~EDF argues that ~~cost~~ recovery ~~for *all*~~of LUAF volumes (of which methane emissions is a small subset of total LUAF volumes) ~~be disallowed. Its most recent comments propose~~should be tracked in a memorandum account until the Commission resolves the extent to

[41] In particular, total methane emissions by each utility as reported in Table 6 "Emissions by Utility and Independent Storage Provider, 2015-2017) of the SB 1371 2018 Annual Report is a sub-component of total LUAF volumes reported by each utility in annual GO 112-F and PHMSA reports as required by D.15-06-044.

which utilities should be able to recover from ratepayers the cost of gas lost to the atmosphere. (EDF January 22, 2019 Comments at 6.) It proposes implementing a mandatory annual percentage reduction in the methane emissions component of total LUAF and imposing financial penalties, if performance standards are not met.

More specific comments of parties are set forth below:

5.1.1. **PG&E**

According to PG&E, "[t]he current methods used by the California gas utilities to recover LUAF serve their intended purpose of compensating the gas utilities for the LUAF they experience." (PG&E January 22, 2019 Comments at 6.) It argues that a change to these methods, or adoption of a uniform method for all utilities is unnecessary and would not provide any benefit in terms of reduced methane emissions. "Further such a change could be costly, potentially requiring a utility to change its tariffs, contracts, billing systems, and system balancing practices, which would in turn result in additional costs for the utility's customers to align their systems and practices with the utility." (PG&E January 22, 2019 Comments at 6.)

PG&E claims that any effort attempt to create incentives to reduce methane emissions should address those emissions directly and need not address LUAF broadly. (PG&E January 22, 2019 Comments at 6.) It claims that "it should be clear from the discussion that methane emissions are a relatively small subset of total LUAF, and that the other components of LUAF are varied and complex and exist for reasons that utilities either cannot or should not control." (PG&E January 22, 2019 Comments at 10.)

PG&E summarizes:

> Any financial incentives should be: (i) Limited to Recovery of Methane Emissions, (ii) consistent with the approach and schedule undertaken in this proceeding, (iii) consistent with the funding granted to utilities to reduce methane emissions,

> and (iv) limited to methane emissions that can be reliably estimated. (PG&E January 22, 2019, Comments at 11.)

PG&E asserts there are existing mechanisms in place to challenge LUAF (*e.g.*, appropriate cost recovery proceeding or in a complaint filed with the Commission).

PG&E asserts that EDF's proposal to disallow utility recovery of LUAF is misplaced for a number of reasons:

> It does not appropriately distinguish methane emissions from LUAF. It appears to view LUAF as a problem of mismanagement rather than a reasonable and legitimate accounting practice. It ignores the trade-offs involved in limiting LUAF on the one hand and controlling operating costs on the other hand. It appears to assume that LUAF and methane emissions can be reduced to zero. If they cannot be reduced to zero, it proposes to arbitrarily penalize utilities by disallowing recovery. It would create an incentive for utilities to make uneconomic investments to reduce LUAF. If the Commission denied cost recovery for such investments, the utilities would be faced with the unfair choice of either absorbing the cost of the investments or foregoing the investments and absorbing the cost of LUAF. In the end, EDF's proposal would arbitrarily penalize utilities without necessarily reducing either LUAF or methane emissions. (PG&E January 22, 2019 Comments at 11-12.)

5.1.2. SoCalGas/SDG&E

SoCalGas/SDG&E points out that "contrary to what EDF has sought, the Commission has supported LUAF recovery in other proceedings." They remind parties that "[i]n March of 2017, after considering briefings from EDF and SoCalGas on the LUAF issue, Commissioner Randolph ruled that 'denying LUAF gas cost recovery in the GRC would provide a counter-productive incentive for the company to invest in totally trivial and unimportant meter errors with expensive solutions that escalate costs without any environmental benefit.'"[42] In that proceeding, the Utility Reform Network (TURN) and the Commission recognized that most of LUAF is measurement variance. SoCalGas has over six million meters in its service territory. Ensuring 100% accuracy on every meter at all times is not only impossible, the cost to customers to try to manage that level of measurement accuracy would be extremely prohibitive." (SoCalGas/SDG&E January 22, 2019 Comments at 8.)

SoCalGas/SDG&E also agree with PG&E that any incentives or penalties must be based on approved funding and activities. They opine, that "[a]s long as the IOUs meet the requirements of the approved Compliance Plan they should not be subject to penalties." (SoCalGas/SDG&E January 22, 2019 Comments at 10.) However, SoCalGas/SDG&E believe that a reasonable exception could be incentives or penalties for exceeding or under achieving repair of Grade Three Leaks within three years. (SoCalGas/SDG&E January 2, 2019 Comments at 10.)

SoCalGas/SDG&E agree with PG&E that "reported emissions are an estimate and utilities should not be penalized based on estimated numbers." (SoCalGas/SDG&E January 22, 2019 Comments at 9.) They observe that

[42] *See* "Assigned Commissioner Ruling on Lost and Unaccounted for Gas Issue" dated March 8, 2018" in A.17-10-007 "Application of San Diego Gas and Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019."

"[a]ccording to the 2017 Joint Staff Report, 61% of reported emissions are based on population-based emission factors." (SoCalGas/SDG&E January 22, 2019 Comments at 9.) Unless the current reporting framework is changed, it is impossible to demonstrate a 40% reduction from the utility gas sector because over 60% of emissions cannot be measurably reduced. They emphasize that "[t]o have an effective incentive or penalty program, goals should be specific, measurable, achievable, and reasonable." (SoCalGas/SDG&E January 22, 2019 Comments at 9.)

SoCalGas/SDG&E predict that "LUAF penalties would likely result in increased rates...Clearly, safety, reliability, and affordability take priority over reducing emissions. Imposing a LUAF penalty would force IOUs to implement emission reduction activities that are not cost effective and would increase rates for customers." (SoCalGas/SDG&E January 22, 2019 Comments at 11.)

Finally, SoCalGas/SDG&E emphasizes that LUAF penalties may result in a compromise to safety. "SB 1371 expressly states that "nothing in this article shall compromise or deprioritize safety. There are situations where gas must be vented to prevent unsafe situations." (SoCalGas/SDG&E January 22, 2019 Comments at 10.)

5.1.3. Southwest Gas

Southwest Gas raises the same themes as the other utilities. "Southwest Gas does not believe it is necessary or appropriate to take any action related to the ratemaking for, or recovery of LUAF in this proceeding...Further, any changes to the ratemaking or recovery aspects of LUAF would almost certainly require changes to each utility's accounting processes, as well as potential charges to their contractual agreements with their transportation customers. LUAF is therefore most appropriately addressed in the individual rate proceedings for each utility." (Southwest Gas January 22, 2019 Comments at 3.)

Southwest Gas also expresses concern about the impact about population-based emissions factors could have on an incentive structure. In Southwest Gas' case, 98 percent of their emissions were population based. Southwest Gas argues that unless there is a procedure for modifying EFs, it will not be able to report a meaningful reduction in population-based emissions. (Southwest Gas January 22, 2019 Comments at 3-4.) It also expresses a concern about safety implications of eliminating some intentional leaks. (Southwest Gas January 22, 2019 Comments at 4.)

5.1.4. **EDF**

EDF has an opposing view of whether recovery for LUAF volumes should be limited. It claims that "[w]hen the Legislature required the CPUC to consider an 'adjustment of allowance for lost and unaccounted for gas related to actual leakage volumes,' the *only* option available to the Commission would be to make a downward adjustment and limit the ability of utilities to recover the cost of lost gas." (EDF January 22, 2019 Comments at 11.)

