DOCKETED

Docket Number:	22-OII-02
Project Title:	Gas Decarbonization
TN #:	243588
Document Title:	Environmental Defense Fund Comments - on Gas Decarbonization Order Instituting Informational Proceeding - 3 of 3
Description:	N/A
Filer:	System
Organization:	Environmental Defense Fund
Submitter Role:	Public
Submission Date:	6/17/2022 3:22:01 PM
Docketed Date:	6/17/2022

Comment Received From: Environmental Defense Fund
Submitted On: 6/17/2022
Docket Number: 22-OII-02

on Gas Decarbonization Order Instituting Informational Proceeding - 3 of 3

Additional submitted attachment is included below.

EDF
ENVIRONMENTAL DEFENSE FUND®
Finding the ways that work

Aligning Gas Regulation and Climate Goals

A Road Map for State Regulators

January 2021

Authors
Natalie Karas
Michael Colvin
Ted Kelly
Erin Murphy
Timothy O'Connor

Acknowledgments
The authors would like to thank the following individuals for their help in editing and reviewing this report: Jolette Westbrook, Christie Hicks, Elizabeth Stein, Mary Barber, Mark Brownstein, and Kelsey Robinson.

Environmental Defense Fund
Environmental Defense Fund is dedicated to protecting the environmental rights of all people, including the right to clean air, clean water, healthy food and flourishing ecosystems. Guided by science, we work to create practical solutions that win lasting political, economic and social support because they are nonpartisan, cost-effective and fair.

Table of Contents

Executive Summary

Reduction in the usage of natural gas is critical to mitigate climate change. When combusted, natural gas usages can vary from home heating and cooking to large industrial processes to fuel for electric generation. While many states have adopted greenhouse gas (GHG) emissions targets and are conducting long-term planning for the transition away from natural gas, retail gas utilities and their regulators have generally continued to operate in a business-as-usual framework assuming static or increased natural gas usage. In most states, there is a lack of reconciliation between these two policy objectives. This paper presents recommendations for State Public Utilities Commissions (Commissions) and other regulators to align decision making regarding gas utility operations, rates and infrastructure with climate goals to drive reductions in GHG emissions. While this paper primarily focuses on states that have enacted climate laws, the recommendations are equally relevant for states without such laws, as they ultimately serve to improve regulatory oversight, protect customers from unnecessary costs, and support continued provision of safe, reliable and affordable service in an evolving industry.

The conversations on the future role of gas utilities often focus on the choice between alternative fuels such as biomethane or hydrogen or substitutes away from the gas system, including electrification. That framing overlooks the immediate need to address existing — and in most instances outdated — policies, programs and processes that lead to continued, and often unchecked, investments in the gas system. These policies, programs and processes determine how much gas is claimed to be needed for the system, how much new and existing infrastructure is required to supply that gas, which resources will meet those needs and who will bear the costs of those resources. Revisiting and refining these existing policies in the context of the current climate goals is a foundational step to decarbonization. Considering the main users of the gas system during this transition, changing energy demand and utilization patterns, and the equity of the transition itself, is critical.

This disconnect is already resulting in large amounts of ratepayer money being committed to new infrastructure based on an assumed useful life of 60 years or longer. While this time frame might have been appropriate in a pre-climate mitigation paradigm, the mismatch between the time horizon of these new investments and climate goals exposes both gas utilities and their customers to new risks of under-collecting or even needlessly stranding infrastructure. As states achieve their climate goals, infrastructure once deemed to be used and useful may no longer be necessary for the same operation of the system, and that transition will accelerate over the next decade depending on the speed of electrification of the end uses of the gas system.

Furthermore, increasing rates resulting from stranded assets creates the potential of a utility death-spiral effect, where higher rates lead customers to electrify more quickly and raise the rates for remaining customers even more. This places the greatest impact on low-income ratepayers, who are least able to make the up-front investments required to electrify but who are the most affected by higher utility bills.

The recommendations in this paper are based on several years of EDF's experience engaging in specific gas regulatory proceedings across the country. They are also informed both by pilots and other early-stage activities underway in certain states as well as by analogous activities in retail electric utility regulation. In addition to proposing improvements to processes and planning requirements, this paper describes a number of new activities that regulators and gas utilities could undertake or explore as part of the energy transition. This paper is not intended to describe every potential transitional program, nor will every activity described make sense in every jurisdiction.

Commissions can close the gap between state climate goals and gas utility actions and put their states on a path to meet their goals and avoid wasteful investments by taking the following three steps:

First, establish inclusive and transparent decision making. Gas utilities tend to make major investment decisions on a case-by-case basis, in rate and capital expenditure proceedings, which by their nature are inadequate to address systemic issues and long-range planning. On top of this, in many states, the regulatory approval of gas utility requests remains opaque and inaccessible to many stakeholder groups. By clarifying the existing approval processes, ensuring utilities provide sufficient information upon which to make a decision and encouraging broader stakeholder engagement, including from disproportionately impacted communities, regulators will provide greater visibility into, and confidence in, the regulatory process as well as enable joint problem solving.

Second, require rigorous long-term planning. Current forecasting and planning exercises performed by gas utilities are often limited to short duration terms, such as five- or 10-year periods, whereas the most aggressive state climate goals often are for more than 20 years in the future. By requiring gas utilities to engage in holistic and transparent long-term planning that includes an assessment of GHG emissions and evaluates a broad range of possible actions and solutions, regulators will ensure gas utilities' investment and supply decisions will not interfere with attainment of climate objectives. Even in states that have near-term climate goals (i.e., 2030), long-term planning is important for utilities as state climate plans are developed or extended and federal climate targets are adopted. This long-term planning will reduce the potential for stranded assets and ensure adequate cost allocation for any new investments that need to be made to the system to ensure safe and reliable service.

Third, coordinate near-term decisions and long-term goals. Commissions currently make a wide range of decisions about gas utility operations, infrastructure and rates. These decisions are often made in silos with limited transparency about how one decision impacts the other, leading to a sub-optimal outcome with respect to both customer cost and long-term system planning. By making these decisions in a coordinated, transparent manner and evaluating them for consistency with long-term plans and climate objectives, regulators will protect against unneeded investments that could result in the imposition of stranded costs.

The following page includes a synthesis of our recommended actions under each of these three categories to align gas regulatory policy and climate goals. Within each of these three broad categories, EDF provides a set of specific, actionable recommendations.

Step 1: Establish Inclusive and Transparent Decision Making	Step 2: Require Rigorous Long-Term Planning	Step 3: Coordinate Near-Term Decisions and Long-Term Goals
• Review and Clarify Existing Processes	• Require a Long-Term Vision Aligned with Climate Targets and Other State Policies	• Connect Long-Term Planning to Cost Recovery
• Ensure Utilities Provide Sufficient Information in Support of Requests	• Define the True Needs of the System	• Identify Changes to Existing Programs that Incent Gas Use and Expansion
• Encourage Broader Stakeholder Engagement	• Plan for Projected Utilization Changes	• Design Targeted Non-Pipeline Alternative Programs
• Consider Equity Input and Impacts	• Conduct Robust, Transparent Gas Supply Planning	• Link Shareholder and Societal Value
	• Evaluate Resources Using the All-in Cost Metric	• Align Depreciation Schedules with Climate Targets
	• Integrate Non-Pipeline Alternatives into Long-Term Planning	• Evaluate Cost Allocation
	• Establish a Gas Investment Priority Order	• Explore New Tariff Services
	• Conduct Thorough GHG Assessments	• Scrutinize Affiliate Transactions
	• Ensure Gas and Electric Utility Coordination	• Consider Pilots to Test Innovation
		• Review Pipeline Replacement Programs and Surcharge Mechanisms
		• Deploy Advanced Leak Detection and Data Analytics
		• Review Lost and Unaccounted for Gas Mechanisms

While it may not be feasible to implement all of these recommendations simultaneously, a crucial first step in many jurisdictions will be to establish a holistic gas planning docket and require gas utilities to make thorough and transparent filings identifying current planning activities. Commissions should also identify the process for development and review of long-term plans aligned with state climate goals. By enhancing transparency and review of gas utility long-term gas plans and holding utilities accountable to decisions made in accordance with those plans, Commissions can ensure that the gas system continues to operate in a safe, reliable and affordable manner while placing gas utilities on a pathway to meet climate goals and protecting customers from unnecessary investments.

This paper first sets forth an overview of the climate science driving the need for changes to traditional gas utility regulation, jurisdictions that have adopted climate laws, and state policy and utility programs that incentivize gas use and infrastructure buildout. It then presents recommendations for transparent, equitable and inclusive decision making. The paper next details how long-term planning can be enhanced to better serve climate goals. Finally, the paper explains how near-term decisions must be measured against those long-term plans to ensure that regulatory approval and rate authorization will not interfere with attainment of GHG emissions goals.

Background

Recent findings in climate science — such as an understanding of the short-term climate forcing effects of methane — have made clear the need for regulation that is consistent with achieving swift and dramatic reductions in emissions associated with natural gas. Consistent with these science-based findings, many states have adopted climate goals that require substantial reductions in GHG emissions over the coming decades.[1] However, in most states, gas utility planning and operations have remained disconnected from these requirements and have continued to operate under traditional regulatory paradigms. In fact, many of these states continue to allow and even incentivize expansion of gas service to new customers and continued build-out of gas infrastructure. Left unaddressed, states will be challenged to meet their climate goals and customers could be saddled with unnecessary costs of infrastructure for decades to come.

When considering the future role of gas utilities in a decarbonized economy, it is important to consider the end uses of the gas system and how each end use must be decarbonized. The three major users of the gas system include: 1) residential and small business heating and cooking; 2) electric generation; and 3) large non-core customers, including industrial customers and large commercial customers. The projected decarbonization of each of these sectors will shift the usage of the gas system in unexpected ways. Without proper coordination, gas utilities could be left with either stranded assets or inequitable cost allocation among their customers.[2]

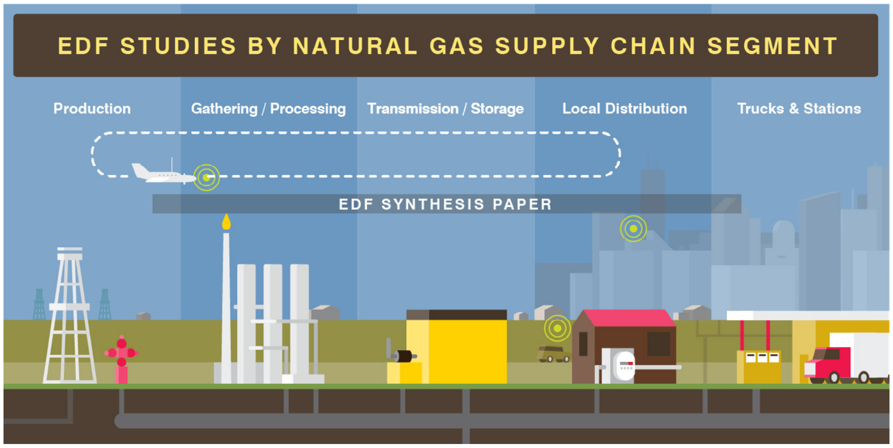
Climate Science

The production, transmission, distribution and use of natural gas causes GHG emissions that contribute to global warming, as well as other forms of pollution.[3] Not only does the combustion of natural gas result in the release of carbon dioxide, leakage of natural gas before it reaches the final customer results in the release of methane, a potent GHG. Climate science firmly indicates that carbon dioxide emissions and methane leakage from the gas system contribute to climate change on a significant scale.

Methane is the principle component of natural gas, and when released without being burned, such as through leakage, is a potent GHG that traps 86 times more heat than carbon dioxide over the first 20 years after it is released into the atmosphere. As a result, methane emissions increase global warming significantly in the near-term, potentially accelerating the onset of major climate change impacts.[4] Methane emissions are responsible for 25% of current global warming.[5]

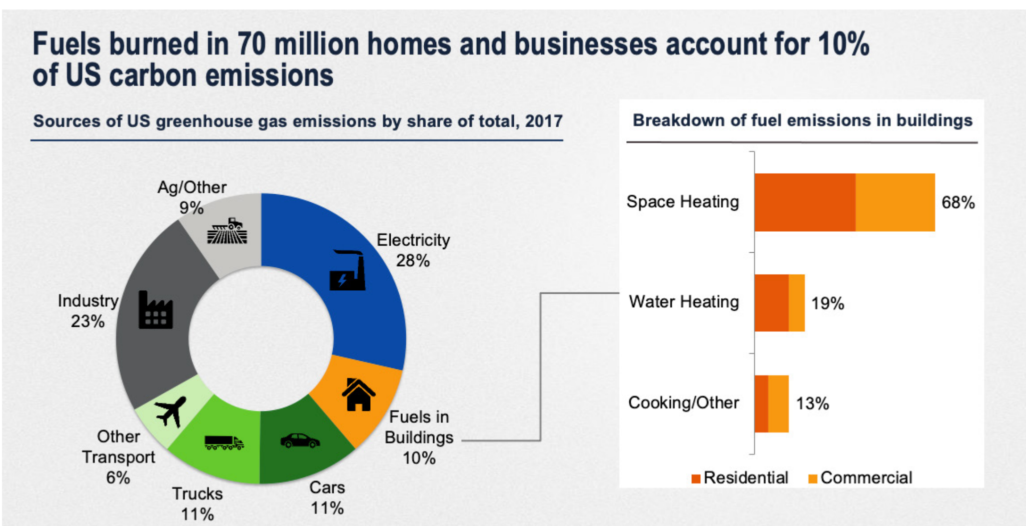
Despite a broad awareness of the harmful impact of methane emissions on the global climate, emissions of methane are significant across the natural gas supply chain. For example, a 2018 nation-wide synthesis study by EDF found that emissions of methane across the entire supply chain of the U.S. oil and gas system (from production to end use) are 60% higher than previously reported by the U.S. Environmental Protection Agency.[6]

Figure 1: EDF Studies by Natural Gas Supply Chain Segment



In addition, natural gas is a fossil fuel that, when burned, releases carbon dioxide. Across the U.S., combustion of natural gas for heating and cooking in buildings produces 466.3 million metric tons of carbon dioxide every year, or about 10% of total U.S. carbon emissions. These emissions have been growing as commercial space increases 2.1% annually and 1.4 million new homes are built every year. The following chart shows the carbon emissions from the residential and commercial sectors.

Figure 2: Carbon Emissions Sources, Referencing 2017 U.S. EPA GHG Inventory



Source: Rocky Mountain Institute, based on EPA Greenhouse Gas Inventory, 2017 (excludes land use, land use change, and forestry); EIA Residential Energy Consumption Survey (RECS), 2015

In sum, the climate science further highlights the need for regulation of gas utilities to be undertaken in a manner that is consistent with achieving dramatic, and rapid, reductions in GHG emissions associated with natural gas — especially in light of the short-term climate forcing effects of methane.[7]

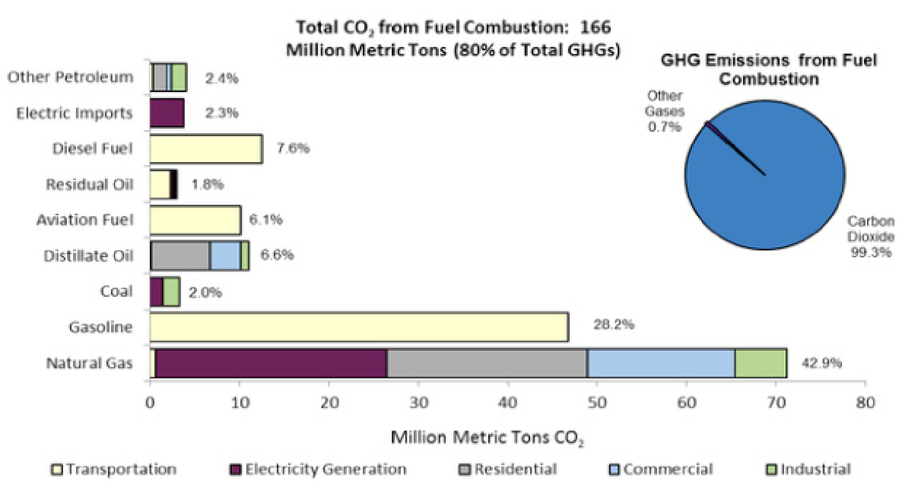
Climate Goals

Climate change policies relevant to state utility regulation are entering into effect at various levels of government in the United States. Currently, 25 states, the District of Columbia and Puerto Rico have established GHG emissions targets.[8] While the targets can vary in scope (e.g., cover all GHG emissions or specific gases) and coverage (e.g., sector-specific or economy-wide), all aim to reduce emissions to a specific amount by a date certain. For instance, the Climate Leadership and Community Protection Act (CLCPA) mandates that the State of New York adopt measures to reduce state-wide GHG emissions by 40% by 2030 and 85% by 2050 (from 1990 levels), with an additional goal of achieving net zero emissions across all sectors of the economy by 2050.[9,10] Numerous other states, including California, New Jersey, Massachusetts, Maine, Connecticut, Colorado, as well as the District of Columbia, have enacted similar goals.

