A Regulator’s Blueprint for 21st Century Gas Utility Planning

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Acknowledgments

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Executive Summary

The energy sector is in the midst of a profound transition as it shifts away from fossil fuels to renewable energy and a decarbonized economy. Natural gas utilities are not immune to this transition as their main product is a fossil fuel. Unlike electricity, where either fossil fuels, nuclear energy, or renewable resources can generate an electron, there is not a commercially available, zero-carbon substitute resource that can be used in the existing gas distribution system at the scale that would be needed to replace natural gas at current usage levels. Gas utilities in certain regions, such as New York and Washington state, are beginning to see stagnating customer growth, declining demand per customer, and competition from the electric sector due to decarbonization policies and increasingly cost-effective electrification solutions.[1]

Despite these major changes, ratepayers, stakeholders, and public utility commissions (PUCs) have little insight into gas utility capital investments and resource supply plans. Unlike electric utilities, only a handful of states require natural gas utilities to file long-term plans. Given the rapidly changing energy landscape, regulatory oversight of gas utility spending is more important than ever. Without detailed analysis and evaluation of utility forecasts and plans, it is challenging for the public to determine if utility spending is reasonable. Ultimately, unwise utility investment decisions are most likely to be borne by the customers through higher rates.

It is against this backdrop that this paper has been prepared: to introduce gas planning, lay out the key components of a gas plan, and discuss different types of gas plans. The paper also provides specific state examples of these concepts in action through short case studies. In total, this paper reviews five existing methods of gas planning, highlighting the strengths and drawbacks of each. It then makes some recommendations for states looking to create new, modern gas plans or strengthen existing plans, based on experiences and challenges with existing gas and electric planning processes.

Gas system planning delivers four primary benefits: cost and risk mitigation, transparency, compliance with climate goals, and intra utility coordination.

[1] Consolidated Edison, Inc. *Long-Range Plan*. January 2022. Available at: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/gas-long-range-plan.pdf; Puget Sound Energy, *2023 Gas Utility IRP and Electric Progress Report*. March 2023. Available at: https://www.pse.com/en/IRP/Past-IRPs/2023-IRP

A gas system planning exercise forces utilities to coordinate internally to consider a range of scenarios that meet customer demand. The utility then tests the impact of technological, economic, and policy changes, and confronts resource and investment tradeoffs. The resource, throughput, weather, and capital forecasts amassed during gas planning form a single repository of information useful to the utility, regulators, stakeholders, and the general public. Rather than having key pieces of data scattered across several proceedings, the information compiled during planning proceedings allows for a transparent forum in which stakeholders can better understand a utility's strategic direction and compliance with policy goals, such as emissions targets.

There are two main components to modern gas planning: process requirements and analytical features, described below and summarized in the accompanying Table 1.

- **Process requirements** are the basic structural components of a gas planning process beneficial to customers. Requirements include a set filing cadence and planning horizon, robust stakeholder involvement, and a PUC review process. The involvement of the public in gas planning is essential and results in a diversity of voices that help to refine utility strategy, ultimately benefiting ratepayers.
- **Analytical features** are the tools and analyses used to assemble a portfolio of resources and capital investments deemed to best balance cost and risk. By accounting for technological, economic, and policy variables, utilities can better identify risks associated with specific investment approaches and construct a portfolio of resources that mitigates unnecessary spending and ensures compliance with state laws, including emissions reduction targets. Analytical features also enable utilities to quantify impacts on disadvantaged populations and society in general.

Overall recommendations, process requirement recommendations, and analytical feature recommendations are included in the Conclusion.

Table 1 – Process Requirements and Analytical Features of a Modern Gas Plan

Process Requirements
Filing cadence
Planning horizon
Stakeholder involvement
Draft and final plans
PUC review

Analytical Features
Short-term action plan
Load forecasting
Scenario and sensitivity analysis
Non-pipeline alternatives
Identification of preferred portfolio
Capital investment forecast
Bill impact analysis
Equity analysis
Coordination with the electric sector
Mapping

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Introduction

Gas and electric utilities are always planning for their future investments and expenditures to ensure that they are providing safe and reliable service. Internal utility investment planning is standard practice. Although public-facing resource planning, often called integrated resource planning (IRP), gained traction among electric utilities in the 1980s after changes in global economic conditions and a series of expensive utility planning mistakes in the 1970s, gas utility planning did not receive a similar focus. Still, the reasons that made electric integrated resource planning attractive, such as the need to better integrate demand-side resources, like energy efficiency, into utility planning, are present on the gas side as well.

An Energy Transition is Underway

The use of natural gas in the United States has reached an inflection point. For the past several decades, natural gas has been considered an affordable and environmentally friendly fuel. Other fuels like heating oil produce greater emissions (and are typically more expensive than natural gas), while electric heating (using electric resistance technology) has historically been considerably more expensive. However, the energy transition has brought forth a new, energy efficient and increasingly cost-competitive competing technology: electric heat pumps. Meanwhile, large sectors of the global economy are undergoing a parallel transformation: the fleet of electric generators that power electric heating technologies is rapidly converting from fossil fuels to renewable electricity, the transportation sector is electrifying, and industrial sectors are looking to decarbonize with electrification and alternative fuels. The concern to natural gas distribution utilities that deliver gas to end-use customers is not theoretical – natural gas use in residential and commercial buildings has stagnated[2] and gas prices are rising and becoming more volatile than electricity.[3]

Gas utilities are experiencing four primary headwinds:

1. The lifetime costs of electric appliances are comparable to gas appliances;
2. States, cities, and the federal government are adopting decarbonization policies;
3. Gas prices are increasingly volatile and are more heavily influenced by global supply and demand dynamics; and
4. Utility delivery system investments are outpacing load growth.

[2] U.S. Energy Information Administration. *Natural gas explained*. November 7, 2022. Available at: https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php

[3] Talor Gruenwald, Rocky Mountain Institute. *Reality Check: The Myth of Stable and Affordable Natural Gas Prices.* November 17, 2021. Available at: https://rmi.org/the-myth-of-stable-and-affordable-natural-gas-prices/

The first two headwinds are closely related. Efficient electric appliances – such as electric heat pumps and induction stoves – are emerging as cost-competitive alternatives to their gas counterparts. This is in-part due to government decarbonization policies, such as state-level emissions reduction requirements driving market growth and customer adoption, and federal incentives through the Inflation Reduction Act.[4]

State climate goals are catalyzing the energy transition and ramping up pressure on businesses to decarbonize. Twenty-five states and the District of Columbia have established economy-wide greenhouse gas reduction goals, as shown in Figure 1.[5] For example, Rhode Island passed a law requiring a state-wide emissions reduction of 45% in 2030 and 80% in 2040, with a requirement to achieve net zero emissions statewide by 2050.[6] Meeting such targets requires immediate action from all sectors of the economy, including commercial and residential buildings. The United States Energy Information Administration (EIA) estimates that, in 2021, natural gas combustion (including electricity generation) accounted for 34% of US CO_2 emissions.[7] Additionally, the EIA estimated that methane leaks during natural gas extraction, processing, and transportation accounted for 4% of total US greenhouse gas emissions, based on carbon-dioxide equivalents, in 2020.[8] Since gas system end users account for about 58% of natural gas consumption,[9] addressing the direct use of gas in buildings and industry is critical in meeting economy-wide decarbonization goals.

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[4] Advanced Energy United. *Making the Most of the Federal Home Energy Rebates*. September, 2023. Available at: https://blog.advancedenergyunited.org/reports/homes_heehra_guide_2023

[5] Center for Climate and Energy Solutions. *U.S. State Greenhouse Gas Emissions Target*. September 2023. Available at: https://www.c2es.org/document/greenhouse-gas-emissions-targets/

[6] Rhode Island General Laws § 42-6.2-2 (2021 Act on Climate). http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2.HTM

[7] U.S. Energy Information Administration. *Natural gas explained*. November 7, 2022. Available at: https://www.eia.gov/energyexplained/natural-gas/natural-gas-and-the-environment.php

[8] *Id.*

[9] U.S. Energy Information Administration. *Natural Gas Consumption by End Use*, September 29, 2023. Available at: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

Figure 1 – States with Economy-Wide Emissions Goals[10]

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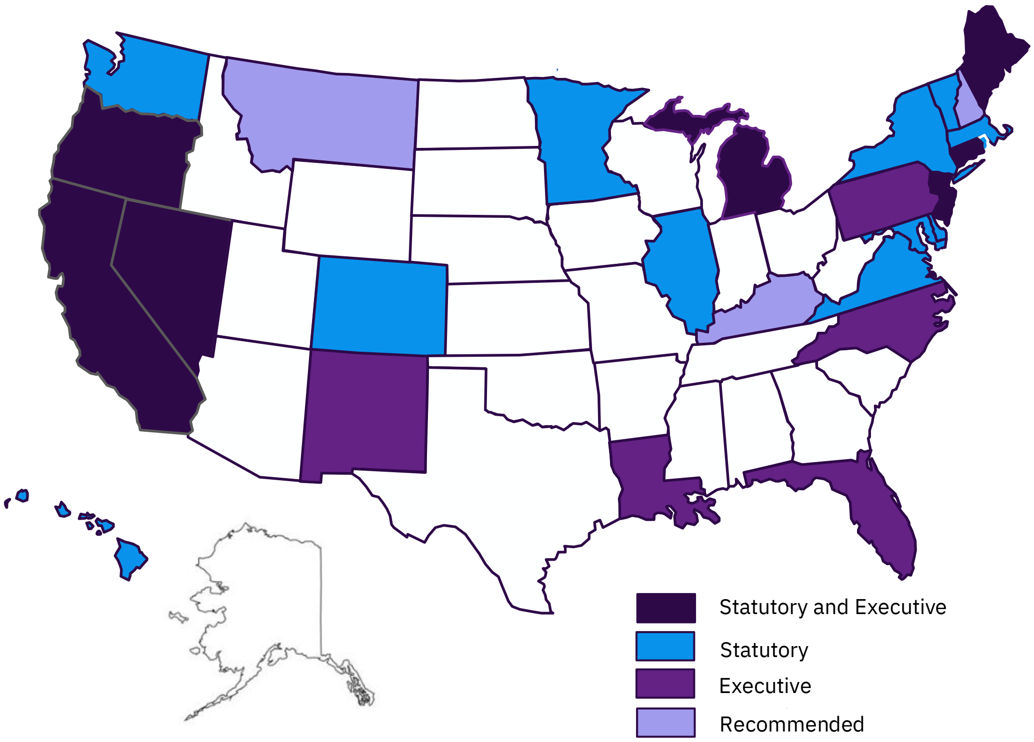

While renewable resources and emerging battery technologies, combined with energy efficiency and other distributed and demand-side resources offer promising pathways to achieving carbon neutrality in the electricity sector, there are no clearcut solutions for the natural gas sector. Historically, gas utility efforts to reduce emissions have centered on energy efficiency measures and avoiding methane leaks primarily through pipeline replacements. Although these measures reduce emissions, gas systems remain primarily fossil-based sources of energy. Therefore, climate goals challenge gas utilities to develop new solutions to reduce fossil fuel usage.

The third headwind is the increasingly volatile price of natural gas. After a decade of relatively low gas prices spurred by the development of shale gas, there has been an increase in both the price and volatility of natural gas (see Figure 2). In that time, the United States switched from being a net importer of liquefied natural gas (LNG) to a net exporter, and in 2022, the US became the world's largest LNG exporter.[11] This occurred as overall global trade of LNG increased, meaning that the US domestic market for gas is now more closely tied to global demand and prices, and thus the volatility of the market. For example, there was a substantial

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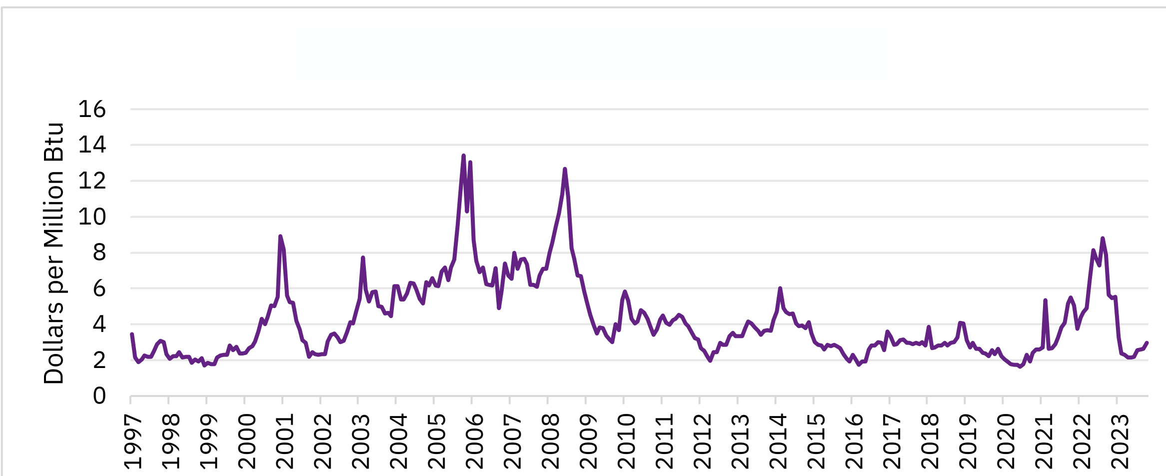
[10] Center for Climate and Energy Solutions. *U.S. State Greenhouse Gas Emissions Target*. September 2023. Available at: https://www.c2es.org/document/greenhouse-gas-emissions-targets/
[11] U.S. Energy Information Administration. *The United States became the world's largest LNG exporter in the first half of 2022*. July 25, 2022. Available at: https://www.eia.gov/todayinenergy/detail.php?id=53159

increase in gas prices after Russia's invasion of Ukraine and European nations reduced their import of gas from Russia.

Extreme weather events are also disrupting gas commodity markets, which supply both gas-powered electric generation facilities and gas distribution utilities. During the five-day Winter Storm Uri in 2021 in Texas, natural gas prices increased up to $400/per million Btu (MMBtu) (where they are normally "much less than $10/MMBtu").[12] Electric utilities across the middle of the country using gas for electricity generation incurred billions of dollars of incremental costs that customers will be paying off for years.[13] More generally, the rise and volatility in natural gas prices in the 2021-2023 period had significant impacts on both gas utility customers and on the cost of electricity generation, which is influenced heavily by natural gas prices.

Figure 2 – Henry Hub Natural Gas Spot Price[14]



The fourth headwind is the mismatch between utility infrastructure investments and load. Gas utilities are increasing investments in their delivery systems, far exceeding what would be expected to meet demand. As shown in Figure 3 below, residential, commercial, and industrial customer demand has remained relatively flat over the last twenty-five years[15] while construction spending has increased nearly sixfold.[16] Without a new approach to the gas

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[12] University of Texas at Austin. *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts.* July 2021. Available at:https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf.

[13] American Public Power Association. *Winter Storm Uri, Extreme Winter Events, And Natural Gas Reforms.* January 2022. Available at: https://www.publicpower.org/system/files/documents/January%202022%20-%20Winter%20Storm%20Uri.pdf

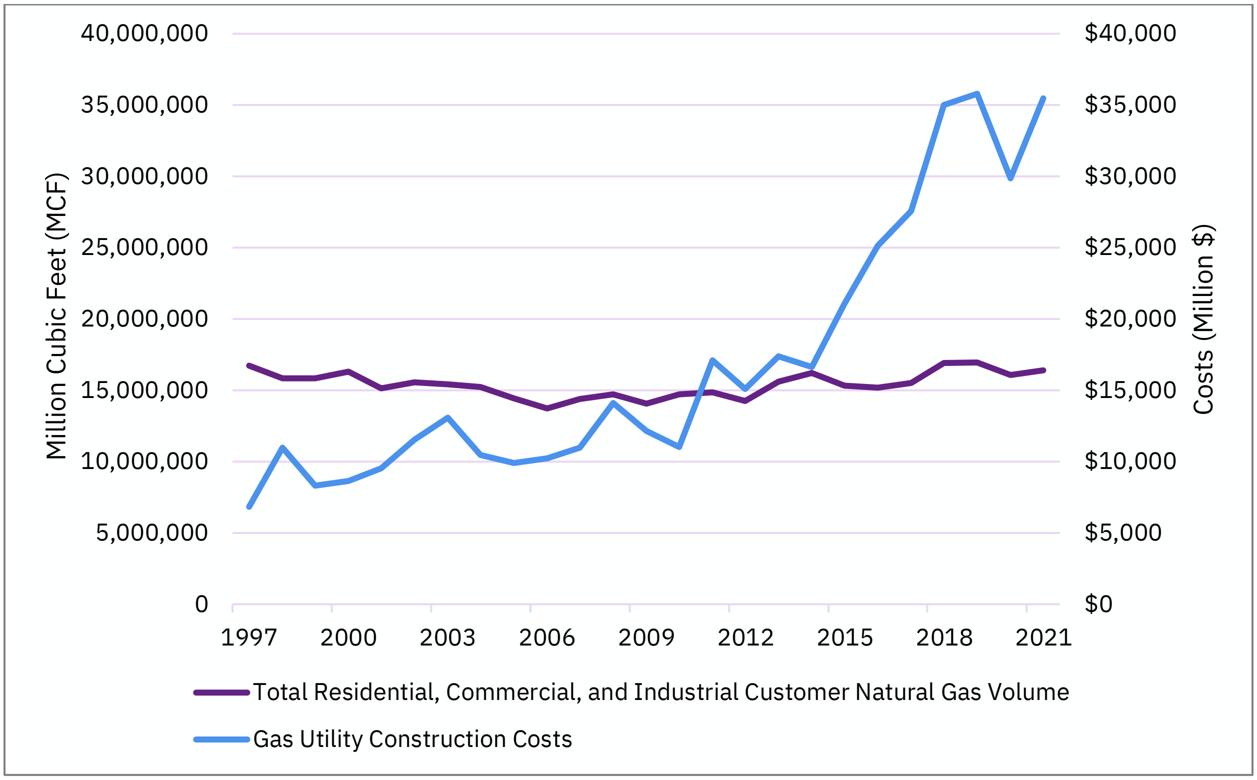
[14] U.S. Energy Information Administration. *Henry Hub Natural Gas Spot Price*. Available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

[15] U.S. Energy Information Administration. *Natural Gas Consumption by End Use*. Available at: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[16] American Gas Association. *Gas Utility Construction Expenditures by Type of Facility*. 2023. Available at: https://www.aga.org/wp-content/uploads/2023/01/Table12-1.pdf

planning process, customers, stakeholders, and PUCs face challenges in understanding the reasonableness of this dramatic increase in gas utility infrastructure investments.