EDF strongly believes that disallowance of rate recovery should incentivize utilities to reduce emissions. It asserts that "California's current system of cost recovery for LUAF does nothing to incentivize utilities to reduce the methane emissions. Currently SoCalGas and SDG&E receive payments from ratepayers through an adjustment to the gas purchase price in their Triennial Cost Allocation Proceeding. PG&E and Southwest are both compensated through a shrinkage allowance that covers the cost of LUAF gas. "(EDF January 22, 2019 Comments at 12). It further opines that "[u]tilities should only be compensated for the value of those services they confer to the public." According to EDF, "this principle has roots in utility regulation and involves a regulator's duty to ratepayers to protect them from unreasonable risks including risk of imprudent management." (EDF January 22, 2019, Comments at 12.) Although EDF espouses this principle, EDF acknowledges the Supreme Court case *West Ohio Gas. v. Public Utilities Commission* in which the Court found error in reducing the West Ohio Gas Company's rates for LUAF and explained that some lost gas will always be unavoidable, but believes this situation is distinguishable.[43]

EDF recommends that "[r]ather than engage in a lengthy post-hoc review of the reasonableness of utilities emissions on a yearly basis, the Commission should establish a performance standard for methane emission reductions that ensures utilities are vigilant in their implementation of plans and that they have incentive to continue to innovate beyond the corners of the SB 1371 Compliance Plan." (EDF January 22, 2019 Comments at 16.) EDF's performance standard proposal would establish 2018 as a base year and would allow decreasing recovery for methane emissions in all subsequent years. In 2019, emissions cost recovery would be reduced by 17 percent, to 83 percent of 2018 levels. In subsequent years, emissions cost recovery would be reduced by an additional 2-3 percent each year. (EDF January 22, 2019 Comments at 16-17.)

5.1.5. Reply Comments

In reply comments, PG&E opposes EDF's proposed standard, stating that "[i]mposition of a performance standard on the utilities would be at best premature and at worst an arbitrary penalty." (PG&E February 4, 2019 Comments at 5.) It claims that "EDF's proposal would in effect impose a schedule on the utilities for reducing methane emissions and unfairly saddle the utilities with emissions measurement risk, emissions variability risk, and the uncertainty regarding the effectiveness of the Best Practices." (PG&E February 4, 2019 Comments at Reply at 5.)

[43] In that case, the state commission reduced the LUAF recovery retroactively and without any warning to the utility. West Ohio Gas Co. v. Public Utilities Commission, 294 U.S. 63 (1935).

5.2. Discussion

Initially, we note that "Pub. Util. Code Section 977(b) states that "the commission [CPUC] *shall consider* all of the following...(b) Providing revenues for all activities identified and required pursuant to Section 975, including any adjustment of allowance for lost and unaccounted for gas related to actual leakage volumes." We agree with SoCalGas/SDG&E that the legislation gives the CPUC discretion to determine whether it makes sense to make adjustments to revenue allowances for LUAF. We also find that Pub. Util. Code § 977(b) does not direct the CPUC to consider adjustments to allowance for all LUAF, but only to the portion of LUAF "related to actual leakage volumes" – in other words, the methane emission component of LUAF.

5.2.1. Current Methods of LUAF Recovery

Except as provided below, we find that there is no compelling reason to change the current methods of LUAF accounting and recovery. Current methods to account for LUAF through a material balance (either dollars or shrinkage allowances) represent different accounting practices that have been accepted by the CPUC.

The CPUC must directly focus on emissions reductions through implementation of the 26 Best Practices as approved in the First Phase Decision rather than on reducing LUAF more broadly. If EFs are modified, and this changes the utilities' annual reported methane emissions, we assume that the "baseline" emissions will be modified as well; or some other method will be adopted so that annual reports reflect actual emission reductions, not just EF modifications.

5.2.2. Financial Incentives

We agree with PG&E that any financial incentives should be limited to recovery of methane emissions and not LUAF, consistent with the approach and schedule undertaken in this proceeding, consistent with funding granted to utilities to reduce methane emissions, and limited to methane emissions that can be reliably estimated. Currently approximately 60 percent of reported methane emissions are "population -based" using fixed EFs. Little if any reductions are possible from population-based emissions, so virtually all the emissions reductions must come from the *remaining* 39 percent of the emissions categories that ~~utilities can control~~are not population-based including graded pipeline leaks (19 percent), blowdowns (10 percent), vented emissions (4 percent), all damages (4 percent), unusual large leaks (1 percent), and other leaks (1 percent).

Total Emissions Grouped by Source Classification, 2015-2017[44]

Source Classification	2015 Baseline		2016		2017		2015 Baseline to 2017 Change		2016 - 2017 YOY Change	
	MMscf	%	MMscf	%	MMscf	%	MMscf	%	MMscf	%
Population Based Emissions	3,931	60%	3,898	62%	3,926	61%	(5)	(0.1%)	27	0.7%
Graded Pipeline Leaks	1,458	22%	1,401	22%	1,207	19%	(252)	(17%)	(194)	(14%)
Blowdowns	603	9%	373	6%	635	10%	32	5%	262	70%
Vented Emissions	258	4%	135	2%	242	4%	(16)	(6%)	107	80%
All Damages	318	5%	365	6%	227	4%	(91)	(29%)	(138)	(38%)
Other Leaks	33	0.5%	94	2%	79	1%	46	138%	(15)	(16%)
Unusual Large Leaks	0	0%	0	0%	83	1%	83	NA	83	NA
Total Sector Emissions	**6,601**	**100%**	**6,267**	**100%**	**6,399**	**100%**	(202)	(3.1%)	**132**	**2.1%**

We believe it is important to develop a process for utilities to use adjusted EFs for their annual emission reporting, if they implemented a methane reduction measure that achieves reasonably quantifiable reductions of methane emissions. Within 60 days of the issuance of this decision, we direct SED and ED to hold a workshop, in consultation with CARB, to address this issue and to develop such a process that utilities can rely on prior to submittal of the next Compliance Plans in March 2020. This will allow utilities to propose measures to reduce methane emissions that are reported based on EFs in their Compliance Plans, and if approved, reflect those reductions in their annual reports, to the extent they achieve reasonably quantifiable reductions.

[44] 2018 Joint Staff Report, Table 3 at 9.

We also acknowledge that work remains to be done by CARB and the CPUC to ensure that EFs are updated, as necessary, to reflect emission volumes as accurately as possible.[45]

6. Rate Recovery for Methane Emissions

6.1. CPUC Response to EDF's Proposal

Following up the summary of comments in Section 5, we believe that EDF's proposed limitations on rate recovery for methane emissions standard should be rejected for several reasons. First, we believe that EDF's proposal would accelerate requirements for reducing methane emissions too quickly and does not fully account for the fact that more than 60 percent of the current best estimates of utility methane emissions are based on population counts and EFs that produce static emissions that are unaffected by utility activities to reduce emissions. As noted above, we expect that the CPUC and CARB will work together to address this in time for the March 2020 Compliance Plans. Second, EDF proposes a base year of 2018, but offers no rationale regarding why this year should be used. If the standard begins in a current year, "credit" is not given to utilities that have already substantially addressed the "low hanging fruit" of emissions reductions. Further, after much deliberation among parties in the prior First Phase Decision, we determined that 2015 would be used as the base year to track emissions reductions. Third, as PG&E points out, EDF proposes to impose the largest reduction in cost recovery (17 percent in 2019), but 2019 will largely be complete by the time a decision is reached in this proceeding.

Emissions by Utility and Independent Storage Provider, 2015-2017[46]

[45] If EFs are modified, and this changes the utilities' annual reported methane emissions, we assume that the "baseline" emissions will be modified as well; or some other method will be adopted so that annual reports reflect actual emission reductions, not just EF modifications.

[46] *See* 2018 Joint Staff Report, Table 6 at 19.

Entity	2015 Baseline		2016		2017		2015 Baseline to 2017 Change		2016 - 2017 YOY Change	
	Mscf	%	Mscf	%	Mscf	%	Mscf	%	Mscf	%
Pacific Gas & Electric	3,294,368	50%	3,049,809	49%	3,202,937	50%	(91,431)	(3%)	153,128	5%
Southern California Gas	2,779,853	42%	2,697,020	43%	2,696,511	42%	(83,342)	(3%)	(509)	(0.02%)
San Diego Gas & Electric	282,041	4%	282,759	5%	256,794	4%	(25,247)	(9%)	(25,965)	(9%)
Southwest Gas	214,309	3%	217,324	3%	212,575	3%	(1,734)	(1%)	(4,749)	(2%)
Wild Goose GS	24,003	0.36%	13,301	0.21%	17,755	0.28%	(6,248)	(26%)	4,454	33%
Gill Ranch GS	3,636	0.06%	3,772	0.06%	5,094	0.08%	1,458	40%	1,322	35%
Lodi GS	1,638	0.02%	1,476	0.02%	5,697	0.09%	4,059	248%	4,221	286%
Central Valley GS	806	0.01%	445	0.01%	469	0.01%	(337)	(42%)	24	5%
West Coast GC	509	0.01%	391	0.01%	472	0.01%	(37)	(7%)	81	21%
Alpine Natural Gas	6	0.00%	245	0.00%	244	0.00%	238	4,257%	(1)	(0.4%)
Total	**6,601,169**	**100%**	**6,266,544**	**100%**	**6,398,549**	**100%**	**(202,620)**	**(3%)**	**132,005**	**2%**

The above chart shows that for year 2017 the top four utilities comprise approximately 99 percent of the emissions inventory and the six other utilities and independent storage providers (ISPs) make up the remaining 1 percent of the total emissions. PG&E and SoCalGas comprise 92 percent of the emissions inventory and SDG&E and Southwest Gas comprise 7 percent of the emissions inventory.