President-elect Biden is committed to a target of net zero emissions and a 100% clean energy economy by 2050, and to rejoining the Paris Climate Agreement on Day 1 of his incoming administration.[11] These commitments and additional forthcoming policies from the Biden-Harris administration can be anticipated to affect the plans and operations of gas utilities. Local governments in the United States are also adopting climate commitments that can affect utility planning.[12]

Achieving economy-wide climate goals will require massive transformation across all sectors. While much focus has been given to reductions needed in the electric and transportation sectors, deep reductions will also be required in GHG emissions attributable to gas utilities. Rhode Island's state roadmap acknowledged that "even if all non-heating sectors were to become completely emissions-free by 2050, the heating sector would still need to be significantly decarbonized to meet the current GHG emissions reduction goals."[13] In California, building usage accounts for approximately 25% of the state's GHG emissions.[14] An analysis of New York's GHG inventory yields similar results — even if all gas combustion with the exception of residential consumption were to stop, gas combustion by residential customers alone would exhaust more than half of the 2050 carbon budget of approximately 35 million metric tons, as shown in the chart below.[15]

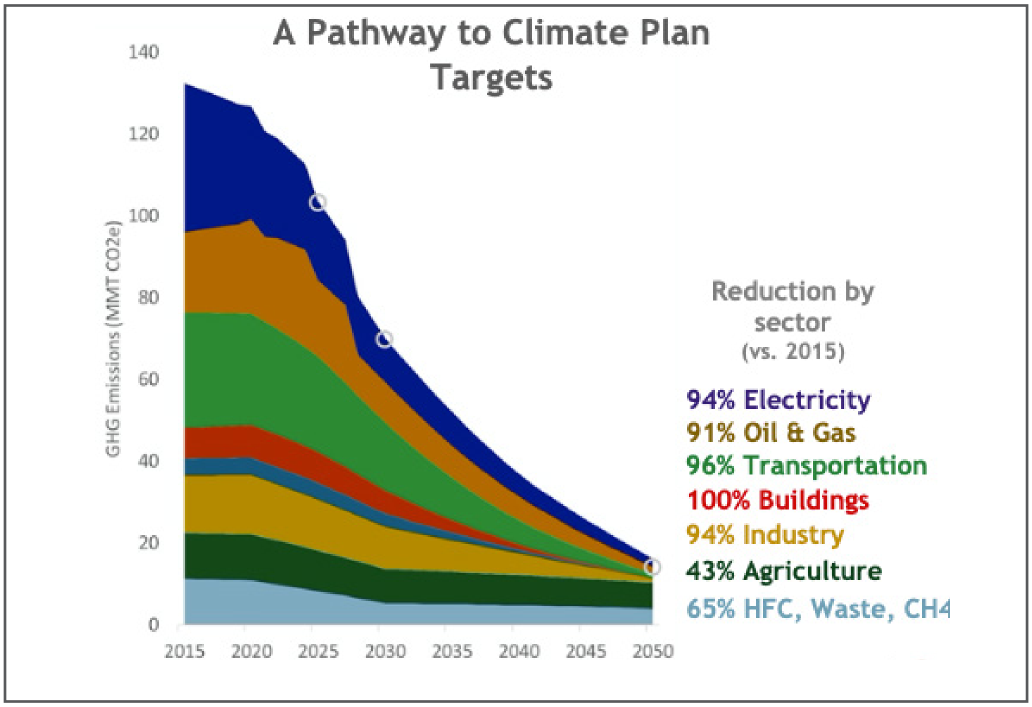
Figure 3: New York GHG Inventory, Shown as an Example of Gas Combustion in Relation to Overall State Goals



Source: New York State Energy Resource and Development

In Colorado, environmental regulators project that emissions associated with buildings will need to be reduced by 100% in order to achieve climate goals, as shown in the chart below.[16]

Figure 4: Colorado Pathway, Showing an Imperative to Reduce GHG Emissions from Buildings to Achieve State Climate Goals



Source: Colorado Air Quality Control Commission

Such projections will have profound consequences for gas utilities and demand new regulatory frameworks, tools and solutions to address these challenges.

Incenting Gas Use and Infrastructure Buildout

At the same time that several jurisdictions have promulgated aggressive GHG reduction goals consistent with science-based targets, the policy framework relating to gas supply, use, planning, expansion, cost recovery and review has remained static. These older policies and frameworks were adopted when gas was viewed as a cost-effective and cleaner alternative to fuels such as oil and kerosene, when its environmental downside was unknown or unacknowledged, and when climate science was less clear on the degree of reductions needed to avoid dangerous levels of warming. For instance, the New York Public Service Commission's 2012 Policy Statement on natural gas is still a significant driving force in the New York State Department of Public Service (DPS) staff's review of utility gas supply plans — where utilities are asked to detail all expansion projects, and if there are none, how this is justified "given the Commission's stated goal of expanding the gas system in New York State."[17, 18] In 2017, the Massachusetts Department of Public Utilities approved a gas expansion program, noting that it "is reasonably designed to increase the availability, affordability, and feasibility of natural gas service for new customers."[19] In the decade since the 2010 gas pipeline explosion in San Bruno, California has authorized extensive major new investment in the gas system for safety enhancements without reconciling such approval with its 2006 climate change laws.[20]

Against this backdrop, utilities continue to rely on business-as-usual scenarios, assumptions and programs. They propose gas capital projects and programs costing billions of dollars, project year-over-year growth on their systems, and assume 80 year lives for gas mains and 60 year lives for services.[21,22,23] Some gas utilities, in concert with their affiliate pipeline developers, have proposed massive new greenfield, interstate pipelines. Ratepayers are asked to pay for these investments for decades to come, without consideration of the climate objectives.[24] Meanwhile, recovery of opaque gas costs — through purchased gas adjustment mechanisms or various infrastructure surcharges — is often viewed by regulators as "rote" and remains disconnected from any long-term planning or GHG analysis.

Further compounding the challenge is the fact that there are few, if any, financial mechanisms to adequately reward gas utility shareholders based on early retirement of assets, avoidance of capital investment through non-pipeline alternatives, or incorporation of other decarbonization strategies into their business models. Decarbonizing the end uses of the gas system will require prudent management; there is a fundamental misalignment between shareholder interests and public policy. Regulators must consider new ratemaking approaches and tools — employing a "business-as-usual" approach to gas utility oversight will only serve to hinder achievement of climate goals. Before climate regulation was enacted, shareholder interests were aligned with the prudent management of the system, which included the ability to earn profit on expenditures for safe operations and expansion to new customers. Now regulators need to align shareholder interests with prudent management of the *contraction* of the system and other ways to decarbonize it, in addition to ensuring continued safe and reliable service. Fewer customers, less throughput and increasing risk all need to be considered.

Regulatory oversight must keep pace with evolving market and legal developments. While several existing laws permit, if not compel, Commissions to perform their public service responsibilities with due consideration of climate change, these provisions have not been activated with any great force in gas rate cases to date.[25,26] That said, several leading Commissions have taken the important first step of opening broad, state-wide proceedings to evaluate the future role of natural gas and how best to reconcile their climate goals with existing gas utility policies and business models. Governing in this new era will require both procedural changes, such as more inclusive proceedings with opportunities for robust stakeholder input, and substantive ones, such as enhanced regulatory oversight to protect against the threat of significant stranded assets. Below are recommendations that Commissions can follow to begin to bridge the disconnect between gas policy and climate commitments.

Inclusive and Transparent Decision Making

Gas utilities tend to make major investment decisions on a case-by-case basis, in rate and capital expenditure proceedings, which by their nature are inadequate to address systemic issues and long-range planning. On top of this, in many states, the regulatory approval of gas utility requests remains opaque and inaccessible to many stakeholder groups. Depending on the state and the particular process, decisions may happen behind closed doors based on brief summary documents or may happen in public proceedings that are only open to certain types of participants. Often times these decisions happen in disconnected silos without clear notice to potentially impacted stakeholders. Approval of unnecessary new infrastructure can adversely impact low-income and disproportionately impacted communities, who can least afford rate increases.

Commissions should make the decision making processes for gas utility activities more transparent and accessible to all stakeholders. Furthermore, these processes should include detailed evaluation of the impact of potential actions on disproportionately impacted communities as well as the environmental and energy justice implications of any approvals.

Review and Clarify Existing Processes

A natural starting place to refresh regulatory tools is a review of the state's various gas processes and proceedings to identify gaps, deficiencies and potential linkages. Commissions regulate gas utilities through several types of proceedings, including rate cases, forecast and supply plans, and purchased gas adjustments, among others. Narrowly reviewing utility filings in each of these silos fails to capture the incremental economic and environmental impacts of each approval. Furthermore, the separation of decision making related to gas utilities into multiple, separate proceedings without clear linkages or appropriate cross-proceeding notice can pose a barrier to participation by non-utility stakeholders and members of the public. Several Commissions have already recognized the need to open broad, umbrella policy proceedings to address the future role of gas and gas utility viability.[27] This type of holistic inquiry can begin to address the deficiencies of the current piecemeal review as well as identify the challenges associated with maintaining necessary infrastructure to support and ensure a workable transition.

Existing processes should also be reviewed to determine important linkages. As one example, the recovery of gas costs — whether in a rate case or through a purchased gas adjustment mechanism — is not conditioned on, and generally is not even reviewed for consistency with, filings in long-term gas planning dockets. Linking these two efforts could provide an important means of holding utilities accountable for their decisions and protecting customers from unnecessary rate increases. Other improvements, such as advance review of certain costs, could also provide benefits, including assurance of cost recovery and reduction in the number of litigated issues. For instance, a Rhode Island planning protocol provides that the gas utility will seek advance approval through a filing and proceeding at the Commission for long-term commitments that meet certain triggering criteria.[28]

Ensure Utilities Provide Sufficient Information in Support of Requests

While it is well established that the utility bears the burden of proof to demonstrate its costs are just and reasonable, many filings simply contain a few sparse tariff sheets, without any meaningful demonstration of how those rates were calculated.[29] Utilities sometimes omit critical information from these filings, such as when they fail to disclose an affiliate relationship between a pipeline developer and a retail gas utility customer.[30] These deficiencies, in effect, shift the burden from the utility to customers and intervenors to demonstrate why a proposal should not be approved, as opposed to why it *should* be approved.

New infrastructure investments often require the granting of a Certificate of Public Convenience and Necessity, which requires a finding that the investment is reasonable, prudent and in the public interest. Regulators must view the "used and useful" standard in light of climate goals. This may require requesting additional information, opening companion investigation proceedings, or being willing to deny projects without prejudice until the utility meets its burden of proof.

These evidentiary deficiencies can be compounded by the absence of any meaningful pathway or forum to address requests for heightened scrutiny of gas contracts.[31] For example, in New York, EDF has been waiting for more than three years to obtain clarity for the appropriate forum to review a disputed affiliated transportation contract.[32] Commissions can resolve these challenges by ensuring that processes and proceedings for review of gas costs and new infrastructure are subject to clear and transparent requirements, responding to requests for heightened review of particular transactions, and ensuring that utilities provide sufficient information upon which to make a reasoned decision.

Encourage Broader Stakeholder Engagement

Gas utility dockets were designed primarily with a limited set of stakeholders in mind — Commission staff, the state consumer advocate and perhaps a small subset of sophisticated customers. Generally, a state's consumer advocate typically limits its representation to a generic residential customer profile and does not exclusively represent frontline communities, low-income customers or other vulnerable stakeholders. In the past, some Commissions have denied intervention or full party status to environmental groups in certain proceedings.[33] Commissions should ease limitations on intervenor participation in formal proceedings and consider new structures and approaches to stakeholder involvement in order to invite a broader swath of input, such as community public participation hearings, and should ensure that these approaches facilitate stakeholder participation in all decision making, not just during rate cases. For example, the California Public Utilities Commission (CPUC) created a program (later adopted and expanded by the state legislature) to give financial resources to intervenors who face a significant financial hardship and make a substantial contribution to the record. The state also provides for community public participation hearings and solicits correspondence through community groups and includes that information in the record of the proceeding.[34] In general, proceedings benefit from more inclusivity to enable joint problem solving including quality outreach to, and public participation from, disproportionately impacted communities.[35]

Commissions should also ensure that other state regulators with overlapping or otherwise related jurisdiction are aware of, and have the opportunity to engage in, relevant proceedings. In many states, multiple regulatory bodies have responsibilities for, or related to, achievement of state climate goals.[36] To the extent that decisions made in Commission proceedings impact the pathway to achieving those climate goals and the remaining potential carbon budgets for other resource types, coordination between regulators is important.

Consider Equity Input and Impacts

The existing regulatory construct does not provide for adequate consideration of equity in processes or decisions. While there is increased understanding of the importance of equitable outcomes, that has, to date, rarely resulted in meaningful changes to the process, let alone decisions impacting gas investments. Disproportionately impacted communities face greater energy burdens (spending a higher proportion of their income on energy bills), environmental burdens (experiencing greater exposure to pollution from energy infrastructure) and infrastructure burdens (living in areas with older housing stock). It is imperative to invite, encourage and enable participation in the regulatory process from disproportionately impacted communities, and to consider equity in all regulatory decisions. There is no one-size-fits-all approach for enabling equitable participation and ensuring equitable decisions in every jurisdiction. Disproportionately impacted communities are integral to the conversation and their perspectives must be included at the outset. Right now, in this nascent stage of transforming the regulatory construct, it is imperative to embed equity in the process of developing regulatory reforms. The considerations below are not exhaustive and local organizations must be consulted in developing any reforms.

As an initial matter, regulators and stakeholders should consider barriers to participation from stakeholders not historically represented at Commission proceedings. These include, but are not limited to, requiring in-state counsel for participation; requiring live, in-person participation; and addressing economic barriers to participation. Some options for addressing these barriers include providing compensation to organizations for whom participation creates an economic hardship; reforming requirements of retaining in-state counsel when doing so presents a hardship; gathering stakeholder feedback through workshop processes with a lower barrier to participation; and enabling virtual participation.

In addition to increased equity in regulatory procedures, environmental, energy and climate justice must be high-priority considerations in regulatory decisions. Tools such as the Initiative for Energy Justice's Equity Scorecard could be deployed to help assist Commissions in evaluating the equity implications of various proposals.[37] Equity experts should be invited to present on how issues of environmental and energy justice should be considered by Commissions and stakeholders.[38] For example, in California, prominent equity groups authored "Equitable Building Electrification: A Framework for Providing Resilient Communities" which presents a five-step framework for how the current goals of building electrification can be aligned with producing healthy homes, creating high quality, local jobs, and establishing stronger connections between everyday Californians and our climate change policies and goals.[39]

One area of particular concern should be rate impacts on disproportionately impacted communities. Households that can least afford increases should be explicitly considered, along with alternative rate options, where appropriate, for those households.[40] Households of all income levels should be able to participate in demand response and energy efficiency programs and renters should have the same opportunities as homeowners.[41] Low-income households face unique challenges that must be considered. See "Consider Pilots to Test Innovation" section below for recommendations on pilot projects that ensure equitable access.

These same communities tend to be unable to afford to electrify their homes or lack the site control to make these capital improvements because they are renters. That means that as wealthier customers depart the system to electrify and become early actors to meet the state's decarbonization goals, these same disproportionately impacted communities will be left "holding the bag" on the existing gas system costs. Absent policy intervention, spreading the same costs out over fewer customers will lead to a rate increase that will be unaffordable, with disproportionate impact on these communities. Without policy action, regulators are in danger of creating a highly regressive customer cost recovery system. Regulators will need to thoughtfully consider the existing financial obligations of the gas system and manage its contraction so that these critical equity considerations will be taken into account. Using metrics such as remaining book value, expected useful life and depreciation schedules will be critical for considering how to prudently manage the decarbonization of the end uses of the gas system.

Long-Term Planning Requirements

A necessary first step to harmonize the activities of gas utilities with climate goals is for gas utilities to conduct forecasting and planning activities that match the tenor of those goals and consider the system changes that will be necessary for achievement of those goals. Current forecasting and planning exercises performed by gas utilities are often limited to short duration terms, such as five- or 10-year periods, whereas the most aggressive state climate goals often are for more than 20 years in the future. In addition, gas planning often narrowly focuses on meeting peak usage and demand needs, which are usually forecasted to be static or growing based on dated assumptions and policies. To the best of our knowledge, no Commission has successfully completed a long-term gas planning docket that aligns with that state's climate goals.[42]

Commissions should require gas utilities to engage in holistic and transparent long-term planning that includes a consideration of consistency with state climate goals and evaluates a broad range of possible actions and solutions. This long-term planning should look beyond just a five-year or 10-year time horizon and determine how gas utilities can support achievement of end use decarbonization, as reinforced by state climate goals. Furthermore, the long-term plans should consider a broad range of possible actions, coordinated solutions and attendant transformations of business models. Gas utilities' long-term plans should be evaluated through a transparent and open public process with participation from a diverse group of stakeholders.