Figure 3 – Gas Consumption and Gas Utility Construction Expenses (1997-2021)



Overview of Paper

The remainder of this paper is organized into two halves. The next three sections describe the need for, and key elements of a modern gas plan, with deeper dives into several of those key elements and case studies embedded throughout. The latter two sections then explore existing gas plans in the Pacific Northwest, New York, Colorado, Michigan, and British Columbia, and compare their features with that of the comprehensive set of best practices outlined in the first half of this paper. Specifically:

- **Section II** provides a general overview of the benefits of modern, public gas planning.
- **Section III** provides an overview of the process requirements, analytical features, and tools that enable robust modern gas plans.
- **Section IV** offers a deeper dive into Public Engagement, Non-Pipeline Alternatives, Embedding Equity, Evaluating RNG and Hydrogen Proposals, and System Mapping.
- **Section V** provides an overview of existing gas planning requirements and, through case studies, highlights the strengths of various State planning requirements.
- **Section VI** compares existing gas plans and provides recommendations to establish a comprehensive, modern gas plan.

Part I: A Framework for Modern Gas Planning

Benefits of Modern Gas Planning

A more transparent, and public modern gas planning process offers a myriad of benefits to the utility, to the PUC, and to the public. First and foremost, a gas plan identifies the "least cost, least risk"[17] set of investments for meeting the utility's needs via a comprehensive assessment of resource costs, availability, state policy alignment, and technological barriers in combination with demand forecasts.

Modern gas planning should result in a portfolio of resources and investments for each year of the planning period. For example, an alternative fuel scenario may forecast the quantities of supply-side resources, such as green hydrogen and renewable natural gas, as well as measures aimed at reducing demand, such as energy efficiency. The cost of each resource and measure becomes part of a larger portfolio that is compared to other portfolios that use a different mix of resources and measures across a planning period. In assembling resource portfolios, utilities weigh the cost against less tangible factors, such as technology and availability risks. Utilities must also model changes to assumptions, such as demand reductions due to climate change, state clean energy policies, or customer reductions due to a forthcoming reduction in gas line extension allowances. Utilities then typically select a "preferred" portfolio of resources and measures that best aligns with a least-cost, least-risk investment approach.

Gas plans are also iterative – a utility files a plan every two to three years – to enable utilities to revise assumptions and analyze new portfolios in response to economic, technological, and policy changes. For example, changing commodity prices for natural gas can result in energy efficiency measures becoming comparatively more cost-effective and major infrastructure upgrades becoming less useful for customers. Technological changes, such as innovations and cost reductions in heat pump technologies, can lead to a reduction in gas demand and usage patterns. Policy changes, such as the establishment of firm emissions reduction targets, can dramatically alter future demand such that revising a previous gas plan does not sufficiently account for the impact of the change. The short duration between plans allows for forecasting to remain current and roughly aligns with the frequency of general rate cases, allowing investment plans, also referred to as a "preferred portfolios" or "short-term action plans," to translate directly into utility spending decisions.

Ultimately, gas customers bear the risks of inadequate system planning, and utility regulators have a responsibility to understand and mitigate those risks. Utilities recover the cost of gas

[17] Also known as "lowest reasonable cost."

and capital investments from ratepayers, who may have little knowledge or influence over the direction of the utility's investments. Planning shortcomings, especially those that obscure the bigger picture via fragmented data and decision-making, significantly increase the risk that a utility unwisely invests in – and regulators approve – infrastructure that requires significant capital investments in assets that will be recovered over a shrinking customer base and sales volume. In particular, low-income gas customers, who are the least likely to be able to afford the capital costs to exit the gas system via electrification, are the most exposed to the risk of the resulting bill increases.

Although there are a range of benefits to modern gas planning, this paper focuses on four: risk mitigation, transparency, compliance with state policy goals, and intra-utility coordination.

Risk Mitigation

The two overarching risks for the utility and customers are cost and reliability. Inaccurate forecasts can lead to over-investment in the system, the wrong mix of resources, or a system unable to meet the demands of customers. The already difficult forecasting process is rendered far more challenging due to rapidly changing energy sector dynamics. Gas utilities must consider the appropriate role for alternative fuels, like hydrogen and renewable natural gas, new demand-side resources, including gas demand response and electrification, and decarbonization policies. In particular, given the long-lived nature of traditional gas system infrastructure, there is both path dependency, an investment opportunity cost, and stranded asset risk for investing now in one type of decarbonization pathway over another.

Robust modern gas planning can reduce cost and reliability risks. Gas planning considers a range of scenarios, tests the impact of technological, economic, and policy changes, and then analyzes resource and investment tradeoffs. The results of this process can expose risks associated with a particular portfolio and help ensure that short-term investments benefit ratepayers while being compatible with a long-term vision.

Transparency

A more transparent, modern gas planning process helps shed light on a utility's plans and operations by serving as a central repository of information and allowing the public to weigh in. In the absence of such transparency, PUCs, the public, and other stakeholders are not typically privy to the utility's long-term forecasts and capital plans. A PUC might only see the utility's annual or short-term demand forecast in regulatory filings. In contrast, a modern gas plan as described here requires the utility to walk through its analysis and provide accompanying narrative details of its business, including data on customer base, customer demand, state of the distribution system, existing resource supplies, and future investments into system upgrades and resource acquisitions. Furthermore, gas plans often provide an overview of how the utility leverages storage, interruptible tariffs, and peaking facilities to meet demand. Utilities bear the burden of demonstrating that their actions and investments are prudent, but, without this data, it is challenging for PUCs and stakeholders to adequately evaluate utility decision-making.

The public process also allows stakeholders and ratepayers an opportunity to provide direction and feedback on the utility's future. In designing gas plans, PUCs can pursue various approaches to data sharing, as detailed below in the Issue Spotlight. Examples of these approaches in action are included in the Appendix.

Issue Spotlight: Data Access

Improving access to data and modeling is a key strategy to make utility regulatory processes on both the gas and electric side more effective and more equitable. To make decisions, PUCs rely on the information that is submitted into the record during a proceeding. Notably, utilities have the most resources for data collection, modeling, and analysis – and the most intimate knowledge of their systems. Other stakeholders, including regulators, may not have access to utilities' modeling tools and assumptions, nor to all the data used in their planning decisions, reports, and proposals. This creates an information asymmetry that many states are trying to address.[18]

Ultimately, the addition of different perspectives allows for more comprehensive and robust gas planning. The challenges associated with the energy transition only increase the complexity of gas planning and therefore reinforce the need for the involvement of the public.

Options for Commissioners to increase access to data for regulatory decisions:

- Commissioners can require utilities to provide modeling licenses or remote access to the software to stakeholders, Commission staff, and/or consumer advocates
- Commissions can require the utility to provide scenario development opportunities to stakeholders
- Commissioners can require utilities to run specific scenarios

[18] All processes can be tailored to comply with local privacy and confidentiality requirements.

Compliance with State Policy Goals: Emissions Reductions and Energy Equity

Gas utilities are subject to state regulation and with it the policies and preferences articulated by the state legislature and PUC. Although state legislatures have always been involved in energy policy, the last few years have seen an uptick in focus on emission reductions and equity. Emission standards significantly increase the complexity of utility modeling exercises since status quo operations are typically insufficient for compliance with state and local laws. Modern gas planning is necessary for modeling emissions reduction pathways because utility investments can differ radically based on the preferred portfolio. For example, futures that rely upon alternative fuels versus electrification require very different types of investments to transform the utility's system. However, a utility cannot easily, cheaply, or quickly pivot from one pathway to another if circumstances change without burdening customers with rate increases. Gas planning is therefore paramount in helping utilities chart a long-term, least-cost, least-risk approach to decarbonization and avoiding path dependency that is incompatible with state policy. Additionally, each iteration of a utility's gas plan provides a checkpoint at which the utility can adjust its plans if confronted with new information, and at which a PUC and stakeholders can assess a utility's accountability and progress toward goals.

Several states, including Washington, New York, Colorado, California, and Nevada, have passed legislation requiring utilities to examine their investments' impacts on disadvantaged communities.[19] In recognition that past energy decisions have disproportionately impacted certain communities, these states are requiring the utilities to identify those communities and design programs so that residents within them are also benefiting from the energy transition. Through modern gas planning, utilities can identify where investments will occur and who will be impacted in both positive and negative ways and provide quantitative and qualitative analysis of the impacts to disadvantaged communities.

Intra-Utility Coordination

One of the least discussed benefits of gas planning is the coordination it requires from within a utility. A gas planning process requires multiple departments of a gas utility, such as distribution planning, transmission planning, storage and reservoir engineering, gas supply and procurement, demand-side management, and gas operations staff to discuss their internal department plans, learn from each other and coordinate. Gas utilities, like their electric counterparts, tend to be siloed, and departments often do not interact more than is required for day-to-day operations and occasional business needs. Gas planning provides the broader enterprise with a regular opportunity to discuss planned projects, iterate and improve coordination, and offer suggestions for improvement that might not otherwise be made.

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[19] Nevada Senate Bill 281 (2023); Colorado Senate Bill 264 (2021); New York Senate Bill 6599 and Assembly Bill 8429 (2019); Washington House Bill 1181 (2023); California Senate Bill 350 (2015).

Core Elements of Modern Gas Planning

Designing a modern gas planning regulatory process is complex, though several PUCs have already developed a variety of analytical and procedural requirements to guide utility filings. Furthermore, decades of experience with electric utility integrated resource planning and distribution system planning processes can be drawn upon where relevant. The most comprehensive gas plans are the result of regulations that ensure that filings are a single repository of key utility data and assumptions. As will be shown in Section V, there are a variety of types of existing gas plans, and although the best approach for a state will depend on the needs and goals of the state, there are several common features. In this section, those key features are identified and divided into two categories: Process Requirements and Analytical Features.

Process Requirements

Process requirements describe the rules and actions for developing a modern gas plan.

- **Filing cadence:** Filing cadence refers to the period of time between required gas plan filings. Gas plans are iterative because the forecasts and assumptions inherent to a gas plan will change as economic, technological, and policy conditions change. A longer filing period may reduce the responsiveness of utility planning strategy to changes in forecasts and stakeholder concerns. However, a longer filing period also reduces the administrative burden of developing, participating in, and reviewing a gas plan. Existing gas plans are typically filed every two to three years.

- **Planning horizon:** Planning horizons refer to the period of time evaluated in gas plans. Gas plans typically have a planning horizon of 15-20 years. The planning horizon is broken down into a short-term period, for which an "action plan" is developed that details specific investments within the next three to six years, and a long-term period outlining broad utility strategies.

- **Stakeholder involvement:** Gas planning offers fewer benefits without robust stakeholder involvement, including that of both the more frequent participants and those representing vulnerable populations. The inclusion of the public throughout the entire process – from the initial plan design to the evaluation of the end product – results in the discussion of different viewpoints and more robust feedback to the utility.

  A gas plan should be public, and the people on whose behalf decisions are being made should have a role in its development. Common stakeholders include members of the public, including those residing in environmental justice or low-income communities, PUC staff, consumer advocates, representatives of the business community, environmental advocates, and large consumers.

- **Draft and final plans:** The utility should present (or file) a draft plan before submitting the final plan, with a defined period for stakeholders to submit comments (with sufficient time for stakeholders to conduct their own analysis). Although a utility may present segments of its analytical approach during stakeholder meetings, the utility's methodological approach or analysis may change during the development of the plan. Moreover, the draft plan is the first opportunity stakeholders have to see the comprehensive plan. By filing a draft, utilities can amend the plan based on stakeholder feedback and minimize the number of disputes left unresolved when it files its final plan with the PUC.

- **Evaluating gas plans with a PUC review process:** Ultimately, PUCs pass judgment on the utility's plan, but the manner in which they do so varies from state to state.

  Final plans should be adjudicated whenever the process leads to a formal "green light" to proceed with a given investment plan, though a utility must still demonstrate prudent investment activity in its next rate case to receive approval for cost recovery. Furthermore, states can look to the manner in which they litigate or review electric utility resource or distribution plans for guidance on whether or not their gas planning process should also be litigated.

  In the Pacific Northwest, the PUCs have decided to either "acknowledge" or "not to acknowledge" gas utility plans after a stakeholder process.[20] In New York, the Public Service Commission can either approve, approve with modifications, or reject a utility's long-term plan.[21] While a non-acknowledgment or rejection does not directly or immediately impact return on equity or the revenue requirement, the utility is generally expected to modify its gas planning per the PUC decision, or else it faces a significant challenge when it seeks cost recovery during a rate proceeding. For example, this could mean avoiding, delaying, or providing further assessments of planned investments that the PUC deemed inconsistent with the utility's long-term planning approach. The failure of the utility to align infrastructure investments with a PUC order on its gas plan threatens the recovery of assets in a general rate case and could lead to a reduction in utility profits. Therefore, PUC acknowledgment or approval of gas plans is highly

[20] Oregon Public Utility Commission. Docket UM 1056, *Order No. 07-002*, page 2. January, 2007. Available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

[21] New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process,* page 25. May 12, 2022. Available at: https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211

consequential, and utilities are incentivized to work with stakeholders to determine the best path forward.

Analytical Features

For gas planning to provide the greatest benefits, public stakeholders and PUCs must understand the utility's strategy and its impacts on customers. This requires the utility to model the evolution of its business by integrating internal investment strategies with forecasts of customer growth, fuel costs, policy changes, and other factors. The following analytical features provide participants with adequate information to evaluate a utility's strategy.

- **Load forecast:** The first analytical task of a gas plan is to develop a load, or demand, forecast for the planning horizon. It is paramount that a utility can accurately predict its demand so that it can meet demand on even the coldest days but is not so conservative that the utility spends unnecessarily on capital investments, such as pipeline capacity. Consequently, long-term load forecasting should be performed on a regular cadence to allow ample time to address potential future constraints driven by changes to load.

  There are two primary components of a load forecast: energy demand (also called throughput) and peak demand. Energy demand is typically calculated as the total demand for all customers throughout the year. Peak demand is the amount of gas needed to serve customers on the coldest day of the year. The gas utility's demand forecasts should explicitly identify the utility's design day criteria and planning standard used for developing the load forecast. It should also explicitly consider and identify how it incorporates the impacts of climate change and federal, state, and local policy. Importantly, load forecasting must also be conducted on more granular levels, including climate zones and neighborhoods/localities, which may be experiencing different trends in gas use than other parts of the system. As future demand is uncertain, typically a utility will develop several demand forecast scenarios.

- **Short-term action plan:** The utility proposes specific capital investments that address short-term needs over a period of three to six years that align with its long-term vision. Few projects that are planned for four or five years in the future are likely to be finalized upon submission of the short-term action plan, but it is nonetheless important that utilities reflect investment opportunities in the short-term action plan such that they may be evaluated in advance – especially if the project is a candidate for a "Non-Pipeline Alternative" (NPA) as described further below.

- **Comparative evaluation of demand- and supply-side investments:** A modern gas plan, regardless of the name, should consider commercially available demand- and supply-side investments as solutions for meeting customer needs in the short-term, though the solutions should be compatible with an approved pathway towards the state and utility's long-term goal. Typically, gas utilities develop demand-side portfolios and then apply the impact as a load reduction. Like their electric counterparts, the best gas plans also allow the model that determines the utility's capacity expansion needs to select additional demand-side management resources rather than only allowing supply-side investments to meet customer needs.

- **Scenario and sensitivity analysis:** Scenario and sensitivity analysis are critical for testing the robustness of the utility's investments under various futures. A scenario is a set of assumptions about variables not entirely controlled by the utility (including energy prices, customer demand, and resource costs) that will have a significant impact on the utility's decision-making. A sensitivity analysis isolates one variable for cost and risk assessment, such as a policy change impacting customer growth or commodity prices. Such analysis is especially helpful in evaluating risk to the preferred portfolio. Portfolios are then compared to one another to determine the least-cost, least-risk set of investments that meet customer demand.

Case Study: Puget Sound Energy's IRP Scenarios and Sensitivities

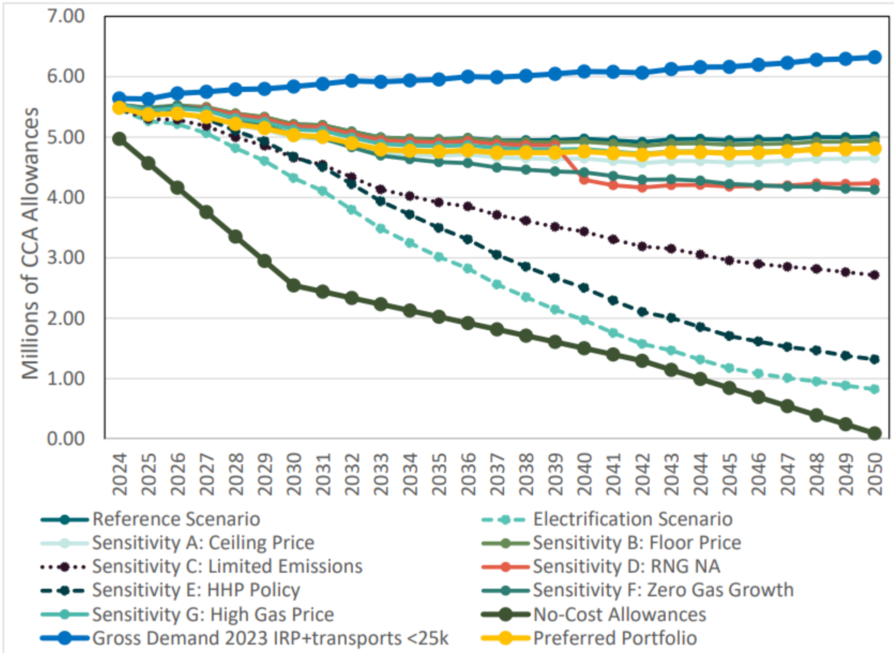
Figure 4 below displays the sensitivity analysis Puget Sound Energy (PSE) conducted in its 2023 Natural Gas Integrated Resource Plan in Washington.[22] PSE's sensitivities analyzed technological, economic, and policy changes. The "High Gas Price" scenario models the impact of changing economic conditions that result in a long-term increase in gas prices. The "Floor Price" and "Ceiling Price" sensitivities, which measure the impact of variable emissions allowance costs under Washington's cap-and-invest policy called the Climate Commitment Act (CCA),[23] also capture economic uncertainty. A high allowance price indicates state-wide decarbonization challenges, while a low allowance price suggests that other businesses can cut emissions more cost-effectively. The "RNG NA" sensitivity assumes that Renewable Natural Gas (RNG) can only be acquired regionally, as opposed to nationally.