Based on 2018 annual report data, the chart below highlights the percentage of population-based emission factors for the four largest utilities. Of the large utilities, PG&E and SoCal Gas (Class A Utilities)[47] have more capability to influence emissions reduction since the percent of their 2017 population-based emissions reductions is 61.5 percent for PG&E and 56.1 percent for SoCalGas; SDG&E and Southwest Gas (Class B Utilities) have less capability to influence emissions reduction since the percent of their population-based emissions are 90 percent and 97.4 percent, respectively.

Population -Based Emissions by Individual Utility 2017[48]

[47] Based on 2015 annual emissions baseline data, Class A Utilities have an annual emissions equal to or greater than 500,000 Mscf. Class B Utilities have an annual emissions in between 50,000 and 500,000 Mscf. (*See* First Phase Decision at 119-125 for a description relating to classification of utilities.)

[48] Data derived from 2018 Joint Staff Report Data.

2017 Population Based Emissions:		
Entity	Emissions (Mscf)	% of Entity's Total Emissions
Alpine	235	96.3%
Central Valley Gas Storage	-	0.0%
Gill Ranch Gas Storage	-	0.0%
Lodi Gas Storage	2,128	37.4%
Pacific Gas & Electric	1,970,864	61.5%
Southern California Gas	1,513,800	56.1%
San Diego Gas & Electric	231,170	90.0%
Southwest Gas	207,117	97.4%
West Coast Gas	194	46.0%
Wild Goose Storage	-	0.0%
Total	**3,925,508**	**61.4%**

As indicated, for SDG&E and Southwest Gas, most of their methane emissions are reported using fixed EFs (90 percent and 97.4 percent, respectively). In addition, these two utilities are responsible for a relatively small percent of total statewide reported methane emissions (7 percent).

Although we reject EDF's proposal, we find it is reasonable to implement a modified "interim" limit on rate recovery for the largest gas utilities' methane emissions to help ensure timely, successful implementation of best practices. Accordingly, beginning in 2025, we limit PG&E and SoCalGas' rate recovery for methane emissions greater than 20 percent below their 2015 baseline levels. This will help to ensure that expenditures authorized to implement their Compliance Plans achieve the intended methane emission reductions. For 2018-2019, the Commission has authorized expenditures of $66 million for PG&E and $234 million for SoCalGas for methane reduction activities.

An interim limit on rate recovery will ensure that that aggregated intentional and non-intentional emissions are reduced in a downward direction towards the 2030 goal. This reduction of methane emissions as compared to the 2015 baseline represents approximately half of the SB 1383 target of 40 percent reduction by 2030 and half of the 40 percent volumes of PG&E and SoCalGas' methane emissions that are not population-based (*i.e.,* reported using fixed emission factors).

We believe that this performance standard, while significant, is realistic to achieve based on recent annual report trends, and estimated reductions that PG&E and SoCalGas have already provided in Compliance Plans. It is simple to administer since it focuses on the "big picture" of overall methane emissions and not specific categories of methane emissions and provides needed flexibility for utilities to focus on areas that they can control.

For example, in 2018 Compliance Plans, PG&E projected a 17 percent of methane emissions reduction as compared to the 2015 baseline by 2020. This level of reduction will be a significant step toward the 40 percent reduction by 2030 target.[49] SoCalGas projected a 14 percent reduction by 2020 and 19 percent reduction by 2030.[50] SoCalGas stated that additional reductions will be difficult because of the method of reporting emissions using a population-based emissions factor. We expect that a process will be in place to account for implementation of measures that achieve actual emission reductions for these sources in time for the 2020 Compliance Plans.

Because our adopted limit on rate recovery will not apply until 2025, PG&E and SoCalGas have ample time to propose necessary measures to achieve the expected methane reductions, in the Compliance Plans required in 2020, 2022 and 2024. Moreover, we fully expect PG&E and SoCalGas to exceed a 20 percent reduction of methane emissions from their 2015 baseline by 2025, so that they will be on a trajectory to meet the soft target of 40 percent reduction by 2030.

[49] Resolution G-3538 Attachment A SED Evaluation Report, 2018 Leak Abatement Compliance Plan at 22.

[50] Resolution G-3528 Attachment A at 35-36.

We acknowledge that in the First Phase Decision, the CPUC approved a *soft target* of 40 percent methane emission reduction to help ensure timely implementation of the 26 Best Practices and also found that establishing a hard target or performance incentives should be addressed after the first program evaluation.[51] On the other hand, Pub. Util. Code § 977(b) requires the CPUC to consider limiting allowance of recovery for methane emissions, and this consideration is was undertaken in Phase Two of the proceeding. Based on the record developed in Phase Two regarding the question in Pub. Util. Code § 977(b), we find that it is appropriate at this time to establish the modest limit on rate recovery described above beginning in 2025, to give utilities ample time to achieve the expected reductions, and to ensure substantial progress is made towards meeting the 2030 soft target. While this performance standard on rate recovery could be viewed as more than a soft target and more akin to a performance incentive, it is adopted here as a reasonable limitation on rate recovery for the methane emissions component of LUAF, as contemplated by Pub. Util. Code § 977(b). This cost recovery limitation is reasonable in light of the substantial expenditures (to be collected from ratepayers) that we have approved to reduce methane emissions, the utilities' ability to plan and implement additional methane reduction measures over the next six years, and ample notice of the limitation that will apply in 2025 and beyond. Moreover, the potential financial impact on PG&E and SoCalGas from the proposed limit on recovery for methane emissions is very modest. For example, if PG&E only reduced methane emissions 15 percent below its 2015 baseline in 2025, then it would be disallowed approximately $444,821 in rate recovery for LUAF gas; for SoCalGas, the amount disallowed would be

[51] The first program evaluation is now scheduled to be completed in 2021, in time for use in preparing the 2022 Compliance Plans.

$468,169.[52] While very modest, these potential disallowances should provide a clear message that emissions are expected to go downward.

If the Joint Staff Report[53] with 2025 utilities' emissions reflect a 20 percent reduction from PG&E's and SoCalGas' 2015 baseline emissions, no changes to PG&E and SoCalGas methane emissions recovery is necessary. If, however, SED and CARB staff determine in their final report that PG&E and SoCalGas did not reduce their methane emissions by 20 percent from their 2015 baseline emissions, PG&E and SoCalGas must file a Tier 2 Advice Letter within 60 days from the Joint Staff Report issuance date identifying the amount of methane emissions above the 20 percent reduction from their 2015 baseline emissions and the methodology for removing recovery of any methane emissions above the 20 percent reduction from their 2015 baseline emissions.

As noted in D.17-06-015 at 22, the 2015 baseline for PG&E is 3,294,368.32 Mscf (thousand Standard Cubic Feet) and for SoCalGas is 2,779,852.63 Mscf.[54] Accordingly, in 2025 and subsequent years, PG&E may not recover shrinkage allowances of any methane emissions reported for the year exceeding 2,635,495 Mscf and SoCalGas may not recover the cost for any methane emissions exceeding 2,223,882 Mscf.

