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# Coordinated Natural Gas and Electric Planning

Case Studies of Current Approaches and Practices

July 2026

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## Executive Summary

This paper examines how natural gas and electric utilities across eight U.S. states and two Canadian provinces are beginning to coordinate historically separate planning processes in response to growing system interdependencies, policy mandates, aging infrastructure, and changing customer energy choices. Electricity planning has long relied on robust integrated resource planning frameworks that weigh numerous objectives, risks, and costs. Natural gas planning, on the other hand, has typically been less transparent to regulators and more narrowly focused on safety and system integrity. As economic, reliability, and policy drivers place new and shared demands on both systems, jurisdictions and utilities are experimenting with approaches such as coordinated forecasting, non-pipeline alternatives, and combined planning pilots. A few have issued regulatory or statutory directives for greater data sharing and methodological alignment. Case studies from British Columbia, California, Colorado, Illinois, Massachusetts, Minnesota, New York, Québec, Rhode Island, and Washington illustrate a wide range of approaches to rethinking siloed planning.

Across these jurisdictions, several common themes emerge.

- Coordinated planning is a nascent discipline, with varying levels of legislative, regulatory, utility, and stakeholder initiation and involvement. Regulators are encountering novel challenges requiring innovative regulatory solutions that have not yet coalesced into a collection of best practices.
- Natural gas planning has generally not been required to be as transparent as electricity planning, making coordinated decisions about planning and investments difficult.
- The historical separation of planning processes between natural gas and electric utilities means that very few utilities have experience with processes or methods for analyzing the systems together. For example, load forecasting, scenario analysis, and cost-benefit analysis are key aspects of planning that have rarely been conducted in an aligned fashion.
- Institutional silos—both within utilities and regulatory agencies—create barriers to coordination.
- Agreement between utilities and other stakeholders is lacking on which natural gas investments should be subject to joint analysis. Consistent criteria on investment types for joint planning are needed.
- Some states and utilities are required by law to begin exploring alternatives to natural gas infrastructure. The most common approach—non-pipeline alternatives—faces practical, economic, and regulatory hurdles.

Based on our review of the approaches taken in the ten jurisdictions surveyed, we share observations on methods, processes, and organizational steps that may be needed in the future to address the identified challenges.

|                             |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
|-----------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Methods</b>              | <ul style="list-style-type: none"> <li>• Enhance visibility into natural gas system planning.</li> <li>• Determine appropriate data access for utilities, regulators, and stakeholders, balancing costs and benefits.</li> <li>• Align planning approaches across fuels, particularly forecasting, cost-benefit analysis, and scenario/sensitivity development.</li> <li>• Implement iterative modeling between natural gas and electric systems using consistent inputs and assumptions.</li> <li>• Test existing industry planning tools and methods to reveal strengths and gaps.</li> <li>• Identify which size and type of investments in both systems are suitable for integrated planning.</li> </ul> |
| <b>Processes</b>            | <ul style="list-style-type: none"> <li>• Conduct investigations (formal or informal) or initiate collaborations to deepen understanding of system interdependencies and strengthen relationships</li> <li>• Clarify benefits and barriers of coordinated planning to guide priority focus areas for utilities or jurisdictions.</li> <li>• Examine how gas-electric interdependencies affect foundational regulatory practices (e.g. cost socialization, cost recovery).</li> </ul>                                                                                                                                                                                                                          |
| <b>Organizational Steps</b> | <ul style="list-style-type: none"> <li>• Build internal structures at utilities and regulatory commissions to improve information flow and remove barriers to integrating planning functions.</li> <li>• Create mechanisms for greater coordination across separate utilities.</li> </ul>                                                                                                                                                                                                                                                                                                                                                                                                                    |

Jurisdictions and utilities discussed in this paper often approach coordinated planning with a consistent set of initial steps. A common starting point is more robust and transparent planning from natural gas utilities that describes how to efficiently meet customer demand, meet state policy goals, or weigh investment alternatives. Several utilities are aligning natural gas and electric demand forecasting assumptions. Regulatory investigations or processes are being set up to foster conversation between utilities, regulators, and customers, and create a common understanding, language with defined terms, and a shared set of objectives. Finally, regulators and utilities are working to break down internal organizational barriers to all of the above. These actions, even if incremental, offer “no regrets” foundations for more integrated, cost-effective, and policy-aligned energy system planning, regardless of whether a full-scale shift to integrating natural gas and electric planning is a desired future state.

## Acknowledgments

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## Glossary of Terms

| Term(s)                                                                                          | Definition(s)                                                                                                                                                                                           |
|--------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| “Combination” or “dual-fuel” utilities                                                           | A utility that provides both natural gas and electric service to customers.                                                                                                                             |
| “Coordinated” or “integrated” natural gas and electric planning, or “integrated energy planning” | A framework that merges or coordinates energy planning across both fuel types to optimize system planning and investments and holistically meet desired objectives.                                     |
| “Deregulated” or “restructured”                                                                  | A state or utility that has transitioned from a traditional monopoly model to a market-driven system by decoupling energy generation from delivery, allowing consumers to choose their energy supplier. |
| Distribution system planning (DSP) (electric)                                                    | A process that systematically develops plans for the future of the distribution system and considers all possible solutions to distribution system needs.                                               |
| Dual-energy heating                                                                              | A space heating system that combines two different energy sources (e.g. electricity and natural gas) within a single building. Also sometimes referred to as hybrid heating systems.                    |
| “Electric distribution companies (EDC)” or electric utilities or electric companies              | Entities that deliver electricity to end-use customers through local distribution networks.                                                                                                             |
| Integrated resource plans (IRPs)                                                                 | A comprehensive plan for meeting projected energy and peak demand requirements over a long-term horizon (e.g. 15-20 years).                                                                             |
| “Local distribution companies (LDC)” or “natural gas utilities”                                  | Entities that deliver natural gas to end-use customers through local distribution pipelines.                                                                                                            |
| Non-pipeline alternative                                                                         | An investment, technology, or operational strategy that reduces, defers, or avoids the need to build or expand physical natural gas pipeline infrastructure.                                            |
| Non-wires alternative                                                                            | An investment, technology, or operational strategy that reduces, defers, or avoids the need to build or expand physical electric system infrastructure.                                                 |

## Acronyms and Abbreviations

|         |                                                 |
|---------|-------------------------------------------------|
| AB      | Assembly Bill                                   |
| BC      | British Columbia                                |
| BCA     | benefit cost analysis                           |
| BCUC    | British Columbia Utilities Commission           |
| CAISO   | California Independent System Operator          |
| CARB    | California Air Resources Board                  |
| CCA     | Community Choice Aggregators                    |
| CEC     | California Energy Commission                    |
| CGR     | California Gas Reports                          |
| CHG&E   | Central Hudson Gas and Electric                 |
| CHP     | Clean Heat Planning                             |
| CLCPA   | Climate Leadership and Community Protection Act |
| ConEd   | Consolidated Edison                             |
| COPUC   | Colorado Public Utilities Commission            |
| COU     | consumer-owned utilities                        |
| CPUC    | California Public Utilities Commission          |
| DPU     | Department of Public Utilities                  |
| DSP     | distribution system planning                    |
| EAA     | Expansion Alternatives Analysis                 |
| ECO     | Energy Conservation and Optimization            |
| ECO Act | Energy Conservation and Optimization Act        |
| EDC     | electric distribution company                   |
| ERP     | Electric Resource Plans                         |
| ESMP    | Electric Sector Modernization Plan              |
| ESP     | Energy Service Provider                         |
| GIP     | Gas Infrastructure Plans                        |
| GSEP    | Gas System Enhancement Plan                     |
| IEP     | integrated energy planning                      |
| IEPR    | Integrated Energy Policy Report                 |
| ICC     | Illinois Commerce Commission                    |
| IOU     | Investor-owned utility                          |
| IRP     | integrated resource plan                        |
| ISP     | Integrated System Plan                          |
| ISR     | Infrastructure, Safety, and Reliability         |
| LCP     | Least Cost Procurement                          |

|        |                                                      |
|--------|------------------------------------------------------|
| LDC    | local distribution company                           |
| LT-GIP | long-term gas infrastructure plans                   |
| LTGRP  | long-term gas resource plan                          |
| MERC   | Minnesota Energy Resources Corporation               |
| NGIA   | Natural Gas Innovation Act                           |
| NYSEG  | New York State Electric and Gas                      |
| OIR    | Order Instituting Rulemaking                         |
| PG&E   | Pacific Gas and Electric Company                     |
| PGE    | Puget Sound Energy                                   |
| PGIRE  | Plan de gestion intégrée des ressources énergétiques |
| PSC    | Public Service Commission                            |
| PUC    | public utility commission                            |
| PUD    | public utility district                              |
| RG&E   | Rochester Gas and Electric                           |
| RIE    | Rhode Island Energy                                  |
| RPAG   | Resource Planning Advisory Group                     |
| SB     | Senate Bill                                          |
| SCE    | Southern California Edison Company                   |
| SDG&E  | San Diego Gas and Electric Company                   |
| SRP    | System Reliability Procurement                       |
| T&D    | transmission and distribution                        |
| TAC    | Technical Advisory Committee                         |
| TEP    | Transportation Electrification Plan                  |
| UTC    | Utilities and Transportation Commission              |