Require a Long-Term Vision Aligned with Climate Targets and Other State Policies

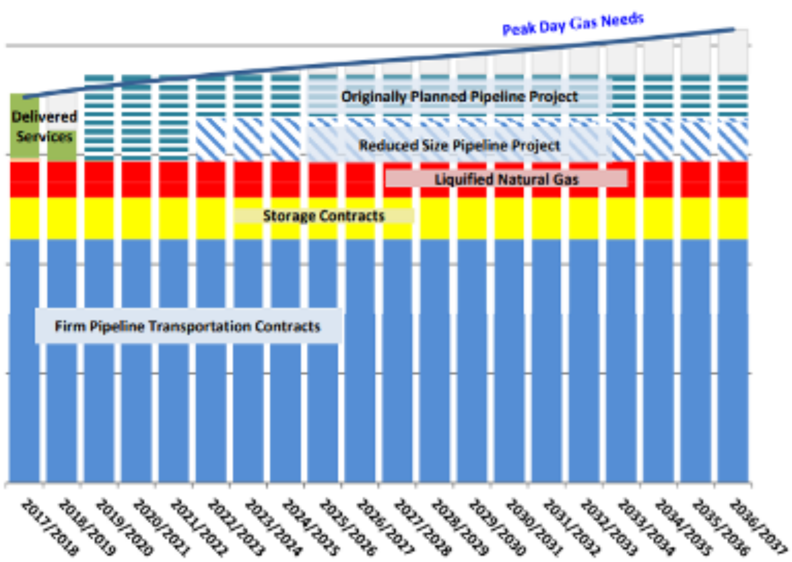
As a starting point for review and discussion by stakeholders, Commission staff and ultimately Commissions, gas utilities should be required to present a vision for how their business model will evolve to support and serve climate goals. While traditional planning efforts generally consider shorter-time frames (e.g., five to10 years) and often narrowly focus on the sufficiency of capacity, this longer-term approach would consider all tools available to retail gas utilities to reduce GHG emissions across their systems and achieve state climate compliance. A long-term vision can help to identify regulatory barriers that may be specific to the jurisdiction and elucidate any disconnects between climate requirements and the expectations and long-term vision of other agencies and stakeholders. A holistic picture of a company's system can also identify low-hanging fruit to be addressed in the near term, such as through aggressive methane leak mitigation. One example of such a plan is Washington Gas Light Company's (WGL) Climate Business Plan.[43] Although parties have critiqued several aspects of WGL's Plan, it has served as a basis to elucidate the disconnect between the vision of the gas utility and other interested stakeholders.[44] Since natural gas infrastructure is inherently long-lived, alignment with this long-term vision will change the overall investment planning framework, expected useful life, depreciation schedule and workable decommissioning plans.

Define the True Needs of the System

Long-term forecasts of demand have been traditionally based on assumptions developed by individual gas utilities and approved by Commissions.[45] In almost all circumstances, these assumptions predict that overall gas demands will either increase or stay flat. This trajectory aligns with shareholder interests of continued use and expansion of the system. However, this may no longer reflect the true needs of the customer the system serves in light of the imperative to decarbonize energy end use.

In Massachusetts, for example, a long-range forecast and supply plan is developed over a five-year planning horizon and describes the forecasting utility's resource planning process and strategies to meet the current forecast of customer requirements and prevailing market conditions.[46] Throughout the country, these long-term forecasts often project year-over-year growth, even for utilities within states that have adopted stringent GHG targets.[47] These projections have profound implications for new gas infrastructure buildout, as demonstrated by Consolidated Edison's 2017 plans to develop a new pipeline to meet its projected 2037 peak day gas needs.[48]

Figure 5: Example of Con Edison's 2017 Projection of Impacts of Future Pipeline Projects on Meeting Customers' Needs



Source: ConEdison

A revamped forecasting framework will be needed to address the more uncertain future and incorporate likely demand changes related to climate goals. Improvements to demand forecasts could follow recommendations already being considered or implemented on the electric side, including incorporating weather impacts attributable to climate change, embedding state climate goals into the model, explicitly modeling non-pipeline alternatives, and requiring forecasts to be based on publicly available data and publicly available accessible models.

Gas utility planning should also consider what risks and impacts the effects of climate change, including sea level rise, worsening storms and wildfires, and drought, will create for gas infrastructure and projected utilization patterns. By way of comparison, recent electric utility forecasting has revealed significant potential risks to parts of the electric system; it is unclear the extent to which similar forecasting has been done for the gas system.[49] Analysis of these risks would reveal what actions should be taken to ensure that the gas system remains safe and reliable and what assets are particularly vulnerable, which may inform retirement, electrification and/or replacement decisions.

Plan for Projected Utilization Changes

Beyond recognizing likely demand reductions, long-term planning should incorporate projected changes to system usage. Currently, gas distribution system demand peaks during the winter heating season, with a relatively small number of cold days driving capacity needs. Gas utility planning activities should consider whether, as heating electrification increases, the system will see peaks that are smaller not just in absolute terms but also as compared to average usage. System peak could shift from winter to other periods when gas demands may be high, changing both procurement and storage capacity needs. They may also result in a significantly larger number of customers with small and consistent usage, if some customers electrify their heat but retain gas cooking appliances. Changes in usage patterns should inform decisions about what infrastructure will continue to be necessary as overall usage decreases. Investments to maintain system pressure may be different under this scenario, especially if a percentage of customers depart the system entirely. As discussed above, more research is needed as to how customer use patterns and reliability may or will change as a consequence of climate change.

Commissions should also expect that in a gas market that is anticipated to decline over the next two decades, reliability concerns may be overtaken by deliverability concerns. Thus, the issues of greatest concern in the future may not be related to peak gas demand or cold day conditions (reliability) but instead ramping and acute, locationally-sensitive requirements for gas-fired generators (deliverability). This planning may require more robust forecasting of where gas-fired electric generators will continue to operate (establishing sensitive parts of the gas pipeline network), and when those operations are most likely to occur. In light of these dramatic changes, as Commissions evaluate issues of reliability and resilience, they should prevent over-investing and consider the expected profile of the customers who will be using the system in the future, not just the profile of today's customers.[50]

Conduct Robust, Transparent Gas Supply Planning

Approaches to gas supply planning vary by state and utility. For instance, in North Carolina, Piedmont Natural Gas files historic and projected load duration curves and against such curves presents its "resource stack" of pipeline capacity and on-system supplementals (e.g., LNG and CNG) to demonstrate its resource sufficiency.[51] In Massachusetts, the utilities present design day demand (net of conservation and energy efficiency) against which they present their contractual and on-system resource stack and identify surplus or deficit conditions with respect to the matching of forecasted demand to contracted resources.[52] The New York Public Service Commission has historically not made any formal public findings regarding the sufficiency of each gas utility's supply plan, and the process is primarily an exchange between the utility and DPS Staff.[53] In California, gas utilities develop an annual report that forecasts supply and demand out 15 years, but that report receives no public comment and the utilities have no obligation to map them against state-wide climate targets.[54] Utilities and Commissions have started to recognize the deficiencies of the current approach.[55,56]

There are three categories of changes Commissions should consider in improving long-term traditional gas supply planning: 1) changes to the process to facilitate stakeholder participation; 2) changes to how planning is presented for Commission and stakeholder review; and 3) changes in the types of information that each gas utility should submit.[57] First, the process should be annual and open to a wide variety of ntervenors with opportunities for discovery rights. Second, gas utilities should be required to submit long-range plans, which set forth projections of demand by peak hour and hourly demand curve projections. Against that demand, the long-range plans would list each resource by cost and projected load factor utilization. Each utility's approved long-range plan would become the basis for an annual gas cost reconciliation proceeding and provide the baseline for recovery. Any difference between costs proposed in the reconciliation proceeding and the long-range plan would be deemed a "variance from the plan." Third, gas utilities should be required to provide historic and forecasted demand curves, resource stacks, including a presentation of each resource's fixed and projected variable costs and projected load factor utilization, and information on non-pipeline solutions considered and not considered.[58] This presentation of potential resources, as well as their timing, annual all-in costs, and capabilities would assist Commissions and stakeholders in both understanding and evaluating the available alternatives and the trade-offs involved with each.

Evaluate Resources Using the All-in Cost Metric

As part of a robust gas supply plan, gas utilities should be required to present an apples-to-apples comparison of all resource options using an all-in cost per dekatherm of use metric (All-in Cost).[59] This metric considers the annual total fixed and variable costs of an option, divided by the projected annual use in order to arrive at a representative dollar per dekatherm ($/Dth) benchmark cost. Below is an example.

Figure 6: Example of All-In Cost Metric, comparing new pipeline capacity to a Compressed Natural Gas facility

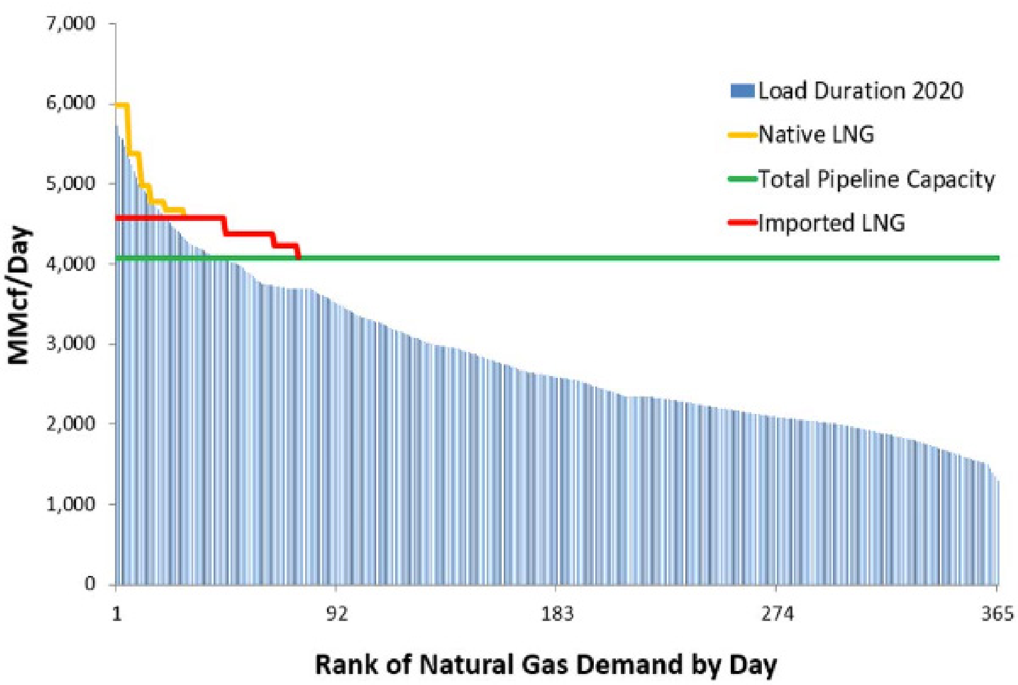
	Annual Facilities'/ Fixed Costs	Annual O&M/ Commodity Costs	Peak Hour Demand (Dth/Hr)	Annual Incremental Demand Met	All-in Cost ($/Dth)
Ex. 1	$5,000,000	$1,800,000	1,000	150,000	$45.33
Ex. 2	$15,768,000	$420,000	1,000	150,000	$107.92

Ex. 1 Assumptions: Annual Cost of CNG Facility is $5MM;CNG $/Dth $12
Ex. 2 Assumptions: Annual Cost of New Build PL Capacity at $1.80/Dthd; $/Dth $2.80

Common Assumptions: 1,000 Dth/HR (24,000 Dthd); and 150 Hours/Yr Equivalent Full Use/

This type of metric is critical to weighing the cost of new long-term investment such as new pipeline capacity, which is not used on every day of the year. As shown below in the illustrative New England load duration curve, pipeline capacity constraints exist for less than 50 days of the year:

Figure 7: Illustrative New England load duration curve, showing pipeline constraints on approximately 50 days of the year



Solving these seasonal constraints with a pipeline solution, as compared to an alternative such as imported Liquefied Natural Gas (LNG), would come at significant cost to ratepayers. This is because the annual fixed costs of new pipeline capacity are significantly higher than alternatives such as LNG or Compressed Natural Gas (CNG). Because new pipeline capacity is not needed every day of the year, this results in a much higher all-in cost. The all-in cost metric can serve as a valuable tool in elucidating the least cost option for customers.

Integrate Non-Pipeline Alternatives into Long-Term Planning

Non-pipeline alternatives (NPAs), which resolve gas constraints without developing large, expensive, long-lived infrastructure projects, have the potential to make gas planning more consistent with state climate goals.[60] NPAs are the gas equivalent of non-wires alternatives in the electric utility context, consideration of which has increasingly become accepted and even required as a part of the electric system planning process. NPAs fall into two categories: those which address peak-day constraints, such as demand response programs, CNG or LNG and those which address total annual customer demand, such as energy efficiency programs and fuel switching programs like targeted electrification. A GHG assessment for each of these options must be employed to understand overall climate impact, as some options will present zero emissions (energy efficiency) and others will present varying levels of impact (e.g., for fuel switching to electricity, the life cycle analysis should account for all GHG emissions from electricity generation to power the replacement heat pump).

While certain frameworks for NPA suitability criteria and incentive mechanisms have been proposed, to date efforts to deploy NPAs have often been explored on a piecemeal basis and divorced from any rigorous long-term planning effort.[61,62] Identifying and assessing non-pipeline alternatives outside of a company's formal planning and needs assessment will tend to limit deployment and could present missed opportunities to better align gas policy with the state's climate goals. And without transparency and visibility into the traditional utility solution planning process, including demand projections, projected load factor utilization and the all-in costs of potential solutions, impediments to pursuing non-pipeline alternatives will remain.

As part of the long-term plan and for those forecasted demands not met by existing contract rights plus utility-operated facilities, utilities should be required to identify all potential resources — including NPAs — under consideration.[63] An assessment of each resource should include the resource's all-in cost and provide the detailed analysis and assumptions underlying those costs. Where no NPA is under consideration or when NPAs have been proposed but are not being considered, utilities should also be required explain why NPAs are not under consideration and identify any specific proposed or potential NPAs that are not under consideration.[64]

Commissions should also consider employing a more systemized approach to comparing non-pipeline alternatives modeled after Consolidated Edison's December 21, 2017 Request for Proposals submitted in the Smart Solutions proceeding (New York Public Service Commission Case No. 19-G-0606).[65] In brief, after establishing an identified need, the retail gas utility would issue a Request for Proposals, seeking a broad array of innovative solutions from non-utility third parties that could either provide gas supply or demand relief. This competitive-type process would not only protect against affiliate abuse but would also incentivize service providers to develop solutions that are narrowly tailored (in terms of size and cost) to the ultimate need while minimizing adverse impacts on communities and the environment.[66] As a result of this robust and competitive process, the retail gas utility would have several options to choose from and its selection process would be transparent to the Commission and interested stakeholders.[67]

Establish a Gas Investment Priority Order

Regulators can facilitate long-term planning by establishing a "gas investment priority order." This investment hierarchy serves two critical objectives: it helps align future gas utility expenditures with decarbonization goals by reducing the total amount of natural gas throughput and it accomplishes a balance between customer affordability and system reliability.

A "gas investment priority order" could be modeled on California's Loading Order, which mandates that, in electric procurement plans, energy efficiency and demand response be pursued first, followed by renewables and lastly by clean-fossil generation.[68] In California, the Energy Action Plan that created the Loading Order enabled a shared vision of how new investments should occur so that regulators did not need to consider the merits of an individual utility application in a silo but rather had proper context for the new investment. The same need exists for new gas investments. Establishing this order of operations will help manage the contraction of the gas system as decarbonization occurs. While the actions in this "gas investment priority order" may need to be adjusted depending on the jurisdiction, a long-term system plan should acknowledge the role of the following actions before turning to traditional infrastructure investment:

- Non-pipeline alternatives to optimize total customer demand, including gas energy efficiency programs and fuel switching programs such as targeted electrification
- Non-pipeline alternatives to address peak day constraints such as gas demand response programs

Related to this hierarchy, as Commissions consider new investments in the system, they should prioritize those which reduce lost and unaccounted for gas (LUAF or LAUF) through advanced leak detection technology, reprioritize repair timeframes to account for the climate harm of the leak and not just the leak's proximity to densely populated areas, and establish appropriate incentives to prevent methane leaks. California regulators, for example, have taken these steps and that state's PUC also found ways to align shareholder responsibility with the accounting mechanisms associated with the LUAF to further incent the elimination of leaks. These steps aligned the safe operation of the system with an environmental objective and could be replicated in other places to consider how investments could be prioritized. More detail on this is provided in the "Review Lost and Unaccounted for Gas Mechanisms" section below.

Commissions should also explore additional ways to reduce throughput expenditures, through gas trading reforms, capturing the value of investments in Advanced Metering Infrastructure technology to fashion time-of-use rates and leveraging gas storage facilities.

While the topics are still emerging, regulators should consider alternative non-fossil gases (such as biomethane or hydrogen) carefully, and reserve allocation of new infrastructure investments to support these alternative fuels for hard-to-decarbonize remaining end uses.