In its Tier 2 Advice Letter filing, PG&E should include the methodology and calculation by which it will remove any shrinkage allowance for methane emissions exceeding the above amount for the next calendar year. SoCalGas should include in its Tier 2 Advice Letter the methodology and calculation by which it will remove in rates any methane emissions costs exceeding the above

52 Per staff calculation using 2015 baseline emissions and gas price of $3.25/MMBtu.

53 Joint Staff Report as prescribed in the First Phase Decision, OP 1. Joint Staff Reports report emission volumes for the previous calendar year. Therefore, the 2016 Joint Staff Report will be used to calculate 2015 emission volumes.

54 The SoCalGas 2015 baseline emissions for the Natural Gas Leak Abatement Program does not include emissions from Aliso Canyon.

amount for the next calendar year. For subsequent years thereafter, PG&E and SoCalGas will continue to file annual Tier 2 Advice Letters identifying the methane emission rate recovery adjustment until such time that the 20 percent reduction is met.

Any methane emissions above the 20 percent reduction necessary to balance the utilities' operating system will be borne at shareholder expense and not recovered from ratepayers. Except as provided herein, both PG&E's and SoCalGas' rate recovery calculations will continue to be subject to the factors approved in the utility's most recent General Rate Case or Cost Allocation Proceeding.

It is possible that the CPUC, in consultation with CARB, may approve adjustments to the utilities' 2015 baseline emissions. If so, the new baseline shall be used for determining rate recovery for methane emissions as described above. If there is any uncertainty regarding the appropriate baseline, the utility shall consult with SED, which shall specify the appropriate 2015 baseline for purposes of rate recovery, after consultation with CARB. If adoption of new emissions factors, or other conditions, present barriers to achieving the desired downward trend in emissions, utilities should identify these barriers in the narrative of their 2020 Compliance Plans. In addition, the 2021 Natural Gas Leak Abatement Program Evaluation will evaluate whether the CPUC should approve additional limitations on rate recovery for future years with the benefit of additional experience with the program and consideration of more recent annual report data.

In the First Phase Decision, respondents were required to include information in the 2018 Compliance Plan regarding how they expect to achieve a 40 percent reduction of emissions below 2013 levels by 2030, what level of reduction would be achieved in 2020, and how they plan to achieve the 2020 reduction level. Following a similar format for 2020 Compliance Plans, we direct

PG&E and SoCalGas to include information regarding how they expect to achieve or exceed a 20 percent reduction of emissions below 2015 baseline levels by 2025, and how they plan to achieve a 40 percent reduction by 2030.

7. Integration of 26 Best Practices into CPUC General Orders

With the implementation of SB 1371, GO 112-F, Section 123-K, Gas Safety Plans, was modified to accommodate the integration of Biennial Compliance Plans into the utilities' Annual Gas Safety Plans. Utilities must make modifications to their Gas Safety Plan at the direction of SED.[55]

A key scoping memo question aims to decide when Pub. Util. Code § 975 (f) rules and procedures, best practices and repair standards developed in this proceeding, should be incorporated into the applicable GOs.

7.1. Parties' Comments

According to SoCalGas/SDG&E, "incorporating rules and procedures, including Best Practices, into GO 112-F is premature at this time. Each utility has varying challenges based on geological terrain, age of infrastructure, pipeline materials, and system dynamics." (SoCalGas/SDG&E January 22, 2019 Comments at 11.) They further opine that the Compliance Plan currently offers the IOU's flexibility to assess which methods and technologies can achieve emission reductions in their service territory in a cost-effective manner giving priority to safety and continuity of service. They conclude that, "[u]ntil an emission reduction activity is demonstrated to successfully reduce emissions across the IOUs in a cost-effective manner, the IOUs need the flexibility of modifying and updating implementation strategies." (SoCalGas/SDG&E January 22, 2019 Comments at 12.)

Similarly, Southwest Gas believes that it is not necessary to incorporate SB 1371-related rules, procedures or Best Practices into GO 112-F at this time. It warns

[55] First Phase Decision at 116-117.

that "[d]oing so runs the risk of having to repeatedly modify GO 112-F as the utilities continue to implement and evaluate the results of their emissions reductions practices and strategies. It would also stand to reduce, if not eliminate, the current flexibility offered to the utilities in the form of exemptions from Best Practices and consideration of the differing size, areas of operation, and operating systems across the utilities." (Southwest Gas January 22, 2019 Comments at 4.)

7.2. Discussion

We concur with parties that integrating the 26 Best Practices in GO 112-F or a separate GO does not appear to provide any benefits, since the Best Practices adopted in D.17-06-015 are fully enforceable.

Instead of opening up a separate rulemaking proceeding to incorporate the natural gas leakage abatement best practices into the existing GO 112-F or a new GO, it is appropriate to revisit this issue after an SED/ED evaluation of the program in 2021.

8. Harmonization of SB 1371 Annual Report Requirements and 26 Best Practices with PHMSA and DOGGR Information and Requirements

The related scoping memo question explores how the CPUC's Annual Report Requirements and 26 Best Practices should be harmonized with information or action required by other entities such as PHMSA and DOGGR.

8.1. Parties' Comments

Utilities support harmonizing the SB 1371 Report and 26 Best Practices with other methane or natural gas leak data collected by California agencies and tout the benefits of such an approach. "SoCalGas and SDG&E support harmonizing the SB 1371 Annual Report and 26 Best Practices with other methane or natural gas leak data collected by various California agencies. Such harmonization will better inform utility customers, the community, the various agencies and other stakeholders about methane emissions and reduction efforts, reduce confusion, and eliminate duplicative work." (SoCalGas/SDG&E January 22, 2019 Comments at 5.) SoCalGas/SDG&E refer to specific areas where requirements of SB 1371 overlap with the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (CARB Oil & Gas Reg). (SoCalGas/SDG&E January 22, 2019 Comments at 5.)

SoCalGas/SDG&E also point out various inconsistencies in reporting methodologies among the various reports. (SoCalGas/SDG&E January 22, 2019 Comments at 6.) SoCalGas/SDG&E recommend "that a comprehensive assessment of the differences between calculation methodologies and data sets to be undertaken to assess what is useful for harmonizing reporting requirements and begin collaborative efforts with various agencies to adopt a more centralized and consistent reporting structure." (SoCalGas/SDG&E January 22, 2019 Comments at 6-7.)

Similarly, "PG&E appreciates and agrees with the Commission's goal of harmonizing the annual report requirements and 26 best practices with current mandatory reporting regulations (*e.g.*, CARB/EPA's Mandatory Reporting of Greenhouse Gas (GHG) Emissions (MRR) and CARB Oil & Gas Regulation) to avoid duplicative effort, unnecessary costs and public confusion, and thereby a clear and consistent GHG emissions profile for each utility." (PG&E January 22, 2019 Comments at 3.) PG&E also concurs that "existing and emerging regulations should neither impede nor increase the reporting under this OIR." (PG&E January 22, 2019 Comments at 4.)

"Southwest Gas supports a collaborative effort across agencies to assess and address any overlap in the information reported or the compliance actions that are required, including the methodologies by which emissions information is calculated. A more consistent structure would reduce confusion on the part of both the entities providing the information and that agencies that are interpreting and analyzing it." (Southwest Gas January 22, 2019 Comments at 2.)

EDF did not provide any comments on this issue.

8.2. Discussion

8.2.1. Status of Harmonization Efforts

We laud the benefits of harmonizing SB 1371 Annual Report data with data of the CPUC and other agencies (*e.g.,* CARB, DOGGR, Oil and Gas Regulations). According to CARB and CPUC Staff, data that are reported for all of the respective reports is similar but not necessarily the same. Therefore, there is not as much overlap of report categories as previously contemplated. Both SB 1371 and Oil and Gas Regulations require descriptive entries, such as compressor facility name, type of compressor and facility address. For example, SB 1371 collects data to determine total annual emissions, whereas the Oil and Gas Regulations evaluates quarterly reports of compressor components to determine if a component leaks above an emission threshold. As for CARB's Regulation for Mandatory Reporting of Greenhouse Emissions (MRR), the CPUC and CARB collect more detailed data under SB 1371. SB 1371 uses a "higher tier" methodology than CARB's MRR and the higher tier is expected to provide more accurate emissions estimates and allow easier emission reduction accounting and utilizes updated EFs.