## Contents

|                                                         |      |
|---------------------------------------------------------|------|
| Executive Summary .....                                 | ii   |
| Acknowledgments .....                                   | iv   |
| Glossary of Terms .....                                 | v    |
| Acronyms and Abbreviations .....                        | vi   |
| Contents .....                                          | viii |
| Figures .....                                           | ix   |
| Tables .....                                            | ix   |
| 1.0 Introduction .....                                  | 1    |
| 1.1 History and Foundations .....                       | 1    |
| 1.2 Contextual Drivers for Coordinated Planning .....   | 2    |
| 1.3 Case Study Themes and Takeaways .....               | 2    |
| 1.4 Case Study Research Approach .....                  | 4    |
| 2.0 Case Studies .....                                  | 5    |
| 2.1 British Columbia .....                              | 5    |
| 2.2 California .....                                    | 10   |
| 2.3 Colorado .....                                      | 19   |
| 2.4 Illinois .....                                      | 25   |
| 2.5 Massachusetts .....                                 | 30   |
| 2.6 Minnesota .....                                     | 34   |
| 2.7 New York .....                                      | 39   |
| 2.8 Québec .....                                        | 47   |
| 2.9 Rhode Island .....                                  | 51   |
| 2.10 Washington .....                                   | 55   |
| 3.0 Summary Themes and Takeaways .....                  | 65   |
| 3.1 Coordinated Energy Planning Themes .....            | 65   |
| 3.2 Initial Steps for Jurisdictions and Utilities ..... | 72   |

## Figures

|            |                                                                                                                                         |    |
|------------|-----------------------------------------------------------------------------------------------------------------------------------------|----|
| Figure 1:  | Service territory map of BC Hydro electricity franchise area and Fortis BC electricity franchise area. ....                             | 6  |
| Figure 2:  | California utilities' electric service territories. ....                                                                                | 12 |
| Figure 3:  | California utilities' gas service territories ....                                                                                      | 13 |
| Figure 4:  | Example natural gas distribution maps showing differing levels of detail regarding foreseeable natural gas infrastructure projects..... | 17 |
| Figure 5:  | 2023 Colorado Electric Utility Service Territories.....                                                                                 | 19 |
| Figure 6:  | 2023 Colorado Gas Utility Service Territories.....                                                                                      | 20 |
| Figure 7:  | Public Service Company of Colorado (Xcel Energy) Key Planning and Rate Recovery Processes.....                                          | 22 |
| Figure 8:  | Illinois Electricity and Natural Gas Utilities Service Area Maps.....                                                                   | 26 |
| Figure 9:  | Massachusetts Electricity and Natural Gas Utility Service Areas.....                                                                    | 30 |
| Figure 10: | Service Territories of Electric Utilities in New York. ....                                                                             | 40 |
| Figure 11: | Electric and Natural Gas Service Territories in New York City.....                                                                      | 41 |
| Figure 12: | NYSEG and RG&E New York Service Territories ....                                                                                        | 41 |
| Figure 13: | Service Territories of Electric Utilities in Washington.....                                                                            | 55 |
| Figure 14: | Regulated Natural Gas Service Areas in Washington ....                                                                                  | 56 |
| Figure 15: | Puget Sound Energy Service Area Map.....                                                                                                | 56 |
| Figure 16: | Puget Sound Energy's Integrated System Plan Portfolio Development Process.....                                                          | 60 |
| Figure 17: | Avista Utilities' Electric and Natural Gas Service Territories.....                                                                     | 62 |
| Figure 18: | Avista's Integrated Natural Gas and Electric Planning Process.....                                                                      | 63 |

## Tables

|          |                                                                                         |    |
|----------|-----------------------------------------------------------------------------------------|----|
| Table 1: | Key Dates in Massachusetts' Integrated Planning Processes .....                         | 32 |
| Table 2: | Timeline of Minnesota Key Filings and Decisions Related to Long-Term Gas Planning ..... | 36 |

## 1.0 Introduction

### 1.1 History and Foundations

Comprehensive, long-term planning has long been a core analytical framework used by electric and natural gas utilities to understand future energy demand and find the set of investments needed to serve customers at the least cost while accounting for risk. This traditional planning framework attempts to find the right balance of system attributes such as low rates, resource adequacy, achievement of state and federal energy policies, and low-risk system investments. Utilities have used integrated resource plans (IRPs) to examine energy generation and production, transmission, and distribution system needs and solutions. Distribution system planning (DSP) is a relatively new planning approach focused solely on the local energy delivery system (e.g., distribution wires and natural gas mains).

Historically, natural gas and electric system planning were separate exercises, even within a combination utility. Siloed planning in natural gas and electric systems has historically had different timing, used different models and data, and used different load forecast assumptions. Yet, natural gas and electric systems are becoming increasingly interdependent at the bulk and distribution levels. Energy demand growth from artificial intelligence computing and manufacturing is fueling a growing reliance on natural gas-fired generation to serve growing system load peaks and to balance intermittent generating resources. At the distribution level, natural gas and electric utilities provide similar energy services to residential and commercial customers and together must manage energy system peaks.

As interdependencies between the natural gas and electric systems become clearer to utilities and regulators, increased coordination is becoming necessary to capture least cost alternatives, maintain system reliability, address policy priorities, and manage weather extremes. Several jurisdictions and utilities have begun exploring and implementing coordinated natural gas and electric system planning. “Coordinated” and “integrated” are two terms now being used to describe planning processes that attempt to break down some of the silos that have historically existed.

Retail natural gas and electric utilities come in different permutations, which has implications for planning purposes. In general, retail distribution natural gas utilities tend to be investor-owned and generate a rate of return based on capital invested in distribution infrastructure. There are also examples of municipal-owned natural gas utilities that serve the same function but have a different corporate structure. Investor-owned electric utilities (IOUs) can be distribution-only or vertically integrated, owning distribution, generation, and transmission assets. Consumer-owned electric utilities are frequently just distribution-only, although some consumer-owned utilities (COUs) own generation and transmission as well. Finally, there are investor-owned combination electric and natural gas utilities that operate both systems, but often the natural gas and electric services territories are not entirely overlapping. For example, one utility’s natural gas distribution system could serve a neighboring electric company’s territory.

Other major players include interstate pipeline companies, which maintain the network to deliver bulk natural gas to retail utilities, generators, liquefied natural gas facilities, and large customers, and independent electric generators, which deliver electricity to retail utilities and large customers. These entities will ultimately be important to regional coordinated natural gas and electric planning, but are not the focus of this paper primarily because they are not subject to

state regulation or COU oversight, which are the primary venues moving coordinated planning forward at this time.

This paper presents case studies of several jurisdictions and utilities that are attempting to increase the coordination of natural gas and electric utility system planning, often by first improving natural gas planning. Each jurisdiction has a unique utility landscape and motivations for improving planning processes. The case studies help identify areas of commonality and differences in approach. This exploration of approaches highlights a wide range of challenges, values, processes, and solutions to increase coordination of planning across systems and achieve improvements in operations and resource development.

## 1.2 Contextual Drivers for Coordinated Planning

Each jurisdiction or utility examined in the case studies has its own reasons for pursuing integrated planning. These motivating factors stem from the unique market, policy, and utility context in each jurisdiction, but can be grouped into four general categories.

One motivating factor common to all jurisdictions that are exploring natural gas and electric coordinated planning is the desire to **achieve energy system efficiencies and cost savings**. Increasing efficiency between the two systems through optimized operations and least cost infrastructure investments can lead to economic savings across the combined system.

Jurisdictions and utilities are recognizing that coordination of natural gas and electric systems is an important strategy for **ensuring safe and reliable operation of both systems**, especially in times of peak demand and extreme weather events. Recent experience shows that riding through extreme weather events often requires both systems to operate in concert at both the distribution and bulk levels. Coordinated planning offers the possibility of operating protocols and optimal system investments designed in advance of extreme weather events, thus promoting resource adequacy and resilience of the combined energy system.

Several jurisdictions have enacted or are considering **explicit statutory requirements** to pause the growth or reduce the footprint of natural gas usage. Such requirements impact operations and future investments in both electric and natural gas systems. Better coordination between systems can clarify timing, staging of future investments, costs, and retail rate implications.

In some jurisdictions, even where there are no mandates specific to natural gas usage, there are **regulatory directives to examine “non-pipeline” solutions** to serving growing natural gas retail load. Similar to “non-wires” analysis on the electric system, the non-pipeline analysis is part of distribution system planning that attempts to delay the need for new pipeline investment or expansion by using demand-side solutions, including possibly electric conversion. Delaying new large capital investments helps to stretch out rate impacts and allows additional time to consider new technology options.

## 1.3 Case Study Themes and Takeaways

Jurisdictions and utilities that have expressed an interest in increasing the coordination of natural gas and electric utility system planning have faced some common challenges in doing so. Addressing these challenges is a central focus of the processes and proposals we reviewed, and it often stems from gaps and inefficiencies in the current planning approach.

These gaps and inefficiencies largely result from the historical separation between natural gas and electric resource planning. The two sectors were seen as related but were not considered necessary to coordinate. As a result, as planning matured, each sector developed its own standard practices and methods.

The case studies examine how 10 jurisdictions and their associated utilities are responding to this historical separation and their particular contextual drivers. The observed themes are briefly summarized below. Section 3.0 provides more detail on these themes and observations on ways jurisdictions and utilities are, or may want to consider, addressing the associated challenges.

**Coordinating natural gas and electric planning is a nascent effort.** Jurisdictions and utilities are driven by different policy and market drivers, and are deploying tools to address gaps and challenges. Regulators and utilities are encountering novel challenges requiring innovative solutions.

**In most jurisdictions, natural gas planning is not as robust or transparent as electricity planning.** The historic lack of regulatory visibility into the natural gas system is making decisions about planning and investments difficult. Natural gas system planning has historically been focused on maintaining integrity and physical safety, but is now being asked to explore a broader range of planning criteria.

**Utilities and regulators have historically organized planning and operations by sector, creating institutional silos.** Organizational silos at both the utility and the regulator create physical, institutional, procedural, and economic barriers to conducting coordinated planning.