Several factors are relevant in this sensitivity, such as slow technological development that could limit the cost-effective adoption of RNG, significant competition for RNG that could lead to less available supply and higher costs, and policy changes limiting PSE from acquiring RNG from outside its service territory. Finally, the "Electrification" scenario and "HHP Policy"(hybrid heat pump policy) sensitivities modeled electrification adoption to meet the Washington State Energy Strategy, and a policy where gas heating appliances would be replaced with hybrid heat pumps at the end of their life, with all other gas end-uses electrified, respectively. The sensitivity analysis allowed PSE to determine the quantity of allowances needed – and therefore purchased with an additional cost to customers – to meet compliance with state climate goals and the associated costs in each scenario.

[22] Puget Sound Energy. *2023 Puget Sound Energy Integrated Resource Plan,* Chapter 4. March 31, 2023. Available here: https://www.pse.com/en/IRP/Past-IRPs/2023-IRP

[23] Washington Department of Ecology. *Climate Commitment Act.* https://ecology.wa.gov/air-climate/climate-commitment-act#:~:text=In%20the%20CCA%2C%20the%20Legislature,commitments%20set%20in%20state%20law

Figure 4 – Puget Sound Energy Natural Gas IRP Sensitivity Analysis[24]



Capital Investment Forecast

A gas plan categorizes a utility's proposed capital investments by investment type (e.g., capacity expansion, new business, mandatory relocation, safety and reliability). A capital forecast should accompany each of the scenarios modeled in order for the utility to provide stakeholders with a complete understanding of portfolio costs. This is necessary to include alongside a scenario analysis because a scenario analysis on its own only covers resource acquisition costs and does not quantify distribution costs such as pipeline replacements and asset repairs. Infrastructure investments are a significant portion of customer bills and may vary substantially by scenario. Gas planning analysis is incomplete if regulations do not require comprehensive capital investment forecasts.

- **Non-Pipeline Alternative assessment:** These analyses compare traditional utility investments to non-pipeline alternatives, described in Table 2. NPAs can reduce costs, reduce the likelihood of stranded assets, provide options value over traditional investments, and avoid emissions. Gas planning regulations in New York and Colorado have recently included NPA assessment requirements, and examples are provided in the NPA spotlight in Section IV.

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[24] Puget Sound Energy. *2023 Puget Sound Energy Integrated Resource Plan.* Chapter 2.20. March 31, 2023. Available here: https://www.pse.com/en/IRP/Past-IRPs/2023-IRP

Table 2 – Examples of Non-Pipeline Alternatives

Demand-Side Solutions	Supply-Side Solutions
Targeted Demand Response	On-system Renewable Natural Gas
Targeted Energy Efficiency	On-system Liquefied Natural Gas (LNG) Peaking Storage
Heat Pumps	Compressed and Liquefied Natural Gas Trucking (Virtual Pipelines)
Thermal Storage	
Other Electrification & Fuel Switching	LNG Liquefaction Port Terminals
Behavior Change & Market Transformation	

Source: What can we learn from New York's non-pipeline solutions ruling? ICF International, March 18, 2019

- **Identification of "short term action plan" or "preferred portfolio":** The utility selects the portfolio it assesses as the least-cost, least-risk among the ensemble of portfolios analyzed. The identified short-term investments are expected to align with the preferred portfolio.

- **Bill impact analysis:** This analysis measures changes in customer bills based on the utility's preferred portfolio and capital forecast. This is an analysis aimed at evaluating the short-term implications of all utility spending, including capital spending, operations and maintenance, and fuel costs.

- **Equity impact analysis:** Traditional bill impact analysis can hide inequities through averages, such as distributional impacts and transfers of wealth. Specifically measuring costs and benefits to disadvantaged populations provides an assessment of portfolio equity impacts. This analysis can be done qualitatively and quantitatively and is improved by involving local stakeholders from impacted communities.

- **Coordination with electric sector:** Gas utilities – whether gas-only utilities or part of a combined gas and electric utility – do not operate in a silo. Customers that electrify will increase the load on the electric sector, impacting electric distribution, transmission, and generation capacity needs. Coordination is especially critical in evaluating these impacts, which may otherwise go unquantified. We discuss this further in Spotlight on Gas Planning Elements.

- **System mapping:** Gas distribution and transmission maps allow PUCs and stakeholders to understand system constraints and possible resolutions, especially where they overlay with disadvantaged communities. Northwest Natural's 2022 Gas IRP provides one such example, detailed below.

Spotlight on Gas Planning Elements

Fostering Stakeholder Engagement

Robust stakeholder engagement is a critical element of a successful gas planning process. The public should be involved throughout the entirety of the planning period from the plan's development to public meetings, technical working groups, and formal comments on the final plan.

There are two primary opportunities to strengthen stakeholder feedback in addition to hosting public comment hearings and allowing formal comments/testimony, technical working groups, and third-party evaluations.

- **Technical working groups** are formed in the early stages of the planning process and are the initial voice of stakeholders. Utilities disseminate gas plan details, including initial forecasts and portfolios, and collect feedback in technical working groups. The best stakeholder processes are built to have sufficient time to incorporate stakeholder suggestions, feedback, and suggested analysis before the utility completes its analysis for the draft plan. Technical working groups are most commonly open to any interested participant but require technical skills to meaningfully participate. **Example: Oregon's Gas Planning Technical Advisory Group, detailed below.**

- **Third-party evaluation** of gas plans allows for a neutral party to assess gas plans in a way that supports stakeholder participation. The PUC hires a consultant to provide an initial and revised analysis of the utility's initial and final gas plans, respectively. While not common, the involvement of third parties through independent assessments can elevate public discourse. **Example: Third-party evaluations of New York's Long-Term Plans, detailed in Part II.**

Evaluating RNG and Hydrogen in Modern Gas Plans

A PUC's scrutiny of a gas plan is a critical component of the process. While many of the same principles that apply to electric resource plans also apply to gas resource plans, there are some potentially unique features including the assessment of new supply-side resources such as RNG and hydrogen.

When a utility proposes an RNG or hydrogen pilot project or a gas plan that relies heavily on the future use of RNG and/or hydrogen for decarbonization, PUCs should confirm that the alternative fuels are feasible and cost-effective options at scale and in the timeframe proposed.

Checklist for Evaluating Utility RNG/Hydrogen Proposals

- Does modeling acknowledge and evaluate limitations to RNG supply and pricing, including competition from other sectors?
- Does the cost assessment include system and end-use equipment retrofits/replacements needed to accommodate high hydrogen blends?
- Does the plan direct RNG and hydrogen to the highest-value use cases?
- Are the costs of decarbonizing industrial customers included in the modeling scope?
- Is there a plan to meet gaps between RNG/hydrogen supply and total gas demand with cost-effective, zero-emission resources through other means (e.g., efficiency, electrification)?
- Does the plan confirm a firm, long-term supply of the RNG and hydrogen fuels that will be used to meet projected demand?
- Do overall plan costs include the costs of any required carbon offsets?
- Are interconnection points for RNG and hydrogen focused on areas of the system that minimize stranded asset risk (e.g. near hard-to-electrify end users or self-contained distribution systems that can be disconnected from the main system)?

Case Study: Oregon's Non-Acknowledgement of RNG investments

In Northwest Natural's (NWN) 2022 gas IRP, the Oregon Public Utilities Commission (OPUC) elected not to acknowledge specific RNG investments in the short-term action plan. In its acknowledgment letter, the OPUC explained its decision stating, "Without an analysis that demonstrates that the level of RNG procurement proposed is the least-cost, least-risk way to meet the company's compliance needs, we cannot acknowledge [the RNG Procurements]" (OR Order 23-281, page 11). The OPUC Order identified utility shortcomings and provided a standard for the utility to meet in order to recover RNG investments in a general rate case.

Non-Pipeline Alternatives

Non-pipeline alternatives (NPAs) are critical for avoiding unnecessary gas system investments. NPAs in the gas sector are the equivalent of the electric sector's "non-wires alternatives" and refer to activities or investments that delay, reduce, or avoid the need to build or upgrade traditional gas system infrastructure such as pipelines, storage, and peaking resources. Best developed via competitive solicitation, NPA solutions are composed of a variety of strategies, programs, and technologies on both the demand side and supply side,[27] including demand response, energy efficiency, electrification, thermal storage, behavioral changes, liquefied natural gas (LNG) peaking storage, and mobile pipeline injection, as illustrated above in Table 2. In practice, NPAs are typically a portfolio of solutions that offset pipeline gas demand in a defined geographic area.

The primary benefits of NPAs: cost reduction, risk reduction, emissions reductions

NPAs can be less expensive than traditional utility capital investments (e.g. pipeline replacements). This is especially pertinent if new pipelines are at risk of being stranded or recovered through a dwindling customer base, a risk that is increasing with ongoing building electrification. Implementing NPAs instead of pipeline solutions can therefore reduce the risk of asset under-recovery and customer rate shocks. Additionally, demand-side NPAs reduce gas consumption, thus enabling emissions reductions and compliance with a state's climate goals.

A robust regulatory NPA process consists of three steps: a preliminary screening, the development of NPA resource portfolios, and the evaluation of portfolios.[25]

- **PRELIMINARY SCREENING:** This first step filters out potential NPA projects that are not technically feasible. Screening criteria include safety, time required for NPA assessment and project implementation, and capital cost.

    a. **Safety:** Capital project types that cannot be delayed for safety reasons are not suitable for NPAs. For example, emergency investment projects, sometimes referred to as "Failed Plant and Operations," require immediate remediation.

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[25] Ron Nelson, et al., Strategen Consulting. *Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado.* 2023. Available at: https://www.strategen.com/strategen-blog/non-pipeline-alternatives-framework

b. **Timeline:** There must be ample time for the utility to perform an NPA analysis and implement a solution. A timeline threshold filters out projects with insufficient lead time before the required implementation of the solution. Generally, a utility should be working early and often to identify NPA opportunities well in advance of the need so that as many viable NPAs as possible can be pursued.

c. **Cost:** Evaluating small capital projects for NPAs may not be cost-effective due to the cost of the NPA evaluation. By setting a cost threshold, a utility can efficiently identify suitable capital projects for NPA evaluation. The cost threshold should reflect the size of the utility.

- **PORTFOLIO DEVELOPMENT:** Upon completion of the preliminary screening, a utility must assemble NPA resources into a portfolio that addresses the technical needs of the project.

a. **Eligible Resources:** Demand-side resources, such as energy efficiency and electrification, and supply-side resources, such as mobile liquified natural gas injections, are potential NPA resources. Regulations should indicate a preference for demand-side solutions since such resources typically provide more customer benefits and lead to greater emissions reductions than supply-side resources.

b. **Project Solicitation:** For larger projects, utilities should acquire NPA resources through Requests for Proposals ("RFPs"). Competitive procurements, such as RFPs, drive down prices and provide a range of options from qualified vendors. Competitive solicitations also provide the utilities with the essential flexibility to target specific locations, sizes, and durations based on the local distribution need, and to expect contracts with creditworthy and reliable counterparties with viable projects. Such needs-based solicitations would not presuppose the exact technology solution but instead leverage the competitive market to come forward with solutions, or portfolios of solutions, based on needs identified by the utility. For smaller NPA projects undergoing a streamlined assessment (e.g., confined to one or several streets), internal utility estimates may be a viable option.

c. **Confirmation of Portfolio Requirements:** Once the utility has amassed information on NPA resources, it must determine if a set of resources can meet technical project criteria. For example, if a project requires a reduction of 100 million cubic feet per hour, a portfolio is only viable if it can reduce demand by such an amount. If possible, a utility should develop more than one portfolio to weigh different policy goals, such as cost-effectiveness and emissions reductions.

- **PORTFOLIO EVALUATION:** Once the utility has assessed a portfolio of resources that can meet the technical project requirements, the utility needs to assess the portfolio for cost-effectiveness, vendor qualifications, and equity. Evaluating the portfolio as a whole is important because not all measures may individually lower costs compared to the traditional capital solution required, but the sum of the portfolio's parts may save ratepayers money over the business-as-usual option.

    a. **Benefit-Cost Analysis (BCA):** A BCA determines if the NPA portfolio provides greater net benefits (or fewer net costs) than the traditional capital solution. The Societal Cost Test, which measures benefits and costs incurred by individuals and by society as a whole, including emissions, should be the primary BCA test used in the evaluation of portfolios. The utility should be transparent with its BCA framework by detailing data inputs, assumptions, variables, and methods for quantifying cost-benefit analyses impacts, ensure that the test is symmetrical, and include the value of deferral or avoidance of the traditional gas infrastructure project and the social cost of methane in its NPA analyses.

    b. **Vendor Evaluation:** Utilities should assess third-party vendors for qualitative and quantitative measures such as vendor experience, technical reliability, environmental impacts, and safety.

    c. **Equity:** NPA impacts on disadvantaged communities should be quantified. The results of an equity analysis can override BCA results. For example, an NPA project that provides significant equity benefits but produces greater net costs than the traditional solution may be approved.

Finally, complementary policy changes, such as a **shared savings mechanism**, can help reduce the utility's inherent financial preference for traditional capital solutions over NPAs. While utilities typically do not receive a rate of return on demand-side NPA implementations, a shared savings mechanism allows utilities to earn a financial reward for successful NPA projects. Shared saving mechanisms typically allocate to the utility a fixed percentage of net benefits produced by the project but can take several forms. For example, New York allows utilities to earn up to 30% of an NPA project's net benefits through an incentive mechanism.[26]

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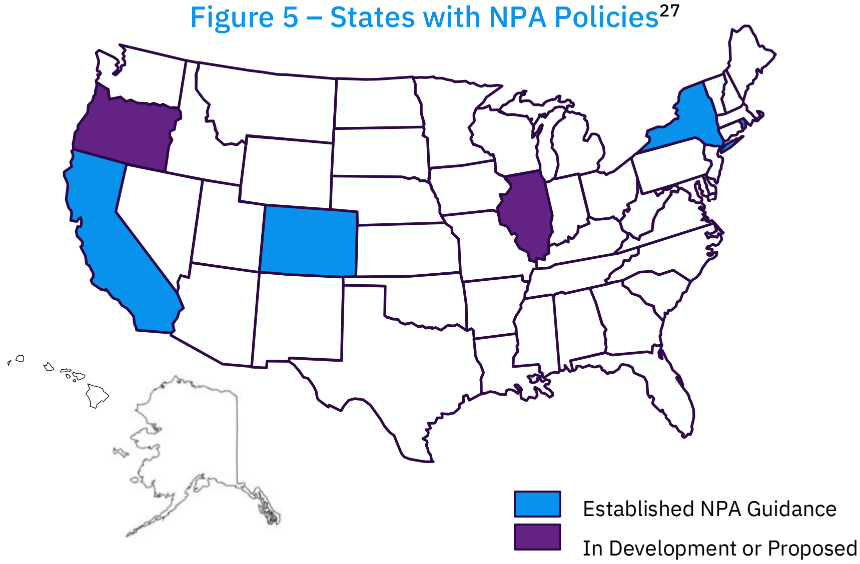
[26] New York Public Service Commission. Docket No. 19-E-0378. *Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, With Modification, Appendix HH.* November 19, 2020. Available at: https://app.insightengine.org/dockets/ny-19-01236-19-e-0378/filings/15514210?version=beta&filing_search_id=1615769&document_id=163555515

Figure 5 – States with NPA Policies[27]



State Example: NPAs in New York's Long-Term Gas Planning Framework

As part of its gas planning order, the New York Public Service Commission (NY PSC) required each utility to assess NPAs in its long-term plan filings. The regulations require that the gas utilities include information that would allow clean heat developers to target programs toward areas with leak-prone pipes or areas in need of infrastructure improvements to maintain reliable service.[28] Specifically in addressing leak-prone pipes, the NY PSC encourages gas utilities to take a "neighborhood approach" and work with local groups and state agencies on a comprehensive program that simultaneously removes the leaking infrastructure and employs programs such as weatherization and demand response along with electrification.[29]

The New York rules allow utilities to form portfolios of demand- and supply-side resources as NPAs, since individual measures may not entirely resolve capacity issues. Demand-side resources must provide permanent reductions through measures that include electrification, energy efficiency, and weatherization.[30] Notably, solutions that result in a switch to other fossil fuels, such as propane, are not viable.[31]

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[27] Ron Nelson, et al., Strategen Consulting. *Non-Pipeline Alternatives: A Regulatory Framework and a Case Study of Colorado.* 2023. Available at: https://www.strategen.com/strategen-blog/non-pipeline-alternatives-framework

[28] New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process,* page 21-22. May 12, 2022. Available at: https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211

[29] New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process,* page 39. May 12, 2022. Available at: https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211.

[30] New York Public Service Commission. Docket No. 17-G-0606, *Petition of Consolidate Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program. Request for Proposals of Non-Pipeline Solutions to Provide Peak Period Natural Gas System Relief.* December 21, 2017. Available at: https://app.insightengine.org/dockets/ny-17-02100-17-g-0606/filings/7998384?version=beta&filing_search_id=1615796&document_id=163612284

[31] *Id* at p. 8.

NPAs in practice are not new to New York; several utilities have implemented NPA solutions before the promulgation of the 2022 gas planning regulation, as illustrated in the NYSEG case study below.