Conduct Thorough Greenhouse Gas Assessments

Gas supply plans to date have largely ignored the GHG emissions impact of various supply options. In those plans that have considered environmental impact, such as National Grid's Long-Term Capacity Report, the GHG assessment has been sparse.[69] Gas utilities should be required to provide a rigorous, consistent and transparent approach to evaluating the GHG implications of different gas supply options. The utilities should also assess how their plan will, or will not, affect the state's ability to meet its climate objectives.[70] Such an assessment would be used in conjunction with an evaluation of the all-in cost metric described above. A robust lifecycle assessment should:

1. Account for all combustion-related GHG emissions and fugitive methane emissions at each stage (upstream, gas utility operations and end-use combustion);
2. Account for both supply- and demand-side options;
3. Use the most recent publicly available data;
4. Identify and incorporate significant uncertainties in methane leakage assumptions used to develop the life cycle GHG inventory for each option;
5. Align the analysis with economy-wide GHG emission reduction targets; and
6. Monetize life cycle GHGs using the Social Cost of Carbon Dioxide and Social Cost of Methane.

While this GHG assessment for gas supply planning is a crucial first step, ultimately gas utilities will need to provide sufficient information in order for their regulators to determine the reasonableness of all future requests. Such requests must be consistent with statewide GHG emissions limits. Broadly speaking, this would first require a comprehensive baseline of GHG emissions in each utility service territory. Once the baseline is established, the Commission would need data to assess progress towards GHG reductions, ideally on an annual basis. Finally, the utility would need to provide estimated GHG impacts from any proposal as well as projections of GHG emissions with an assessment of variability and uncertainty to determine whether such proposals will interfere with climate goals.[71]

Ensure Gas and Electric Utility Coordination

Once a gas utility proposes a long-range plan which presents its supply plans in concert with its GHG emissions reductions efforts (including cost-effective electrification), it will be necessary to coordinate such efforts with the electric utility serving the same service territory. This is because electric generation profiles will be different during the decarbonization transition, and gas-fired generation profiles will be different as more intermittent renewable energy (such as solar and wind) are integrated into the electric grid. For combined gas and electric utilities, this coordination would of course occur more organically. For gas-only utilities, Commissions may need to institute more formal channels of communication between the gas-only utility and its electric utility counterpart to coordinate respective capabilities and plans. Such coordination is already occurring in some jurisdictions, such as Vermont Gas' announced partnership with the Energy Co-Op of Vermont. These utilities plan to "work together to help customers find the right low-cost, low-carbon solution for their energy needs, including non-gas alternatives such as electric cold climate heat pumps, advanced wood heat systems, and other options in support of the State's 90% renewable by 2050 plan."[72]

Similar coordination is also informally occurring in California between Southern California Edison and Southern California Gas Company, where ramping needs for gas-fired electric generators to help integrate solar and other variable renewable electric generation create new gas system demands in that portion of the state. In California, the coordination also involves the California Independent System Operator (CAISO) as the state's balancing authority to forecast the ramping needs of electric gas-fired generators. As discussed above, with additional electrification, the gas peak demand in some areas could shift from the winter heating season to times of high electric usage and limited renewable production, when demand by gas-fired electric generators is highest. Over time, these electric generators will probably run less frequently and gas demands will be less predictable than in previous decades. This will cause new costs on the gas pipeline network, with implications on pressure and storage requirements. States like California are considering implementing new tariffs for gas-fired electric generators to pay for these changing system costs. [73]

Coordination must account for issues associated with increased competition for market share, as increased electrification for heating reduces the need for gas expansion and even reduces existing gas demand. For example, California adopted a four-year $200 million pilot program on electrification of new and existing residential buildings.[74] This competition will become more pronounced as electric utilities offer rebates for heat pumps and electric utilities develop beneficial electrification plans as a result of legislation and Commission action.[75,76]

Coordination of Near-Term Decisions and Long-Term Goals

Commissions currently make a wide range of decisions about gas utility operations, infrastructure and rates. These decisions are often made in silos with limited transparency about how one decision impacts the other, leading to a sub-optimal outcome with respect to both customer cost and long-term system planning. These decisions should be made in a coordinated, transparent manner and should be evaluated for consistency with long-term plans and state climate goals. In particular, decisions about building, repairing or replacing infrastructure should consider the potential long-term need for that infrastructure given climate goals. Any investment with long-term assets should include evaluation of alternatives, including non-pipeline alternatives.

In the long-term plan, Commissions can establish a “bright line” for new investments. This establishes a different ratemaking treatment for new investments, including new assumptions for expected useful life, depreciation schedules, decommissioning costs assumptions, etc. Each of these can be aligned with the dates established in the state’s climate goals. In support of this, Commissions should align ratemaking and rate design authorizations with climate policies, develop electrification and alternative technology programs or pilots, enhance scrutiny of affiliate transactions, revisit depreciation and cost allocation issues in light of the changing energy industry, and ensure that policies and programs related to leak-prone pipes are effective in reducing GHG emissions and supporting state climate goals.

Connect Long-Term Planning to Cost Recovery

Requiring gas utilities to comply with a more robust planning framework would help manage and avert the challenges raised by rate filings that fail to demonstrate, or even consider, whether the continued and significant gas investment proposed therein are consistent with state climate goals. For example, in Consolidated Edison’s 2019 gas rate proceeding, the company proposed over 60 gas capital projects and programs that would represent approximately $2.9 billion in investments over the course of a three-year rate plan.[77] Some of these projects were proposed after the initial rate filing was made and were declared necessary in order to avoid a moratorium on new customer connections.[78] The request raised significant questions regarding need, alternatives and consistency with climate goals — all issues that should be addressed well in advance of the time that cost recovery is sought.

Separate from rate case proceedings, several Commissions have implemented purchased gas cost mechanisms to stabilize gas costs and minimize base rate filings. These mechanisms typically include commodity-related costs as well as demand related costs (e.g., fixed transportation costs).[79] Some utility filings are shocking in their lack of transparency.[80] Others, such as the New Jersey Basic Gas Supply Service filings, glaringly omit any reference to state energy or climate goals, despite their significant implications for the long-term management of gas supply portfolios.[81] These deficiencies could be corrected by centering a gas utility’s decisions around a long-range plan, which would then become the basis for recovery in gas cost reconciliation proceedings. Rhode Island has provided a model for how this could work in practice, linking the gas utility’s Long Range Plan (LRP) to the annual gas cost reconciliation (GCR) filing:

> The annual GCR filing will reflect the final costs and volumes that are derived from the annual LRP filings. The Company will prepare a comparison of volumes and costs presented in its GCR filing in the same form (i.e., presentation format) as its annual LRP filing from June of the same year and identify any differences. By the time the GCR is filed, these items found in the Company's LRP submission will have already been fully vetted, and the Division will only need to review any changes that have occurred in the interim or are projected by Company to occur during the upcoming GCR period, subject to the Division's right to review and dispute any costs in the GCR that were not approved in accordance with the process identified in this Joint Memorandum or otherwise.[82]

Planning processes must be connected to rate recovery in order to bring the necessary accountability and discipline to utility decision making in an era of rigorous climate commitments. When authorizing rate recovery for new proposals, Commissions can connect "used and useful" assumptions with climate goals to ensure that new investments are not left stranded because of these climate commitments.

Identify Changes to Existing Programs that Incent Gas Use and Expansion

Many states and utilities have adopted policies and programs that subsidize new customer connections (both line extensions and service connection subsidies) to the gas system.[83] These policies create a default to gas in many geographies, which make the transparent evaluation of alternatives difficult if not impossible. These policy mechanisms were summarized in a 2017 NARUC report and include offering no-cost extensions for consumers that are located a short distance from an existing gas main or offering individual consumers the ability to finance extensions through on-bill financing surcharges or other payment plans.[84] Commissions also routinely approve programs which target fuel switching from propane to natural gas and pilot programs that incentivize efficient expansion of the distribution system.[85,86] These programs and incentives must be revisited and evaluated to determine whether their continued operation will interfere with compliance of state climate goals.

The same frameworks used to expand the gas system — such as Niagara Mohawk's Neighborhood Expansion Program — could be deployed in assessing how best to target electrification opportunities. The Neighborhood Expansion Program uses a modeling methodology to review all end points on the Company's existing gas distribution system and analyze customer density in these areas to identify main extension opportunities. As states are trying to align the economics of climate policies and decarbonization of the gas system, elimination of these line extension subsidies are an important step to take. There is no longer a "network benefit" of having more customers connected to the system, and sufficient non-gas alternatives exist to provide basic heating and cooking needs such that a connection does not need to be subsidized.

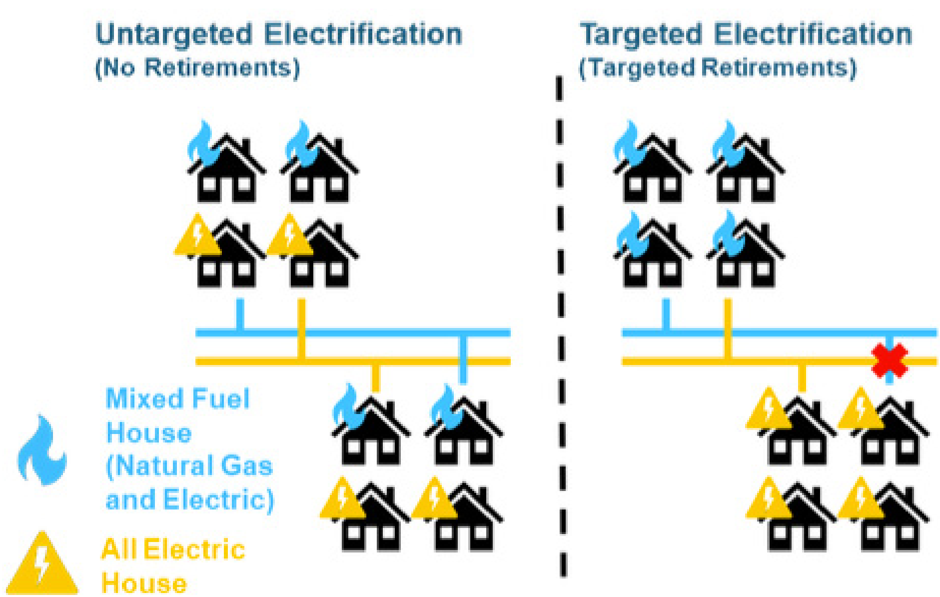
As detailed further below, Commissions should explore opportunities to model electric heat pump pilot programs instead of traditional gas expansion efforts, such as through targeting specific locations and neighborhoods for fuel switching opportunities.[87] These fuel switching opportunities should leverage existing energy efficiency programs, when possible. States may want to provide incentives to make the switch and identify areas where opportunities for networked geothermal loops exist.[88] In particular, networked geothermal loops present an example of business model innovation potentially available to gas utilities.

Design Targeted Non-Pipeline Alternative Programs

As discussed above, non-pipeline alternatives can be a critical way to contain system costs. One of the largest customer segments are residential customers, and building electrification is already highly cost-effective and accessible in many parts of the country.[89] Electrifying a building means a reduction in gas throughput and also a reduction in the gas utility's customer base. Decision makers should coordinate this contraction in a managed way in order to ensure costs remain reasonable for the remaining gas customer base. In California, one estimate projects an approximate 5x cost difference between a managed and an unmanaged transition.[90] Electrification is expensive and requires site control, both of which may create an unlevel playing field. If a state's wealthier customers (who typically own their own home) can afford to electrify and have the ability to do it, they leave the costs of the legacy gas system to the low-income populations (who typically rent and do not have site control). Therefore, absent policy intervention, untargeted electrification could create an unintended cost shift to the most vulnerable populations.

At the same time, state regulators must consider the gas infrastructure and maintaining a reliable system, including the embedded costs of the system. As demonstrated in the figure below, assume you have two similarly situated neighborhoods supplied with gas service. In the left-hand side graphic below, electrification occurs in an untargeted way, where 50% of the homes electrified but the remaining infrastructure stays in place and costs increase for the remaining customers. In the right-hand side of the figure below, electrification is targeted: the same 50% of the homes electrified, but now a piece of the gas system can be taken out of service. Ratemaking techniques can be deployed to keep rates affordable for the remaining customers and keep shareholders whole for their existing investments.

Figure 8: Example of Targeted Electrification



Source: E3

Regulators should further consider the embedded value of the gas line in their targeting. Again, on the right-hand side of the figure, there are two lines that could have been targeted. Assume that the top blue line has recently been worked on and has a large remaining book value, and the lower neighborhood is about to be upgraded and has a relatively low embedded value. All else being equal, using electrification as a non-pipeline alternative to the upgrade saves all the customers more money since the residual value of taking that line out of service is less compared to the upper line. Regulators should require targeted electrification using specific gas metrics, such as remaining book value, depreciation rates and other financial considerations as ways to minimize any stranded value.

As Commissions explore strategies to manage the contraction of the natural gas system via non- pipeline alternatives (such as electrification of customer energy usage currently served by the gas system), there are four key considerations to ensure equity during the transition:

1. Target deployment of building electrification as non-pipeline alternative programs;
2. Ensure that the targeting considers the embedded cost of the gas system;
3. Make non-pipeline alternatives accessible to all building stocks and ownership profiles in that area; and
4. Craft an appropriate rate design for the remaining customer base to protect against unnecessary cost shifts.

Link Shareholder and Societal Value

Against a backdrop of change spurred by new technologies, evolving customer expectations and state climate goals, regulators are forced to consider how regulated companies "make money in order to better manage this change, reward innovation, and provide more value for customers' money."[91] In order to link shareholder and societal value, regulatory policies should create incentives for companies to innovate. Instead of relying on rate of return as the sole value driver, regulators should allow companies to earn increased revenues when they provide value-based products and services.[92] There must also be a means to differentiate among company performance.[93]

This is particularly critical where system buildout and expansion is no longer a primary objective. Under the current regulatory framework, companies create investor value every time they make capital investments. While traditional cost-of-service regulation provides a return sufficient to finance and build essential infrastructure, it offers few incentives for higher levels of reliability and safety, and lower levels of cost and environmental impact demanded today. To achieve emissions reductions needed to safeguard climate, it is necessary for the market design to reward efficient and more capable use of regulatory assets rather than simply incentivizing more steel in the ground. Regulators should determine strategies to reward the prudent management of the contraction of the gas system so that there are parallel shareholder incentives to the continuous expansion model.

Different approaches will be needed for stand-alone gas utilities as compared to combined gas and electric utilities. Whereas the latter will face growth opportunities to pursue electric infrastructure options, stand-alone gas utilities will face diminished growth opportunities and thus will require new regulatory tools and approaches.

For stand-alone gas utilities, there are a number of methods for changing utility incentives, including increased use of revenue decoupling mechanisms for gas utilities, shareholder earnings/allowance of return for non-pipeline alternatives and other non-traditional assets, and performance-based ratemaking strategies. Shared savings strategies and revenue decoupling mechanisms break the link between the revenues a utility receives and the level of sales it makes, eliminating the incentive for a utility to expand its sales and the disincentive for energy efficiency programs.[94] However, as gas system usage decreases due to electrification, revenue decoupling mechanism targets will also decrease, resulting in a continued misalignment between needed electrification and utility incentives; similarly, increased gas infrastructure will continue to result in greater shareholder profits. Performance-based ratemaking strategies have the potential to address this, by offering direct incentives to gas utilities for engaging in activities that result in decreased usage and infrastructure buildout; however, these strategies must be carefully designed to ensure that shareholder and societal value are aligned. Regulators can also consider allowing gas utilities to earn a return on non-traditional assets, including non-pipeline alternative projects and alternative technologies like networked geothermal loops.

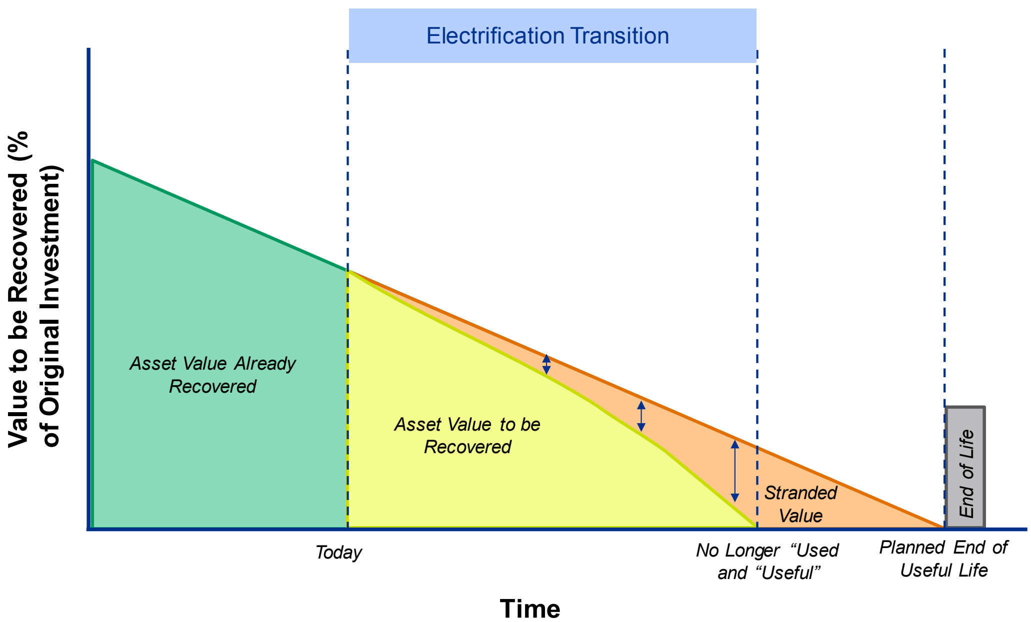
In several of the ratemaking techniques outlined throughout this paper, the risk to shareholders is explicitly considered. The strategies are designed to minimize investment risk; implicit is that regulators should “honor the promises of the past” to have future clean energy investments be as affordable as possible. When implementing policies to align with climate goals, regulators should continue to find ways to minimize investment risk for both existing and new investments. This lowering of risk profile should be further integrated and reflected in the gas utility’s authorized return on equity.