**Natural gas and electric planning methods are developed, refined, and deployed separately.** Very few utilities have experience with processes or methods for analyzing the systems together. For example, load forecasting, scenario analysis, and cost-benefit analysis are key aspects of planning that have rarely been conducted with aligned assumptions or methods across natural gas and electric utilities (or the natural gas and electric businesses within a single utility).

**Agreement is lacking on the types of natural gas system investments to include in joint planning.** Stakeholders and utilities disagree about whether certain types of investments—safety investments, for example—should be excluded from joint planning conversations. Consistent criteria on investment types for joint planning are needed.

**Some jurisdictions and utilities are required to start exploring alternatives to natural gas infrastructure investments.** Some jurisdictions have specific statutory direction to shift consumer end-uses off natural gas. This comes with special considerations around serving peak load, preventing cost-shifting, and avoiding unnecessary investments, all of which benefit from more coordinated energy planning.

## 1.4 Case Study Research Approach

The case studies described in this paper explore natural gas and electric system coordination activity in 8 U.S. states and 2 Canadian provinces. The research team conducted outreach interviews to state regulators and utilities, reviewed utility plans, party comments, and public utility commission (PUC) orders, and revisited other literature on this topic, many of which are cited in our earlier literature review.<sup>1</sup> The survey of activity helps identify the range of jurisdictional motivations, procedural paths toward coordination, methodological motivations, and the outcomes or next steps. To the extent that consistent trends are identified, they will be described, but the differences in approach are also instructive and might serve as a catalogue of options for future exploration. Each case study is presented as the state or province as a whole and covers one or more utilities within the jurisdiction. It should be noted that jurisdictions in addition to those represented in these case studies are beginning to explore coordinated natural gas and electric planning, which will add innovative approaches to the discipline as well as help confirm best practices.

Each case study provides a brief summary and covers five distinct areas.

1. Context. This includes the landscape of natural gas and electric service in the jurisdiction, including details on service territory, data on customers, and related information. In addition, the background policies relevant to coordinated planning will be described.
2. Planning Framework. This describes the new planning requirements, processes, and regulatory decisions specific to coordinated planning.
3. Planning Methodologies. Methodologies covering forecasts, non-pipes analysis, and integration of natural gas and electric plans will be identified.
4. Remaining Issues. Any additional issues under consideration or unique to the jurisdictions will be identified.
5. Next steps. A description of upcoming decisions, filings, or processes that are expected.

---

<sup>1</sup> Shipley, J. A., J. T. Barlow, and G. Relf. 2024. *Review of Literature and Utility Commission Proceedings Relevant to Integrated System Planning*. Pacific Northwest National Laboratory, PNNL-37056. <https://www.osti.gov/biblio/2479185>

## 2.0 Case Studies

### 2.1 British Columbia

#### 2.1.1 Summary

The two major electricity and natural gas providers in British Columbia (BC)—BC Hydro and FortisBC—each develop long-term resource plans that are submitted to the British Columbia Utilities Commission (BCUC) every four to five years. The BCUC has encouraged greater collaboration and alignment between the utilities’ plans by asking the companies to use shared forecasting assumptions; explain how the other utility’s scenarios could affect supply choices, customer rates, and policy targets; and identify a set of assumptions common to the development of each plan, along with information on those in their next filing. The utilities have responded by joining each other’s advisory committees and sharing planning methods, which helped the utilities align assumptions about regional residential growth and reach consistent projections of fuel switching. Both utilities’ current plans are under BCUC regulatory review.

#### 2.1.2 Context

In BC, electricity is supplied by vertically integrated utilities that operate in a monopoly franchise area (see Figure 1), with utility customers receiving a single bill for the generation and delivery of their electricity.<sup>1</sup> Major regulated utility providers like BC Hydro (electricity) and FortisBC (natural gas) submit independent, long-term resource plans to the BCUC.

BC Hydro, a public sector corporation, provides electric service to about 95% of the province's population. FortisBC, an investor-owned utility (IOU), serves most of the remainder and is the primary distributor of natural gas for much of the province. Its natural gas service territory primarily overlaps with BC Hydro’s electric territory, making integrated planning necessarily a joint utility effort. The differences in corporate structure between the two utilities complicate this somewhat due to differing mandates, market objectives, and ultimate financial accountability.

---

<sup>1</sup> Morton, D. 2025. “The future of integrated resource planning: how integrated should it be?” *Energy Regulation Quarterly*. April 2025. <https://energyregulationquarterly.ca/articles/the-future-of-integrated-resource-planning-how-integrated-should-it-be#sthash.31yN4qO7.dpbs>



Figure 1: Service territory map of BC Hydro electricity franchise area and Fortis BC electricity franchise area.<sup>1</sup>

BC utilities have been required to submit long-term natural gas and electric resource plans for at least two decades. The long-term gas resource plan (LTGRP) requirement sets BC apart from many other jurisdictions in that it provides an in-depth examination of energy supply, demand projections, and resource alternatives on the natural gas system. This provides a foundation upon which the BCUC has begun to encourage greater coordination between the two utilities.

<sup>1</sup> BC Hydro. BC Hydro service area map. Accessed July 1, 2026.

<https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/safety/bchydro-service-area-map.pdf>

During the development of the utilities' 2021–2022 long-term resource plans, the BCUC encouraged both BC Hydro and FortisBC to create load forecasts informed by the other utility's planning scenarios. The utilities were asked to file the load forecasts resulting from this analysis and provide commentary regarding the impacts on supply resources, rates, and policy targets to meet the load scenarios.<sup>1</sup>

### 2.1.3 Planning Framework

During the 2021–2022 LTGRP and electric IRP processes, the companies provided responses to various scenarios put forward by the other, which were filed in both companies' proceedings for that planning cycle.<sup>2, 3</sup> However, challenges also arose during the forecast development process, including the lack of sectoral and geographical resolution and an understanding of the impact of increased electric use on the load forecast (e.g., the effect on peak load under colder temperatures than BC Hydro's system design temperature).<sup>1</sup>

In concluding comments within the resource plans, the companies noted potential alignment with each other's future resource plans, in particular, the design of load shifting scenarios and the examination of potential future specific end uses.<sup>4</sup>

In Decision and Order G-58-24, formally accepting BC Hydro's 2021 Integrated Resource Plan, and Decision and Order G-78-24, formally accepting FortisBC's 2022 LTGRP, the BCUC strongly encouraged the utilities to enhance communication on resource planning issues and to identify planning assumptions that are common to each plan to facilitate easier comparison between the approaches taken by each utility.<sup>1</sup>

The regulators noted that it could be useful for the utilities to identify a set of assumptions common to the development of each plan and to provide information on those in their next filing. They noted several assumptions that would likely be relevant for both utilities' future resource plans, including:

1. customer growth rates by region
2. cross-price elasticity
3. volume of fuel switching
4. capture rates of new customers for major end-uses (e.g., space and water heating)
5. hydrogen production or other low carbon gas facilities located within BC
6. whether provincial emissions targets are assumed to be met in certain scenarios.

Beyond the above modeling suggestions, the BCUC did not make any determinations regarding collaboration between the major utilities in these decisions.

<sup>1</sup> BCUC. "2021 Integrated Resource Plan: Decision and Order G-58-24." March 6, 2024.

<https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/522156/1/document.do>

<sup>2</sup> BCUC. "FortisBC 2022 Long Term Gas Resource Plan Proceeding." 2024.

<https://www.bcuc.com/OurWork/ViewProceeding?applicationid=1000>

<sup>3</sup> BCUC. "BC Hydro 2021 Integrated Resource Plan Proceeding." 2024.

<https://www.bcuc.com/OurWork/ViewProceeding?applicationid=965>

<sup>4</sup> FortisBC. "British Columbia Hydro and Power Authority (BC Hydro) 2021 Integrated Resource Plan (IRP) – Project No. 1599287: Final Argument." December 21, 2023.

[https://docs.bcuc.com/documents/arguments/2023/doc\\_75498\\_2023-12-21-fortisbc-finalargument.pdf](https://docs.bcuc.com/documents/arguments/2023/doc_75498_2023-12-21-fortisbc-finalargument.pdf)

### 2.1.4 Planning Methodologies

During the current round of resource planning processes, both FortisBC and BC Hydro made efforts to respond to the BCUC suggestions from the 2021–2022 plans. The utilities participated in each other's technical advisory committees and met throughout their respective planning processes to identify opportunities for information sharing that could benefit the development of future long-term resource plans. The plans were under development during similar timeframes, which facilitated collaboration and the sharing of information. However, the slightly staggered processes meant that information from FortisBC was not always available simultaneously with BC Hydro.<sup>1</sup> BC Hydro's plan was filed in October 2025;<sup>2</sup> FortisBC filed in March 2026.<sup>3</sup>

The collaboration between the utilities primarily centered on providing information on the assumptions that the BCUC identified as being useful to facilitate a comparison of the approaches taken by each utility. The utilities describe efforts related to these assumptions in their respective plans. Some highlights of the companies' approaches are described here.

**Customer growth rates by region:** The utilities identified how residential customers were defined under one another's rate schedules, determined the portion of BC Hydro's service territory that overlapped with FortisBC's, and collaborated on residential customer account growth rates by region (residential represents the greatest consumer share for both utilities), allowing planners to model the same baseline assumptions for population growth in shared service regions.<sup>3</sup> Going forward, the companies agreed to share the cost of a more detailed regional outlook, so both utilities can use the same region-specific forecast for population growth, housing stocks, and other economic predictors.

**Volume of fuel switching:** Both companies conducted analyses of the volume of energy estimated to shift from natural gas to electricity in various scenarios. The results indicate similar expectations for electric load growth in a future where the province adopts policies that encourage fuel switching. BC Hydro estimates 11,900 GWh of incremental load growth by 2050,<sup>2</sup> which falls within FortisBC's estimated range of 9,800–12,500 GWh under a similar scenario.<sup>3</sup> FortisBC's plan, which was finished and filed after BC Hydro's, compares the utilities' scenarios.