In addition, as previously stated in the First Phase Decision, content of the existing 26 Best Practices may go beyond other related regulations from DOGGR, CARB, Oil and Gas Regulations or CPUC GO 112-F. Just as the CPUC has broad authority to implement regulations (and associated reporting requirements) that are stronger than regulations at federal agencies, the CPUC has the authority to implement regulations (and associated reporting requirements) that go beyond those of companion agencies or our own existing applicable GOs. This capability gives the CPUC needed flexibility to ensure that its existing mandatory best practices (and associated reporting requirements) can be more stringent over time. This ensures that best practices and are not inadvertently diluted or weakened based if other agencies' regulations are updated less frequently.

8.2.2. CARB and CPUC Process to Update EFs

Many reported emission volumes are based on estimated EFs that may not accurately reflect actual methane emission volumes. Currently, there are several methodologies and EFs used by various agencies to estimate emissions from the natural gas transmission sector which may result in different emission estimates. In some cases, further data collection and evaluation may be needed to ensure that EFs are as accurate as possible.

For the program to have continued success consistent with its objectives, CARB and CPUC should make it a priority to establish a process to update EFs, to ensure that they are as accurate as possible, and to identify opportunities to replace use of EFs with actual measured emissions. We are encouraged that short-term undertakings are underway to update EFs in the areas of MSAs that comprise approximately 20 percent of emissions volumes according to the 2018 Joint Annual Report. The Gas Technology Institute completed a 2018 study and the report is currently under review.[56] But we remain concerned that methane emissions attributed to MSAs have remained more or less the same during the annual reporting periods for 2015-2019. Other leak sources that could use updated EFs include compressor stations and meter and regulating stations. Although the existing inter-agency process to update EFs has been quite slow, we anticipate that ongoing pilots/R&D programs will help establish better methods for determining emission factors that represent actual performance in utilities' systems.

[56] Initial results show significant rate of leaks from residential MSAs. *See* PG&E presentation "Methane Emissions from Gas Residential Meter Set," January 17, 2019 Workshop, available at: https://www.cpuc.ca.gov/General.aspx?id=8829. Potentially, these leaks could be reduced by more frequent maintenance, and/or different sealants that are being evaluated.

We have already directed SED, in consultation with CARB, to hold a workshop and develop a process to use before the next Compliance Plans are submitted in March 2020, that allows adjustment to EFs to account for methane emission reduction measures proposed in approved Compliance Plans that achieve reasonably quantifiable reductions in methane emissions from sources whose annual emissions are calculated using fixed EFs.

8.2.3. **CARB and SED Interagency Cooperation**

Consistent with already delegated authority, SED staff should continue to refine and improve the Annual Report Template, and similar templates, in consultation with CARB and other agencies. CARB and CPUC and stakeholders need to work together to identify template differences and potential solutions. CARB and CPUC staff have already made one change to the Natural Gas Leakage Program template, to improve consistency with the CARB MRR.[57] Amendment of CARB MRR to include all of the categories that are reported under SB 1371 would require a change to the CARB regulation and CARB Board approval. We understand there are no current plans to update or amend the MRR. At the same time, beginning in July 2019, CARB's Oil and Gas Regulations is requiring more stringent reporting in specific areas that don't mirror the SB 1371 annual reports. The ability of one agency to require *more comprehensive* reporting than another is appropriate and does not create an inconsistency.

9. Natural Gas Leak Abatement Program 2021 Evaluation

The First Phase Decision directed SED, with support from ED, to conduct a comprehensive assessment of the Natural Gas Leakage Abatement Program no later than 2020 and submit a report with recommendations to the CPUC. CPUC, in

[57] For example, in the 2018 annual emission inventory report, wellheads will use the leaker-based emission factors based on whether a leak is found or not, with the latter case having an emission factor of zero. Prior to this change, utilities reported wellheads, independent of a leak being found or not.

consultation with CARB, provides direction for improvements as well as recommendations on the content and format of Compliance Plans.[58]

Significant progress has been made to achieve the primary requirements of the OIR. But more work needs to be accomplished to not only manage the program but also to evaluate it. Accordingly, at a minimum, the pending SED/ED evaluation of the program should address the following comprehensive program areas:

- Summarize emission reductions achieved through the measures approved in the first Compliance Plans;
- Identify refinements made to the annual reporting template, including technical definitions as necessary through the technical working groups and workshops, and discuss whether additional refinements should be considered;
- Identify additional Best Practices-related metrics to be reported in annual reports;
- Identify additional refinements to the Biennial Compliance Plan Framework that should be considered;
- Discuss whether modifications should be considered to the process for evaluating cost-effectiveness of Best Practices and future rules, including consideration of the social costs of methane;
- Provide guidance for collection of cost and emissions data in 2020 and beyond;
- Examine current processes for cost forecasting, cost limits, and cost recovery and make recommendations regarding any needed modifications;
- Recommend whether the CPUC should consider adopting further limitations on rate recovery for the Class A Utilities for years following 2025, and/or extending the limits to other utilities;
- Whether the Commission should consider adopting a hard target for 2030;

[58] *See* First Phase Decision at 163.

- Identify opportunities to further harmonize 26 Best Practices with other state and federal agency existing and emerging regulations (*e.g.,* DOGGR, CARB, EPA) if appropriate and practicable;
- Consider incorporation of mandatory 26 Best Practices into existing or separate CPUC GO 112-F; and
- Recommend further consultation with CARB to update EFs, if necessary, collaborate to institutionalize an interagency process to timely update EFs to ensure more accurate methane emissions reporting over time.

The First Phase Decision originally directed that the Staff Evaluation occur in 2020. Based on the record, more time is needed to gather and evaluate information related to 2020 Compliance Plans, recent annual report data, and to update emission factors. Therefore, we direct that this evaluation be completed no later than June 2021 to allow time for the CPUC to evaluate potential modifications to the Compliance Plan content and templates and allow utilities to make appropriate changes to March 2022 Compliance Plans. Based on 2021 Staff recommendations, the CPUC will determine whether another proceeding is necessary to address any issues that cannot be addressed by the SED and ED staff in cooperation with CARB.

10. Categorization and Need for Hearing

The amended scoping memo confirmed the CPUC's preliminary categorization of R.15-01-008 as quasi-legislative and that hearings were not necessary. Like Phase One, Phase Two of this proceeding was primarily resolved through comments and replies, workshops, and ongoing work of the TWG.

11. Comments on Proposed Decision

The proposed decision in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the CPUC's Rules of Practice and Procedure. ~~Comments were filed on ________________, and~~On July 25, 2019, PG&E, SoCalGas/SDG&E and EDF filed opening comments. On July 30, 2019, SoCalGas/SDG&E and EDF filed reply comments ~~were filed on ____________________ by ________________________________~~.

All parties agree with resolution with the first three issues teed up in the decision (*i.e.* Cost Effectiveness, Harmonization of Best Practices, Incorporation into General Orders) but PG&E and SoCalGas/SDG&E disagree with resolution of the fourth issue pertaining to how LUAF ratemaking treatment (methane emissions component only) should be structured and evaluated. In general, EDF supports the CPUC's proposed 2025 performance standard for emissions reduction with coinciding rate reduction and utilities oppose it.

With respect to PG&E and SoCalGas/SDG&E comments, the decision fully explains why the limit on rate recovery beginning in 2025 is reasonable. We believe that EDF accurately elaborates on the reasons for this conclusion in its Reply Comments. Despite the existence of population-based methane emission categories, utilities should be accountable for the success of their ratepayer funded Compliance Plans. We agree with EDF that "while it is true that utilities have little ability to control population levels in their jurisdictions, they can eliminate methane leaks." (EDF January 22, 2019 Opening Comments at 5.)

Further, utility concerns about annual variations due to major unexpected incidents are misplaced or entirely speculative. When there was an unexpected, catastrophic event involving months long emissions from the Aliso Canyon storage facility, those emissions were tracked separately and not included in the utilities' annual reported methane emissions. We also note that, in reviewing future Compliance Plans, the Commission will consider cost-effectiveness but it is not being applied as a requirement for Compliance Plans. The Commission will determine what investments are reasonable, in light of the goal of reducing methane emissions by at least 20%, to avoid triggering a limit on rate recovery in 2025.