Depending on the actions taken by the regulatory body, the utility’s return on equity can reflect a more securitized investment climate. For combination gas and electric utilities, regulators should also ensure that the return on equity and other ratemaking treatment of gas assets as compared to electric assets is properly aligned with the actual characteristics of those assets and achievement of state policy goals. Many of the actions proposed in this toolkit come with the aim of minimizing investment risk for gas infrastructure and operations, and that reduction in risk should be reflected in the calculation of the authorized rate of return for gas versus electric. This includes an acknowledgement that there will be increased growth opportunities for electric infrastructure as gas infrastructure undergoes its managed contraction.

Align Depreciation Schedules with Climate Targets

When a new gas asset is put into service today with a depreciation rate based on ratemaking practices developed based on historic policies, that creates an implicit assumption that the long-term usage of that asset will not be impacted by climate goals. It also creates an accompanying risk of the asset becoming stranded if those policies do result in changes. In essence, regulators are determining that the asset will be “used and useful” for the entire life of the asset, even if that date extends beyond its climate goals. While gas utilities depreciate all kinds of assets, their largest asset is their pipes. The depreciation rate for pipes is typically around 2.5%, given the assumption that the economic life will be long-lived and it will be considered “used and useful” over that long life.[95] For example, an asset put into rate base in 2020 with a 2.5% depreciation rate will be in rate base until at least 2060, far beyond the target dates of the state climate laws. As described above, continued usage of natural gas at current levels is not consistent with achievement of state climate goals. Therefore, as electrification increases, and particularly where a path to full electrification is pursued, some assets will reach the end of their used and useful status before the end of their expected useful life, and therefore before they are fully depreciated. This means that certain investment could become stranded.[96] An illustrative example of this shortfall is demonstrated in the figure below.

Figure 9: Example of Changes to a "Used and Useful" Asset as Electrification Occurs



As an initial matter, gas utilities must assess how the imperative to decarbonize energy end use by midcentury will impact the economic useful lives of their infrastructure, both through evaluation of existing infrastructure and as part of any proposal for new infrastructure. Some gas utilities have started down this path. Consolidated Edison Company of New York Inc.'s Joint Proposal, approved by the New York Public Service Commission, obligates the Company to file a study on "the potential depreciation impacts of climate change policies and laws on its gas, electric, steam, and common assets."[97] Corning Natural Gas Corporation in New York states that, as a consequence of New York's climate law, Corning's assets (and improvements that reduce GHG emissions) should be permitted to have "depreciable lives [that] match the expected economic lives of utility assets."[98]

Shortening depreciation schedules could, by definition, shorten the cost recovery timeline and raise gas rates. Regulators will then need to allocate those new costs in the most equitable way possible, including to customers who will remain on the system long term. Increasing gas system costs may also further motivate a transition away from the gas system to electrification, and regulators must consider the right balance and timing of these changes.[99] Changes to accelerate the depreciation schedule to make existing infrastructure in line with climate goals is only one method; additional options are detailed in an earlier EDF report "Managing the Transition: Proactive Solutions for Stranded Gas Assets in California."[100]

Evaluate Cost Allocation

Reduction in demand for gas spurred by climate laws could also mean a significant reduction in the need for, and utilization of, extensive gas infrastructure. If utilities face a declining customer base, the already committed investments and the ongoing costs of operation and maintenance of the gas system will be spread over a smaller number of customers. This could lead to an increase in gas rates for remaining customers. Left unaddressed, this could result in a "death spiral," where low to moderate income ratepayers, who are most sensitive to rate increases and least able to electrify without focused support, become increasingly burdened with higher rates.[101]

As part of a managed contraction of the gas system, regulators will need to determine who will be using the system long term. One customer category may be gas-fired electric generators. A second may be industrial consumers, where substitutes for natural gas as a feedstock or fuel for process heat are not currently readily apparent. Commissions will be required to resolve these tensions through changes to rate design and cost allocation. California has been forced to address this issue today, as it reevaluates costs associated with gas-fired electric generation use of the gas utility system.[102] The equity concerns here are critical, since low-income populations will not be first actors and could bear a large cost increase without policy intervention.

As discussed above, Commissions may want to implement a gas investment priority order. As part of the guidance contained in that document, Commissions may want to change how they charge for the infrastructure, including fixed charges to access the pipeline. In some states, customers who leave when the utility has previously made a large fixed cost investment on their behalf are issued a departing load charge or an exit fee. This fee makes it so that the customer pays for their "fair share" of the investment made on their behalf and that the remaining customers and the utility shareholders are left indifferent; regulators may want to examine if an exit fee would be appropriate for the gas context, with the recognition that such a fee could act as a disincentive against decarbonization, so the exit fee may need to be paid through other sources of funds, as opposed to customer monies. Legislative authority may be required to issue a securitized bond or tax funds or other non-ratepayer funds.

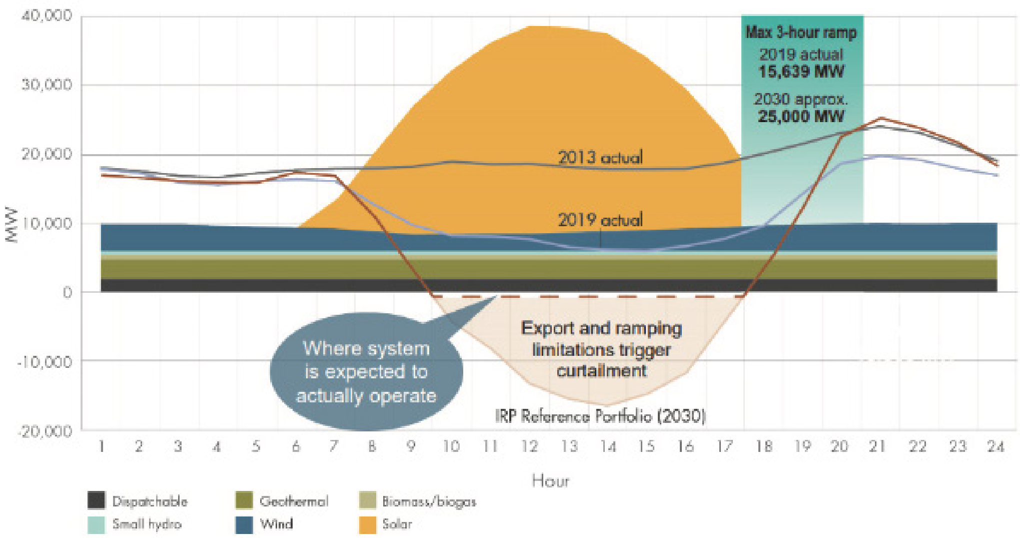
Regulators may also want to consider how to more clearly delineate the value between firm and interruptible gas services and allocate costs accordingly. Firm gas service in a decarbonized economy may have different system costs, and under the principle of cost causation pays, re-assignment of cost allocation to those who will remain on the system may be a viable option. Regulators should prioritize the equity considerations of this cost allocation transition.

Explore New Tariff Services

The changing needs and dynamics of the electric system should also inform regulators' actions, given the interplay between the gas and electric systems. Against the backdrop of laws and policies driving decarbonization, Commissions must consider what market design constructs will most effectively support a future electricity system with high penetrations of renewables and other zero/low carbon resources. The role of gas generators in this future system will evolve and the services supporting these generators will need to reflect this new reality. Commissions should follow first actor states like California and New York and reevaluate generator pricing policies in light of these contemporaneous and evolving market conditions.[103]

Gas-fired generation use of the system will become increasingly variable as more renewable resources penetrate the grid. As projected by CAISO, gas-fired electric generation will increasingly provide ramping and flexibility to accommodate renewable integration. While the need for afternoon ramping barely existed in 2013, it becomes quite pronounced by 2030 as shown in the figure below.

Figure 10: California's "Duck Curve" Demonstrating the Need for Additional Gas-fired Electric Generator Ramping, which May Require a New Gas Tariff for System Cost Implications

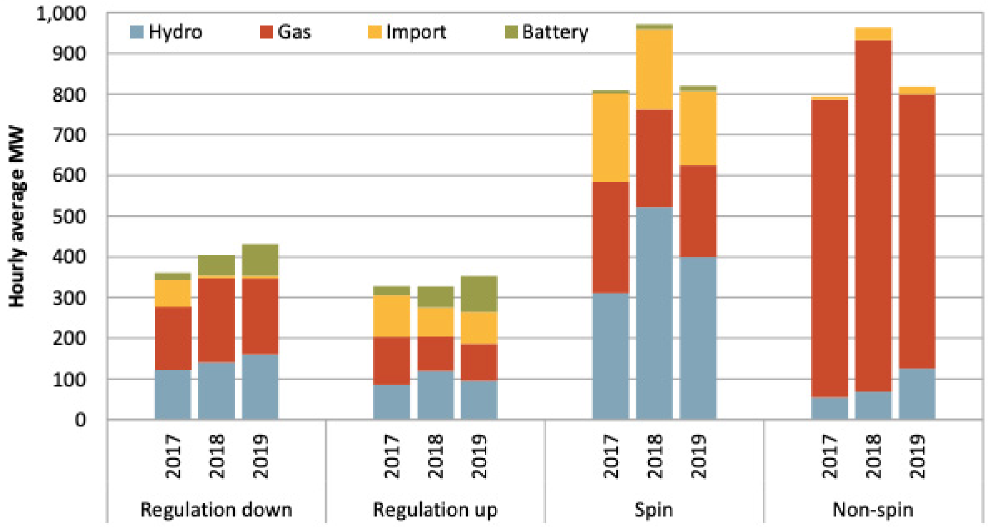


Source: California Independent System Operator Corporation

In order for gas generation units to provide the required ramping capability to the electric grid, they need to be able to access gas supplies and capacity services that correspond to their daily variations in load.[104] The suite of transportation and balancing services should complement and facilitate the variable needs of generators. New tariff services — such as a Renewable Balancing Tariff proposed by Southern California Gas Company for consideration by CPUC staff — will need to be offered in order to send correct operational and price signals for the cost and relative value of the flexible services provided by gas utilities to these gas-fired electric generators.[105]

Bringing transparency and price discovery to gas transportation service for generators has implications for the competitiveness of the electric grid and those resources which can compete with natural gas to provide flexibility services. Today in CAISO, for example, costs associated with the balancing service provided by the gas system are not reflected in electric generator bids.[106] Thus, one of the most essential attributes to our future grid — flexibility — is not specifically delineated but rather embedded within the cost of transportation capacity. This muddles the market for participation by more dynamic, data-driven resources like batteries and demand response. Although various types of resources can provide flexibility services, the market for these services is currently dominated by gas-fired units.[107]

Figure 11: CAISO Ancillary Service Procurement by Internal Resources and Imports



Source: California Independent System Operator Corporation

Without delineating and pricing the flexibility that gas provides (i.e., sub-day non-ratable flows), electric markets will not effectively spur competition, innovation or investment in the provision of these services. As more fossil fuel units are eliminated from the system, a portfolio of zero-emitting resources will necessarily be required to match, either individually or collectively, the balancing capabilities of these units.[108] Commissions should consider the types of gas market changes that will be needed in order to facilitate this more dynamic electric grid.

Scrutinize Affiliate Transactions

Numerous utility holding companies are transacting on both sides of pipeline expansion projects, as both pipeline developer and long-term gas shipper.[109] Although the risks associated with self-dealing affiliate transactions have been widely detailed at both the state and federal level, these transactions are not subject to a sufficient level of review at the federal level and likely are also under-reviewed in many states.[110,111] At the federal level, the Federal Energy Regulatory Commission (FERC) has historically declined to review the terms of precedent agreements between affiliates unless there is evidence of self-dealing, finding that "any attempt by [FERC] to look behind the precedent agreements [in a certificate] proceeding might infringe upon the role of state regulators in determining the prudence of expenditures by the utilities that they regulate."[112,113]

At the state level, depending on state law, review of affiliate precedent agreements may not occur until after the pipeline is placed into service and the utility seeks to recover its pipeline transportation costs. Once FERC grants a certificate application, state Commissions are limited to reviewing whether the contracting utility was prudent in contracting with its affiliate pipeline developer, as compared to other alternatives.[114] The cure for this gap in oversight is to ensure sufficient regulatory safeguards are in place at both the federal and state levels prior to construction of a pipeline capacity expansion. State Commissions should consider standards of conduct that specifically protect against affiliate contracts for transportation service.[115] Additional reviews of state level affiliate transition rules may be necessary to ensure that the affiliates are acting in alignment with the new climate objectives.

Consider Pilots to Test Innovation

There are opportunities for gas utilities to participate in the energy system transition offering new options to their ratepayers, including alternative heating and cooling options and alternative, lower carbon fuels. Certain utilities have started exploring these options through pilots, including those related to geothermal heating and cooling and distribution of biomethane.

Distribution of biomethane, as well as other lower carbon fuels like hydrogen produced with no or low GHG emissions, has the potential to allow continued use of gas utility infrastructure to serve customers for whom electrification is likely to be particularly expensive and difficult. However, any proposed usage of these fuels must recognize the potential impacts of continued gas usage, including emissions, as well as the limited overall availability of these fuels.

Gas utilities could also support achievement of state climate goals in coordination with electric utilities by participating in the expansion of geothermal heating and cooling where feasible, including through developing and owning networked geothermal loops serving multiple residential and non-residential customers, as proposed by the Home Energy Efficiency Team.[116] These networked geothermal loops could be developed and billed for under a relatively traditional utility ratemaking paradigm, with the gas utilities transitioning to a business model where they act as "thermal utilities." In Massachusetts, Eversource Energy recently received approval to develop a networked geothermal loop as a demonstration project as part of its gas rate proceeding.[117] Similar thermal services have been offered by utilities in Europe, with Engie operating 320 district heating and cooling systems worldwide, some employing geothermal and others using a variety of different heat and cooling sources, including biomethane, river water and waste heat from factories, as well as more traditional fossil-fueled generators.[118]

In approving new pilot programs, regulators should ensure that such exploration adheres to the following principles:

- Accountability
- Scalability
- Equity
- Reducing GHG emissions

Accountability. Pilot projects and other new initiatives should require regular and detailed reporting during the project and at its conclusion, ensuring that regulators and the public can track the pilot and understand its progression. Reporting requirements and time intervals should be clearly specified as part of the project approval process, and the utility should disclose detailed data collected during the pilot so that it can be effectively analyzed by others.[119]

Scalability. A pilot project is by nature a small-scale application of a technology or program, with the idea that a successful pilot could lead to broader implementation and broader benefits. Thus, prior to approval, regulators should require a utility to articulate its vision for the future of the project if the pilot were to succeed, including a demonstration that the pilot could in fact be scaled up and that the scope of the pilot is adequate to generate useful information and results.[120] For example, gas utilities are articulating plans to incorporate the use of biomethane into their systems and proposing biomethane pilot projects, but many experts have raised concerns about levels of availability and overall environmental integrity of the gas.[121,122,123] It is reasonable and responsible for a utility to demonstrate anticipated supply and scalability of biomethane as part of a justification for such a pilot project.

Equity. The clean energy transition should not only treat disproportionately impacted communities fairly, it should remedy past harms and ensure expanded access to clean energy opportunities for overburdened neighborhoods and homes. Gas utilities now have a universal duty or obligation to serve all customers who request service; the obligation to serve was created, in part, to promote equity to customer groups who were initially denied gas service because of a form of "redlining" where utilities refused to serve lower-income neighborhoods for fear of not being able to recover costs. Gas service was fought for on equity grounds, and universal service through an obligation to serve was a large win.[124] Now in an era of decarbonization, equity must be reconsidered. These same communities who fought for gas service when it was seen as a luxury should not be left "holding the bag" on a polluting system. Specific pilots should be done to uplift disproportionately impacted communities.