**Additional planning assumptions:** Both utilities engaged in efforts to understand what other resource planning information could be shared between utilities, beyond the initial list suggested by the BCUC, and discussed potential future sharing of market price forecasts and macroeconomic inputs to further enhance comparability and alignment between the plans.

**Dual-fuel case study:** FortisBC is currently studying the impacts of customers switching from natural gas to the electric system within its shared service area, known as the Kelowna Dual-Fuel Study. The study assesses impacts on peak demand and energy usage, lifecycle costs

<sup>1</sup> BC Hydro. "Integrated Resource Plan (IRP) Technical Advisory Committee (TAC) Meeting #5." July 2025. <https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/2025-irp-tac-mtg5ab-20250700-summary-bchydro-fortisbc-collaboration.pdf>

<sup>2</sup> BC Hydro. "BC Hydro 2025 IRP Exhibit B-1." October 31, 2025. [https://docs.bcuc.com/documents/proceedings/2025/doc\\_84202\\_b-1-bch-2025-irp-application.pdf](https://docs.bcuc.com/documents/proceedings/2025/doc_84202_b-1-bch-2025-irp-application.pdf)

<sup>3</sup> FortisBC. "FEI 2026 Long Term Gas Resource Plan Exhibit B-1." March 27, 2026. [https://docs.bcuc.com/documents/proceedings/2026/doc\\_86847\\_b-1-fei-2026-long-term-gas-resource-plan-application.pdf](https://docs.bcuc.com/documents/proceedings/2026/doc_86847_b-1-fei-2026-long-term-gas-resource-plan-application.pdf)

and benefits, and bill impacts from switching from a natural gas furnace to dual-energy or fully electric heating systems. The study has thus far concluded that dual-energy heating solutions are an effective strategy to avoid capacity resources for the electric system, and potentially defer investment in electric generation, transmission, and distribution infrastructure that would otherwise be required to meet peak winter heating requirements.<sup>1</sup> The analysis shared by FortisBC is an example of how coordinated planning—in this case, across the natural gas and electric functions within one company—can provide a detailed understanding of the impacts of customer energy choices on both systems.

### 2.1.5 Remaining Issues

Both utilities' current plans are being debated within BCUC regulatory processes. It remains to be seen whether the regulators will require new or enhanced collaborative efforts in future planning cycles. For example, neither BC Hydro nor FortisBC explicitly modeled a cross-price elasticity assumption in their load forecasts, as previously requested by the BCUC.

### 2.1.6 Next Steps

Final arguments in BC Hydro's and FortisBC's current plan proceedings are scheduled for July 2026 and September 2026, respectively.

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<sup>1</sup> FortisBC. "FEI 2026 Long Term Gas Resource Plan Exhibit B-1." March 27, 2026.  
[https://docs.bcuc.com/documents/proceedings/2026/doc\\_86847\\_b-1-fei-2026-long-term-gas-resource-plan-application.pdf](https://docs.bcuc.com/documents/proceedings/2026/doc_86847_b-1-fei-2026-long-term-gas-resource-plan-application.pdf)

## 2.2 California

### 2.2.1 Summary

California's regulatory oversight of electric and natural gas utilities is shared by three state agencies with various authorities; however, there is no formal requirement for utilities to conduct coordinated planning. Recent legislation, including SB 1221 and SB 1359, mandates some coordinated infrastructure mapping, alters subsidies for expanding the natural gas networks, and establishes pilot projects to safely decommission natural gas infrastructure. Planners are working to overcome siloed planning processes, while regulatory conversations continue to center on managing financial risks posed to utilities and customers and designing fair cost recovery mechanisms. The California Public Utilities Commission (CPUC) recently adopted requirements for a new neighborhood decommissioning pilot program and is now awaiting utility proposals for initial projects.

### 2.2.2 Context

Following the 2000–2001 California electricity crisis, the state shifted away from the deregulated spot-market model and began requiring utilities to secure long-term power purchase agreements and conduct long-term utility planning. CPUC was required to review and approve utility energy procurement plans and establish policies and cost-recovery mechanisms for energy procurement.<sup>1</sup>

Currently, California maintains a hybrid energy market structure for retail commodity costs: natural gas is fully deregulated for all customers, while retail electricity is primarily regulated.<sup>2</sup> With the rollback of traditional retail choice following the 2001 crisis, Assembly Bill (AB) 117 was passed in 2002 to enable the creation of Community Choice Aggregators (CCAs) and restore some consumer choice and local control over energy procurement. The California Independent System Operator (CAISO) operates competitive day-ahead and real-time wholesale electricity markets. On the gas side, customers may buy their gas from gas retailers or core transport agents, which are competitive, third-party natural gas suppliers. In almost all locations, the utility delivering electricity or gas is a monopoly that bills the customer for the transportation costs, which may be most of the bill.

California has five investor-owned natural gas utilities, alongside a handful of smaller, municipally owned systems (such as the Long Beach Gas & Oil Department), and 17 privately-owned natural gas core transport agents.<sup>3</sup> There are six investor-owned electric utilities, 49 publicly owned electric utilities run by municipalities, irrigation districts, or public utility districts,

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<sup>1</sup> Pechman, C. 2007. "California's Electricity Market: A Post-Crisis Progress Report." In California Economic Policy, edited by E. Hanak, (3) 1. [https://www.ppic.org/wp-content/uploads/content/pubs/cep/EP\\_107CPEP.pdf](https://www.ppic.org/wp-content/uploads/content/pubs/cep/EP_107CPEP.pdf)

<sup>2</sup> The main exception to this is the state's "Direct Access" program for large commercial and industrial energy users, which allows them to purchase their electricity supply from an independent Energy Service Provider (ESP) instead of the utility (although participation is capped by law).

<sup>3</sup> CPUC. 2026. "Core Transport Agents." California Public Utilities Commission. Accessed July 14, 2026. <https://www.cpuc.ca.gov/industries-and-topics/natural-gas/core-transport-agents>

and 4 rural electric cooperatives.<sup>1</sup> CCAs, non-profit public entities that act as the default energy buyer for a community, operate "on top" of these IOU territories.<sup>2</sup>

California's three largest IOUs—Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E)—service nearly 80% of the state (see Figure 2).<sup>3</sup> PG&E delivers electricity and natural gas to approximately 16 million customers across northern and central California, covering major metropolitan areas like San Francisco, Sacramento, and Fresno. SCE, which is electric-only, provides service to approximately 15 million people through 5 million customer accounts within Central, Coastal, and Southern California.<sup>4</sup> SCE does not serve the City of Los Angeles (which is served by a municipal utility), Anaheim (which has its own municipal utility), or Burbank, Glendale, and Pasadena, despite these cities being geographically overlapping with SCE's service territory. SDG&E provides electric and natural gas services to 3.7 million people through 1.49 million electric meters and 905,000 natural gas meters, principally covering San Diego County and southern Orange County (including 27 cities).<sup>5</sup>

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<sup>1</sup> CEC. 2026. "Electric Load-Serving Entities (LSEs) in California." California Energy Commission. Accessed July 14, 2026. <https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-load-serving-entities-lses>

<sup>2</sup> Residents and businesses may opt out of a CCA and return to their designated IOU service.

<sup>3</sup> CRS News, "California Directs State's Largest Utilities to Offer Green-e Energy Certified Green Power Programs," news release, February 5, 2015. <https://resource-solutions.org/press-releases/california-directs-states-largest-utilities-to-offer-green%E2%80%91e-energy-certified-green-power-programs/>

<sup>4</sup> SCE, *Southern California Edison's Service Area*, updated March 17, 2025. [https://download.newsroom.edison.com/create\\_memory\\_file/?f\\_id=5cc32d492cfac24d21aecf4c&content\\_verified=True](https://download.newsroom.edison.com/create_memory_file/?f_id=5cc32d492cfac24d21aecf4c&content_verified=True)

<sup>5</sup> SDGE. 2025. "About us." San Diego Gas and Electric. Accessed on July 14, 2026. <https://www.sdge.com/more-information/our-company/about-us>