For the reported methane emissions that use emissions factors, those factors are based on actual collected data; moreover, future reporting will allow for adjustments to reflect quantifiable reductions achieved by relevant measures included in a future compliance plan. In addition, if utilities obtain their own actual data for a category of emissions, they may propose to use this for reporting instead of the current approved emissions factor.

Accordingly, based on comments, no substantive changes were made to the decision.

However, the proposed decision makes the following clarifications:

1. *Finding of Fact 46 is changed to the following: Emissions reductions are currently coming from the approximately 39 percent of the emissions categories **that are not "population-based"** [emphasis added] including graded pipeline leaks (19 percent), blowdowns (10 percent), vented emissions (4 percent), all damages (4 percent), unusual large leaks (1 percent), and other leaks (1 percent).*
2. *Clarifies that EDF did not take a previous blanket position in comments that all LUAF recovery be eliminated.*
3. *Clarifies that the 2016 Joint Staff Report will be used to calculate utility 2015 emission volumes. (See minor edits to Footnote 53, and Ordering Paragraphs 4 and 5.)*

12. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner. Colette E. Kersten is the assigned Administrative Law Judge.

Findings of Fact

1. Under Pub. Util. Code § 975, *et seq.*, the CPUC must adopt rules and procedures to minimize natural gas leaks from commission-regulated gas pipeline facilities and operations to the greatest extent practicable.

2. The First Phase Decision directed the CPUC to conduct a follow up second phase to address issues that were not fully resolved due to lack of quantifiable data and lack of experience with the new program.

3. Establishing a comprehensive cost effectiveness or cost-benefit methodology during the first phase of this proceeding would have delayed emissions reductions expected through the implementation of 26 Best Practices adopted in the First Phase Decision.

4. Pub. Util. Code § 975, *et seq*., directs the CPUC to adopt rules and procedures that reduce natural gas pipeline emissions to the maximum extent feasible and that provide for the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components, while taking into consideration the impact of affordability of gas service for vulnerable customers as a result of incremental costs of compliance with the adopted rules or procedures.

5. AB 197 (Garcia, Statutes 2016, Chapter 250) directed CARB to consider the social costs of GHG emissions.

6. Parties disagree on whether the CPUC should adopt a cost-effectiveness methodology for operators to evaluate and prioritize best practices or develop a broader cost-benefit analysis that considers the social cost of methane.

7.

8. Based on the latest 2018 Joint Staff Annual Report, parties generally agree that the report provides a credible assessment of trends regarding the natural gas emissions from leaks and vented emissions in transmission, distribution and storage facilities in California.

9. The baseline emissions estimate based on 2015 data provides a starting point to measure future natural gas emission reductions.

10. If a current year is used as a baseline, then "credit" cannot be given to utilities that have already substantially addressed the "low hanging fruit" of emissions reductions.

11. CARB supports continued use of the IWG values for social cost of GHG emissions and strongly recommends that other agencies support and promote the IWG social cost values for transparency and consistency of regulatory analyses.

12. In 2009, IWG was convened to develop a methodology for estimating the social cost of carbon using standardized assumptions that could be used consistently when estimating the benefits of regulations across agencies.

13. The social cost of methane for a given year is an estimate, of the present discounted value of future damage by a one metric ton increase in methane emissions into the atmosphere in that year, or equivalently, the benefits of reducing methane emissions by the same amount in that year. It provides a comprehensive measure of net damages—the monetized value of net impacts from global climate change that results from an additional ton of methane.

14. Estimating environmental impact is highly sensitive to discount rates that represent the value placed on future environmental damages.

15. Until there is scientific and modeling consensus on new valuations that implement NAS recommendations and are based on the best available science, modeling, and data, it is reasonable to rely on the existing IWG estimates.

16. More information to evaluate the cost-effectiveness of each individual compliance plan and best practices will be available following submission of Annual Reports and the required Compliance Plans to be submitted again in March 2020.

17. SB 1371 does not require nor authorize a threshold determination of cost effectiveness.

18. It is reasonable that utilities continue to calculate proposed cost-effectiveness measures based on costs per unit of methane reduction as they did in recent Compliance Plans.

19. Existing cost-effectiveness calculations may be too narrow as they do not include benefits such as the avoided social cost of methane, avoided Cap-and-Trade compliance costs, safety benefits that accrue due to more rapid detection and repair of super emitters, and reliability improvements, for examples.

20. Gas utilities incur costs to comply with the Cap-and-Trade program, including for lost and unaccounted for gas, which the Commission has implemented in D.15-10-032.

21. Gas utilities forecast their annual revenue requirement for compliance with the Cap-and-Trade program in Advice Letter filings, using an “Emissions Conversion Factor" and “Proxy GHG Allowance Price.”

22. In 2018 Compliance Plans, utilities used inconsistent cost effectiveness methodologies in Compliance Plans that results in both difficulties in performing comprehensive evaluations and inability to do meaningful comparisons across the utilities.

23. Compliance Plan data problems include incomplete data, lack of net present value analysis to account for long lives of programs, inconsistent use of performance metrics and time frames for evaluation, and lack of compatibility of approaches with general rate case approaches.

24. It is not reasonable to adopt cost effectiveness benchmarks that compare the results of this program versus those in other sectors such as transportation, agriculture, and dairy because those sectors may receive significant subsidies, incentives and/or grants from ratepayers, taxpayers and other sources, which would make an accurate comparison extremely difficult.

25. It is worthwhile to continue to focus on implementing the "biggest bang for the buck" strategies in development and implementation of the 26 Best Practices. Such an approach would systematically balance tradeoffs between emissions reductions, safety, and affordability of gas service for a particular utility given its unique business model, operating conditions, and physical configuration of the gas system.

26. It is reasonable to require continuous improvements in the development of a more uniform approach using common assumptions to evaluate the cost effectiveness of emissions reductions projects.

27. Utilizing the Utilities Proposed Cost-Effectiveness Methodology will enable operators to target "low hanging fruit" for emissions reductions and not disadvantage programs that may have high startup costs.

28. It is reasonable for Utilities to include, where practicable, utility documentation and quantification of miscellaneous other benefits of methane reduction initiatives in their Biennial Compliance Plans.

29. Without having access to the social cost of methane metric, the CPUC will have incomplete information and may have difficulties making policy choices that optimize net social welfare over time.

30. CARB supports specific use of social cost valuations for social cost of GHGs as developed by the IWG.

31. In D.19-05-019, the CPUC approved use of a Societal Cost Test that includes the social cost of carbon, to evaluate cost-effectiveness of electricity investments in the Integrated Resources Planning proceeding, for informational purposes.

32. D.19-05-019 requires cost-effectiveness analyses using both the IWG social cost of carbon 3 percent average value, and the high impact value.

33. D.19-05-019 requires an evaluation of the Societal Cost Test by the Energy Division in 2021, including how to continue using of the test, and whether to

continue use of the IWG social cost of carbon 3 percent average value, or the high impact value.

34. In the 2017 Climate Change Scoping Plan, CARB found that IWG social cost of greenhouse gas valuations are robust, reliable, and appropriate and should be considered as an aid to decision making.

35. In the 2017 Climate Change Scoping Plan, CARB found that State agencies should use the social cost of methane in monetizing the impacts of GHG emissions.

36.

37. Two 2016 legislative actions provide important context for CPUC implementation of Pub. Util. Code § 975. SB 1383 directs CARB to implement a comprehensive short-lived climate pollutant strategy to achieve a reduction in the statewide emissions of methane by 40 percent below 2013 levels by 2030; SB 32 sets a statewide 2030 greenhouse gas reduction target of 40 percent below 1990 levels.

38. A 40 percent soft target for methane emission reductions by 2030 supports SB 1383 and provides a basis to potentially set a hard target in the future.

39. PHMSA defines LUAF, of which methane emissions is a sub-component; the CPUC uses this definition in GO 112-F reporting.

40. The utilities' cost recovery mechanisms and the gas rate calculation are determined in the utilities' cost allocation proceedings. Currently, PG&E, SoCalGas and SDG&E recover LUAF costs through annual Advice Letter filings.

41. For Southwest Gas residential and small commercial customers, LUAF is recovered monthly through its core gas cost adjustment Advice Letter included in its Purchased Gas Cost Adjustment Balancing Account.