To ensure that such access is part of projects from Day 1, regulators should require pilot projects and new initiatives to specifically provide outreach to, and inclusion of, disproportionately impacted communities.[125] Academic research indicates that it is not enough for a utility to make a program available to any interested customer: "Incentive programs, even those that offer more generous payments to applicants that meet low-income require¬ments, are consistently under-utilized by lower-income and minority cohorts due to financial barriers, limited awareness of such programs, and lower rates of property ownership."[126]

Reducing GHG Emissions. If the central purpose or benefit of a proposed pilot project is to reduce a utility's GHG emissions, then the utility should be required to demonstrate that benefit. The utility should be required to: estimate the GHG emission reductions to be achieved by the project as a condition of regulator approval; report on the emissions impact throughout the project; and quantify the achieved GHG emission reductions at the conclusion of the pilot. Verifying progress is essential to achieving climate progress. As New York's climate law states, GHG emission reductions must be "real, permanent, quantifiable, verifiable, and enforceable."[127]

Review Pipeline Replacement Programs and Surcharge Mechanisms

Utilities around the country have thousands of miles of aging gas lines made from cast iron, unprotected steel and other leak-prone materials. While gas utilities continually invest in modernization programs to replace aging natural gas infrastructure, several programs have been subject to increased scrutiny and challenges.[128,129,130] Addressing leak-prone pipe is critical to ensuring safety and also creates near-term climate benefits. However, like the development of new gas infrastructure, it is often predicated on an assumption that the replaced pipe will continue to be useful and necessary well into the future. Leak-prone pipe replacement is also expensive — Central Hudson Gas & Electric estimates an average cost of $1.9 million per mile.[131] Thus, as continued investments are made, Commissions should require gas utilities to demonstrate how pipeline replacement programs will evolve to support and serve state climate goals. This assessment should be done with stakeholder input and should precede the utility's next request for cost recovery.[132]

Rather than simply replacing all leak-prone pipe with new pipe, deliberate planning to retire gas infrastructure will be necessary, including through demand reduction strategies such as fuel substitution including electrification. As discussed above, regulators should explicitly consider the service of this leak-prone pipe — if the pipe is primarily serving residential or other distribution level assets, it may be more cost-effective to deploy a NPA and take the asset out of service. If the leak-prone pipe services backbone or transmission level uses, then prioritizing its replacement to eliminate these leaks should be a top priority.

Deploy Advanced Leak Detection and Data Analytics

Gas utilities can, and should, incorporate advanced leak detection technology and data analytics (ALD+) into their leak management practices to more cost-effectively and rapidly reduce methane emissions while improving safety and reliability. In most utility service territories in the U.S., gas utilities historically repair and replace distribution infrastructure based primarily on safety and cost considerations, without considering environmental impacts — but that is changing. ALD+ uses highly sensitive sensors that can detect methane emissions on the level of parts per billion, and the emissions data are then analyzed using algorithms to draw out key information, identifying leaks and assessing leak size with much greater accuracy and precision than traditional leak survey methods.[133] EDF has contributed to scientific research to demonstrate the efficacy of ALD+ technology and advocates before Commissions across the country for the expanded use of ALD+.[134]

Peer-reviewed research has demonstrated that utility crews using traditional technologies locate only 35% of leaks on the gas distribution system compared to the leaks identified using ALD+.[135] Research has demonstrated that observed methane emissions from cities are about twice that reported in the U.S. EPA GHG inventory.[136] And more recently, researchers using data collected with ALD+ estimated that nationwide methane emissions from gas distribution pipes are about five times greater than projected by the U.S. EPA GHG inventory.[137]

Importantly, a few "super-emitter" leaks are responsible for a significant proportion of the leakage from gas distribution systems, making it essential for utilities to identify and address these leaks to reduce methane emissions.[138] ALD+ is an available technology that utilities should be using across the U.S. for exactly this purpose, and Commissions should require utilities to incorporate ALD+ into their operations. For example, California utility PG&E worked with ALD+ provider Picarro to identify and prioritize for repair the highest-emitting leaks in its system, as well as to collect methane emissions data that it reports to the CPUC. In 2018, PG&E used ALD+ to survey its entire service territory for high-emitting leaks larger than 10 standard cubic feet per hour (scfh).[139] Within that, PG&E surveyed 1/3 of its territory to identify leaks for compliance, while the remaining 2/3 of the territory was surveyed for emissions data without triggering sub-10 scfh leak indications that require follow-up.[140]

ALD+ has numerous useful applications. Utilities can use ALD+ to improve leak management practices, to prioritize leak-prone pipeline replacement as well as retirements, and to track their system-wide methane emissions.[141] These applications benefit public safety, ratepayers and the environment. Utilities should incorporate ALD+ into their operations, and regulators should require the use of ALD+ as a standard practice. Additionally, regulators should update leak incentive programs that disincentivize utilities from identifying additional leaks on their system.

Review Lost and Unaccounted for Gas Mechanisms

Every gas utility suffers some amount of shrinkage or loss associated with leakage of natural gas, as well as other factors, from the distribution system they manage. Gas utilities account for the amount and value of this lost gas within a metric known as Lost and Unaccounted for Gas (LUAF or LAUF), which encompasses leaked gas as well as meter error, accounting and billing error, and imprecision associated with changes in system pressure. Utilities report on their lost and unaccounted for gas annually to the Pipeline and Hazardous Materials Safety Administration (PHMSA), and both PHMSA and the Energy Information Administration publish LUAF information.[142] Utilities are generally permitted to recover LUAF costs from ratepayers, though calculation and recovery methods vary.[143]

Quantifying the portion of LUAF attributable to distribution system leakage — aka, methane emissions — is possible based on system-wide leak surveys, recordings of discovered leaks and venting, and emissions factors.[144] Accordingly, gas utilities should be held accountable for these emissions under appropriate regulatory schemes, including restrictions on their ability to recover the cost of leaked gas and requirements to incorporate the societal cost of methane into long-term planning.

As mentioned above, actions by the CPUC provide a helpful model. The CPUC recently ordered that utilities must include in the cost-benefit analysis for their Leak Abatement Compliance Plans a quantification of the avoided social cost of methane.[145] This quantification should be provided for individual proposed methane reduction measures as well as for the plan as a whole, using the U.S. Government Interagency Working Group social cost of methane metric.[146] In the same order, the CPUC stated that major gas utilities will be limited in their rate recovery for LUAF attributable to methane emissions starting in 2025, to ensure the companies are achieving the intended methane reductions detailed in their leak abatement plans.[147] To avoid disallowed cost recovery for LUAF, each major gas utility must achieve a 20% reduction in methane emissions below 2015 levels. It is of note that in order to effectively track methane emissions reductions, a regulator must require annual, comparable reporting on leak reduction efforts by gas utilities. This can be achieved through use of advanced leak detection, as discussed above. Commissions should revisit their practices and standards for LUAF attributable to leaked gas and consider whether they are consistent with climate commitments.

Conclusion

Climate science and ambitious climate goals create an imperative to immediately eliminate or reduce GHG emissions to a small fraction of what they are today. Meeting those goals requires concerted and focused action across all emitting sectors. Particularly in the many states targeting a reduction in emissions of more than 80% or net zero emissions by 2050, retail gas utilities must immediately begin planning for substantially declining natural gas usage to avoid excessive emissions and wasted investments.

Commissions can close the gap between state climate goals and gas utility actions and put their states on a path to meet their goals and avoid wasteful investments by taking the following three steps:

1. Establish inclusive and transparent decision making;
2. Require rigorous long-term planning; and
3. Coordinate near-term decisions and long-term goals.

Below is a synthesis of our recommended actions under each of these three categories to align gas regulatory policy and climate goals.

Step 1: Establish Inclusive and Transparent Decision Making	Step 2: Require Rigorous Long-Term Planning	Step 3: Coordinate Near-Term Decisions and Long-Term Goals
• Review and Clarify Existing Processes • Ensure Utilities Provide Sufficient Information in Support of Requests • Encourage Broader Stakeholder Engagement • Consider Equity Input and Impacts	• Require a Long-Term Vision Aligned with Climate Targets and Other State Policies • Define the True Needs of the System • Plan for Projected Utilization Changes • Conduct Robust, Transparent Gas Supply Planning • Evaluate Resources Using the All-in Cost Metric • Integrate Non-Pipeline Alternatives into Long-Term Planning • Establish a Gas Investment Priority Order • Conduct Thorough GHG Assessments • Ensure Gas and Electric Utility Coordination	• Connect Long-Term Planning to Cost Recovery • Identify Changes to Existing Programs that Incent Gas Use and Expansion • Design Targeted Non-Pipeline Alternative Programs • Link Shareholder and Societal Value • Align Depreciation Schedules with Climate Targets • Evaluate Cost Allocation • Explore New Tariff Services • Scrutinize Affiliate Transactions • Consider Pilots to Test Innovation • Review Pipeline Replacement Programs and Surcharge Mechanisms • Deploy Advanced Leak Detection and Data Analytics • Review Lost and Unaccounted for Gas Mechanisms

End Notes and References

1 Center for Climate and Energy Solutions, U.S. State Greenhouse Gas Emissions Targets, www.c2es.org/document/greenhouse-gas-emissions-targets/.

2 Environmental Defense Fund, Managing the Transition, Proactive Solutions for Stranded Gas Asset Risk in California, www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

3 The distribution of natural gas by state-regulated gas utilities to end-use customers results in greenhouse gas emissions at a number of points along the supply chain. First, the production of natural gas results in venting, flaring, and leakage of methane. Second, methane leakage occurs during the transmission of natural gas from production fields to the distribution utility's system, generally through interstate transmission pipeline regulated by federal agencies. Third, methane leakage occurs from the distribution utility's pipelines, overseen by state commissions. Finally, the combustion of natural gas by end-use customers, for heating, cooking, and other uses, results in carbon dioxide emissions. In addition, the energy used in producing and transporting natural gas causes greenhouse emissions.

4 D.C. Department of Energy and Environment, Clean Energy DC: The District of Columbia Climate and Energy Action Plan at 24 (Aug. 2018), https://doee.dc.gov/sites/default/files/dc/sites/ddoe/page_content/attachments/Clean%20Energy%20DC%20-%20Full%20Report_0.pdf.

5 EDF calculation based on the Intergovernmental Panel on Climate Change's Fifth Assessment Report. IPCC, Climate Change 2014: Synthesis Report (2014).

6 Alvarez et al., Assessment of methane emissions from the U.S. oil and gas supply chain, Science, 13 Jul 2018: Vol. 361, Issue 6398, pp. 186-188, science.sciencemag.org/content/361/6398/186.

7 2018 IPCC Special Report, Global Warming of 1.5 degrees, http://www.ipcc.ch/report/sr15/.

8 Id.

9 Climate Leadership and Community Protection Act ("CLCPA"), 2019 N.Y. Sess. Laws 106.

10 CLCPA § 1(4); id. § 2 (codified at N.Y. Envtl. Conservation Law ("ECL") § 75-0107(1)).

11 Biden Harris Campaign, The Biden Plan for a Clean Energy Revolution and Environmental Justice, joebiden.com/climate-plan/.

12 Climate Mayors, a group committed to leading on climate action, represents over 71 million Americans in over 435 U.S. cities. Climate Mayors, Statement on the Trump Administration's Announcement of Formal Withdrawal from the Paris Agreement (Nov. 4, 2019), climatemayors.org/actions/letters-and-statements/; see also Carly Wipf, San Jose bans natural gas in new commercial buildings, San Jose Spotlight (Dec. 1, 2020), https://sanjosespotlight.com/san-jose-bans-natural-gas-in-new-commercial-buildings/. As an example, the City of Orlando, Florida is committed to achieving 100% percent clean energy by 2050 and the local electric utility has adopted a strategic plan to achieve net-zero carbon emissions by 2050. Amy Greene, WMFE, Orlando aims high with emissions cuts, despite uncertain path (Jan. 24, 2020), www.wmfe.org/climate-prone-orlando-florida-tackles-emissions/142909.

13 The Brattle Group, Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050 (Apr. 2020), www.energy.ri.gov/documents/HST/RI%20HST%20Final%20Pathways%20Report%204-22-20.pdf.

14 California Air Resources Board, Building Decarbonization, arb.ca.gov/our-work/programs/building-decarbonization.

15 Justin Gundlach and Elizabeth B Stein, Harmonizing States' Energy Utility Regulation Frameworks and Climate Laws: A Case Study of New York, Energy Law Journal, Volume 41:211 at 225 (2020).

16 Colorado PUC Proceeding No. 20-M-0439G, Clay Clarke and Keith Hay, Colorado's Statutory Greenhouse Gas Reductions and the Governor's Greenhouse Gas Pollution Reduction Roadmap (Nov. 5, 2020).

17 NYPSC Case No. 12-G-0297, Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service, Order Instituting Proceeding and Establishing Further Procedures (Nov. 30, 2012), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=83153&MatterSeq=40220.

18 See, e.g., NYPSC Case No. 20-M-0189, Report on the New York State Electric & Gas Supply Readiness for 2020-2021 Winter, Con Edison Winter Supply Review Data Request at 33 (July 15, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=249285&MatterSeq=62435.

19 Mass. DPU Docket No. 16-79, Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of a Natural Gas Customer Expansion Pilot Program, Order at 17 (Feb. 10, 2017).

20 California PUC, California Electric and Gas Utility Cost Report at 53-55 (Apr. 2020), www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2020/2019%20AB%2067%20Report.pdf.

[21] NYPSC Case No. 19-G-0066, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service, Con Edison Response to Motion to Strike at 3 (July 19, 2019).

[22] See, e.g., Mass. DPU Case No. 18-148, Petition of Boston Gas Company and Colonial Gas Company, each d/b/a National Grid, for review and approval of their five-year Forecast and Supply Plan for the period November 1, 2018 through October 31, 2023, Petition at 5 (Nov. 1, 2018) ("National Grid projects incremental sendout to traditional markets of 8,527 BBtus over the forecast period or 2,132 BBtus per year [assuming normal weather] [see Chart III-A-1, Base Case]. Overall, this growth represents a 7.1 percent total increase in sendout requirements over the forecast period, or 1.7 percent per year on average.").

[23] See, e.g., NYPSC Case No. 19-G-0066, Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Consolidated Edison Company for Gas Service, Con Edison Gas Depreciation Rate Panel Exhibit No. DP-2 at 3 (proposing to recover the costs of gas mains over 80 years and gas services over 60 years) (Jan. 31, 2019).

[24] Projects supported by affiliated captive customers include, among others, the projects approved in FERC Docket Nos. CP15-558 (PennEast Pipeline), CP16-22 (Nexus Gas Transmission), CP16-10 (Mountain Valley Pipeline), and CP17-40 (Spire STL Pipeline).

[25] NYPSC Case No. 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, Order Adopting Accelerated Energy Efficiency Targets at 25 (December 13, 2018) ("Reducing carbon emissions is a critical priority and a significant portion of the Commission's responsibility, as identified in the State Energy Plan, authorized in the Public Service Law and Energy Law, and encoded in the BCA Framework adopted by the Commission."); N.Y. Public Service Law § 5(2) ("The commission shall encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources.").

[26] D.C. Law 22-257, Section 103 (effective date Mar. 22, 2019) (amending D.C. Code § 34-808.02) ("In supervising and regulating utility or energy companies, the Commission shall consider the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments." (emphasis added)); CLCPA, 2019 N.Y. Sess. Laws 106, § 7.

[27] CPUC Rulemaking 20-01-007, Long-Term Gas Planning Rulemaking, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning (Jan. 16, 2020); NYPSC Case 20-G-0131, Gas Planning Procedures, Order Instituting Proceeding (March 19, 2020); Mass. DPU Docket No. 20-80, Investigation by the Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals, Order (Oct. 29, 2020).

[28] RIPUC Docket No. 4816, Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27, Joint Memorandum at 6 (Feb. 20, 2019).

[29] Mo. PUC Case No. GR-2021-0127, In the Matter of Spire Missouri, Inc. d/b/a Spire (East) Purchase Gas Adjustment Tariff Filing, Comments and Motion to Establish Procedural Schedule of the Environmental Defense Fund, Office of the Public Counsel, Midwest Energy Consumers Group, and Consumers Council of Missouri (Nov. 9, 2020) (detailing why a one-page tariff filing, which failed to disclose a $600M affiliate pipeline transaction, prevents the Commission from fulfilling its duty to protect customers against unreasonable rates).

[30] NYPSC Case No. 93-G-0923, Restructuring of the Emerging Competitive Natural Gas Markets, Letter from Environmental Defense Fund regarding Heightened Scrutiny of Precedent Agreements Supported by Affiliates (June 19, 2017).

[31] NYPSC Case No. 17-G-0610, Petition of Environmental Defense Fund for a Declaratory Ruling that Natural Gas Precedent Agreements and Transportation Agreements are Subject to Review Under Public Service Law Section 110(4), EDF Letter Requesting Action on Declaratory Petition (June 10, 2020) (requesting action on a petition filed three years ago regarding review of Consolidated Edison's Mountain Valley Pipeline affiliate contract).

[32] Id.

[33] See, e.g., Mass. DPU Docket No. 18-47, NSTAR Gas Company, Hearing Officer Ruling on Petitions to Intervene (July 17, 2018), Appeal to Commission (July 24, 2018); Mass. DPU Docket No. 17-166, Bay State Gas Company, Order at 10-14 (October 30, 2018) (affirming hearing officer's ruling on CLF's petition to intervene), appeal docketed No. SJ-2018-0556 (Mass. November 28, 2018); Mass. DPU Docket No. 16-181, Boston Gas Company and Colonial Gas Company, Order at 11-14 (2017) (affirming hearing officer's ruling on CLF's petition to intervene), appeal denied No. SJ-2017-0466 (Mass. January 8, 2019) (Single Justice).

[34] For more information, see California Public Utilities Code 1801-1812 and www.cpuc.ca.gov/icomp for additional program details.