Case Study: NYSEG's Non Pipeline Alternative Analysis in Lansing, NY
In 2020, the NY Public Service Commission approved NYSEG's NPA project in the Town of Lansing in Tompkins County. A growth in natural gas demand caused a decrease in in system operating pressure, leading to a reliability concern on very cold days.32 The traditional solution to such an issue would have been the addition of a compressor, but instead, NYSEG issued an RFP for NPAs. NYSEG received sixteen proposals that included electrification via heat pumps, energy efficiency, community ground source heat pump loops, industrial waste heat recovery, demand response, smart thermostats, Compressed Natural Gas (CNG) injection, LNG, and a rebate program to incent heat pump adoption.33 The Commission ultimately approved a portfolio of six resources, including residential air source and ground source heat pumps plus energy efficiency, new efficient gas boilers, a waste heat recovery system for an industrial customer, demand response, and education and outreach with heat pump incentives for space or water heating fuel switching. Together, these measures sufficiently reduced peak day demand and thereby avoided traditional infrastructure investments.[34] While not all resources individually produced a net benefit as measured by a societal cost test, collectively, the portfolio of resources did.

The rise of electrification of building heating is likely to lead to more cost-competitive demand-side NPA portfolios. The Lansing NPA is an example of avoiding gas capacity expansion investments, but NPAs can also be beneficial when infrastructure investments are needed in an area with decreasing throughput. Those NPAs can prevent capital projects that may become stranded or underused if trends continue, producing benefits for both the customers who are fuel switching and the remaining gas customers. NPAs are a nascent, but critical tool in avoiding infrastructure investments to prevent gas rate increases.

[32] New York Public Service Commission. Docket No. 17-G-0432, *Order Approving Petition for Non-Pipe Alternative Projects, With Modifications.* June 21, 2021. Available at: https://app.insightengine.org/dockets/ny-17-01528-17-g-0432/filings/15506679?version=beta&filing_search_id=1615810&document_id=163588518

[33] *Id.* at p. 6-9.

[34] *Id.*

Embedding Equity

Disadvantaged populations generally face high rates of energy insecurity,[35] with some having to forgo necessities to pay energy bills. Fewer financial resources also prevent disadvantaged populations from investing in energy efficiency and fuel-switching in response to high or volatile energy prices. Thus far equity analysis has not played much of a role in gas planning regulations and without explicit PUC guidance, existing planning tools are unlikely to factor in impacts on disadvantaged communities. For example, a reduction in average energy consumption and residential customer bills does not indicate that all customers are benefiting since a subset of high-income customers could be driving the trend and receiving the majority of benefits. Similarly, not all communities are equally impacted by infrastructure projects and the impact of gas emissions, including pollutants such as nitrous oxide that lead to adverse health consequences.[36] There are several dimensions of equity analysis, but this paper largely focuses on distributional equity, which examines how impacts or benefits are distributed among target populations. For more information on recognition, procedural, distributional and restorative equity, see the Energy Equity Project.[37]

Both the federal government and states are increasingly interested in embedding equity into clean energy policies. For example, a new Pipeline and Hazardous Materials Safety Administration Gas Distribution Safety Requirements proposed rule, created in August of 2023, proposes a requirement for gas distribution utilities to "[promote] environmental justice for minority populations, low-income populations, or other underserved and disadvantaged communities, or others who are particularly likely to live and work near higher-risk gas distribution pipeline systems."[38] If this rule is formally published, distribution operators will have to consider the effect that certain programs, including their distribution integrity management programs (DIMP) and asset condition remediation programs, potentially including NPAs, will have on disadvantaged communities. The implementation of this rule will help create additional justification to prioritize historically disadvantaged and low-income groups.

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[35] U.S. Energy Information Administration. *One in three U.S. households faced challenges in paying energy bills in 2015.*Available at: https://www.eia.gov/consumption/residential/reports/2015/energybills/#:~:text=Transportation-,One%20in%20three%20U.S.%20households%20faced%20challenges%20in%20paying%20energy,in%20their%20home%20in%202015

[36] Jeffrey Kluger, Time. *Your gas stove may be leaking benzene into your kitchen.* October 20, 2022. Available at: https://time.com/6223219/gas-stove-leaking-benzene/

[37] University of Michigan School of Environment and Sustainability, Energy Equity Project. *Energy Equity Framework: Combining data and qualitative approaches to ensure equity in the energy transition.* 2022. Available at: https://energyequityproject.com/wp-content/uploads/2022/08/220174_EEP_Report_8302022.pdf

[38] Pipeline and Hazardous Materials Safety Administration, Federal Register. *Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives.* September 7, 2023. Available at: https://www.federalregister.gov/documents/2023/09/07/2023-18585/pipeline-safety-safety-of-gas-distribution-pipelines-and-other-pipeline-safety-initiatives

The US Department of Energy also recommends creating several Distributional Energy Analysis (DEA) metrics for every Distributed Energy Resource (DER) project and evaluating these metrics for both disadvantaged populations and other customers.[39] The DEA metrics utilize pass/fail criteria to determine if the DEA has an equal or larger positive impact on disadvantaged customers compared to other customers. The pass/fail criteria are established by stakeholders before the analysis of a specific project and should align with equity goals set by the operating utility and PUC.

States are similarly beginning to incorporate aspects of equity into their planning process,[40] however, the requirements appear to be largely focused on electric resource planning at this time. New York's Climate Leadership and Community Protection Act (CLCPA) requires at least 35% of benefits from energy program spending, including gas energy efficiency and electrification, to be directed towards disadvantaged communities.[41] New York's gas utilities are recognizing this requirement in their long-term plans, but the implementation, like in other states, is still in its infancy. NYSEG and Rochester Gas & Electric (RGE), gas utilities owned by Avangrid, mapped disadvantaged communities in their initial joint Long-Term Plan and noted that they are developing a "Just Transition" framework for future use.[42]

Incorporating impacts on disadvantaged populations will require iterations and improvements in each subsequent gas plan. How states incorporate the various aspects of equity, including recognition, procedural, distributional, and restorative equity into the policies and procedures is a question much larger than gas planning. As a starting point for modern gas planning, PUCs should leverage national and state work to define and map disadvantaged communities for use in the gas plans. PUCs should also consider requiring gas utilities to overlay a map of proposed capital projects and resource acquisitions in the short-term action plan across a map of all disadvantaged populations in the utility's service area. Through this process, decision-makers will have a greater understanding of areas that are likely to be impacted by utility investments.

Mapping

Maps serve as an important tool in creating comprehensive, modern gas plans that effectively communicates system capacities, constraints, needs, and potential solutions to address issues and provide useful information to stakeholders. Where a state has mapped environmental justice or

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[39] U.S. Department of Energy and Lawrence Berkeley National Lab. *Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resource Programs: A Practical Guide*. May, 2023. Available at: https://www.energy.gov/sites/default/files/2023-05/bto-peer-2023-dea-frick.pdf

[40] Berkeley Lab and Pacific Northwest National Laboratory. *22 States + D.C. are Advancing Energy Equity through Executive, Legislative, and Regulatory Actions*. February 21, 2023. Available at: https://emp.lbl.gov/news/22-states-dc-are-advancing-energy-equity

[41] New York Senate Bill 6599 and Assembly Bill 8429 (2019)

[42] New York Public Service Commission, Docket No. 23-G-0437. *NYSEG and RG&E Initial Gas Long-Term Plan.* October 2, 2023. Available at: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=23-G-0437

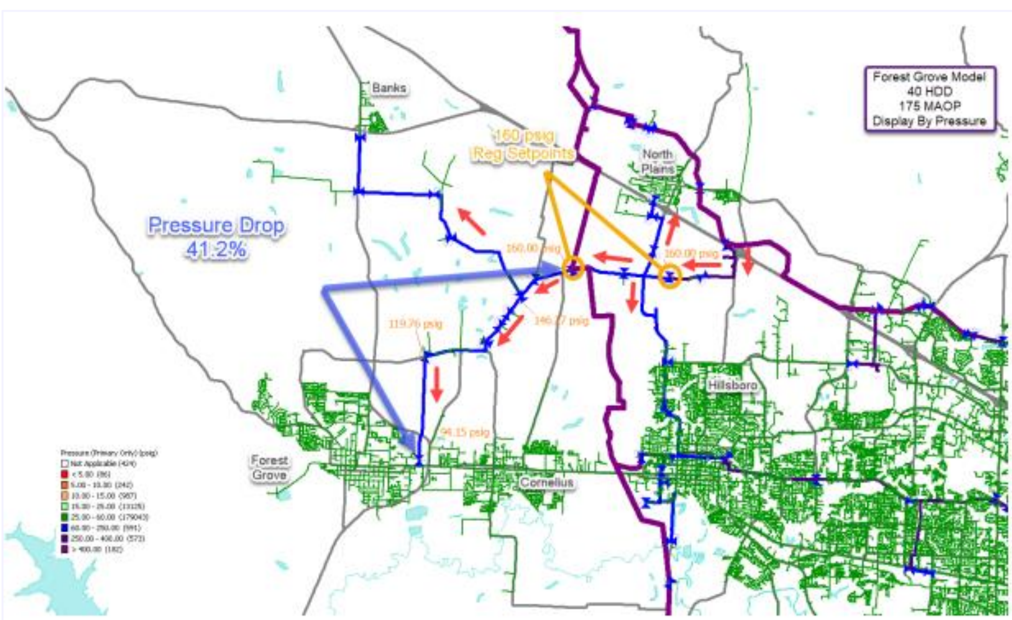
disadvantaged communities, gas systems can be overlayed with those geographies to uncover environmental hazards or injustices and to better shape solutions that address historical inequities. The inclusion of maps allows stakeholders to better understand the system constraints that utilities must address as well as be better equipped to determine whether the solutions utilities identify are reasonable and appropriate.

Case Study: Northwest Natural's System Maps

A recent example of a utility effectively including maps in its gas IRP is Northwest Natural's (NWN) 2022 IRP, shown in Figure 6. The maps served as an important visual guide in discussions, creating a more comprehensive narrative, illustrating the current state of the system, and better describing the plans the utility has for its system.

NWN first provided a map that shows all existing natural gas pipelines and storage infrastructure in the region, including total pipeline capacities. NWN utilized maps to illustrate which pipelines and natural gas sources would serve the NWN's service territory in the case that certain LNG facilities were decommissioned, to demonstrate possible routes identified for a pipeline that NWN's modeling determined was necessary, and to illustrate the interchangeability of certain LNG facilities via a gas flow diagram. The maps supplemented the utility's discussion of its exploration of options for the sizing of pipelines to address constraints and potential decommissioning of LNG facilities.

Figure 6 – NWN Gas IRP Map Denoting Pressure Drop[43]



[43] Oregon Public Utility Commission. Docket No. LC 79. *NW Natural's 2022 Integrated Resource Plan, p. 388.* September 2022. Available at: https://app.insightengine.org/dockets/or-lc-79?version=beta&docket_search_id=1615821

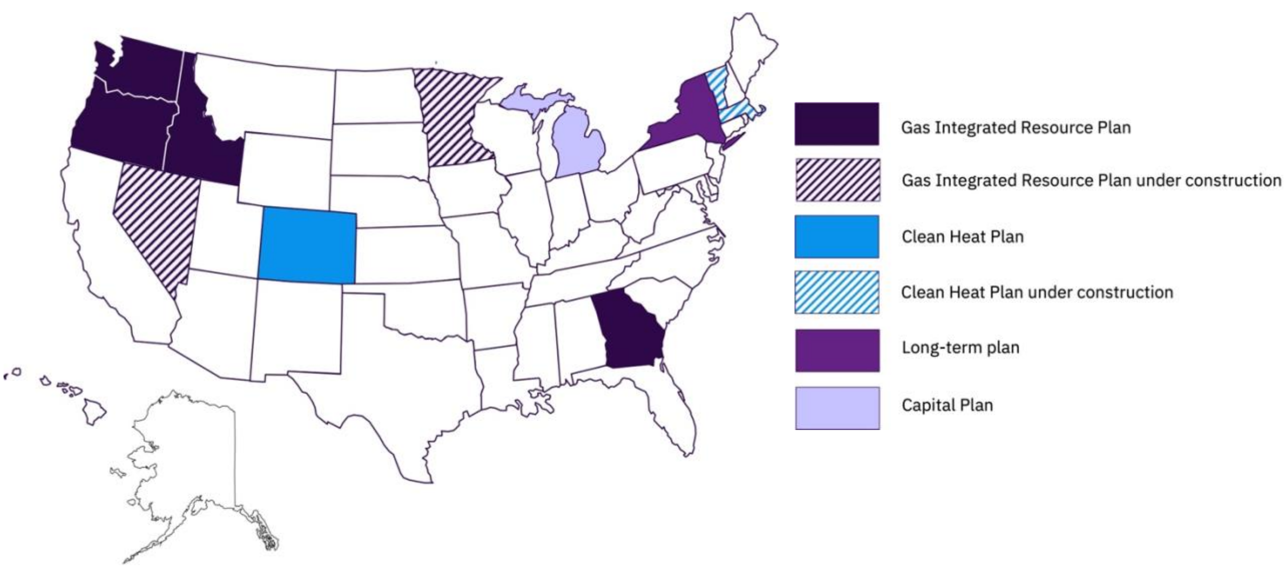
Part II: An Overview and Comparison of Existing Gas Plans

Types of Gas Plans

This section provides a detailed review of four different approaches to gas system planning**.** **New York long-term plans (LTPs), Colorado Gas Infrastructure Plans (GIPs) and Clean Heat Plans**, and **Pacific Northwest Gas Integrated Resource Plans (IRPs)** are gas planning requirements that identify the optimal portfolio of resources that meet customer needs and account for state policy goals, including climate goals. In Michigan **Consumers Energy voluntarily produces Capital Plans**. This section also provides an overview of the Canadian Province of **British Columbia's Coordination between Gas and Electric Utilities' Plans,** to illustrate a novel approach to coordination.

Emissions considerations are recent additions to gas planning and, as such, utilities in New York, Colorado, and the Pacific Northwest are, as of 2023, submitting their first iterations of gas plans that include climate targets.

Figure 7 – 2023 Gas Planning Landscape in the United States



Each of the state's gas planning regulations requires several analytical elements, however, no state mandates all the analytics features detailed above. In general, utilities produce more robust gas plans in states with more extensive analytical requirements.

New York Long-Term Plans (LTPs)

In May 2022, an NY PSC order established a gas system planning process that requires gas utilities to file long-term plans every three years, detailing demand and supply forecasts over a 20-year horizon.[44] Each utility must provide a "no-infrastructure option" in which the utility models a scenario that does not rely on traditional capital spending for meeting system reliability needs and forecasted gas demand. As part of the planning requirement, the utilities must develop a framework for the acquisition and assessment of NPAs. Additionally, the Order requires utilities to provide bill and emissions impacts and identify a preferred portfolio.

Stakeholder engagement is a core part of the NY LTP process. The Order stipulates that utilities must hold a technical conference within a few weeks of the initial LTP filing. Stakeholders are granted the opportunity to submit comments and engage with utilities in additional meetings. The Commission also recommends that an independent third-party consultant evaluate the utility plans. Following the submission of stakeholder comments, utilities must then provide a revised long-term plan. Stakeholders have an additional opportunity to submit a second set of comments in response to the revised LTP and engage with the utility at another stakeholder meeting. Finally, the Commission decides whether to adopt, reject, or modify the revised long-term plan.

A driving factor for the establishment of gas planning is the CLCPA, which specifies emissions reduction targets across the state's economy. Although the CLCPA does not specifically identify emissions reduction goals for gas utilities, the NY Climate Action Council (CAC) recently submitted its Final Scoping Plan that sets targets for building decarbonization, including a goal of electrifying 85% of home and commercial building space by 2050.[45] Although the utilities are not legally required to adhere to the Final Scoping Plan, they will likely need to decarbonize rapidly to meet future policy requirements. As such, the Commission ordered utilities' LTPs to be consistent with the CAC's Scoping Plan.[46]

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[44] New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process.* May 12, 2022. Available at: https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211

[45] New York State Climate Action Council. *New York State Climate Action Council Scoping Plan*, p 180. 2022. Available at: https://climate.ny.gov/resources/scoping-plan/

[46] New York Public Service Commission. Docket No. 20-G-0131, *Order Adopting Gas System Planning Process.* May 12, 2022. Available at: https://app.insightengine.org/dockets/ny-20-00652-20-g-0131/filings/16815248?version=beta&filing_search_id=1615753&document_id=165777211

Case Study: National Fuel Gas Distribution Corporation (NFG) LTP

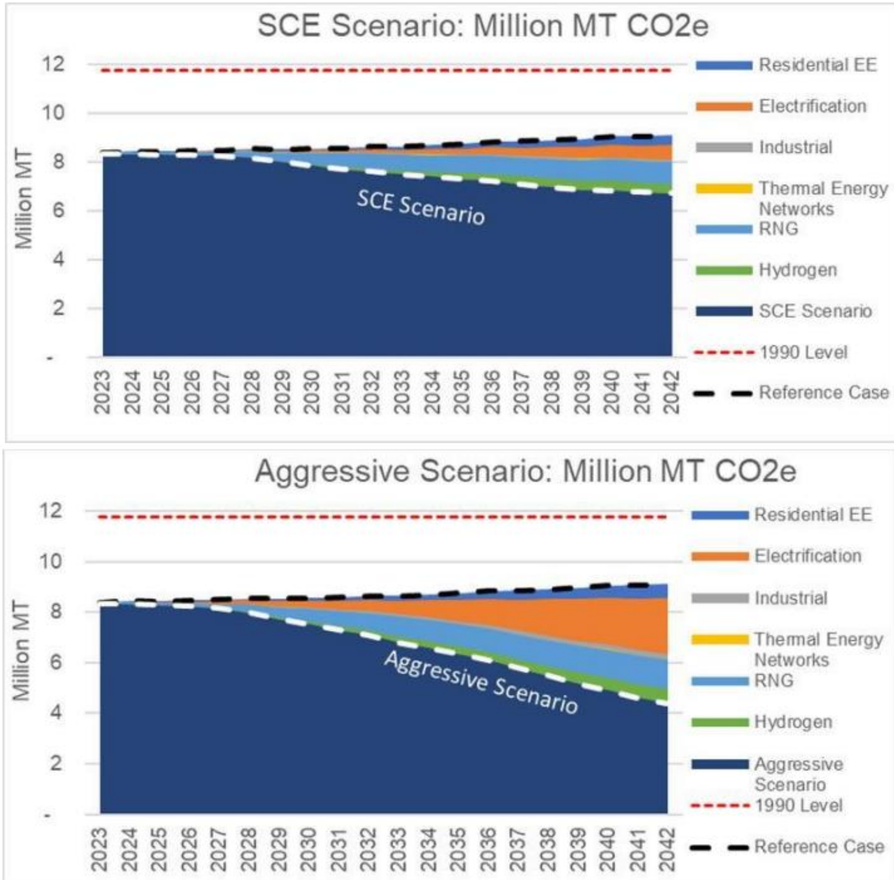
National Fuel Gas Company was the first utility to submit a long-term plan in accordance with the NY gas planning process in December 2022. NFG operates in western New York and Pennsylvania and supplies gas to approximately 540,000 customers in New York.[47] NFG submitted an LTP that included three scenarios: a reference case, a "supply-constrained economy" (SCE) scenario, and an "aggressive" scenario. Over the 20-year planning horizon, the SCE scenario results in only modest emissions reductions, largely driven by the blending of green hydrogen and renewable natural gas. In addition to similar alternative fuel assumptions, the aggressive scenario assumes electrification plays a substantial role in decarbonization, though also includes similar alternative fuel assumptions to the SCE scenario.[48] As a result, the aggressive scenario results in double the emissions reductions relative to the SCE scenario, as illustrated in Figure 8 below.[49]

While NFG found the aggressive scenario to more greatly reduce emissions, it also determined that, across the planning period, customer bills would increase by 121% in the aggressive scenario and only 33% in the SCE scenario.[50] The Company assessed that the net present cost of decarbonization in the aggressive scenario was over three times greater due to the higher costs of all-electric assets, such as heat pumps.[51]

NFG did not propose to adopt one scenario over the other; instead, it provided a set of actions that will guide its long-term planning. These included weatherization investments, implementing hybrid heat pumps with gas backups, and the adoption of RNG and hydrogen.[52] Overall, the proposed long-term plan most closely resembled the SCE scenario.