42. Different accounting approaches are sufficiently consistent for purposes of defining, identifying, and accounting for LUAF, especially the methane emissions leakage component that is a subset of the total aggregated LUAF.

43. LUAF is first and foremost an accounting tool used by utilities to manage inventory and not a proxy for gas emissions.

44. Methane emissions represents approximately 30 percent of total LUAF, for the large four utilities based on 2017 data.

45. Non-methane components of LUAF, which comprise approximately 70 percent of total LUAF, are unrelated to methane emissions and include measurement error, accounting and billing error, and gas theft, utility usage (e.g., compressor stations, etc.) and "non-study" components.

46. SB 1371 gives the CPUC discretion to determine whether to make adjustments for revenue allowances of the methane emissions component of LUAF.

47. Approximately 60 percent of reported methane emissions are "population-based" using industry wide fixed emission factors that produce static emissions that are unaffected by utility activities to reduce emissions.

48. Emissions reductions are currently coming from the approximately 39 percent of the emissions categories that ~~utilities can control~~are not population-based including graded pipeline leaks (19 percent), blowdowns (10 percent), vented emissions (4 percent), all damages (4 percent), unusual large leaks (1 percent), and other leaks (1 percent).

49. In 2017, 61.5 percent of PG&E reported emissions were population-based and 56.1 percent of SoCalGas' reported emissions were population-based.

50. EDF's proposal does not fully account for the fact that approximately 60 percent of the current best estimates of utility methane emissions are based on population counts and EFs that produce static emissions that are unaffected by utility activities to reduce emissions.

51. The First Phase Decision the Commission determined that 2015 would be used as the base year to track methane emissions.

52. EDF proposes to change base year to 2018 but offers no rationale why this year should be used; if the standard begins in a current year, "credit" is not given to utilities that have already substantially addressed the "low hanging fruit" of emissions reductions.

53. More work is needed to validate and update EFs to ensure that population-based emissions are as accurate as possible.

54. Based on the 2018 Joint Staff Report, the top four utilities comprise approximately 99 percent of the emissions inventory and the six other utilities and ISPs make up the remaining 1 percent of the total emission inventory.

55. PG&E and SoCalGas comprise 92 percent of the emissions inventory and SDG&E and Southwest Gas comprise 7 percent of the emissions inventory.

56. In 2018 Compliance Plans, PG&E projected a 17 percent reduction of the 2105 baseline by 2020 that will be a significant step toward the 40 percent reduction by the 2030 target. Similarly, SoCalGas projected a 14 percent reduction by 2020 from the 2015 baseline.

57. Reducing methane emission by at least 20 percent below the 2015 baseline for the Class A utilities in 2025 and subsequent years is realistic to achieve based on recent annual report trends and estimated reductions that PG&E and SoCalGas have already provided in Compliance Plans. The target is simple to administer since it focuses on overall methane emissions and not specific categories of methane emissions~~,~~ and provides needed flexibility for utilities to focus on areas that they can control.

58. PG&E and SoCalGas (Class A Utilities) have the greatest ability to influence emissions reduction since their share of 2017 population-based emissions reductions is approximately 60 percent; SDG&E and Southwest Gas (Class B Utilities) have less capability to influence emissions reduction since their percent of population-based emissions are 90 percent and 97.4 percent, respectively.

59. Beginning with 2025 data, it is reasonable to reduce PG&E's and SoCalGas' recovery for methane emissions by 20 percent of their 2015 baseline emissions.

60. It is appropriate to establish a modest limit on rate recovery in 2025 and subsequent years, to give ample time for utilities to achieve the expected reductions and to ensure substantial progress is made toward meeting the 2030 soft target.

61. Because the limit on rate recovery will not apply until 2025, PG&E and SoCalGas will have ample time to propose necessary measures to achieve the expected methane emissions, in the biennial Compliance Plans required in 2020, 2022, and 2024.

62. The potential financial impact on PG&E and SoCalGas from the proposed limit on recovery is very modest but provides a clear message that emissions are expected to decrease.

63. Integrating 26 Best Practices into GO-112F or a separate GO does not appear to provide benefits, since the 26 Best Practices adopted in the First Phase Decision are fully enforceable.

64. It is appropriate to revisit potential integration of 26 Best Practices into GO 112-F or a separate new GO in the evaluation of the program in 2021.

65. SED can ensure a more rigorous and consistent reporting framework consistent with its authority to provide direction to utilities, in conformance with current federal (PHMSA) and state (CPUC GO 112-F) regulations and SB 1371 requirements.

66. In comparing SB 1371 Annual Leak Report data with data from other agencies (*e.g.*, CARB, DOGGR, Oil and Gas Regulations), there is not as much overlap of report categories as anticipated.

67. Some existing Best Practices go beyond or are more stringent than other related regulations from DOGGR, CARB, Oil and Gas Regulations or CPUC GO 112-F.

68. Just as the CPUC has broad authority to implement regulations (and associated reporting requirements) that are stronger than regulations at federal agencies, the CPUC has authority to implement regulations (and associated reporting requirements) that go beyond or are more stringent than those of companion agencies or our own existing applicable GO.

69. The Gas Technology Institute is updating EFs in the area of MSA that comprise approximately 25 percent of emissions volumes.

70. If a Best Practices provision ends up as part of a CARB, DOGGR, or local district rule, then those entities will have independent enforcement authority to inspect and enforce progress with that requirement, in addition to the CPUC's enforcement authority for the Best Practice.

71. The ability of one agency to require more comprehensive reporting than another is appropriate and does not create an inconsistency.

72. The First Phase Decision originally directed that the Staff Evaluation occur in 2020. However, more time is needed to 1) gather and evaluate information related to 2020 Compliance Plans and most recent annual report data; and 2) update emission factors to the maximum extent practicable.

Conclusions of Law

1. Since Phase Two of this proceeding does not involve any material disputed issues of fact, evidentiary hearings were not necessary for this decision.

2. The CPUC and CARB should consult to ensure that updated EFs are available for the annual reporting process.

3. Consistent with Pub. Util. Code §975, *et seq.*, we conclude that in determining rules, regulations and transportation rates for natural gas pipelines,

we must consider the global warming impact of methane emissions alongside our duty to ensure safety, reliability, and just and reasonable rates.

4. Pub. Util. Code §977(b) requires the Commission to consider adjustment of allowance for lost and unaccounted for gas related to actual leakage volumes.

5. Based on a review of the December 2018 Joint Annual Leak Report, it is reasonable to require compliance plans to include information on how each gas corporation plans to achieve a 20 percent reduction below 2015 baseline levels by 2025, and how they plan to achieve a 40 percent reduction below 2015 levels by 2030.

6. SB 1371 allows the CPUC to consider cost-effectiveness when establishing best practices.

7. As a matter of policy, Pub. Util. Code § 451 requires the CPUC to adopt just and reasonable rates.

8. Utilities should make an effort to quantify other benefits, including, future reduced leak repair costs, reduced gas lost to leakage, shifting from emergency to planned work, safety improvements, system reliability improvements, avoided Cap-and-Trade compliance costs, and lower insurance costs, to the extent practicable.

9. It is reasonable for the CPUC to adopt the Utility Proposed Cost Effectiveness Methodology and Cost- Benefit Analyses to provide useful information when evaluating proposed methane reduction measures and for evaluating the Biennial Methane Leaks Compliance Plans while maintaining full discretion for the CPUC to also consider qualitative factors and policy goals.

10. It is reasonable for the Commission to also require PG&E, SoCalGas, SDG&E, and Southwest Gas to use the following two cost-benefit tests in future Compliance Plans, for information and comparison purposes:

a. The first test calculates the cost-benefits of individual proposed methane reduction measures, and the Compliance Plan as a whole, by determining the ratio of all reasonably quantifiable benefits to costs. In addition, methane reduction measures that together are intended to reduce one type of emission may be grouped together for purposes of the cost-benefit calculation, if this is most appropriate.

b. The second cost-benefit test is the same as above but includes as a benefit the avoided social costs of methane, using the IWG's average value with a 3% discount rate.

11. It is reasonable to require that all cost-effectiveness calculations and cost-benefit tests include avoided Cap-and-Trade costs as a benefit, using the Emission Conversion Factor and Proxy GHG Allowance Price used for the gas utilities' forecast revenue requirements pursuant to D.15-10-032.