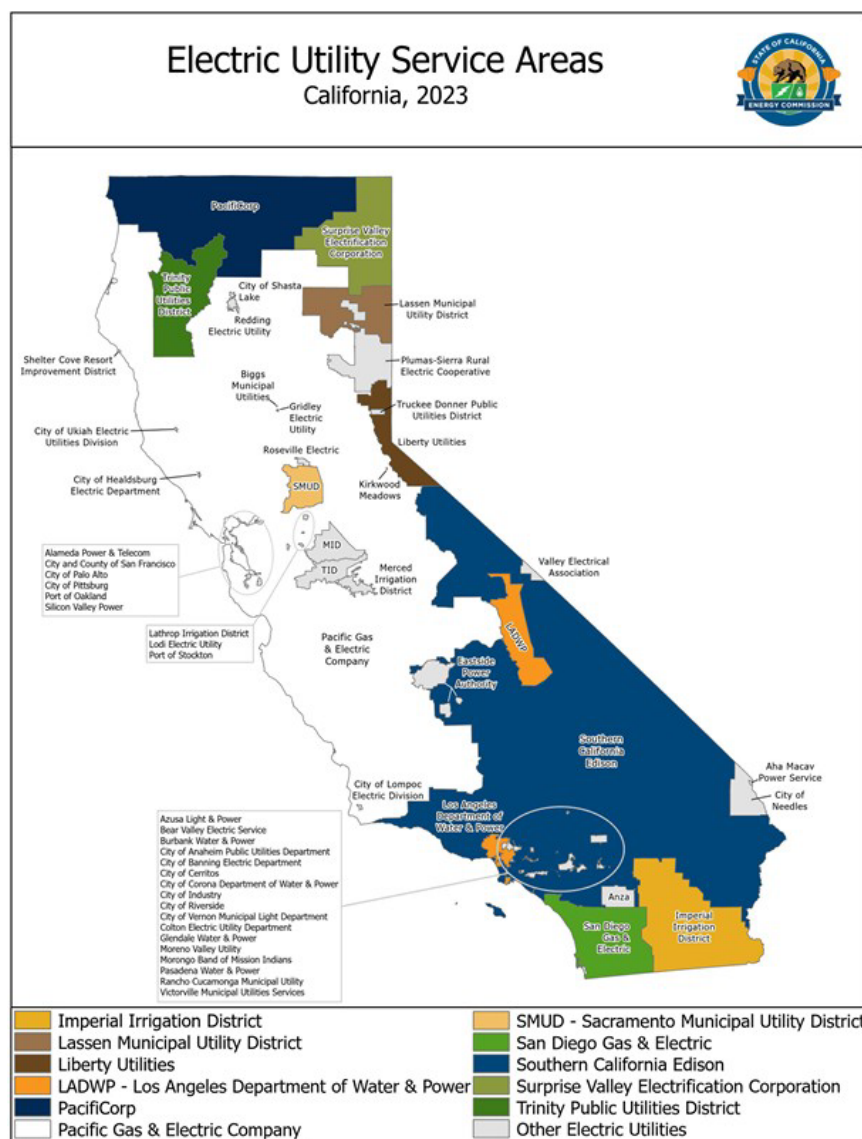


Figure 2: California utilities' electric service territories.<sup>1</sup> The state's largest electric utilities include SCE, PG&E, SDG&E.

The state's largest natural gas-only IOU, SoCalGas, provides natural gas services to over 20 million customers across much of Southern California (see Figure 3).<sup>2</sup> Although most natural gas customers are residential and small commercial users, a small number of large volume gas customers, including electric generators and industrial end-users, account for roughly 65% of the natural gas consumed.

<sup>1</sup> CEC. 2023. "Electric Utilities Service Areas." California Energy Commission. Last modified June 7, 2023. Accessed July 14, 2026. <https://cecgis-caenergy.opendata.arcgis.com/documents/CAEnergy::electric-utility-service-areas/explore>

<sup>2</sup> CPUC. 2026. "Natural Gas and California." Accessed on July 14, 2026. <https://www.cpuc.ca.gov/industries-and-topics/natural-gas/natural-gas-and-california>



Figure 3: California utilities' gas service territories.<sup>1</sup> SoCalGas and PG&E are the largest gas utilities in the state.

The responsibility for overseeing utility planning is shared by the state legislature and three state agencies: CPUC, the California Energy Commission (CEC), and the California Air Resources Board (CARB). While the legislature sets statewide and sector-specific policies, the CPUC regulates utility capital investments and spending, the CEC forecasts energy needs and provides research and funding toward activities that complement state goals, and CARB enforces pollution control rules.<sup>2</sup>

<sup>1</sup> CEC. 2022. "Natural Gas Utility Service Area." California Energy Commission. Last updated January 24, 2022. Accessed on July 14, 2026. <https://gis.data.ca.gov/documents/CAEnergy::natural-gas-utility-service-area-california-2020/explore?path=>

<sup>2</sup> CARB leads the Scoping Plan process, which outlines pathways and actions to achieve the State's climate targets. The Scoping Plan is updated at least once every five years.

In the 2010s, a series of natural gas safety incidents, including the 2010 PG&E pipeline explosion in San Bruno, the 2015 natural gas leak at SoCalGas's Aliso Canyon storage facility, and the 2017 SoCalGas transmission pipeline rupture, resulted in stricter infrastructure regulations, leak-reduction mandates, and enforcement. Following the 2017 rupture, SoCalGas depleted its Aliso Canyon storage capacity and mandated curtailments for noncore customers, causing costs to spike from an average of \$3 per MMBtu to as high as \$40 per MMBtu in July 2018 (costing electric ratepayers more than \$800 million).<sup>1</sup>

In 2015, Senate Bill (SB) 350 increased the state's renewable electricity procurement goal from 33% by 2020 to 50% by 2030, mandated the doubling of energy efficiency savings in electricity and natural gas uses by the same year, and formally established a coordinated integrated resource planning process for electric load serving entities (including IOUs and publicly owned utilities). Another impetus for coordinated planning is the state's mandatory emission reduction law, which applies to both the electric and natural gas sectors. Compliance with this state law will necessitate close coordination between the two systems.

In 2020, the CPUC launched the Long-Term Gas Planning Rulemaking (R.20-01-007, succeeded by R.24-09-012)<sup>2</sup> to establish policies and rules for long-term natural gas system planning.<sup>3</sup> This was largely driven by concerns from safety incidents in the 2010s, resulting operational constraints, and summer electric reliability shortfalls. California natural gas utilities (specifically the biggest three) invest \$4 billion per year in infrastructure, and there is a growing recognition that more oversight is needed to ensure this spending is supportive of state policy goals.<sup>4</sup> The Long-Term Gas Planning Rulemaking (R.20-01-007) sought to address reliability and compliance processes, data transparency, and the implications of state policy on natural gas demand, hosting a two-phased workshop over the course of 2020 to discuss a) natural gas reliability standards, and b) market structure and transmission pipeline regulations.

On December 14, 2023, the CPUC ruled under a separate proceeding, R.19-01-011, to eliminate electric line extension subsidies for mixed-fuel construction projects. This followed an earlier decision that had already ended subsidies for natural gas line extensions to mixed-fuel buildings starting July 1, 2023.<sup>5</sup>

### 2.2.3 Planning Framework

In support of the Long-Term Gas Planning Rulemaking, the CPUC, CEC, and CARB developed a 2024 joint whitepaper framing key challenges and considerations for ongoing coordinated

<sup>1</sup> Zitelman, K. 2025. *Long-Term Planning among Regulated Natural Gas Utilities: A Review of State Requirements*. National Associate of Regulatory Utility Commissioners.

<https://pubs.naruc.org/pub/B3E9420C-9813-1958-98BB-C5387B4E2A9C>

<sup>2</sup> CPUC. 2026. "Long-Term Gas Planning Rulemaking R.24-09-012." California Public Utilities Commission. Accessed on July 14, 2026 <https://www.cpuc.ca.gov/industries-and-topics/natural-gas/long-term-gas-planning-rulemaking>

<sup>3</sup> CPUC. 2020. "Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning." R.20.01.007. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K641/325641802.PDF>

<sup>4</sup> Smillie, S., D. Alberga, A. Gold-Parker, and D. Aas. 2024. *Avoiding Gas Distribution Pipeline Replacement Through Targeted Electrification in California*. Energy and Environmental Economics <https://www.ethree.com/wp-content/uploads/2024/06/Gas-Decommissioning-Fact-Sheet-2024-06-18.pdf>

<sup>5</sup> CPUC. 2026. "CPUC Eliminates Last Remaining Utility Subsidies for New Construction of Buildings Using Natural Gas." Accessed on July 14, 2026. <https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-eliminates-last-remaining-utility-subsidies-for-new-construction-of-buildings-using-gas-2023>

planning across agencies.<sup>1</sup> That proceeding, R.20-01-007, was officially closed in the same year, giving way to a successor rulemaking, R.24-09-012, which aims to further refine long-term gas planning strategies.<sup>2</sup>

R.24-09-012 has multiple phases, including developing requirements for long-term natural gas planning and implementing SB 1221, which passed the CA legislature in Fall 2024. The Order Instituting Rulemaking (OIR) for R.24-09-012 describes a number of areas of interest and concern, including the need for scenario modeling to assess rate impacts and affordability as the state's energy system continues to evolve.<sup>3</sup> The OIR describes a potential risk of upward pressure in natural gas system costs and rates if demand decreases without a commensurate decrease in gas infrastructure investments, and a need to balance these and other risks through planning.<sup>2</sup>

SB 1221 requires the CPUC to facilitate, and the natural gas utilities to implement, up to 30 pilot projects for decommissioning natural gas infrastructure. See the Text Box below for some history behind SB 1221. The implementation of the pilots will have implications for electric distribution systems.

**Lessons behind SB 1221 – moving too big, too fast:** Believed to be a first-of-its-kind approach, in 2022 PG&E proposed to decommission natural gas pipelines that would have disconnected 400 housing units at Cal State University Monterey Bay. PG&E estimated that avoiding physical pipe replacement would save ratepayers money, even with the cost to convert homes to heat pumps. PG&E formally scrapped the project in early 2025, citing time pressure, unknown asbestos-related costs in buildings, and disagreements over whether the utility should receive the same financial treatment on the costs that avoid gas infrastructure as they would have received on the infrastructure itself. Pipeline infrastructure was degrading, and PG&E faced safety timelines to mitigate risks of natural gas leaks. This highlights how challenging it can be to identify, secure regulatory approval for, and implement projects ahead of emerging safety risks. The lessons learned from the failure of this project led to the development of policy concepts included in SB 1221.

The legislature is currently considering further changes that would alter natural gas utility regulatory practices, such as line extension allowances (SB 1359), and require natural gas utilities to create a program offering eligible natural gas customers a monetary incentive to deploy natural gas service line replacement alternatives (AB 2313).