[47] New York Public Service Commission. Docket No. 22-G-0610. *National Fuel Gas Distribution Corporation Initial Long-Term Plan*, page 5. December 22, 2022. Available at: https://app.insightengine.org/dockets/ny-22-02158-22-g-0610/filings/17545827?version=beta&filing_search_id=1615836&document_id=168444886
[48] *Id.* at 47
[49] *Id.* at 45
[50] *Id.* at 45
[51] *Id.* at 46
[52] *Id.* at 50-51

Figure 8 – Comparison of NFG LTP Scenarios[53]



CASE STUDY FINDINGS

Stakeholders provided comments on several topics including cost assumptions, electrification adoption rates, compliance with state emissions policies, and NPAs. Stakeholder comments were consistent and highlighted the utility's misevaluation of non-infrastructure solutions, such as electrification and NPAs. In response, NFG made minor revisions to its LTP, but still intends to pursue a strategy similar to the SCE scenario. As of the time of writing, the NY PSC has yet to rule on NFG's long-term plan. Nevertheless, the NFG's first LTP illustrates the challenges facing the gas sector, especially gas-only utilities that do not stand to benefit from electrification. Stakeholders opposed critical elements of NFG's LTP, urging greater efforts to decarbonize and electrify, and also disagreed with numerous NFG assumptions. Although the utility and the stakeholders were unable to reach a consensus, the gas planning process has already produced several benefits:

[53] *Id.* at 47

1. NFG analyzed multiple scenarios, quantifying costs, bill impacts, and emission reductions. Although NFG included little assessment of risk, the LTP measured the impact of electrification and alternative fuels on gas rates and emission reductions.
2. The public process allowed for stakeholders and an independent third-party consultant to influence the LTP. While NFG's revisions did not address the majority of the recommendations of other parties, NFG did modify some assumptions. The data NFG provided in its report and appendices also allowed stakeholders to understand the core assumptions that shaped the utility's planning. This transparency allowed stakeholders to more fully critique NFG's electrification and RNG availability assumptions.
3. The LTP provided estimates of emission reductions through 2042, which allowed stakeholders to identify and present concerns related to compliance with New York's climate law.

On the other hand, the New York LTP is not a perfect model for gas planning. NFG's LTP did not model the electric sector load increases and associated costs in the SCE or aggressive scenarios. The impacts of electrification should be quantified to better understand the impacts across the energy system and to begin moving utilities towards greater collaboration between utility gas and electric divisions and with overlapping electric utilities. Furthermore, NFG provided only two alternatives to the reference scenario and did not conduct sensitivity analyses. Additional scenarios and sensitivities could have provided stakeholders with a greater understanding of the impact of specific measures on bills and emissions reductions. For example, modeling changes to policy, such as a gas moratorium, or greater competition for alternative fuels would have provided a more nuanced understanding of scenario risks. Finally, the lack of a short-term action plan limits the impact of any NY PSC decision in the near term. NFG did not provide a specific set of short-term investments related to its preferred long-term plan. For example, instead of specifying potential RNG projects along with associated forecasted cost and emissions impact, NFG's initial RNG action plan is to "promote regional anaerobic digestion projects." As a result, the NY PSC cannot evaluate specific projects, weakening the link between gas planning and rate cases.

Pacific Northwest Integrated Resource Plans (IRPs)

Both Oregon and Washington State require gas utilities to file integrated resource plans. Although some terminology differs (e.g., Washington regulations require the "lowest-reasonable cost" portfolio to be adopted; Oregon regulations require the "least-cost, least risk" portfolio), the requirements are very similar. Both states require the evaluation of all demand- and supply-side resources, alternative scenarios, analysis of various load scenarios, assessments of scenarios by cost and risk, and a sensitivity analysis.[54] Utilities must also detail a short-term action plan that addresses investments in the two years following the acknowledgment of IRP.[55] Additionally, both states stress the importance of stakeholder participation: The Oregon PUC specifies, "[t]he public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP."[56] Oregon rules stipulate that IRP forecasts should extend at least twenty years while Washington requires a minimum of ten years, though Washington utilities have typically exceeded the minimum requirements to also use 20-year planning periods.[57]

Utilities in both states must also model compliance with recently enacted state climate laws; the Climate Protection Program (CCP) in Oregon, and the Climate Commitment Act (CCA) in Washington. The CPP is a cap-and-trade program that mandates a 50% greenhouse gas reduction by 2035 and a 90% reduction by 2050. The CPP covers all natural gas utilities in the state under a declining cap. Washington's CCA caps greenhouse gas emissions and requires the state to reduce emissions levels by 95% by 2050.[58] The CCA provides natural gas utilities with "free" allowances and holds auctions for the trading of allowances, with both free and tradeable allowance totals declining annually.[59]

The enactment of climate laws in the Pacific Northwest has dramatically altered natural gas planning in the region; within a couple of years, gas utilities in Washington and Oregon have shifted from largely business-as-usual planning to IRPs that model significant emission reductions. The following case study explores the first utility to model compliance with the CPP and CCA.

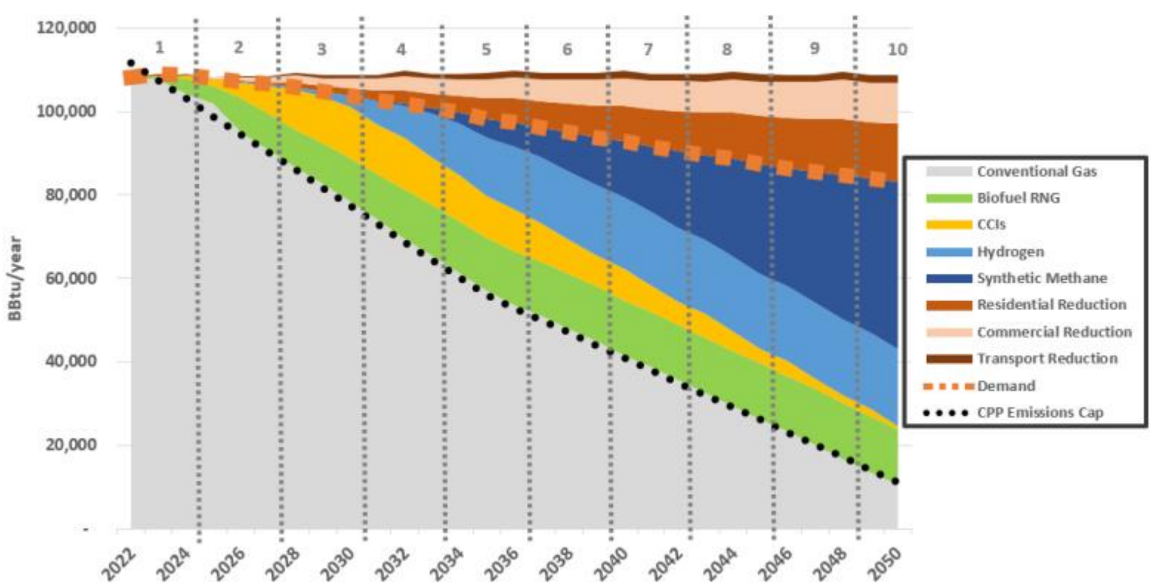
[54] Oregon Public Utility Commission Docket. No. UM 1056. Order 07-002; Oregon Administrative Rule 860-027-0400, available at https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=302069; Washington Administrative Code 480-90-238, available at https://apps.leg.wa.gov/wac/default.aspx?cite=480-90-238
[55] *Id.*
[56] Oregon Public Utility Commission. Docket UM 1056, *Order No. 07-002*, page 2. January 2007. Available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf
[57] Oregon Public Utility Commission. Docket UM 1056, *Order No. 07-002*, page 2. January 2007. Available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf; Washington Utilities and Transportation Commission. Docket No. UG-030312. *Adoption Hearing For Proposed Rules In Chapter Wac 480-90-238, Relating To Least Cost Plan.* March 2003. Available at: https://app.insightengine.org/dockets/wa-ug-030312?version=beta&docket_search_id=1615874
[58] Revised Code of Washington 70A.45.020. Available at: https://apps.leg.wa.gov/rcw/default.aspx?cite=70A.45.020
[59] Kasia Patora. Washington State Department of Ecology. *Final Regulatory Analyses for Chapter 173-446 WAC, Climate Commitment Act Program*. September 2022. Available at: https://apps.ecology.wa.gov/publications/documents/2202047.pdf

Case Study: Northwest Natural 2022 Gas IRP

Spanning across both Oregon and Washington, NWN's IRP addresses the requirements of both the CPP and the CCA. NWN modeled nine distinct scenarios that leveraged varying amounts of alternative fuels and electrification as well as scenarios that modeled potential policies, including a new gas customer moratorium and federal policy support for alternative fuels.[60] NWN provided a comprehensive analysis of resource cost, resource acquisitions (both demand and supply), and customer demand for each scenario. NWN identified a compliance portfolio, which relies heavily on the acquisition of alternative fuels for compliance in both states.

The accompanying short-term action plan identifies goals for RNG acquisition, energy efficiency, compliance investments in Oregon, and emissions offsets and allowances in Washington. NWN's short-term action plan complements its long-term vision for the future of its gas system and compliance with climate laws. The utility's analysis included cost optimization modeling, including a Monte Carlo simulation (a mathematical technique used to evaluate possible outcomes from uncertain events). Notably, the preferred portfolio (Figure 9) was not one of the nine scenarios presented, and the Oregon PUC decided not to acknowledge several sections of the filing.

Figure 9 – NWN Preferred Portfolio in Oregon[61]



[60] Oregon Public Utility Commission. Docket No. LC 79. *NW Natural's 2022 Integrated Resource Plan, Chapter 7*. September 2022. Available at: https://app.insightengine.org/dockets/or-lc-79?version=beta&docket_search_id=1615879
[61] Oregon Public Utility Commission. Docket No. LC 79. *NW Natural's 2022 Integrated Resource Plan*, p. 26. September 2022. Available at: https://app.insightengine.org/dockets/or-lc-79?version=beta&docket_search_id=1615879

CASE STUDY FINDINGS

Stakeholders identified several limitations with the utility's IRP, including NWN's insufficient consideration of risk and lack of detailed analysis in its preferred portfolio.[62] In its reply comments, NWN supported its initial positions and did not waiver from its action plan or long-term preferred compliance scenario.[63]

The Oregon PUC's decision only to acknowledge the IRP in part highlights the benefits of gas planning. The non-acknowledgment of elements in the short-term and long-term plan provides a clear indication that the utility's rationale and assumptions for its investment decisions were inadequate. Despite NWN's significant quantitative work, the PUC deemed that the utility did not meet the state's regulatory standard. To pursue the long-term investments identified in its IRP, NWN will need to provide a more robust risk assessment to demonstrate that its preferred portfolio is the least-cost, least-risk pathway to meeting climate targets – a demand first made by stakeholders and later echoed by the PUC. Regardless of the result of the subsequent analysis, the additional information in an IRP update will provide better insight as to the decarbonization approach that produces the most ratepayer benefits.

In the absence of an IRP, the utility would still have internally assessed compliance approaches but could have relied on unvetted assumptions or failed to adequately assess risk. Via stakeholder and PUC involvement, the IRP process identified these issues in advance of the investment decision, potentially forestalling investments that may not be in the public interest. The IRP process thus reduced the informational asymmetry inherent to utility regulation, whereby the utility holds most information related to its decision-making, by ensuring stakeholders and the PUC had enough information to make informed evaluations of the utility's plan. This is especially important considering the complexity and uncertainty related to meeting climate goals.

While the Oregon regulations have established a high bar for gas planning, the applicable statute does not require gas utilities to quantify electric system costs or benefits, which creates significant gaps in the public's understanding of the societal impacts of modeled scenarios. Even within its electrification scenario, NWN did not quantify any electricity system impacts related to fuel switching, such as, incremental electric transmission, distribution, and generation costs, or efficiencies from increasing electric load at off-peak times. Instead, the electrification scenario only quantifies a reduction in gas system fuel costs. As a result of the

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[62] Oregon Public Utilities Commission. Docket No. LC 79. *Climate Advocates Opening Comments*. December 30, 2022. Available at: https://app.insightengine.org/dockets/or-lc-79/filings/17562241?version=beta&filing_search_id=1615994&document_id=168501265

[63] Oregon Public Utilities Commission. Docket No. LC 79. *NW Natural Reply Comments*. February 3, 2023. Available at: https://app.insightengine.org/dockets/or-lc-79/filings/17670786?version=beta&filing_search_id=1615994&document_id=168867825

omission of incremental electric system costs and benefits, the electrification scenario does not provide an accurate picture to inform PUC decision-making.

Stakeholders were also concerned that NWN's IRP did not allow demand-side management resources, such as energy efficiency, electrification, and demand response, to compete against supply-side resources to meet future customer demand. NWN only modeled demand-side management resources as a reduction to customer load, but once that load forecast was determined, NWN restricted the model from selecting additional demand-side resources to meet future demand. In its comments to the commissioners, OPUC Staff stated that "This likely obscures some of the best pathways for customers as these resources are not compared on an even basis."[64]

Finally, while the scenario analysis provided comprehensive resource cost modeling, the lack of gas capital investment forecasts undermined the planning exercise. Without detailed information, stakeholders have no understanding of how much NWN is investing in its system. Furthermore, the utility assumed that distribution capital investments were the same in each scenario despite the very different customer counts and system needs in the electrification scenarios.[65] The amount of necessary asset replacements, asset upgrades, and new pipelines will vary significantly depending on whether the utility pursues a decarbonization approach based on electrification or alternative fuels, and investments should align with the approved approach. This case study underscores the importance of including capital investment forecasts within regulatory requirements for gas plans.

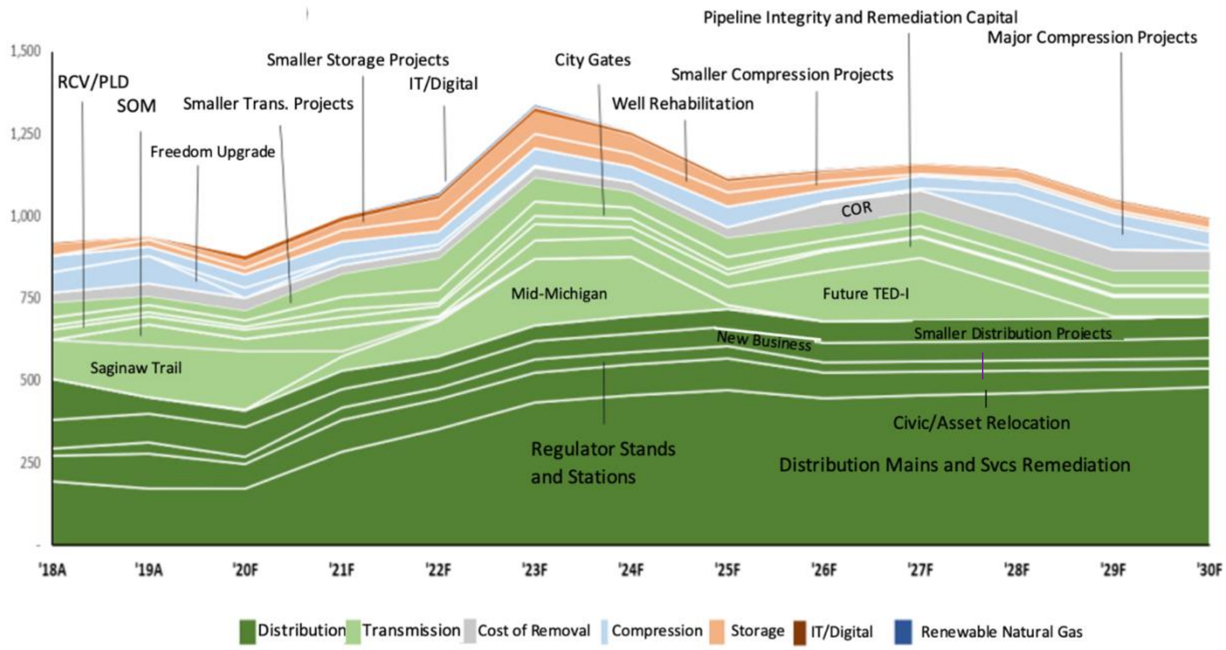
Michigan's Consumers Energy Natural Gas Delivery Plan

Since 2020, Consumers Energy Company in Michigan (Consumers) has been providing an annual "Natural Gas Delivery Plan" (Delivery Plan). Unlike LTPs or IRPs, there is no legislative requirement for Consumers to publish public gas planning documents. Instead, Consumers developed the plan in response to requirements created by the 2019 Michigan Public Service Commission's Statewide Energy Assessment. The Delivery Plan details a ten-year forecast of Consumers' system investments, forecasts for gas prices, and decarbonization initiatives.[66] The Delivery Plan provides valuable data and insights into the utility's strategic planning. Consumers breaks down capital investments by function (transmission, distribution, storage, compression, digital) for each year of their plan. The capital forecast provides elaborate

[64] Oregon Public Utilities Commission. Docket No. LC 79. *Staff Opening Comments,* p. 6. December 30, 2022. Available at: https://app.insightengine.org/dockets/or-lc-79/filings/17562239?version=beta&filing_search_id=1616002&document_id=168501263
[65] *Id.* at 6
[66] Consumers Energy. *Natural Gas Delivery Plan*. December 11, 2020

descriptions of asset age, utilization, and system reliability needs, such that stakeholders can better understand the utility's investment rationale.