[35] The 100% Network, Comprehensive Building Blocks for a Regenerative & Just 100% Policy at 9 (January 2020) www.100percentnetwork.org/uploads/cms/documents/100-network_comprehensive-building-blocks-for-a-just-regenerative-100-policy-2020.pdf ("[F]rontline communities

should be considered leaders, partners, co-sponsors, and co-collaborators. There should be processes for co-governance and collective accountability with frontline communities, as well as consultation with Tribal nations. There should be full accessibility to public hearings and policies should include public funds to cover the costs and fees to enable intervenors to participate in regulatory proceedings."). Such participation can be facilitated through the intervenor compensation model. For example, in California, non-market participants, including environmental groups and equity groups are compensated where they meaningfully contribute to the record in Commission proceedings, including for the hiring of expert witnesses. This statutory program was enacted in 1985 and rewards diverse stakeholder's substantial contribution to the record. California Public Utilities Code 1801-1812. Other states may want to explore similar ways to incorporate compensating non-market participation to ensure a just and equitable outcome.

36 See, e.g., CLCPA § 8(1), 2019 N.Y. Laws 106, https://legislation.nysenate.gov/pdf/bills/2019/S6599 (establishing that state agencies including the Public Service Commission "shall promulgate regulations to contribute to achieving" the statewide GHG limits, though such regulations "shall not limit" the Department of Environmental Conservation's authority to regulate GHG emissions pursuant to article 75).

37 Initiative for Energy Justice, Energy Justice Scorecard, iejusa.org/wp-content/uploads/2019/12/Energy-Justice-Scorecard.pdf.

38 Intervenor compensation is one model. Another innovative model is represented in a Memorandum of Understanding between the New York Power Authority (NYPA) and a coalition of community organizations, wherein NYPA agreed to secure and fund a consultant to provide technical and analytical services to the coalition members to facilitate incorporation of their perspectives. See www.documentcloud.org/documents/7230919-NYPA-PEAK-MOU.html.

39 Greenlining, Equitable Building Electrification (2019), https://greenlining.org/wp-content/uploads/2019/10/Greenlining_EquitableElectrification_Report_2019_WEB.pdf.

40 Approximately one in three U.S. households faces a challenge in paying their energy bills, according to the Energy Information Administration, and about one in five households report reducing or forgoing necessities such as food and medicine to pay an energy bill. U.S. Energy Information Administration, Today in Energy: One in three U.S. households faces a challenge in meeting energy needs (Sept. 19, 2018), www.eia.gov/todayinenergy/detail.php?id=37072. The COVID-19 pandemic is further exacerbating energy burdens for disadvantaged communities and is expected to result in increasing utility bill debt. Vote Solar, Report: COVID-19 and the Utility Bill Debt Crisis, votesolar.org/policy/policy-guides/low-income-solar-access/covid-19-and-utility-debt-crisis/. As low-income gas utility customers struggle to cover their basic needs, it is essential that utilities provide equitable access to programs that can help relieve energy burdens, and that can ensure all customers have access to clean energy options.

41 The 100% Network, Comprehensive Building Blocks for a Regenerative and Just 100% Policy (Jan. 2020), www.100percentnetwork.org. It is not enough for a utility to make a program available to any interested customer. "Incentive programs, even those that offer more generous payments to applicants that meet low-income requirements, are consistently under-utilized by lower-income and minority cohorts due to financial barriers, limited awareness of such programs, and lower rates of property ownership." Fournier, ED, Cudd, R, Federico, F, & Pincetl, S., On energy sufficiency and the need for new policies to combat growing inequities in the residential energy sector, Elem. Sci. Anth., 8:24 (2020), doi.org/10.1525/elementa.419 (citing Bird & Hernández, 2012; Scavo et al., 2016; Parsons et al., 2018).

42 While no state has completed its review, several are in the midst of taking such action. In January 2020, California opened a new rulemaking focusing on long-term gas planning. The Order Instituting Rulemaking explicitly mentions the state's adopted climate legislation and the need to decarbonize the system as a motivation for its need to create a long-term plan. CPUC Rulemaking 20-01-007, Long-Term Gas Planning Rulemaking, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning (Jan. 16, 2020). In response to Executive Order 20-04, the Oregon Public Utility Commission has developed several workplans, one of which is to "identify, prioritize, and deploy strategies to enhance and refine our existing least-cost, least-risk framework to ensure energy utilities are focusing their system-wide resource strategies on making rapid, large scale, and sustained progress to meet GHG reduction goals." Oregon PUC, Executive Order 20-04 Draft Work Plans, https://www.oregon.gov/puc/utilities/Documents/EO20-04-PUC-WorkPlan.pdf.

43 DC PSC Case 1142, In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc., Washington Gas & AltaGas, Natural Gas and its Contribution to a Low Carbon Future: Climate Business Plan for Washington, D.C. ("Climate Business Plan"), (Mar. 2020).

44 DC PSC Case 1142, In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc., Comments of Environmental Defense Fund (June 26, 2020); DC PSC Case 1142, In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc., Comments and Request to Institute an Evidentiary Proceeding of Sierra Club (June 15, 2020).

45 The Mass DPU assesses each LDC's long-range planning standards, demand forecasting methods, and resultant design and normal sendout forecasts in order to determine if they are reviewable, appropriate, and reliable. A forecast method is reviewable, if it "contains enough information to allow a full understanding of the forecast methodology"; appropriate, if it is "technically suitable to the size and nature of the

particular gas company"; and reliable, if it "provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to occur." Mass. DPU Docket No. 08-34, NSTAR Gas Company, Order at 2.

46 Mass. DPU Docket No. 20-76, NSTAR Gas Company d/b/a Eversource Energy, 2019-20 to 2023/24 Forecast and Supply Plan (July 15, 2020).

47 See, e.g., Mass. DPU Docket No. 18-148, Boston Gas Company/Colonial Gas Company d/b/a National Grid, November 1, 2018 through October 31, 2023 Long-Range Resource and Requirements Plan at 5 (Nov. 1, 2018) ("National Grid projects incremental sendout to traditional markets of 8,527 BBtus over the forecast period or 2,132 BBtus per year [assuming normal weather] [see Chart III-A-1, Base Case]. Overall, this growth represents a 7.1 percent total increase in sendout requirements over the forecast period, or 1.7 percent per year on average.").

48 NYPSC Case N. 17-G-0606, Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, Petition at 30 (September 29, 2017).

49 Utility Dive, Climate risks are accelerating. Here's what Duke, PG&E and 16 other utilities expect to pay (Nov. 18, 2020), www.utilitydive.com/news/climate-risks-accelerating-heres-what-costs-duke-pge-and-16-other-utilities-expect/588860/.

50 CPUC Rulemaking 20-01-007, Long-Term Gas Planning Rulemaking, Opening Comments of Environmental Defense Fund on Workshop Report at 3-4 (Nov. 2, 2020).

51 NCUC Docket No. G-9, Sub 727, Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Testimony and Exhibits of Gennifer Raney on behalf of Piedmont Natural Gas Company, Inc. (Aug. 1, 2018), starw1.ncuc.net/NCUC/ViewFile.aspx?Id=feb95b8f-afe1-4fab-8040-edd252c431a3.

52 See, e.g., Boston Gas Company d/b/a National Grid Long-Range Resource and Requirements Plan (Nov. 1, 2018), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10008562.

53 NYPSC Case No. 19-G-0309, Rates, Charges, Rules, and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service, Direct Testimony of Gregory Lander on behalf of Environmental Defense Fund (Aug. 30, 2019), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=232130&MatterSeq=59676.

54 California Gas and Electric Utilities, 2020 California Gas Report (2020), www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf.

55 RIPUC Docket No. 4816, The Narragansett Electric Co. d/b/a National Grid, Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27 at 5 (Feb. 20, 2019) ("In the past, the [Long Range Plan] filings were not controversial and tended to raise few complicated issues. But now, the Company needs to plan in a way that assures adequate capacity and delivery security under supply contracts, the magnitude and implications of which have grown substantially. As a result, the current framework and template for the Company's long-range planning is no longer sufficient for an appropriate regulatory review").

56 NYPSC Case 20-G-0131, Gas Planning Procedures, Order Instituting Proceeding (Mar. 19, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=242672&MatterSeq=62227 (finding that "conventional gas planning and operational practices ... have not kept pace with recent developments and demands on energy systems" and that planning must be conducted consistent with the objectives of the CLCPA).

57 For a detailed summary of each of these changes see Direct Testimony of Gregory Lander, supra n.53, http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=232130&MatterSeq=59676.

58 Specifically, gas utilities should provide: (1) Historic daily winter period demand curves for the prior five years by class along with the prior demand forecasts for the same periods; (2) Historic daily non-winter period demand curves for the prior five years by class along with the prior demand forecasts for the same periods; (3) Historic system winter period demand curves, (hourly and daily) for each of the Company's take stations for the prior five years along with the demand forecasts for the same periods; (4) Historic system non-winter period demand curves, (hourly and daily) for each of the Company's take stations for the prior five years along with the demand forecasts for the same periods; (5) The historic resource stacks of the Company employed to meet those historic demand curves; (6) The Company's forecasted winter period system demand duration curves for the next five years; (7) The Company's forecasted non-winter period system demand duration curves for the next five years; (8) The Company's forecasted winter period demand curves, (hourly and daily) for each of the Company's take stations; (9) The Company's forecasted non-winter period demand curves, (hourly and daily) for each of the Company's take stations; (10) The resource stacks (including separate presentation of their respective fixed and projected variable costs and projected load factor utilization) the Company has under contract to meet the Company's forecasted forward period demand curves; and (11) For those forecasted demands not met by existing contract rights plus Company operated facilities, the Company should identify all potential resources (including non-pipeline solutions) under consideration and each such resource's forecasted all-in cost (as defined above) and provide the detailed analysis and assumptions used for the build-up of such resources' all-in costs presented by the Company. In addition, the Company should identify potential non-pipeline solutions not under consideration for each forecasted period, and the detailed analysis performed as to why the particular potential non-pipeline solutions are not under consideration for the subject period(s). Direct Testimony of Gregory Lander, supra n.53.

59 The "all-in cost" is determined by taking the sum of the fixed cost per year of the project plus the variable O&M cost of the project (i.e., total annual non-gas cost) divided by the projected annual Dth of use of project to arrive at modeled per Dth of use non-gas cost plus the variable commodity cost per Dth of the project.

60 NYPSC Case No. 17-G-0460, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan at 75 (June 14, 2018) (finding that that non-pipeline alternatives should be "explored as a universal practice as an alternative to traditional investments."), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=209297&MatterSeq=54153;
NJ BPU Docket No. GO19070846, In the Matter of the Exploration of Gas Capacity and Related Issues, Order Soliciting an Independent Consultant (May 20, 2020) (acknowledging the role of non-pipeline solutions can have in reducing stress on the gas system). Non-pipeline alternatives reduce the need to invest in new infrastructure to meet new capacity by eliminating that new capacity need through non-physical infrastructure means.

61 NYPSC Case No. 19-G-0066, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service, Direct Testimony of Davide Maioriello at 11-12 on behalf of DPS Staff (May 24, 2019) (recommending that "the Commission require the Company to implement a new process for evaluating capital project suitability criteria to develop NPAs as substitutions for traditional utility solutions"), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=227186&MatterSeq=58902.

62 For example, building upon the efforts of its upstate utility, National Grid filed a Non-Pipeline Alternative Incentive Mechanism as part of its 2019 rate case, acknowledging the "societal benefits of adopting more modern, cost-effective alternatives to traditional gas supply and gas transmission/distribution system solutions." NYPSC Case No. 19-G-0310, Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of KeySpan Gas East Corp. d/b/a National Grid for Gas Service, Future of Heat Panel Direct Testimony on behalf of National Grid, Exhibit FOH-11 at 3 (Apr. 30, 2019), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=225838&MatterSeq=59676.

63 In California, Pacific Gas and Electric ("PG&E") has started to employ non-pipeline alternatives through targeted electrification deployments. These investments tend to be "at the end of the line" where new investments would be expensive and have minimal customer interaction. As a dual fuel utility, PG&E is able to incent end use customers to electrify and capture operational savings. However, the utility does not earn a rate of return on these non-pipeline alternatives. Similar to non-wires alternatives, regulators may want to consider deployment of shared savings mechanisms, performance-based ratemaking or other shareholder incentives to encourage prudent deployment of these non-pipeline alternatives in more central portions of the system.

64 Direct Testimony of Gregory Lander, supra n.53.

65 See CPUC Docket No. 07-12-021, Application of Pacific Gas and Electric Company for Authorization to Enter into Long-Term Natural Gas Transportation Arrangements with Ruby Pipeline, for Cost Recovery in PG&E's Gas and Electric Rates and Nonbypassable Surcharges, and for Approval of Affiliate Transaction, Decision Approving Gas Transportation Agreements at 85-93, 118-122 (Nov. 6, 2008) (citing CPUC D.04-09-022; CPUC D.06-12-029, Appendix A-3, Rule III.B.1; CPUC D.04-12-048) (explaining that the CPUC's rules require utilities to use an open and transparent solicitation process when involving affiliates and have a neutral independent evaluator review solicitations that involve affiliates); Mo. PUC Case Nos. GR-2017-0215 and GR-2017-0216, In the Matter of Spire Missouri Inc.'s Request to Increase Its Revenues for Gas Service, Direct Testimony of Greg Lander at Schedule EDF-06 (Sept. 8, 2017) (proposing modifications to the gas supply and transportation standards of conduct).

66 For instance, an interstate pipeline could distinguish its proposal by incorporating additional features that would provide environmental benefit such as methane reduction measures. See, e.g., Iroquois Spring 2020 Report, www.iroquois.com/site/assets/files/1057/spring_2020_safety_issue_web.pdf ("As part of the ExC Project, Iroquois plans to reduce methane and overall emissions at project sites through the installation of low Nitrous Oxide (NOx) turbine units that will reduce NOx emissions by 40% over standard turbine units, as well as adding oxidation catalysts on the newly installed turbines, thereby reducing Carbon Monoxide (CO) emissions by approximately 90%. In addition, Iroquois is proposing to install methane recovery systems at each project site to capture released natural gas from station operations.").

67 NYPSC Case 19-G-0678, Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid, Comments of Environmental Defense Fund (May 1, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=245648&MatterSeq=60912.

68 CPUC, Integrated Resource Plan and Long-Term Procurement Plan, www.cpuc.ca.gov/irp/.

[69] The Report describes its consideration of "Climate Impact" as encompassing "the GHG emissions resulting from the solution, air quality impacts (which often go hand in hand with GHG emissions), and the potential of the solution to support decarbonization of the entire energy system." NYPSC Case No. 19-G-0678, Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas East Corporation d/b/a National Grid, Natural Gas Long-Term Capacity Report at 50 (Feb. 24, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=241230&MatterSeq=60912. But the descriptions of individual supply options do not describe the associated GHG emissions and do not quantify any contribution to the emissions reduction goals of the Companies, State, or City. See, e.g., id. at 64 (describing the "Climate Impact" of a Peak LNG Facility as "similar to the other LNG options and 10-15% higher than standard natural gas," without providing more specific quantification).

[70] NYPSC Case No. 19-G-0309, Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service, Direct Testimony of James Fine on behalf of Environmental Defense Fund (Feb. 7, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=240233&MatterSeq=59676.

[71] Id.

[72] Vermont Gas, VGS Partners with Energy Co-op of Vermont to Offer Customers Comprehensive Energy Solutions, www.vermontgas.com/vgs-partners-with-energy-co-op-of-vermont-to-offer-customers-comprehensive-energy-solutions/.

[73] Rulemaking 20-01-007 has ordered the consideration of these Renewable Gas Balancing tariffs but they have not yet been adopted.

[74] CPUC Docket No. 19-01-011, Order Instituting Rulemaking Regarding Building Decarbonization, Decision Establishing Building Decarbonization Pilot Programs (Mar. 26, 2020) (explaining that building decarbonization pilot program funding is authorized and financed pursuant to SB 1477).

[75] Southeast Colorado Power Association, Rebates, secpa.com/member-services/rebates.

[76] 2019 Colo. Sess. Law Ch. 359 at 3290.

[77] NYPSC Case No. 19-G-0066, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service, Con Edison Response to Motion to Strike at 3 (July 19, 2019), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=229961&MatterSeq=58902.

[78] NYPSC Case No. 19-G-0066, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service, Consolidated Edison Company of New York, Inc. Gas Infrastructure, Operations and Supply Panel Update/Rebuttal Testimony at 8 (June 14, 2019), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=228276&MatterSeq=58902.

[79] See, e.g., Spire Missouri Inc., Schedule of Rates and Charges Applying to Spire Missouri East Service Areas at 11 (March 20, 2018) (Purchased Gas Cost Adjustment tariff), www.spireenergy.com/sites/default/files/2020-07/MOEastTariffs.pdf.

[80] Mo. PUC Case No. GR-2021-0127, In the Matter of Spire Missouri, Inc. d/b/a Spire (East) Purchase Gas Adjustment Tariff Filing, Comments and Motion to Establish Procedural Schedule of the Environmental Defense Fund, Office of the Public Counsel, Midwest Energy Consumers Group, and Consumers Council of Missouri (Nov. 9, 2020) (detailing why a one-page tariff filing, which failed to disclose a $600M affiliate pipeline transaction, prevents the Commission from fulfilling its duty to protect customers against unreasonable rates).