The CEC's Integrated Energy Policy Report (IEPR) forecasts energy needs and is used in assessing infrastructure needs. The IEPR forecast is used as a benchmark in system-level

<sup>1</sup> CPUC. 2024. "Attachment A: Joint Agency Staff Gas Transition White Paper." R.20-01-007. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M525/K660/525660391.PDF>

<sup>2</sup> CPUC. 2024. "Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Long-Term Gas System Planning." R.24-09-012. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M542/K029/542029029.PDF>

<sup>3</sup> CPUC. 2026. "CPUC Launches New Rulemaking to Advance Long-Term Natural Gas Planning." California Public Utilities Commission. Accessed on July 14, 2026. <https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-launches-new-rulemaking-to-advance-long-term-natural-gas-planning>

electric and natural gas demand forecasting and local reliability by natural gas utilities in developing mandated California Gas Reports (CGRs), also required every two years.<sup>1</sup>

## 2.2.4 Planning Methodologies

The R.24-09-012 rulemaking is intended to examine multiple planning topics and methods, including:

- Updating demand forecasting methodologies to account for the growing interplay between electric and natural gas systems.<sup>1</sup>
- Examining the financial risks of shrinking gas demand and approaches to minimize financial losses associated with stranded assets.
- Identifying processes to facilitate non-pipeline alternatives for some or all distribution projects, both within and outside of the regulatory constructs required by SB1221.

Due to statutory timelines and requirements, implementation of SB1221 has become the focus of R.24-09-012, which has meant that consideration of issues related to utility-scale coordinated planning across sectors has been postponed.<sup>2</sup> Instead, SB1221's focus is on program-level approaches to finding cost savings through alternatives to natural gas infrastructure. As mentioned, SB1221 requires the establishment of a voluntary program to facilitate pilot natural gas decommissioning projects. Notably, these pilots only require the consent of 67% of affected natural gas customers (rather than unanimous consent), and CPUC must relieve the natural gas utility of its obligation to serve project participants after adequate substitute energy service is reasonably available.

The bill also requires natural gas utilities to provide maps detailing planned maintenance and replacement projects on the distribution network, intended to enhance visibility and facilitate coordinated planning (See Figure 4).<sup>3</sup> The utilities submitted maps by July 1, 2025, and updated them to include the CPUC's designated priority neighborhood zones by July 1, 2026, as required.<sup>4</sup> In addition to details on potential and foreseeable natural gas distribution pipeline replacements, the maps must include layers representing currently available integration capacity for load in MW, copied from maps provided by the electric IOUs.

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<sup>1</sup> CPUC. 2025. "R.24-09-012 Workshop: Forecasting Analytics and Facilitating Non-Pipeline Alternatives." PowerPoint. September 22, 2025. <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/sb1221/r2409012-workshop-slides.pdf>

<sup>2</sup> CPUC. 2025. "Second Amended Assigned Commissioner's Scoping Memo and Ruling Requesting Comments on Pilot Program." R.24-09-012. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M583/K959/583959017.PDF>

<sup>3</sup> CPUC. 2026. "SB 1221 Maps." California Public Utilities Commission. Accessed on July 14, 2026. <https://www.cpuc.ca.gov/industries-and-topics/natural-gas/sb-1221-implementation/sb-1221-maps>

<sup>4</sup> CPUC. 2026. "Assigned Commissioner's Ruling Directing the Large Gas Corporations to Update Senate Bill 1221 Maps." R.24-09-012. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M609/K525/609525233.PDF>

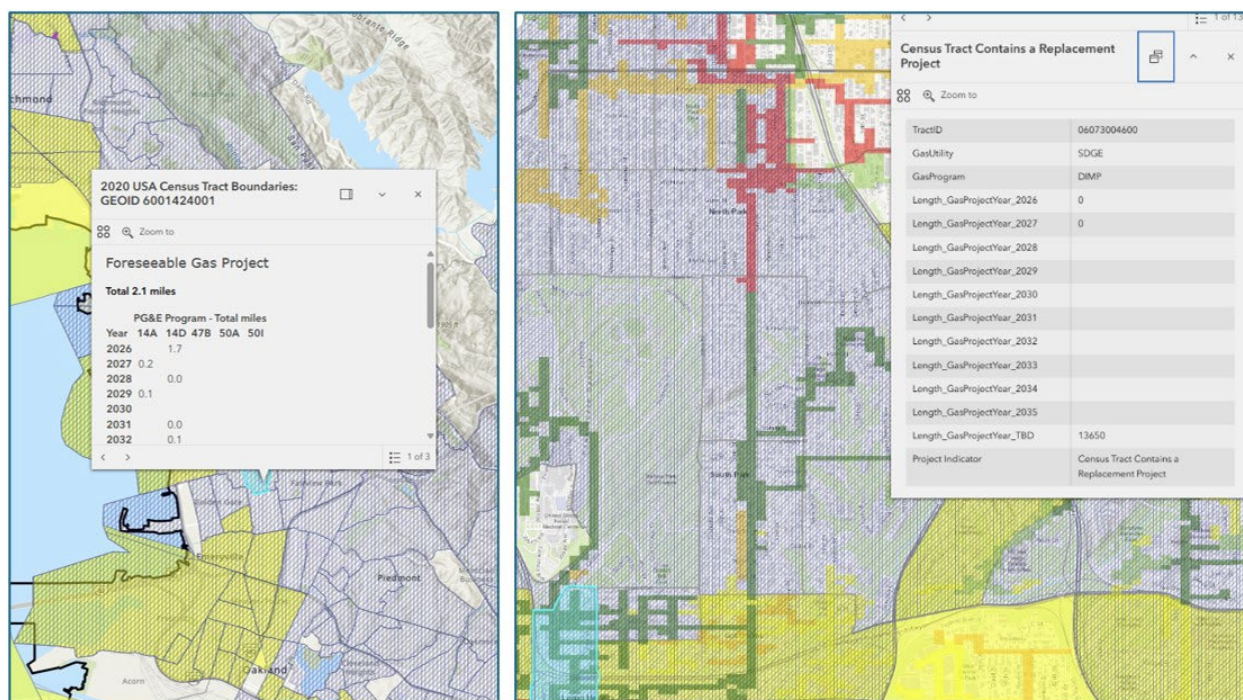


Figure 4: Example natural gas distribution maps showing differing levels of detail regarding foreseeable natural gas infrastructure projects. Publicly-available maps are at the census tract level; confidential maps are available at the street level. The right shows the electric hosting capacity (green and red distribution feeders) functionality of the maps.

In July 2026, the CPUC adopted a decision establishing the voluntary pilot program required by SB 1221.<sup>1</sup> The CPUC directed natural gas utilities to include the anticipated costs of any necessary electric upgrades triggered by their proposed projects within the cost-effectiveness calculations.<sup>1</sup> The natural gas utilities are directed to work with the electric utility that serves the pilot project area to estimate these costs and to demonstrate that the project design evaluated and used all possible ways to avoid or minimize the need for electric infrastructure upgrades.

The pilot program decision also addressed questions on whether behind-the-meter capital costs should be allowed to earn a rate of return, with multiple stakeholders and utilities supportive of such an approach to cost recovery.<sup>1</sup> The CPUC decision instead authorized the natural gas utilities to establish balancing accounts to record the costs of pilot implementation, and allows for the recovery of financing costs. In addition, to provide incentives for natural gas companies to pursue these pilots, the CPUC stated its intent to establish a performance-based shareholder incentive that would be based on the pilot project's realized cost savings and effective implementation. The specifics of this incentive mechanism will be developed within a later track of the R. 24-09-012 proceeding.

<sup>1</sup> CPUC. 2026. "Proposed Decision of Commissioner Karen Douglas Establishing Application Process for SB 1221 Neighborhood Decarbonization Pilot Program." Agenda ID #24265, Rev. 1. R.24-09-012. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M609/K895/609895776.pdf?ref=calregulatory.com>

### 2.2.5 Remaining Issues

California's approach notably does not yet require the utilities to conduct joint planning exercises or to file coordinated plans. Historically, siloed planning has led to diverging assumptions regarding future customer demand on both systems. Through the above rulemakings, the utilities will be required to harmonize assumptions in line with the CEC's IEPR forecast. However, there are remaining disagreements about whether demand projections should reflect the state policy trajectories or be "bottom-up" representations of observed customer behavior and market conditions.

The infrastructure maps required by SB 1221 are at the census tract level, which some parties point out lacks the spatial resolution needed for project-level planning. Relatedly, electric utilities will require more granular natural gas load and attrition data to plan for future electric capacity and distribution upgrades. On September 22, 2025, the CPUC held a workshop discussing options for creating greater access to cost-saving non-pipeline alternatives, with wide-ranging perspectives and recommendations for CPUC action shared by parties.<sup>1</sup>

### 2.2.6 Next Steps

The CPUC's decision on the SB 1221 Pilot Program sets April 1, 2027 as the first deadline for natural gas IOUs to propose projects within the CPUC's designated "priority" zones. Phases 1 and 2 of proceeding R. 24-09-012, which are intended to address near-term "interim actions" and long-term natural gas planning more broadly, are planned to begin in the second half of 2026.

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<sup>1</sup> CPUC. 2025. "R.24-09-012 Workshop: Forecasting Analytics and Facilitating Non-Pipeline Alternatives." PowerPoint. September 22, 2025. <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/sb1221/r2409012-workshop-slides.pdf>

## 2.3 Colorado

### 2.3.1 Summary

Colorado has a complex utility landscape of multiple overlapping investor- and consumer-owned utilities. Recent legislative (SB 21-264) and regulatory (Rule 4552) actions have initiated steps toward more transparent natural gas planning and coordination of those plans with electric system impacts and needs, largely through non-pipeline alternatives analysis. Planning cycles and methodologies across utilities—and across natural gas and electric systems within the same utility—remain separate and largely uncoordinated. Regulators expect future plans to demonstrate improved forecasting methodologies to reduce the risks of capital over-investment and improved cost-benefit analysis of alternatives, among other possible future changes.