Figure 10 – Consumers Energy Michigan Capital Plan Annual Gas Delivery Loaded Capital Spend[67]



There is no commonly accepted format for a "capital plan," though Consumers' Delivery Plans share many common elements with LTPs and IRPs. However, the Delivery Plan is classified as a capital plan because of its focus and detail on its capital investments, wherein Consumers has provided greater depth in their spending estimates and rationale than other utilities do in LTPs and IRPs. Figure 10 offers an illustration of this detail.

[67] Text enhanced for readability

Case Study: Consumers Energy's 2021-2031 and 2023-2033 Delivery Plans

2021-2031 Delivery Plan

The first revision of the Delivery Plan, published in 2020, includes a projection of residential bill impacts and gas commodity costs. Consumers forecasted a 4-5% annual growth rate in residential gas bills through 2025 and a 5-6% growth in bills from 2026 to 2030.[68] Consumers' natural gas spot price base scenario assumed gas prices would hover around $3/MMBtu through 2040.[69] The utility's narrative provided additional insight into the logic for its capital investment forecast; "now is the time to invest as gas is forecasted to be fairly flat over the next 10 years."[70]

This data provides critical transparency for the PUC and stakeholders. Not long after Consumers published its capital plan, gas prices soared to three times their projections.[71] Considering that Consumers projected roughly a 5% annual increase in residential bills over the next decade during a forecasted period of low gas prices, it is evident that the surge in commodity prices will significantly burden ratepayers in those periods of volatility. Insights gained from the capital forecast allowed the PUC and stakeholders to further assess and question infrastructure investments in light of changing economic conditions.

The Delivery Plan also details the utility's efforts to meet climate goals. Consumers' emissions reduction investments focus on the reduction of methane leaks; the utility is aiming for an 80% reduction in methane emissions by 2030.[72] However, the plan forecasted few investments made towards reducing end-use emissions from gas in buildings. Consumers Energy also had no plans to incorporate alternative fuels over the ten years of the plan and did not believe that electrification was "economical from an emissions or cost perspective."[73] Shortly before the release of the Delivery Plan, Michigan Executive Directive 2020-10 established a plan for the state to reach carbon neutrality by 2050.[74] Because Consumers' did not have adequate time to revise its Delivery Plan to meet Michigan's decarbonization goals, the 2021-2031 Delivery Plan data indicated that the utility was planning a business-as-usual investment strategy.

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[68] Consumers Energy. *Natural Gas Delivery Plan*, p. 23. December 11, 2020. Available at:
[69] *Id.* at 30
[70] *Id*.
[71] Data sourced from S&P Capital IQ Consumers Energy CityGate prices.
[72] Consumers Energy. *Natural Gas Delivery Plan*, p. 113. December 11, 2020
[73] *Id.* at 116.
[74] Michigan Department of Environment, Great Lakes, and Energy. *MI Healthy Climate Plan*. April 2022. Available at: https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan

2023-2033 Delivery Plan

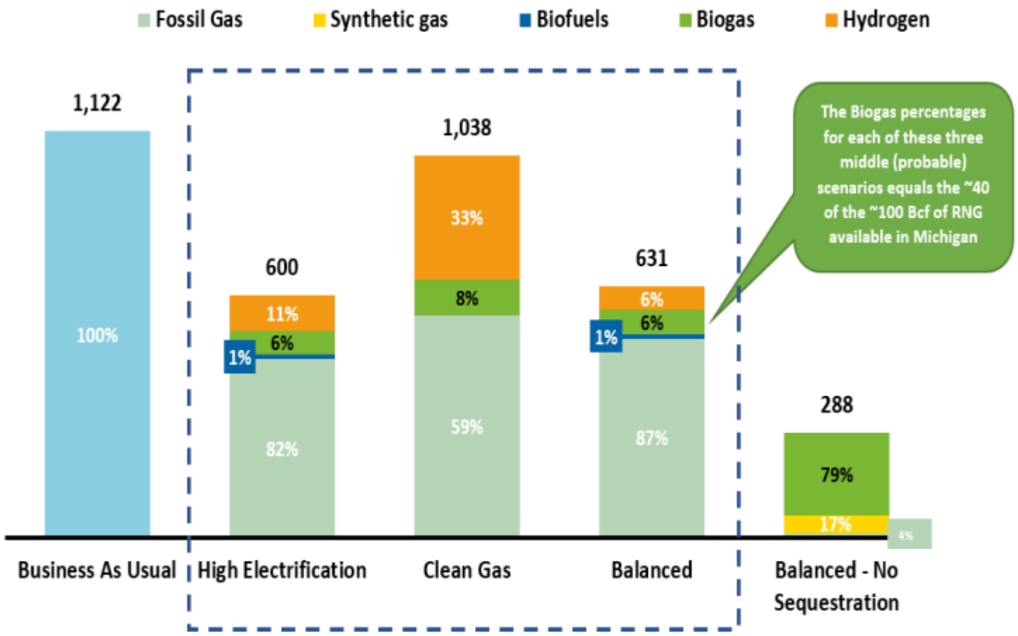
The Delivery Plan released in December 2022 is notably different than the previously issued plans as it is the first plan for Michigan's Executive Directive 2020-10. The 2023-2033 Delivery Plan evaluated six decarbonization scenarios including business-as-usual, decommissioning of the gas system, electrification, alternative fuels with fossil gas, alternative fuels without fossil gas, and carbon sequestration mixed with some electrification (called the "balanced" scenario).[75] Consumers' analysis of these scenarios included impacts on both the gas and electric side,[76] and an assessment of the utility's need for fuels for each scenario (Figure 11). The utility concluded that the electrification scenario could result in 50 GW of electrical system demand, double that of the business-as-usual scenario, and increase winter electricity system peaks to 40% greater than summer peaks.[77]

Consumers then analyzed each scenario to determine a resource mix and the associated net present cost of implementation. Consumers selected the "balanced scenario," which relies on cost-effective electrification and natural gas offset by carbon sequestration, as the least-cost scenario through 2050.

This most recent Delivery Plan also included the other gas planning features present in the 2021-2031 Delivery Plan. Gas price forecasts reflected a more current understanding of commodity price trends, the forecast of annual capital investments reflected the utility's decarbonization approach, and the bill impact analysis was updated to reflect the increases in gas costs and capital spending. The forecasts in the Delivery Plan were significantly different than the first iteration released in 2020, as it accounted for changes in economic conditions.

[75] Consumers Energy. *Natural Gas Delivery Plan*, p. 116. December 1, 2022. Available at: https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-gelivery-plan.ashx
[76] Consumers Energy. *Natural Gas Delivery Plan*, p. 120. December 1, 2022. Available at: https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-gelivery-plan.ashx
[77] Consumers Energy. *Natural Gas Delivery Plan*, p. 117. December 1, 2022. Available at: https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-gelivery-plan.ashx

Figure 11 – Consumers Energy Forecasted Fuels by Scenario in 2050[78]



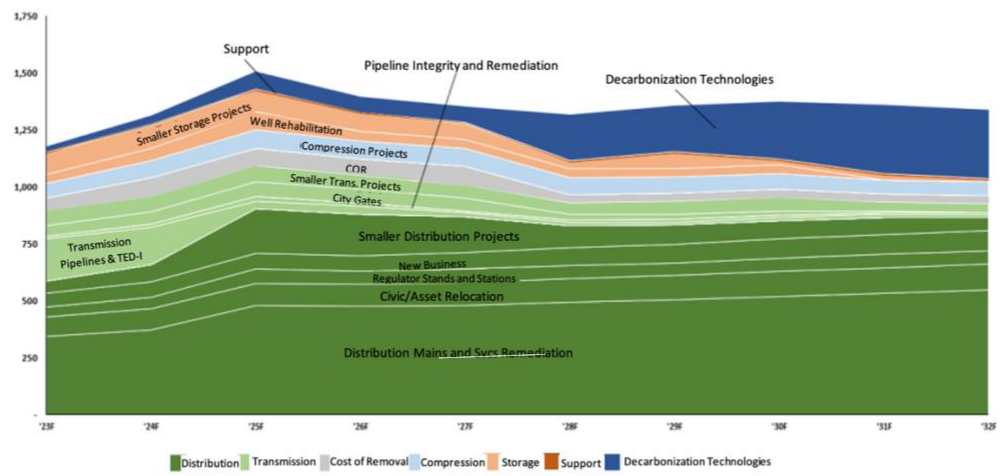
CASE STUDY FINDINGS

Consumers' Delivery Plans provide an excellent example of how policy can influence system investments. The utility's evolution in just two years demonstrates that it was operating business-as-usual until Governor Whitmer's Executive Directive on carbon neutrality. In 2022, the utility dramatically increased its proposed capital spending approach, with decarbonization investments becoming a driver of new capital spending by 2028, as depicted in Figure 12.

While the data in the Delivery Plan is insightful, it also reveals the importance of a formal gas planning proceeding. Because there is no regulatory gas planning requirement in Michigan, Consumers does not provide stakeholders with the opportunity to assess, or the Michigan Commission to approve its Delivery Plan. Yet, Consumers' capital plan poses significant areas of concern for ratepayers. Consumer's bill impact analysis forecasts residential rates to nearly double in a decade, from roughly $65/month in 2021 to just under $115/month in 2030. And given the risk of voluntary customer electrification and efficiency reducing system throughput and that the forecasted pace of investments continues to be quite high, residential rates over the next decade will likely continue to rise beyond the planning horizon.

[78] Consumers Energy. *Natural Gas Delivery Plan*, p. 119. December 1, 2022. Available at: https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-gelivery-plan.ashx

Figure 12 – 2023-2033 Consumers Capital Forecast Annual Gas Delivery Loaded Capital Spend ($M) [79,80]



Specifically, Consumers' new business forecast accentuates rate impact concerns; the utility continues to forecast an annual increase in customers despite significant historical reductions in service connections.[81] Considering the growing cost-competitiveness of electric appliance alternatives, the sudden projected increase in service connections is concerning. If the utility adds fewer customers than forecasted – or loses customers to electrification – fixed system costs will be spread across fewer customers, further raising rates.

These concerns are highly salient for Michigan gas customers, but stakeholders have no opportunity to formally voice their perspectives. Moreover, the Michigan Public Service Commission has no authority to acknowledge or not to acknowledge Consumers' Delivery Plan, preventing the Commission from influencing the utility's decision-making. The Michigan example demonstrates clearly how gas planning does not produce the same benefits to ratepayers when there is no stakeholder and PUC involvement.

Colorado Gas Infrastructure and Clean Heat Plans

In 2021, the Colorado legislature passed several bills related to the clean energy transition, including Senate Bill 21-264. The bill requires gas utilities to file a Clean Heat Plan in which the utilities put forth a portfolio of resources they intend to source to meet a 4% reduction in 2015 GHG emissions by 2025 and a 22% reduction in 2015 GHG emissions by 2030.[82] The utilities

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[79] *Natural Gas Delivery Plan*, Consumers Energy, December 1, 2022. Page 128. https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-gelivery-plan.ashx
[80] Text enhanced for readability
[81] *Natural Gas Delivery Plan*, Consumers Energy, December 1, 2022. Page 87. https://www.consumersenergy.com/-/media/CE/Documents/company/What%20We%20Do/consumers-energy-natural-gas-gelivery-plan.ashx
[82] Colorado Senate Bill 264 (2021)

must file Clean Heat Plans at least every four years and cover a period of five years.[83] The plans must demonstrate emissions reductions at the "lowest reasonable cost."[84]

In addition to Clean Heat Plans, the Colorado Public Utilities Commission (COPUC) also developed regulations for gas utilities to file Gas Infrastructure Plans (GIPs). GIPs must be filed every two years and detail planned capital spending by project type (capacity expansion, system safety and integrity, new business, and mandatory relation).[85] GIP regulations also require utilities to evaluate non-pipeline alternatives, evaluate reference, low, and high demand and resource forecasts, and provide system maps.[86] Together, the GIP and Clean Heat Plan create Colorado's gas planning framework.

Case Study: Xcel Energy's GIP and Clean Heat Plan

In May 2023, Xcel released its first GIP detailing its forecasts, planned investments from 2023 to 2029 (Figure 13), and a non-pipeline alternative methodology.[87] Xcel provided a spending forecast, including a sensitivity analysis of project spending under the low, reference, and high design day forecasts.[88] Additionally, Xcel provided NPA analyses for five capacity expansion projects and chose to advance two.[89]

In its first Clean Heat Plan, Xcel developed and analyzed four scenarios and selected a preferred portfolio.[90] The Company identified forecasted costs and emissions reduction for each scenario. The majority of the data Xcel presented focused on the five-year plan period, although Xcel extended some modeling to 2030 to determine compliance with state laws. Additionally, Xcel provided a bill impact analysis for each of its portfolios (Figure 14).

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83 Colorado Senate Bill 264 (2021)
84 Colorado Senate Bill 264 (2021)
85 Section 4 Code of Colorado Regulations (CCR) 723-4-4552 and Section 4 CCR 723-4-4553
86 Section 4 CCR 723-4-4553
87 Public Service Company of Colorado, Docket No. 23M-0234G. *Initial 2023-2028 Gas Infrastructure Plan*. May 18, 2023. Available at: https://app.insightengine.org/dockets/co-23m-0234g/filings/18120210?document_id=170250685&filing_search_id=1616056
88 *Id.* at 38
89 *Id.* at 73
90 Public Service Company of Colorado. Docket No. 23A-0392EG. *Direct Testimony and Attachments of Jack W. Ihle.* August 1, 2023. Available at: https://app.insightengine.org/dockets/co-23a-0392eg/filings/18299162?document_id=171493905&filing_search_id=1616060

Figure 13 – Xcel 2023-2028 GIP Planning Investments

Planned Project Category	Number of Projects	Action Period 2023	2024	2025	Informational Period 2026	2027	2028	2029	Estimated Total GIP Expenditures	Estimated Total Project Expenditures*
System Safety & Integrity	6	$22.8	$3.1	$0.0	$0.0	$0.0	$0.0	$0.0	$25.9	$26.2
Capacity Expansion[21]	8	$5.4	$10.0	$6.4	$2.9	$2.7	$11.8	$19.0	$39.2	$58.3
Mandatory Relocation	1	$4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.1	$4.2
New Business	0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Planned Projects Total:	**15**	**$32.3**	**$13.1**	**$6.4**	**$2.9**	**$2.7**	**$11.8**	**$19.0**	**$69.2**	**$88.7**

* Includes capital expenditures for included planned projects before and after the GIP total period. Differences in sums due to rounding.

CASE STUDY FINDINGS

Even in its first iteration, Colorado's new gas planning process appears to produce significant benefits for customers. The GIP and Clean Heat Plan together created a direct link between utility investments and gas system emissions reduction goals. The GIP process also resulted in the implementation of two NPAs that relied primarily on electrification measures.

Figure 14 – Example of a Bill Impact Analysis from Xcel's Clean Heat Plan Preferred Portfolio[91]

	2024	2025	2026	2027	2028
CHSEA Annual Costs ($millions)					
Beneficial Electrification - Amortized Costs	$1,270,100	$4,732,958	$10,489,180	$19,168,422	$30,644,615
Total CHSGA Costs	$1,270,100	$4,732,958	$10,489,180	$19,168,422	$30,644,615
Sales Volumes Adjusted for Decreases Associated with DSM & Electrification	29,385,815,257 kWh	29,893,285,261 kWh	30,452,694,053 kWh	30,988,281,473 kWh	31,711,125,576 kWh
Forecasted CHSEA Rate	$0.00004/kWh	$0.00016/kWh	$0.00034/kWh	$0.00062/kWh	$0.00097/kWh
Baseline Average Rate Forecast	$0.12415/kWh	$0.12403/kWh	$0.12766/kWh	$0.12835/kWh	$0.13178/kWh
Average Rate With CHSEA	$0.12419/kWh	$0.12419/kWh	$0.12800/kWh	$0.12897/kWh	$0.13275/kWh
CHSEA Rate Impact	+0.0%	+0.1%	+0.3%	+0.5%	+0.7%
Average Monthly Residential Usage	606 kWh	606 kWh	606 kWh	606 kWh	606 kWh
Impact To Average Monthly Residential Bill	$0.03	$0.10	$0.21	$0.37	$0.59

However, the initial GIP also illuminated challenges with the current regulations. Because the GIP requirements stipulate that only projects (or sets of related projects) above $3 million must be included, Xcel reported a small percentage of its total forecasted investments. In three of the GIP years, Xcel provided data on $32.3 million in investments, $13.1 million, and $6.4 million (see Figure 13). For comparison, in Rate Case 20AL-0049G, Xcel proposed $830.2

[91] *Id.* at 129

million in capital additions from January 2017 to September 2020.[92] This threshold, forecasting methodologies, and benefit-cost methodologies have been some of the main points of contention between stakeholders and the utility.