12. Any adjustment to revenue allowances for LUAF should be limited to recovery of methane emissions and not all LUAF, consistent with the approach and schedule undertaken in this proceeding and consistent with funding granted to utilities to reduce methane emissions.

13. It is reasonable for the CPUC to limit PG&E and SoCalGas's rate recovery for methane emissions greater than 20 percent below their 2015 baseline levels for 2025 and subsequent years, to ensure that expenditures authorized to implement their Compliance Plans achieve the intended methane emissions reductions.

14. For PG&E, any necessary reductions in rate recovery for 2025 and beyond as directed in this Decision should be identified in its annual In-Kind Allowance Adjustment Advice Letter filing. PG&E's shrinkage allowances should be adjusted accordingly.

15. For SoCalGas, any necessary reductions in rate recovery for methane emissions for 2025 and beyond as directed in this decision should be identified in its Annual Regulatory Account Balance Update for rates effective January 1, 2026.

16. Except as provided in this Decision, both PG&E's and SoCalGas' rate recovery calculations should continue to be subject to the factors approved in the utility's most recent General Rate Case or Cost Allocation Proceeding.

17. Within 60 days of the issuance of this decision, the CPUC's Safety and Enforcement Division and Energy Division should convene two workshops:

a. In cooperation with the TWG, refine the scope and detail of the Compliance Plans and Tier 3 Advice Letters pertaining to cost-effectiveness and cost-benefit analysis and other elements as directed in this decision; and

b. In consultation with the California Air Resources Board develop a process that utilities can rely on prior to submittal of the next Compliance Plans in March 2020 to adjust Emission Factors used for annual reports to account for methane reduction measures that may be approved in Compliance Plans that will achieve reasonably quantifiable reductions in methane emissions.

18. By September 15, 2019, and in cooperation with SED, the TWG should submit recommendations on the content and format of the next Compliance Plan due March 15, 2020 and follow the planning format established in the First Phase Decision, OP 6.

19. SED and ED Staff have the authority to convene the TWG every two years to consider updates to the Compliance Plan, and to make clarifying changes to Compliance Plan templates and provide guidance for filing Compliance Plans, as approved in D.17-06-015 and consistent with policy direction provided in this decision.

20. The CPUC has broad authority to implement regulations that go beyond those of companion agencies or our own existing applicable general orders.

21. SED, with support from ED, following CPUC approval of 2020 Compliance Plans and issuance of the SB 1371 2019 Joint Annual Report, should perform a

comprehensive evaluation of the Natural Gas Leak Abatement Program in 2021 as outlined in this decision.

22. All motions not yet ruled on in this proceeding should be denied.

23. This proceeding should be closed. Following CPUC review of the 2021 Natural Gas Leak Abatement Program evaluation, the CPUC should consider whether to open a new proceeding to consider further issues.

24. This decision should be effective immediately.

O R D E R

1. As directed by this decision and the California Public Utilities Commission (CPUC) Safety and Enforcement Division, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Company are directed to use the Utility Proposed Cost-Effectiveness Methodology to provide useful information when evaluating proposed methane reduction measures and for evaluating the Biennial Methane Leaks Compliance Plans, while maintaining full discretion for the CPUC to also consider qualitative factors and policy goals as detailed in this decision.

2. As directed in this decision, Pacific Gas and Electric Company, Southern California Gas Company, San Diego Gas & Electric Company, and Southwest Gas Company shall use two cost-benefit tests in future Compliance Plans, for information and comparison purposes.

   a. The first test shall calculate the cost-benefits of individual proposed methane reduction measures, and the Compliance Plan as a whole, by determining the ratio of all reasonably quantifiable benefits to costs. In addition, methane reduction measures that together are intended to reduce one type of emission may be grouped together for purposes of the cost-benefit calculation, if this is most appropriate.

b. The second cost-benefit test shall be the same as above but shall also include as a benefit the avoided social costs of methane, using the Interagency Working Group's average value with a 3 percent discount rate.

3. All cost-effectiveness calculations and cost-benefit tests shall include avoided Cap-and-Trade costs as a benefit, using the Emission Conversion Factor and Proxy greenhouse gas Allowance Price used for the gas utilities' forecast revenue requirements pursuant to Decision 15-10-032.

4. Pacific Gas & Electric Company (PG&E) is directed to achieve 20 percent emissions reductions below 2015 baseline levels beginning in 2025, to ensure that expenditures authorized to implement its Compliance Plans achieve the intended emissions reductions. If the Joint Staff Report for 2025 results does not reflect a 20 percent reduction from PG&E's 2015 baseline emission, PG&E must file a Tier 2 Advice Letter within 60 days from the Joint Staff Report issuance date:

a. The Advice Letter must identify the amount of methane emissions above the 20 percent reduction from its 2015 baseline emissions.

b. The Advice Letter must include the methodology and calculation by which it will remove any shrinkage allowances for methane emissions exceeding the 20 percent reduction.

c. PG&E will continue to file annual Tier 2 Advice Letters until such time that the 20 percent reduction is met.

d. Except as provided herein, PG&E's rate recovery calculations shall continue to be subject to the factors approved in the utility's most recent General Rate Case or Cost Allocation Proceeding.

5. Southern California Gas (SoCalGas) is directed to achieve a 20 percent emissions reduction below 2015 baseline levels beginning in 2025, to ensure that expenditures authorized to implement its Compliance Plans achieve the intended emission reductions. If the Joint Staff Report for 2025 ~~does~~results do not reflect a

20 percent reduction from SoCalGas' 2015 baseline emission, SoCalGas must file a Tier 2 Advice Letter within 60 days from the Joint Staff Report issuance date:

a. The Advice Letter must identify the amount of methane emissions above the 20 percent reduction from its 2015 baseline emissions.

b. The Advice Letter must include the methodology and calculation by which it will remove any rate recovery for methane emissions exceeding the 20 percent reduction.

c. SoCalGas will continue to file annual Tier 2 Advice Letters until such time that the 20 percent reduction is met.

d. Except as provided herein, SoCalGas' rate recovery calculations shall continue to be subject to the factors approved in the utility's most recent General Rate Case or Cost Allocation Proceeding.

6. Within 60 days of the issuance of this decision, the California Public Utilities Commission Safety and Enforcement Division and Energy Division shall convene two workshops:

a. In cooperation with the Technical Working Group, refine the scope and detail of the Compliance Plans and Tier 3 Advice Letters pertaining to cost-effectiveness and cost-benefit analysis as directed in Decision 17-06-015 and this decision; and

b. In consultation with the California Air Resources Board develop a process that utilities can rely on prior to submittal of the next Compliance Plans in March 2020 to adjust Emission Factors used for annual reports to account for methane reduction measures that may be approved in Compliance Plans that will achieve reasonably quantifiable reductions in methane emissions.

7. By September 15, 2019, and in cooperation with the California Public Utilities' Commission Safety and Enforcement Division, the Technical Working Group shall submit recommendations on the content and format of the next

Compliance Plan due March 15, 2020 and follow the planning format established in the Decision 17-06-015, Ordering Paragraph 6.

8. The California Public Utilities Commission Safety and Enforcement Division, with support from Energy Division, shall conduct a comprehensive evaluation of the Natural Gas Leak Abatement Program consistent with the requirements outlined in this decision by no later than June 2021 and file its report as a compliance report in this proceeding with recommendations to the Commission.

9. The "California Air Resources Board and California Public Utilities Commission (CPUC) Joint Staff Report-Analysis of the Utilities' June 15, 2018 Natural Gas Leak and Emission Reports, SB 1271 (Leno) Natural Gas: Leakage Abatement," dated December 21, 2018 is entered into the record of this proceeding. (*See* CPUC website at:

https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Safety/Risk_Assessment/Methane_Leaks/2017%20NGLA%20Joint%20Report%2012-21-18.pdf.)

10. All directives of Decision 17-06-015 remain in effect, unless they are superseded by directives or guidance provided above.

11. All motions not yet ruled on in this proceeding are hereby deemed denied.

12. Rulemaking 15-01-008 is closed.

This order is effective today.

Dated ____________________________, at San Francisco, California.

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