### 2.3.2 Context

Colorado's energy utility landscape consists of a diverse mix of IOUs, municipal utilities, and rural electric cooperatives serving both electric and natural gas customers across the state. IOUs for electric and natural gas are regulated by the Colorado Public Utilities Commission (COPUC); all others are not-for-profit entities and are not regulated. There are two electric IOUs, Black Hills Energy and Public Service Company of Colorado (Public Service, also known as Xcel Energy), 28 municipal utilities, and 22 rural cooperatives.<sup>1</sup> Figure 5 shows the service territories for all 42 entities.

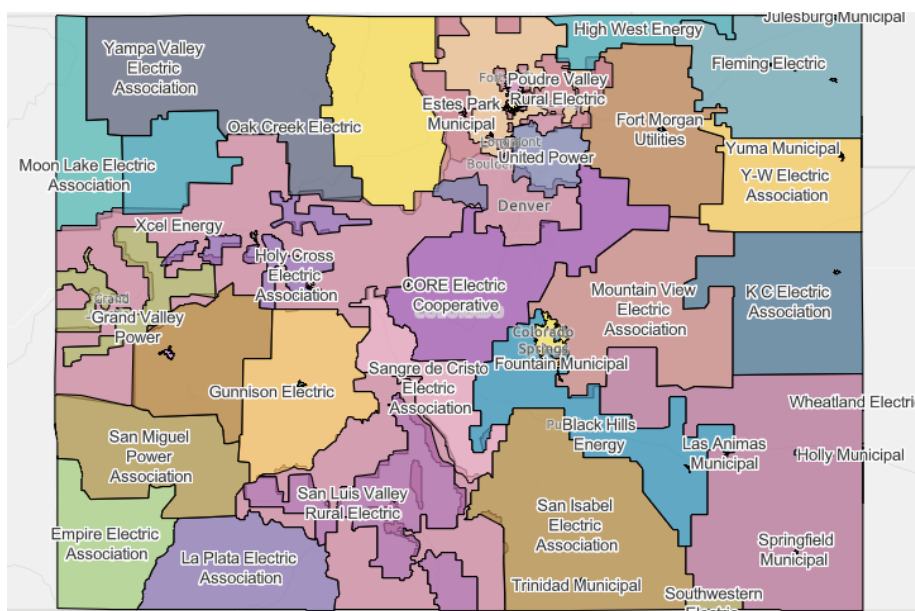


Figure 5: 2023 Colorado Electric Utility Service Territories<sup>1</sup>

There are four natural gas IOUs, Atmos Energy Corporation, Black Hills Energy, Colorado Natural Gas, and Public Service Company of Colorado (Public Service or Xcel Energy).

<sup>1</sup> CEO. 2026. "Energy Utility Service Territories." Colorado Energy Office. Accessed on July 15, 2026. <https://energyoffice.colorado.gov/current-energy-profile>

Additionally, there are 11 natural gas municipal utilities.<sup>1</sup> Figure 6 shows the service territories of all 15 natural gas companies.

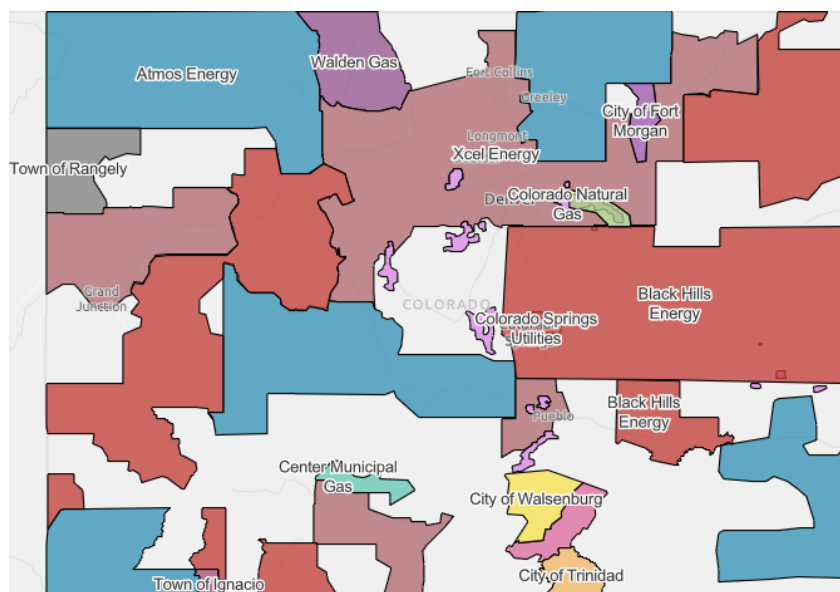


Figure 6: 2023 Colorado Gas Utility Service Territories

Both Black Hills Energy and Public Service operate as combination utilities, providing electricity and natural gas to customers, but their service territories for each commodity do not perfectly align. Public Service is by far the largest utility company in Colorado and has the most overlap, servicing 1.6 million electric customers and 1.5 million natural gas customers. Public Service's electric service overlaps with the natural gas service territories of Black Hills Energy Gas, Center Municipal Gas, Colorado Natural Gas, and the Town of Rangely. Its natural gas service overlaps with its own and Black Hills Electric's territories, as well as the territories of 14 municipal and cooperative utilities. Black Hills Energy has limited overlap between its electric and natural gas service areas.

Colorado has a mature electric resource planning process. Electric utilities in Colorado are required to file Electric Resource Plans (ERPs) with the COPUC every four years.<sup>2</sup> Historically, natural gas planning in Colorado has been less comprehensive and transparent than electric planning.<sup>3</sup> The COPUC website confirms that "Gas infrastructure planning is a new process for the Commission, utilities, and stakeholders."<sup>4</sup>

Colorado has enacted several policies and subsequent regulations applicable to natural gas utilities in recent years, reshaping the regulatory landscape.

<sup>1</sup> CEO. 2026. "Energy Utility Service Territories." Colorado Energy Office. Accessed on July 15, 2026. <https://energyoffice.colorado.gov/current-energy-profile>

<sup>2</sup> The ERP rules specifically include Rules 3600–3619 concerning electric resource planning. <https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=8369&fileName=4+CCR+723-3>

<sup>3</sup> Durkay, J. 2020. "State agencies engaging in utility infrastructure planning for the natural gas system." *Colorado Energy Office* (blog). November 2, 2020. <https://energyoffice.colorado.gov/blog-posts/state-agencies-engaging-in-utility-infrastructure-planning-for-the-natural-gas-system>

<sup>4</sup> COPUC. 2026. "Gas Infrastructure Plans." Colorado Public Utilities Commission. Accessed on July 15, 2026. <https://puc.colorado.gov/gas-infrastructure-plans>

Senate Bill 21-264 (2021) established a Clean Heat Planning (CHP) framework, requiring certain natural gas distribution utilities to obtain Commission approval of plans that meet emissions targets at the lowest reasonable cost.<sup>1</sup>

Following the passage of SB 21-264, the COPUC updated its rules (Rule 4552), establishing requirements for natural gas utilities' infrastructure planning and a schedule for regulated utilities to file Gas Infrastructure Plans.<sup>2</sup>

### 2.3.3 Planning Framework

The Clean Heat Planning framework established by SB 21-264 created specific structural and content requirements. Natural gas distribution utilities with over 90,000 customers must file plans demonstrating how they will utilize resources such as demand-side management, recovered methane, green hydrogen, and beneficial electrification to meet customer needs. The filing schedule established various timelines. Public Service, as the largest natural gas utility in the state, was required to file first by August 1, 2023, with all other regulated natural gas utilities filing by January 1, 2024.<sup>3</sup> All utilities must file subsequent plans at least every four years unless otherwise directed by the Commission. Public Service filed its second Clean Heat Plan on July 1, 2026, as part of a broader "Integrated Customer Filing" that included consolidation with the company's Transportation Electrification Plan and Demand Side Management Plan.

Gas Infrastructure Plans (GIP), established through Rule 4552, operate on a different cycle and serve a different purpose from CHPs. These biennial plans must cover a six-year planning period and include forecasts of: design peak demand, customer count, sales and capacity requirements, gas content (including expected mixtures of hydrogen and recovered methane), and system-wide greenhouse gas emissions.<sup>4</sup> GIPs must include assessments of non-pipeline alternatives for new business, capacity expansion projects, and system safety and integrity projects, requiring utilities to evaluate whether other options could meet system needs more cost-effectively than traditional pipeline investments.<sup>5,6,7</sup> Public Service's second GIP, filed in May 2025, was approved in part and with modifications, and denied, in part, in June 2026.<sup>8</sup>

The integration between natural gas and electric planning occurs primarily through the utility's efforts to conduct the above planning processes, rather than through a unified planning mandate. Public Service's CHP modeling revealed that they would need to electrify heating in at

<sup>1</sup> Adopt Programs Reduce Greenhouse Gas Emissions Utilities, SB21-264. 75<sup>th</sup> Colorado General Assembly (2021) (enacted). <https://leg.colorado.gov/bills/sb21-264>

<sup>2</sup> Xcel Energy 2024-2028 Clean Heat Plan, Proceeding No. 23A-0392EG, page 6. [https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/23A-0392EG\\_Hearing%20Exhibit%20101\\_Attachment%20JWI-1.pdf](https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/23A-0392EG_Hearing%20Exhibit%20101_Attachment%20JWI-1.pdf)

<sup>3</sup> COPUC. 2026. "What is a Clean Heat Plan?" Colorado Public Utilities Commission. Accessed on July 15, 2026. <https://puc.colorado.gov/cleanheatplans>

<sup>4</sup> Xcel Energy. 2021. "Gas Infrastructure Plan" Xcel Energy. Accessed on July 15, 2026. [https://www.xcelenergy.com/company/rates\\_and\\_regulations/filings/gas\\_infrastructure](https://www.xcelenergy.com/company/rates_and_regulations/filings/gas_infrastructure)

<sup>5</sup> 4 CCR 723-4-4553(c)(I)(P)

<sup>6</sup> Decision C24-0233, paragraph 96, Proceeding 23M-0234G. 2024.