While the adjudication of the first Clean Heat Plan is ongoing at the time of this paper's release, stakeholders in that proceeding[93] have taken issue with the inclusion of Certified Natural Gas and carbon offsets as a clean heat resource and cost assumptions around electrification. In direct response to stakeholder pressure, Xcel re-filed the plan without counting Certified Natural Gas and offsets towards its emissions reduction targets.[94]

Colorado's Clean Heat Plan and GIP, considered together, resemble the NY utilities' long-term plans. Xcel filings included demand forecasts, multiple scenarios with the selection of a preferred portfolio, a bill impact analysis, non-pipeline alternatives, and a limited capital investment forecast. The most significant difference between the Colorado legislation and the NY LTPs is Colorado's shorter, five-year planning horizon for the clean heat plan. This is especially critical when considering long-term emissions reduction goals, such as carbon neutrality. Xcel's preferred clean heat portfolio is based only on modeling through 2030. However, resources that are cost-effective and help meet the 2030 emission target may not be viable, long-term solutions. For example, there are significant concerns related to whether RNG and hydrogen can fully decarbonize the gas system. Xcel's analyses determined that a portfolio that leverages RNG and hydrogen resources was the most cost-effective through 2030, but neither fuel is likely to enable the full decarbonization of the gas system due to availability and safety concerns, respectively. The Department of Energy's Clean Hydrogen Strategy and Roadmap identifies hard-to-decarbonize sectors, such as industry and heavy-duty transportation, as the highest-value applications for hydrogen, and recommends building regional networks (Hubs) to site hydrogen production close to high-priority hydrogen users.[95] A five-year planning horizon may be too short-sighted given the longer-term issues associated with the energy transition.

[92] Public Service Company of Colorado. Docket No. 20AL-0049G. *Direct Testimony of Luke A. Litteken*, page 20 February 5, 2020. Available at: https://app.insightengine.org/dockets/co-20al-0049g/filings/21692257?version=beta&filing_search_id=1616063&document_id=178440484

[93] Colorado Public Utilities Commission. Docket No. 23A-0392EG. *Public Service Company – Clean Heat Plan*. August, 2023. Available at: https://app.insightengine.org/dockets/co-23a-0392eg?version=beta&docket_search_id=1616066

[94] Tom DiChristopher, S&P Global Market Intelligence. *Xcel drops certified gas, carbon offsets from Colo. clean heat plan.* November 2023. Available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/xcel-drops-certified-gas-carbon-offsets-from-colo-clean-heat-plan-78391280

[95] U.S. Department of Energy*, U.S. National Clean Hydrogen Strategy and Roadmap*, p. 2. June 2023. Available at: https://www.hydrogen.energy.gov/library/roadmaps-vision/clean-hydrogen-strategy-roadmap

Illinois Long-Term Gas Infrastructure Plan

On November 16th, 2023, the Illinois Commerce Commission (ICC) ruled on three gas utility rate cases: Ameren, Nicor, and People's Gas. In the Peoples Gas Order, the ICC acknowledged that the absence of a publicly-filed gas system plan create an information asymmetry that made it difficult for the ICC, customers, and stakeholders to determine whether the utilities' investments were just, reasonable, and prudent. In addition to disallowing recovery of hundreds of millions of dollars related to pipeline replacement programs, the Order created a new "Long-Term Gas Infrastructure Plan" (LTGIP) "[t]o remedy the difficulty of obtaining information in this case and to aid in the Commission's informed review of the Companies' future rate increase requests."[96]

By order, gas utility LTGIPs are required to: 1) detail a 5-year action plan of investments within a longer-term planning horizon, 2) estimate the total cost and annual incremental revenue requirement of the action plan, 3) explain each project or program and justify why it cannot be deferred to future years; 4) provide comparative evaluations of resource procurements and major capital investments; 5) map the distribution system, identifying areas of constraints and risk, locations of planned projects, pressure districts served by each project, and locations of environmental justice communities; 6) describe the lowest societal cost of investments necessary to meet customer demand and comply with state public policy objectives; 7) demonstrate that programs or projects will minimize rate impacts on customers, particularly low-income and equity investment eligible communities; 8) use scenarios and sensitivities to test the robustness of the utility's portfolio; 9) publicly file workpapers documenting all inputs and assumptions with limited use of confidentiality; and 10) summarize stakeholder participation, and how stakeholder input was incorporated into the filing. At least a year before the filing of the plan, utilities must outline contents of their upcoming LTGIP and the timing and extent of their planned public participation. The ICC expects its first plans by July 1, 2025, and every two years thereafter.

As the ICC Orders are recent and the utilities have not yet filed a workplan, it is impossible to say what the final product will look like. Based on a review of the requirements, the LTGIP looks most similar to New York's Long-Term Plan. The primary difference between the LTGIP requirements and the NY LTP is that ICC's primary focus is on customer rate protection rather than emission reductions. While the NY CAC played a significant role in the establishment of the LTP, the ICC's ruling appears largely borne out of a concern that customers may experience rate increases from unreasonable utility investments. Most notably, the ICC's requirements will enable stakeholders to understand the potential impacts of capital

[96] Illinois Commerce Commission. Docket No. 23-0069. *Final Order*, p. 119. November 16, 2023. Available at: https://app.insightengine.org/dockets/il-23-0069/filings/21929960?version=beta&filing_search_id=1616070&document_id=179007711

investments on customer bills through scenario modeling. At this time, we are also unable to evaluate the extent of public engagement in the development of the LTGIPs.

Coordinated Gas and Electric System Planning

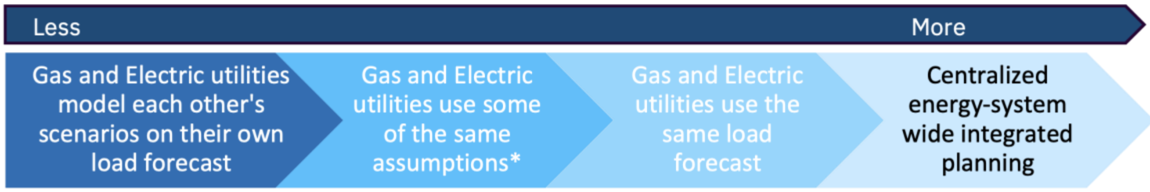
Coordinated gas and electric system planning is an emerging area of planning, so there is little historical precedent upon which to draw. The energy transition, spurred in part by cost-effective building electrification and decarbonization solutions, will accelerate gas-to-electric fuel switching. As will be explained, this shift in energy use – combined with the impacts of transportation electrification – can either yield significant benefits or burden ratepayers and the electric grid, depending on whether the transition is proactively managed.

Electrification of space and water heating will have varying effects, both positive and negative, on electricity generation, transmission, and distribution, and needs to be factored into both gas and electric utility load forecasting. A summer peaking electric utility may not incur marginal capacity costs to accommodate additional space heating load. In this case, the additional space heating load could cause downward pressure on electricity rates, all else constant, by spreading fixed costs over more units of sale – analogous to the benefits electric vehicle charging provides.

In some regions, significant space heating electrification could alter an electric utility's load profile enough to turn the utility into a dual- or winter-peaking utility. In these cases, heating electrification may trigger additional electrical infrastructure needs.

A higher degree of coordination between gas and electric planning, whether across divisions within the same utility or across utilities, can provide a more comprehensive view of the needs and costs of both systems. Ultimately, states may need to move towards formal integrated energy system planning, but as described below, there are several important steps that states can take today to avoid making risky investments with ratepayer dollars while developing the tools, processes, and frameworks for more fundamental changes. These steps, from most incremental to most significant, are illustrated in Figure 15.

Figure 15 – Range of Coordination Options From Least to Most



* Assumptions can be synced around: **RNG** (economic and technical potential, specific offtakers), **hydrogen** (where it will be produced, where will it be used, cost), and **electrification** (costs, technological capabilities, impacts to the electric grid, temperature at which the heat pump is inefficient, economic crossover temperature)

Coordinated Planning in Practice in British Columbia

The most advanced example of coordinated gas and electric planning to date is in British Columbia, Canada. In December 2021, the British Columbia Utilities Commission (BCUC) opened a process to identify pathways for achieving the province's greenhouse gas emissions reduction targets, given that the electric utility, BC Hydro, and the gas utility, FortisBC Energy Inc. (FEI), have a "significant and correlated role" in achieving emissions reductions.[97] The BCUC also identified that the electricity and gas systems had numerous interdependencies including within the emerging areas of hydrogen, synthetic gas production, and carbon capture and storage (CCS). The BCUC identified six different energy scenarios: 1) Diversified energy; 2) Diversified energy with less renewable natural gas by 2040; 3) Diversified energy with more carbon capture and storage by 2040; 4) Diversified energy achieving BC's sectoral GHG emissions targets by 2030; 5) Electrification; and 6) Deeper Electrification.[98] The Commission then invited the two utilities to comment on the scenarios.

In response, BC Hydro proposed that "the load scenarios in BC Hydro and FEI's respective integrated resource plans should be the basis for developing a view of the province's evolving needs for electricity and gas resources."[99] The BCUC agreed with BC Hydro's alternative approach and ordered the two utilities to share the data required for each to file the load forecast results based on the other utility's scenarios, with supporting commentary regarding the supply resource impacts, rate impacts, and emissions impacts.[100] The BCUC ordered

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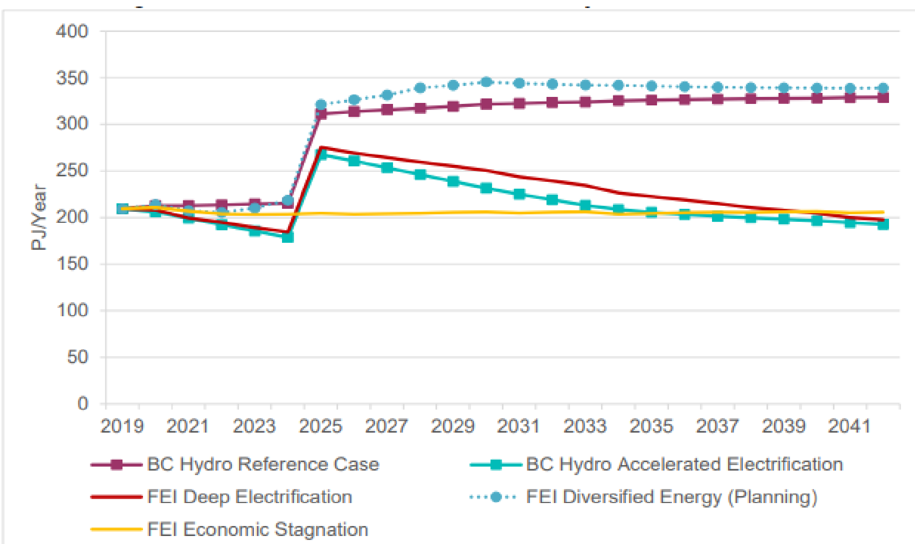
[97] British Columbia Utilities Commission. *British Columbia Hydro and Power Authority and FortisBC Energy Inc.- Energy Scenarios*. December 3, 2021. Available at: https://docs.bcuc.com/documents/proceedings/2021/doc_65110_2021-12-03-bcuc-request-information-on-fei-bch-energy-scenarios.pdf
[98] *Id.* at 2
[99] British Columbia Utilities Commission. *British Columbia Hydro and Power Authority and FortisBC Energy Inc.- Energy Scenarios*. January 21, 2021. Available at: https://docs.bcuc.com/documents/arguments/2022/doc_65400_2022-01-21-fei-bch-energy-scenarios-request.pdf
[100] *Id.*

responsive filings in six months and requested monthly updates from the two utilities. The two utilities reported their findings to the BCUC on August 12, 2022,[101] and the results of the modeling exercise can be seen in Figure 16.

As of Fall 2023, no final determination had been made in either of the separate FEI or BC Hydro planning proceedings. And though the process of using competing load forecasts may be found to be imperfect, especially in its first iteration, the attempt to sync planning inputs across two separate utilities is a meaningful first step. This case study also demonstrates that through PUC oversight, separate gas and electric utilities can work together, share data and inputs, and inform the PUC and public about the potential impacts to demand from various future conditions.

Figure 16 – FortisBC's Forecasted Annual Gas Demand by Scenario[102]



Coordinated Planning Challenges

There are several challenges to coordinated gas and electric planning that PUCs need to consider and/or address. They include:

- What jurisdiction or legal authority do PUCs have to encourage or require joint planning?

[101] British Columbia Utilities Commission. *BC Utilities Commission Energy Scenarios for BC Hydro and FEI*. Available at: https://www.bcuc.com/OurWork/ViewProceeding?applicationid=959

[102] British Columbia Utilities Commission. *British Columbia Hydro and Power Authority and FortisBC Energy Inc. Energy Services, Energy Scenarios – Stage Two*. August 12, 2022. Available at: https://docs.bcuc.com/documents/proceedings/2022/doc_67461_2022-08-12-fei-stage2-submission.pdf. page 4.

- Who develops building electrification values, costs, and benefits assumptions?
- What scenario and sensitivity analyses should the utilities model?
- What information and data do the utilities need to share and how?
- What are the implications for stakeholder participation as two distinct processes begin to align or merge?
- Is it appropriate for gas utilities to develop electrification assumptions and model them as part of their planning process?
- How do gas utilities coordinate with publicly owned utilities that are not regulated by the PUC?

Each state will have to answer these questions for itself, though it is unavoidable that gas and electric utilities will need to share data and inputs such as resource cost assumptions, granular load profiles, and localized and general electrification impacts to better understand the energy transition.

Importantly, gas utilities must have electrification assumptions to use in their planning. There are numerous electric appliances on the market including air-source and ground-source heat pumps, heat pump water heaters, and induction stoves, that are competing with their gas counterparts. A utility must make assumptions about the costs of appliances (as well as ancillary costs including wiring and electrical panel upgrades), whether the electric distribution grid can support the additional load, the efficacy of the appliances under various temperatures, electricity prices, and natural gas prices. Some of these assumptions are outside the internal expertise of the gas utility, or would beget results contrary to the gas utility's financial incentives. Therefore, PUCs will need to decide who develops those assumptions.
In Oregon, the PUC Staff engaged a third-party consultant to develop proxy electrification assumptions for use in gas utility IRPs. In another similar example, the Northwest Power and Conservation Council develops long-term regional demand forecasts for the Bonneville Power Administration (BPA) to include in BPA's planning. Alternatively, if the electric utility has reasonable estimates and forecasts, and those assumptions can be vetted through a stakeholder process, the PUC may be able to require the gas utility to incorporate those assumptions into its own modeling.

Getting Started with Coordinated Gas Planning

Coordinated electricity and gas planning adds complexity but also offers significant benefits. The obstacles for dual-fuel (combined) utilities are less daunting than for coordination between separate gas and electric utilities. There is commercially available cost-optimization modeling software (for example, Plexos) that can model both the gas and electricity systems. Dual-fuel utilities can develop a plan that holistically assesses both systems, recognizes load shifts from fuel switching, and optimizes both electricity and gas capital investments and resource supply to develop a least-cost, least-risk plan for customers.

Coordinating across separate gas and electric utilities is a more significant challenge and PUCs may need to take a more incremental approach. As the British Columbia example showed, for gas-only utilities, there are several options for beginning to tackle coordinated planning:

1. PUC-determined planning scenarios and sensitivities,
2. Gas and electric utilities model the other utility's scenarios and report findings,
3. A third party provides inputs and assumptions to both utilities (after appropriate vetting with stakeholders), or
4. A combination of 1 – 3.

The best approach will depend on the specifics of the state. If the electric and gas utilities already have robust planning processes and established stakeholder engagement, then it may be reasonable to defer to the utilities to model each other's scenarios. On the other hand, if there is not a robust stakeholder engagement process that provides input to scenario development, or one of the utilities does not have a well-developed planning process, then it may be more appropriate for the PUC to determine which scenarios the two utilities should model, and/or which inputs and assumptions utilities must include.

The next step, after coordinated planning, would be a whole-system modeling approach where cost is optimized based on energy demand, inclusive of the electric and gas systems. Such a centralized approach, as far as is known, has only been examined in academic settings.[103] Regardless of approach, PUCs should begin to consider how to capture the interactive effects between the electricity and gas systems. This is true even in states without decarbonization targets, as market-driven gas-to-electric fuel switching could still have a significant impact on both electric and gas customers. Understanding the potential impacts to customers through modeling will help PUCs manage the risk that utility capital investment plans are not aligning with customer demand.

[103] Marko Aunedi, et al. Renewable and Sustainable Energy Reviews, Volume 187, 2023. *System-driven design and integration of low-carbon domestic heating technologies.* November 2023. https://doi.org/10.1016/j.rser.2023.113695

Comparison of Gas Plan Types

With the framework developed in Part I of this paper, we can assess the existing gas planning frameworks referenced in Part II for their comprehensiveness. From there, we may draw some conclusions about minimum best practices and areas that may need further development or refinement across the states. The recommended criteria presented in Table 3 below provide a comprehensive gas planning procedural template that, if followed, should help reduce costs and risk for ratepayers as a result of the energy transition.

None of the case studies presented in this report contain all of the recommended elements of a robust and effective gas plan, though overall, New York's long-term planning framework and the Pacific Northwest's Integrated Resource Plans are the most comprehensive. Still, both approaches would benefit from a greater emphasis on a review of the utility's capital investment plans.

Table 3 – Comparison of Gas Plans[104]

	New York's Long-Term Plan	Pacific Northwest's IRP	Michigan Natural Gas Delivery Plan	Colorado GIP and Clean Heat Plan	BC's Coordinated Gas and Electric Planning
Process Features					
Filing Cadence	Every 3 years	Every 2 years	Annual	GIP: Every 2 years Clean Heat Plan: Every 4 years	Every 2 – 5 years
Planning Horizon	20 years	10+ years (WA)[105] 20+ years (OR)	10 years	GIP: 6 years Clean Heat Plan: 5 years	20 years

[104] As addressed earlier in this paper, the Illinois Commerce Commission ordered three gas utilities to develop and file gas infrastructure plans shortly before publication. Illinois' gas planning requirements include several of the analytical and process requirements identified here. However, because of the recency of the requirements and the relative lack of detail with respect to implementation, we did not include Illinois in this evaluative table.
[105] In practice, Washington gas utilities plan across a 20-year horizon.