[81] NJ BPU Docket No. GR19050676, In the Matter of the Petition of New Jersey Natural Gas Company for the Annual Review and Revision of its Basic Gas Supply Service and Conservation Incentive Program (CIP) Rates for F/Y 2020, Motion of the Environmental Defense Fund to Intervene at 2 (arguing that the Company's gas purchasing strategies, including estimated supply and demand requirements, should be viewed in light of the Energy Master Plan's objectives and goals).

[82] RIPUC Docket No. 4816, Gas Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27, Joint Memorandum at 7-8 (Feb. 20, 2019).

[83] Some of these subsidies are enshrined into commission regulations. See 16 NYCRR § 230.2 (specifying requirements for prospective residential gas customers who apply for heating service).

[84] NARUC, Report of the NARUC Task Force on Natural Gas Access and Expansion (Nov. 2017), www.naruc.org/committees/committee-resources/natural-gas-access-and-expansion-task-force-resources/.

[85] Illinois Commerce Commission Case No. 15-0218, Northern Illinois Gas Company, Application for Approval of Rider 33, Designated Extension Service Area (Feb. 23, 2017).

[86] RIPUC Docket No. 4380, Narragansett Electric Company d/b/a National Grid, 2014 Gas Infrastructure, Safety and Reliability Plan, Report and Order (May 3, 2013); Mass. DPU Docket No. 16-79, Petition of NSTAR Gas Company d/b/a Eversource Energy for Approval of a Natural Gas Customer Expansion Pilot Program, Order at 17 (Feb. 10, 2017).

87 NYPSC Case No. 17-G-0239, Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service, Gas Growth Program Semi-Annual Progress Report (Apr. 30, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=245615&MatterSeq=53410.

88 NYPSC Case Nos. 17-E-0459 and 17-G-0460, Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives (June 21, 2019) ("The Company has identified three separate project locations throughout the service territory where it is likely feasible and cost-effective to permanently retire non-essential sections of [leak prone pipe] ... For this initiative to be successful, an alternate heating fuel would need to be utilized by all customers that are currently being served with natural gas within the identified sections of LPP (i.e., 100% participation)."), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=228704&MatterSeq=54152.

89 California Energy Commission, The Challenge of Retail Gas in California's Low-Carbon Future at page 15 (Apr. 2020), https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf ("This study finds that electrification in buildings is likely to be the lowest-cost means of dramatically reducing GHG emissions from California's buildings.").

90 Gridworks, California's Gas System in Transition: Equitable, Affordable, Decarbonized and Smaller, https://gridworks.org/initiatives/cagas-system-transition/.

91 Steve Kihm et al., You Get What You Pay For: Moving Toward Value in Utility Compensation – Part 1 Revenue and Profit at 2 (June 2015), americaspowerplan.com/wp-content/uploads/2016/07/CostValue-Part1-Revenue.pdf.

92 Id.

93 Alfred Kahn, The Economics of Regulation: Principles and Institutions, John Wiley & Sons (1970).

94 NH PUC Docket No. DG 10-017, EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Direct Testimony of Susan F. Tierney at 35 (February 26, 2010).

95 DC PSC Case No. 1162, In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service, Direct Testimony of Witness White on behalf of Washington Gas at 14, table 2 (Jan. 13, 2020) (showing a current composite rate of 2.45% and a proposed composite rate of 2.54%), https://edocket.dcpsc.org/public/search/details/fc1162/1.

96 Environmental Defense Fund, Managing the Transition, Proactive Solutions for Stranded Gas Asset Risk in California (2019), www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

97 NYPSC Case No. 19-G-0066, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service, Joint Proposal at 113 (Oct. 18, 2019), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=234578&MatterSeq=58902.

98 NYPSC Case No. 20-G-0101, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service, Direct Testimony of Firouzeh Sarhangi at FS-5 (Feb. 27, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=241529&MatterSeq=62108.

99 Environmental Defense Fund, Managing the Transition, Proactive Solutions for Stranded Gas Asset Risk in California (2019), www.edf.org/sites/default/files/documents/Managing_the_Transition_new.pdf.

100 Id.

101 Id.

102 CPUC Rulemaking 20-01-007, Long-Term Gas Planning Rulemaking, Opening Comments of Environmental Defense Fund on Workshop Report at 4 (Nov. 2, 2020).

103 CPUC Rulemaking 20-01-007, Long-Term Gas Planning Rulemaking, Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning (January 16, 2020); NYPSC Case No. 17-G-0011, In the Matter of a Review of Tariff Provisions Regarding Natural Gas Service to Electric Generators, Staff Proposal on Electric Generator Rate Design (Mar. 30, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=243483&MatterSeq=52581.

104 Quadrennial Energy Review Task Force, Transforming U.S. Energy Infrastructures in a Time of Rapid Change, Appendix B – Natural Gas Infrastructure at 10 (Apr. 21, 2015) ("Many gas-fired power plants use large amounts of natural gas over short periods of time throughout the day. These swings can be very large—at full output, one 700MW natural gas power plant consumes as much natural gas on an hourly basis as the entire heating demand of a small city"), https://www.jcs.mil/Portals/36/Documents/Doctrine/Interorganizational_Documents/doe_energy2015.pdf.

[105] CPUC Rulemaking 20-01-007, Long-Term Gas Planning Rulemaking, Assigned Administrative Law Judge's Ruling Issuing Workshop Report and Staff Recommendations, Seeking Comments and Modifying Proceeding Schedule (October 2, 2020) (requiring SoCalGas and PG&E to submit formal analyses outlining a proposal for a Renewable Balancing Tariff in their respective regions).

[106] CPUC Rulemaking 20-01-007, Long-Term Gas Planning Rulemaking, Comments of Southern California Gas Company 45 (August 14, 2020).

[107] CAISO 2019 Annual Report on Market Issues & Performance at 168, www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf.

[108] NYISO Annual Grid and Markets Report at page 26, https://www.nyiso.com/documents/20142/2223020/2020-Power-Trends-Report.pdf/dd91ce25-11fe-a14f-52c8-f1a9bd9085c2.

[109] Select examples of precedent agreements supported by affiliated captive customers include the agreements filed in FERC Docket Nos. CP15-558 (PennEast Pipeline), CP15-554 (Atlantic Coast Pipeline), CP16-22 (Nexus Gas Transmission), CP16-10 (Mountain Valley Pipeline), CP17-40 (Spire STL Pipeline).

[110] See, e.g., Office of the Pub. Counsel v. Missouri Pub. Serv. Comm'n, 409 S.W.3d 371, 377 (Mo. 2013) ("[a]s long as a [utility] is engaged in both monopoly and competitive activities, it will have the incentive as well as the ability to 'milk' the rate-of-return regulated monopoly affiliate to subsidize its competitive ventures").

[111] See, e.g., Brooklyn Union Gas Co. v. FERC, 190 F.3d 369, 374 (5th Cir. 1999) (explaining that an affiliate relationship is "a circumstance that ought to trigger a hard look"); Cross-Subsidization Restrictions on Affiliate Transactions, Order No. 707, 122 FERC ¶ 61,155 at P 4 (2008) (explaining "that a franchised public utility and an affiliate may be able to transact in ways that transfer benefits from the captive customers of the franchised public utility to the affiliate and its shareholders.").

[112] Florida Southeast Connection, LLC, 154 FERC ¶ 61,080 at P 84 (2016).

[113] Mountain Valley Pipeline, LLC, 161 FERC ¶ 61,043 at P 53 (2017).

[114] Pike County Light and Power Co. v. Penn. Pub. Util. Comm'n, 77 Pa. Cmwlth. 268 (1983).

[115] See CPUC Docket No. 07-12-021, Application of Pacific Gas and Electric Company for Authorization to Enter into Long-Term Natural Gas Transportation Arrangements with Ruby Pipeline, for Cost Recovery in PG&E's Gas and Electric Rates and Nonbypassable Surcharges, and for Approval of Affiliate Transaction, Decision Approving Gas Transportation Agreements at 85-93, 118-122 (Nov. 6, 2008) (citing CPUC D.04-09-022; CPUC D.06-12-029, Appendix A-3, Rule III.B.1; CPUC D.04-12-048) (explaining that the CPUC's rules require utilities to use an open and transparent solicitation process when involving affiliates and have a neutral independent evaluator review solicitations that involve affiliates); Mo. PUC Case Nos. GR-2017-0215 and GR-2017-0216, In the Matter of Spire Missouri Inc.'s Request to Increase Its Revenues for Gas Service, Direct Testimony of Greg Lander at Schedule EDF-06 (Sept. 8, 2017) (proposing modifications to the gas supply and transportation standards of conduct).

[116] Home Energy Efficiency Team (HEET), GeoMicroDistrict Feasibility Study (Dec. 2019), heetma.org/wp-content/uploads/2019/11/HEET-BH-GeoMicroDistrict-Final-Report-v2.pdf.

[117] Mass. DPU Docket No. 19-120, Petition of NSTAR Gas Company doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance Based Ratemaking Mechanism, Order at 128-156 (Oct. 30, 2020).

[118] Engie, District heating and cooling systems, www.engie.com/en/businesses/district-heating-cooling-systems.

[119] For example, EDF has advocated that utilities implementing advanced leak technology should provide annual reports detailing their progress implementing the technology and disclosing the leak and methane emissions data obtained. See Picarro Emissions Quantification Results Final Report in Support of the Methane Leak Surveying Report for the PSE&G GSMP II Program (Dec. 14, 2018). In another example, National Grid in Downstate New York conducted a geothermal pilot project and filed quarterly reports detailing its progress. NYPSC Case No. 16-G-0058, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Geothermal Gas REV Demonstration Projects – Q4 2017 Report (Jan. 31, 2018), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=200689&MatterSeq=50089.

[120] For example, the New York Geothermal Energy Organization recommends that geothermal pilot projects include both individual loop and shared loop systems in order to gather data and compare both options. NYPSC Case No. 20-G-0381, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a for Gas Service, NY PSC Case Nos. 20-E-0380 & 20-G-0381, Statement of NY-GEO (Nov. 24, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=256354&MatterSeq=63187.

[121] DC PSC Case 1142, In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc., Climate Business Plan (Mar. 2020), https://edocket.dcpsc.org/public/search/details/fc1142/597; NYPSC Case No. 19-G-0678, Proceeding on Motion of the Commission to Investigate Denials of Service Requests by National Grid USA, The Brooklyn Union Gas Company d/b/a National Grid NY and KeySpan Gas

East Corporation d/b/a National Grid, Natural Gas Long-Term Capacity Report at 50 (Feb. 24, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=241230&MatterSeq=60912.

[122] NYPSC Case No. 20-G-0381, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a for Gas Service, Direct Testimony of the Future of Heat Panel pages 41-49 (July 31, 2020) (describing Renewable Natural Gas Proposal), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=225838&MatterSeq=59676.

[123] See NRDC Issue Brief, A Pipe Dream or Climate Solution? The Opportunities and Limits of Biogas and Synthetic Gas to Replace Fossil Gas (June 2020), https://www.nrdc.org/sites/default/files/pipe-dream-climate-solution-bio-synthetic-gas-ib.pdf.

[124] CPUC Rulemaking 15-03-010, Order Instituting Rulemaking to Identify Disadvantaged Communities in the San Joaquin Valley and Analyze Economically Feasible Options to Increase Access to Affordable Energy in those Disadvantaged Communities, Decision Approving San Joaquin Valley Disadvantaged Communities Pilot Projects (Dec. 13, 2018).

[125] For example, the Massachusetts DPU encouraged Eversource to include a low-income, multi-family building and to specifically document efforts to include such a building in its cost-recovery filing. Mass. DPU Docket No. 19-120, Petition of NSTAR Gas Company doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance Based Ratemaking Mechanism, Order at 143 (Oct. 30, 2020).1

[126] Fournier, ED, Cudd, R, Federico, F, & Pincetl, S., On energy sufficiency and the need for new policies to combat growing inequities in the residential energy sector, Elem Sci Anth, 8: 24 at 3 (2020), doi.org/10.1525/elementa.419 (citing Bird & Hernández, 2012; Scavo et al., 2016; Parsons et al., 2018).

[127] CLCPA, 2019 N.Y. Laws 106, § 2 (N.Y. ECL § 75-0109(3)(b)).

[128] NARUC, Natural Gas Distribution Infrastructure Replacement and Modernization: A Review of State Programs (January 2020), pubs.naruc.org/pub/45E90C1E-155D-0A36-31FE-A68E6BF430EE (describing 41 state infrastructure programs).

[129] DC PSC Case No. 1154, WGL's Request for Approval of a Revised Accelerated Pipeline Replacement Plan, Brief of the Apartment and Office Building Association of Metropolitan Washington at 3 (Oct. 23, 2020) ("Where the Company's current total rate base for the District of Columbia is currently less than $550 million, the Company's estimated costs per mile for Cast Iron main replacement suggest that the Company will need to expend an amount equivalent to more than six times its current total rate base just to replace the remaining 400 miles of Cast Iron mains on its DC distribution system."), https://edocket.dcpsc.org/public/search/details/fc1115/399.

[130] Spire Inc., 2018 Form 10-K at 123, www.spireenergy.com/spire-year-review/downloads/FY18-Form_10-K-FINAL.pdf (describing litigation brought by Office of Public Counsel).

[131] NYPSC Case Nos. 17-E-0459 and 17-G-0460, Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Central Hudson Gas & Electric Corporation's Non-Tariff Implementation Plan & Compliance Filing for Non-Pipe Alternatives: Three Transportation Mode Alternatives (June 21, 2019), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=228704&MatterSeq=54152.

[132] DC PSC Case No. 1154, In the Matter of Washington Gas Light Company's Application for Approval of PROJECTpipes 2 Plan, Brief of Environmental Defense Fund (Oct. 23, 2020), https://edocket.dcpsc.org/public/search/details/fc1154/166.

[133] Weller, Z. D., Yang, D. K., & von Fischer, J. C. (2019), An open source algorithm to detect natural gas leaks from mobile methane survey data. Plos One, 14(2), e0212287, doi.org/10.1371/journal.pone.0212287.

[134] See, e.g., Weller, et al., A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems, Environmental Science & Technology (June 2020), https://pubs.acs.org/doi/10.1021/acs.est.0c00437; NYPSC Case Nos. 19-G-0309 & 19-G-0310, Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service, and of KeySpan Gas East Corp. d/b/a National Grid for Gas Service, Post-Hearing Brief of Environmental Defense Fund (Apr. 6, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=244048&MatterSeq=59676.

[135] Weller, Zachary et al., Vehicle Based Methane Surveys for Finding Natural Gas Leaks and Estimating their Size: Validation and Uncertainty, Envtl. Sci. & Tech., 52, 11922-11930 (2018), https://pubs.acs.org/doi/10.1021/acs.est.8b03135.

[136] G. Plant et al., Large Fugitive Methane Emissions from Urban Centers Along the U.S. East Coast, Geophysical Research Letters V. 46, I. 14 (July 2019), agupubs.onlinelibrary.wiley.com/doi/abs/10.1029/2019GL082635.

[137] Weller et al., A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems, Envtl. Sci. & Tech., 54, 8958-8967 (June 2020), pubs.acs.org/doi/10.1021/acs.est.0c00437.

[138] A. R. Brandt et al., "Methane Leaks from North American Natural Gas Systems, Science, Vol. 343 (Feb. 14, 2011), www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf; Weller, Z. D., Yang, D. K., & von Fischer, J. C., An open source algorithm to detect natural gas leaks from mobile methane survey data, Plos One, 14(2), e0212287 (2019) doi.org/10.1371/journal.pone.0212287; see also Picarro

Emissions Quantification Results Final Report in Support of the Methane Leak Surveying Report for PSE&G's Gas System Modernization Program ("GSMP") II Program.

[139] Aaron Van Pelt, Picarro, Presentation: Picarro Natural Gas Network Management Solution at Slide 14 (Nov. 2019), http://pstrust.org/wp-content/uploads/2019/11/Picarro-Pipeline-Safety-Trust-11-7-19-with-notes.pdf;
see also PG&E, Natural Gas Leakage Abatement Report, Response to CPUC Data Request R.15-01-008, at p3, 9 (June 17, 2019).

[140] Id.

[141] See Palacios, Virginia et al. "Integrating Leak Quantification into Natural Gas Utility Operations," Public Utilities Fortnightly (May 2017), www.fortnightly.com/sites/default/files/whitepapers/2017_Palacios%20et%20al_Integrating%20Leak%20Quantification%20into%20Natural%20Gas%20Utility%20Operations.pdf

[142] 49 CFR § 191.11; see also, U.S. DOT, PHMSA, Report to Congress: Gas Distribution: Lost and Unaccounted for Natural Gas (May 16, 2017), www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/17986/report-congress-lost-and-unaccounted-natural-gas-metrics-may-2017.pdf.

[143] See, e.g., CPUC, Rulemaking 15-01-008, Second Phase Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bills 1371 and 1383 at 41 (Aug. 21, 2019).

[144] Id.

[145] Id. at 36-38.

[146] Id. at 14, 36-38.

[147] Id. at 53-54.