Stakeholder Comments	√	√		√	√
Technical Working Group		√			√
Third-Party Evaluation	√				
Draft and final plan	√	√		√	√
PUC Review	√	√		√	√

	New York's Long-Term Plan	**Pacific Northwest's IRP**	**Michigan Natural Gas Delivery Plan**	**Colorado GIP and Clean Heat Plan**	**BC's Coordinated Gas and Electric Planning**
Analytical Features					
Short-term action plan		2-4 years	Specific investments detailed	GIP: 3 years	4 years
Load Forecasting	√	√	√	√	√
Scenario and Sensitivity Analysis	√	√	√	√	√
Identification of Preferred Portfolio	√	√	√	√	√
Equity Analysis	√				
Bill Impact Analysis	√		√	√	√

Capital Investment Forecast	√ *		√	√	
Coordination with Electric Sector					√
NPA Assessment	√	Recently required by Oregon PUC		√	
System Mapping		Sometimes included but not required		√	

*A capital investment forecast is not explicitly required in the NY PSC's gas planning order. However, a capital investment forecast is necessary for a reasonable bill impact analysis and, at the time this report was published, each of the New York gas utilities have included capital forecasts in their initial filings.

Process Requirements

Both New York's LTP and the Pacific Northwest IRPs provide stakeholders with a strong understanding of utility investments and long-term direction. The LTP excels in its inclusion of independent third-party analysis of gas plans, while the IRPs involve stakeholders in technical working groups throughout the entirety of the process. As of the time of writing, utilities in Colorado have not yet completed the full GIP and Clean Heat Plan cycle; however, public involvement appears to be restricted due to confidential workpapers, limited technical sessions, and short turnaround times. Consumers Energy's Natural Gas Delivery plan stands out for a different reason: Though the natural gas delivery plan provides extensive analytical features, public stakeholders are not involved in the planning process at all, which significantly undermines the benefits of the exercise. All five examples are compared in Figure 17.

Figure 17 – Assessment of Gas Plan Process Requirements[106]

	New York's Long-Term Plan	Pacific Northwest IRPs	Michigan Natural Gas Delivery Plan	Colorado's GIP and Clean Heat Plan	BC's Coordinated Gas and Electric Planning
Process Requirements	◕	◕	◔	◕	◕

Analytical Features

Via their scenario analysis, detailed capital investment forecasts, and bill impact analysis, Consumers' Natural Gas Delivery Plan provides the most comprehensive analytical features among the various types of gas plans reviewed here (illustrated in Figure 18). The only analytical elements lacking from the Michigan Natural Gas Delivery Plans are 1) an equity analysis and 2) coordination with the electric.[107] The New York LTPs include nearly all of the same features as Consumers' Natural Gas Delivery Plans except a short-term action plan detailing specific investments that align with a long-term planning approach. The IRPs provide the best scenario analysis but do not include any forecasts of capital infrastructure investment or bill impacts. Too often, resource portfolios overshadow the impact of capacity investments and other system upgrades, even though infrastructure costs are important factors that drive customer rate increases and must be well understood. Therefore, it is more challenging for Pacific Northwest IRP stakeholders to determine if distribution system investments align with the preferred portfolio than it is for the NY LTP or Michigan Natural Gas Delivery Plan. The combined Colorado GIP and Clean Heat Plan are limited by the 5-year planning period of the Clean Heat Plan, which is too short to effectively evaluate the long-term potential of decarbonization strategies.

While some of the gas regulations governing these various planning processes required bill impact analysis, none of the existing gas plans had a comprehensive equity evaluation. Bill impacts that only reflect averages across a population and can hide inequities. Regulations must do more to ensure that disadvantaged populations not only are not harmed by changes in the gas system but also earn benefits from utility investments and are included in the development of the plan.

[106] The purple fill signifies the gas plan's robustness; the more purple fill, the more robust.

[107] Both plans include some detail on the impacts to the electric grid, but the analysis lacks robustness.

The Colorado GIP is the only gas plan that integrates non-pipeline alternatives substantively. While the New York LTPs require the evaluation of NPAs for leak-prone pipe replacement and there is a history of NPA implementations in the state, utilities in New York have not proposed NPA projects within their gas plans.

Figure 18 – Assessment of Gas Plan Analytical Features

	New York's Long-Term Plan	Pacific Northwest IRPs	Michigan Natural Gas Delivery Plan	Colorado's GIP and Clean Heat Plan	BC's Coordinated Gas and Electric Planning
Analytical Features					

Conclusion and Recommendations

The energy transition is increasing gas customer risks due to competition from high-efficiency building electrification, decarbonization policies, and gas price volatility. Comprehensive gas planning regulations can address each of these risks and ultimately help reduce customer costs. Gas planning generates such benefits through the mitigation of resource acquisition risks, an increase in transparency, compliance with state policies, and greater utility coordination. Ultimately, a balance in cost and risk is critical in ensuring that ratepayers are not unduly harmed by bill increases, and an amalgamation of information allows for the utility, public stakeholders, and the PUC to move together toward an outcome that maximizes societal benefits.

Recommendations

The below list offers a compilation, by topic, of the recommendations, best practices, and suggestions to avoid pitfalls experienced by existing gas plans and/or electric planning processes that have been embedded throughout this report.

Overarching Recommendations:

- In states without an existing gas planning framework, regulators should take proactive steps to set up a modern gas planning framework. In states with existing gas plans, PUCs should consider iterating on their own frameworks to improve outcomes in light of new market conditions, and as appropriate, new state policy goals.
- PUCs should err on the side of more required information, including planned gas infrastructure projects, inputs, and assumptions, when drafting requirements for a new gas plan. It is widely acknowledged that there is an inherent informational asymmetry in utility regulation, as utilities have more information than any other party about their own systems. The more a utility provides, the better stakeholders can assess the impacts and potential benefits of utility investments.

Recommendations for Process Requirements:

- **PLANNING HORIZON:**
    - While a 20-year planning horizon helps identify long-term decarbonization strategies, it is challenging to confidently model resource and capital costs over such a period. There is less uncertainty in a long-term planning period of 10 years

and short-term utility investments can clearly and directly contribute to 10-year targets. Utilities should nonetheless still describe a strategic direction for 20 years but impacts over the next 10 years should be given greater consideration.

- **FILING CADENCE:**
    - Due to the rapid evolution of the energy sector, filings should occur within two years of a PUC decision on a previous gas plan. A shorter cadence is especially critical if the PUC does not acknowledge or approve parts of a gas plan. Following a non-acknowledgment or non-approval, a utility should demonstrate a change in direction that aligns with PUC recommendations through an updated filing. A longer cadence increases the risk that ratepayers will be burdened with unnecessary or unwise investments.

- **STAKEHOLDER INVOLVEMENT:**
    - Stakeholders must be an integral part of the gas planning process. At a minimum, they must be provided the opportunity to comment on utility gas plans, though formalizing public involvement and reducing barriers to information access throughout the entire planning process allows for a more rigorous analysis of utility investment strategies.
    - In the early stages of the planning process, a technical group should be formed to represent the voices of stakeholders.
    - In the leadup to stakeholder comments, the utility must provide non-confidential information whenever possible, as confidential material can reduce transparency and undermine the public process.
    - Stakeholders should be invited to submit comments that detail any recommended revisions to the draft plan. The utility should evaluate stakeholder recommendations and make revisions to its gas plan, as needed, ahead of its final filing.
    - If the utility does not incorporate a piece of stakeholder feedback in its final plan, it should document the reasons in writing. Stakeholders should then be allowed at least one additional opportunity to address any concerns with the utility's plan. The PUC should consider all stakeholder concerns and rebuttals in its evaluation of the utility's final gas plan.

- **EVALUATING GAS PLANS:**
    - PUCs should provide utilities with clear rulings and, in the case of a non-acknowledgment or non-approval, specify the steps the utility should take.
    - PUCs should retain the authority to request additional scenarios, sensitivities, and revised forecasts in response to their own concerns or those of stakeholders.
    - PUCs should consider alternative fuel proposals carefully, and ensure that they have sufficient answers to the questions posed in Part I.C, Evaluating RNG and Hydrogen in Modern Gas Plans.

Recommendations for Analytical Features:

- **FORECASTS:**
    - Given that a thorough gas planning process relies on significant analysis of load forecasts, resource portfolios, supply forecasts, capital forecasts, and bill impacts, establishing a set of regulations governing the forecasting and analysis of data is a key step to establishing a successful gas planning process.
    - Load forecasting must be conducted both on the system-wide scale and down to varying climate zones and localities/neighborhoods that might be experiencing different trends in gas use.
- **SHORT-TERM ACTION PLAN:**
    - The gas planning process should yield a five-year action plan that is congruent with a long-term strategy. To be acknowledged or approved by the PUC, a utility gas plan should identify a least-cost, least-risk portfolio of resources, which details anticipated near-term investments that align with market trends and meet state climate goals, if applicable.
- **INCORPORATING EQUITY:**
    - In designing stakeholder and public engagement around modern gas plans, PUCs and utilities should ensure that communities have an opportunity to meaningfully participate.
    - PUCs should consider adopting the Department of Energy's Distributional Energy Analysis Metric Framework for review of DER-related projects within a gas plan.

- Gas plans should consider equity via a distributional analysis of impacts and define a minimum percentage of clean energy investment or benefits that must be implemented for or accrue to disadvantaged populations, if possible, within state law.
- PUCs should leverage national and state work to define and map disadvantaged communities for use in the gas plans, and consider requiring gas utilities to overlay a map of proposed capital projects and resource acquisitions in the short-term action plan with a map of all disadvantaged populations in the utility's service area.

- **NON-PIPELINE ALTERNATIVES:**
  - PUCs should develop NPA frameworks to embed within their gas planning processes.
  - An NPA framework should include three phases: preliminary screening, portfolio development, and portfolio evaluations. The preliminary screening process should filter projects based on safety as well as cost and time thresholds.
  - Ultimately, *portfolios* (not individual projects) should be judged by their ability to address the system need and their cost, benefit, and risk compared with the traditional infrastructure solution.
  - Regulations may consider indicating a preference for demand-side solutions since such resources typically provide more customer benefits and lead to greater emissions reductions than supply-side resources.
  - Competitive solicitations should be leveraged where possible to ensure that the market has the ability to put forth innovative and cost-competitive solution options.
  - The portfolio evaluation step should include a BCA, a quantitative assessment of vendors, and an equity analysis.
  - PUC should consider complementary policy changes to support NPA projects, such as a shared-savings mechanism.

- **SYSTEM MAPPING:**
  - System mapping should be used to inform stakeholders of capacity plans and to support equity analysis.

- **COORDINATING WITH THE ELECTRIC SECTOR:**
    - Combined utilities should begin to develop an internal team that is responsible for planning across both fuels. A PUC can assist this effort by developing a timeline of expectations. For example, the utility could start on the path toward coordinated planning by simplifying the process and filing a separate, outside-the-plan analysis that examines the impacts on both systems from a single scenario.
    - Any plans, teams, or processes for coordinated planning within a combined utility should be transparent and include opportunities for stakeholder participation and input, wherever appropriate.
    - PUCs overseeing separate gas and electric utilities should explore options, including developing PUC-determined planning scenarios and sensitivities, directing gas and electric utilities to model each other scenarios and report findings, or contracting with a third party to provide inputs and assumptions to both utilities (after appropriate vetting with stakeholders).
    - PUCs should explore with the utilities and the stakeholder community the appropriate level of data to be shared between utilities and stakeholders. For example, electric utilities are increasingly producing hosting capacity analysis maps that inform DER developers and customers of the ability of an individual feeder to absorb additional supply or demand. This level of information may be valuable for conducting gas utility NPA analysis or identifying areas for the state, a municipality, or a utility to prioritize beneficial electrification programs.

Appendix: State Examples of Data Access and Open Access Modeling

Arizona

On March 2, 2022, the Arizona Corporation Commission issued an order[108] in a resource planning and procurement docket to require that utilities, for future Integrated Resource Plans (IRPs), negotiate access to, and cover the costs for, up to 12 Resource Planning Advisory Council members and Staff to perform their own modeling runs in the same software package as the utilities. The order also required utilities to provide all necessary data and support for those stakeholders to fully utilize the models.

New Mexico

In late 2018, the Public Service Company of New Mexico (PNM) proposed to decommission the San Juan Generating Station. When initiating the proceeding, the Public Regulation Commission (PRC) required PNM to provide access to all computer models used to support its selection of replacement resources.[109] Stakeholders could either have virtual access to PNM's modeling software to run their own scenarios or request that PNM run specific scenarios on their behalf.[110] The PUC ultimately selected an intervenor proposal, which provided lower costs, greater resource diversity, and more community benefits than the utility proposal.[111]
In May 2021, the PRC took a broader step towards expanding access to utility modeling by opening a docket to revise its integrated resource planning rules. Its goals were 1) to ensure that utilities prioritize resources aligned with state greenhouse gas reduction targets and grid modernization, and 2) to improve transparency for regulators, stakeholders, and the public.[112]
On September 14, 2022, the PRC issued an order requiring utilities to provide staff and

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[108] Arizona Corporation Commission. Docket no. E-00000V-19-0034. *Order*. December 15 and 16, 2021. Available at: https://docket.images.azcc.gov/0000206081.pdf?i=1663624640116.

[109] New Mexico Public Regulation Commission. Docket No. 19-00018-UT. *Order Initiating Proceeding on PNM's Verified Compliance Filing Concerning Continued Use of & Abandonment of San Juan Generating Station.* January 30, 2019. Available at: https://powersuite.aee.net/dockets/nm-19-00018-ut/filings/13489170?version=beta&filing_search_id=1258879&document_id=157217274.

[110] Public Service Company of New Mexico. Docket No. 19-00195-UT. *Public Service Company of New Mexico's Proposal to Provide Parties Access to Resource Planning Models and Information Regarding Requests for Proposals.* July 29, 2019. Available at: https://powersuite.aee.net/dockets/nm-19-00195-ut/filings/13490125?version=beta&filing_search_id=1258965&document_id=157218322.

[111] New Mexico Public Regulation Commission. Docket No. 19-00195-UT. *Order on Recommended Decision on Replacement Resources – Part II. 2020*. July 29, 2020. Available at: https://powersuite.aee.net/dockets/nm-19-00195-ut/filings/13763830?version=beta&filing_search_id=785299&document_id=157812089.

[112] New Mexico Public Regulation Commission. Docket No. 21-00128-UT. *Order Opening Docket, Initiating Rulemaking and Establishing Workshop Schedule.* May 26, 2021. Available at: https://powersuite.aee.net/dockets/nm-21-00128-ut/filings/15296428?version=beta&filing_search_id=1258851&document_id=161996498.

stakeholders with reasonable access to the same modeling software and all modeling information used by the utility.[113]

Oregon

On October 30, 2020, the Oregon Public Utility Commission accepted a stipulation on one of PacifiCorp's rate adjustment mechanisms, which included measures to increase understanding of and access to the utility's new production cost model.[114] In this stipulation, the utility agreed to 1) host a public workshop on its new modeling, 2) provide modeling licenses for all PUC staff and intervenors, and 3) share all inputs, data, modeling settings, and constraints used by the utility in its forecasts.

Kentucky

On November 25, 2020, the Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E), together referred to as LG&E/KU, filed applications with the Kentucky Public Service Commission requesting approval for significant increases in revenue and several tariff revisions.[115] Upon investigation, the Commission found a notable lack of transparency in LG&E/KU's modeling, which it stated would likely become increasingly problematic as renewable energy penetration deepens. On June 30 and September 24, 2021, the Commission denied the requested increase in revenue[116] and the proposed tariff revisions, ordering LG&E/KU to submit a proposal detailing how they would increase their modeling transparency.[117] In response, LG&E/KU proposed to include more granular summaries of their inputs and outputs in future filings; run models on behalf of intervenors; support the

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[113] New Mexico Public Regulation Commission. Docket No. 21-00128-UT. *Final Order*. September 14, 2022. Available at: https://powersuite.aee.net/dockets/nm-21-00128-ut/filings/17239777?version=beta&filing_search_id=1258833&document_id=167477708.

[114] Oregon Public Utility Commission. Docket No. UE 375. *Order No 20-392.* October 30, 2020. Available at: https://apps.puc.state.or.us/orders/2020ords/20-392.pdf

[115] Kentucky Utilities Company. Docket No. 2020-00349. *Kentucky Utilities Company's Statutory Notice, Customer Notice of Rate Adjustment, Application, Filing Requirements, Direct Testimony, and Petition for Confidential Protection for an adjustment of its Electric Rates and other requests.* November 25, 2020. Available at: https://app.insightengine.org/dockets/ky-2020-00349?filing_search_id=1616084&version=beta&workspace=all#search-results-anchor; Louisville Gas and Electric Company. Docket No. 2020-00350. *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit.* 2020. Available at https://psc.ky.gov/pscecf/2020-00350/rick.lovekamp%40lge-ku.com/11252020085918/05-LGE_Application_%282020-00350%29.pdf

[116] Kentucky Public Service Commission. Docket No. 2020-00349. Order. 2021. Available at: https://psc.ky.gov/pscscf/2020%20Cases/2020-00349//20210630_PSC_ORDER.pdf

[117] Kentucky Public Service Commission. Docket Nos. 2020-00349 and 2020-00350. Order. September 24, 2021. Available at: https://psc.ky.gov/pscscf/2020%20Cases/2020-00349//20210924_PSC_ORDER.pdf

Commission seeking licenses to run the model with alternative inputs; and increase access to online data.[118]

South Carolina

On December 23, 2020, the South Carolina Public Utilities Commission issued an order directing Dominion Energy South Carolina to expand its IRP modeling and transparency, including negotiating a discounted licensing agreement that would allow interested stakeholders to perform their modeling using the same software as the utility.[119]

[118] Louisville Gas & Electric and Kentucky Utilities Company. *2020 Rate Case*. December 22, 2021. Available at: https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp@lge-ku.com/12222021084221/Closed/3-LGE_KU_Response_12-22-2021.pdf

[119] South Carolina Public Utilities Commission. Docket No. 2019-226-E. *Order No. 2020-832, Order Rejecting Dominion's Integrated Resource Plan and Requiring Dominion to Make Modifications to Its 2020 Integrated Resource Plan, Future Updates and Future Integrated Resource Plans.* December 23, 2020. Available at: https://dms.psc.sc.gov/attachments/order/a4b59f43-e545-43bd-9f35-a846b7602c39