[https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=1016721](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1016721)

<sup>7</sup> COPUC. 2026. "Gas Infrastructure Plans." Colorado Public Utilities Commission. Accessed on July 15, 2026. <https://puc.colorado.gov/gas-infrastructure-plans>

<sup>8</sup> Decision C26-0371, Proceeding 25A-0220G. June 2026.

[https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=1066304](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1066304)

least 38,000 single-family homes and 6,000 multifamily units by 2027, with over 60,000 heat pump water heaters installed in that same year.<sup>1</sup> Public Service acknowledges that this scale of load growth will drive "incremental electric system investments to ensure that all customers have the power they need."<sup>2</sup> This indicates an awareness on the part of the company of the need to coordinate across its two energy service areas, but it is unclear whether efforts have yet been made to coordinate with the 15 other electric utilities that share a service territory with Public Service's natural gas system.

Electric infrastructure costs that would result from changes identified in natural gas system modeling are not included in the natural gas system plan budgets. Those costs would need to be addressed through separate electric planning processes.<sup>3</sup>

The coordination challenge is further complicated by differing planning cycles. To illustrate, Figure 7 shows the interconnected regulatory processes that govern Public Service's integrated approach to natural gas and electric infrastructure planning. The figure depicts how multiple regulatory proceedings interact with and influence one another throughout the planning cycle.

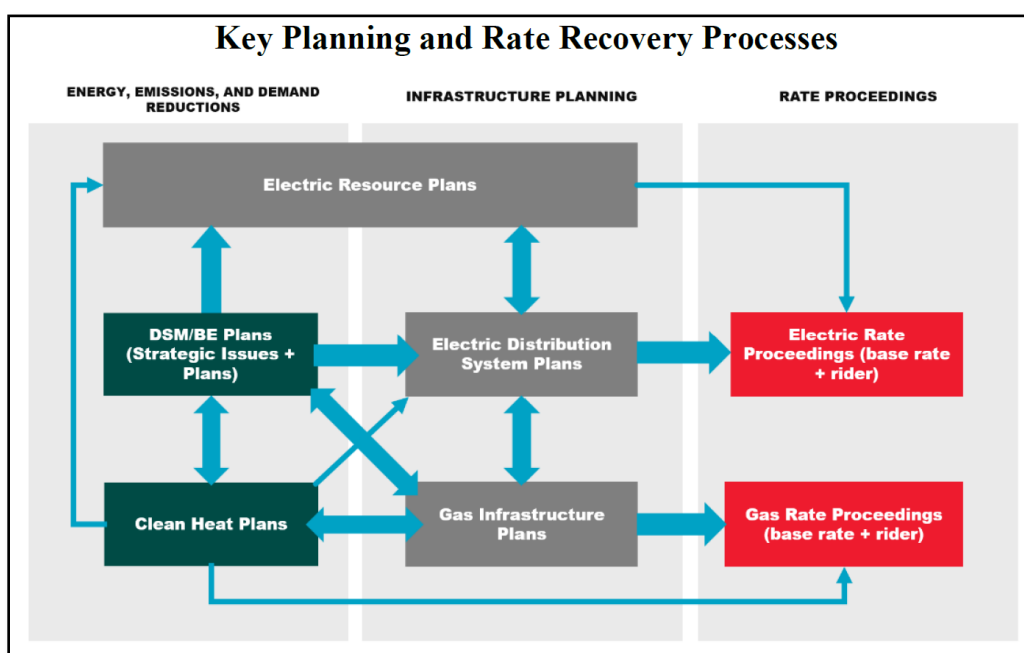


Figure 7: Public Service Company of Colorado (Xcel Energy) Key Planning and Rate Recovery Processes<sup>4</sup>

<sup>1</sup> Brant, J. 2024. "Colorado PUC approves unprecedented spending for energy efficiency and electrification in Xcel Energy Clean Heat Plan—but now the hard work begins." Southwest energy Efficiency Project. Accessed on July 15, 2026. <https://www.swenergy.org/colorado-approves-spending-xcel-energy-efficiency-electrification/>

<sup>2</sup> Xcel Energy 2024-2028 Clean Heat Plan, Proceeding No. 23A-0392EG, pg 7. [https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/23A-0392EG\\_Hearing%20Exhibit%20101\\_Attachment%20JWI-1.pdf](https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/23A-0392EG_Hearing%20Exhibit%20101_Attachment%20JWI-1.pdf)

<sup>3</sup> Xcel Energy 2024-2028 Clean Heat Plan, Proceeding No. 23A-0392EG, pg 26

<sup>4</sup> Xcel Energy 2025-2030 Gas Infrastructure Plan (Hearing Exhibit 101, Attachment JJP-1), page 12. [https://www.dora.state.co.us/pls/efi/EFI.Show\\_Filing?p\\_fil=G\\_825203&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_825203&p_session_id=)

The iterative and dynamic nature of these processes is particularly important. CHP targets will increasingly impact future GIPs, though the right level of coordination between the two plans is still being debated. To manage these complex interactions, Public Service created an internal Integrated System Planning organization with the goal of overseeing integrated planning of both the electric and natural gas systems to strategically develop long-term, interrelated plans for both fuels.

### 2.3.4 Planning Methodologies

This section focuses entirely on Public Service's GIP, as the large, dual-fuel IOU with the most activity to date related to integrated planning.

#### 2.3.4.1 Forecasting

For demand forecasting within the GIP, the company starts with a baseline projection of natural gas use based on economic trends and historical growth patterns, then creates four scenarios by adjusting assumptions about customers' energy preferences and future usage. Public Service has made several adjustments to its forecasting methodology since the initial GIP filing. The company developed a more robust methodology to allocate customer growth to the county level and now incorporates the effects of fuel switching on customer counts and sales. Rather than allocating customers purely based on county-level population growth from Colorado Department of Local Affairs data, the new process uses more granular information on natural gas customer formation and population growth by county.

As noted by staff in the 2025 GIP filing, the forecast used in the GIP and the forecast Public Service used in its electric DSP application contain different assumptions regarding customer energy choices. This is a common approach across dual-fuel utilities in our case studies but has raised concerns about inefficient capital investment among other parties.

#### 2.3.4.2 Non-Pipeline Alternatives

Public Service's non-pipeline alternative Methodology<sup>1</sup> is a structured process for determining whether customer-side alternatives—like heat pumps, building weatherization, efficient appliances, or natural gas demand response—can replace traditional natural gas pipeline projects. When the company's annual system modeling identifies a future capacity shortfall, a traditional natural gas infrastructure project is scoped as the default solution. That project is then screened for non-pipeline alternative suitability and, if it qualifies, evaluated through a series of increasingly refined analyses that estimate how much natural gas demand reduction is realistically achievable, at what cost, and within what timeframe. The most promising combinations of measures are assembled into portfolios and compared against the traditional project on a cost-benefit basis. The analysis is filed with COPUC as part of the company's GIP for regulatory review and approval.

When a non-pipeline alternative measure involves shifting energy demand from the natural gas system to the electric system, the company assesses whether the existing electric distribution infrastructure can absorb the additional load. The non-pipeline alternative methodology calls for those costs to be factored into the portfolio's total cost before comparing it to the traditional

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<sup>1</sup> Xcel Energy Non-Pipeline Alternatives Methodology for Capacity Expansion Projects (Hearing Exhibit 101, Attachment JJP-1, Appendix 12).  
[https://www.dora.state.co.us/pls/efi/EFI.Show\\_Filing?p\\_fil=G\\_825194&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_825194&p_session_id=)

natural gas project. However, COPUC’s recent decision regarding Public Service’s 2025–2030 GIP found that significant electric system upgrade costs are being accounted for elsewhere, and that it is appropriate for the company to remove electric system costs from the cost-benefit analysis of non-pipeline alternatives until the natural gas and electric system load forecasts are better aligned.<sup>1</sup>

### 2.3.5 Remaining Issues

As with many other states, energy affordability is a central concern in Colorado and is challenging to maintain while addressing the many planning requirements. Meeting natural gas system planning requirements while building electric infrastructure to ensure reliability is putting pressure on rates. Public Service has had back-to-back rate cases (\$546 million combined requested electric and natural gas revenue increases), making that tension concrete for ratepayers.<sup>2</sup>

COPUC suggested multiple areas for further adjustments to Public Service’s GIP approach in the June 2026 order. Related to forecasting, COPUC determined that the company had not fully complied with the GIP rules and warned that the company “faces direct risks in over-investing as a result of inaccurate forecasting, and investment that may later be determined to be imprudent by its continued lack of adherence to the rule requirements around forecasting...”<sup>3</sup> The PUC also agreed with staff that the inconsistencies in forecasting across natural gas and electric planning could lead to customers paying for the expensive buildout of both systems.

Regarding non-pipeline alternatives, COPUC found that the cost-benefit methodologies used by Public Service in evaluating non-pipeline alternatives were not compliant with various COPUC directives and directed the utility to file an updated cost-benefit approach within 60 days of the June 2026 ruling.

The “obligation to serve”—a fundamental part of monopoly utility regulation that historically has meant that utilities must provide safe, adequate, and reliable service to any customer in their service territory who requests it—was a topic of debate in the 2025 GIP, with parties and Staff asking the commission to define the utility’s obligation to serve as relating to energy service, not a particular fuel (e.g., natural gas). COPUC declined to do so within the 2025 GIP and signaled that questions related to the obligation to serve could be addressed in an alternative future forum.

### 2.3.6 Next Steps

Public Service’s next CHP was filed on July 1, 2026, and provides the next regulatory forum for discussion on the role of the natural gas and electric systems in meeting Colorado’s energy needs. The filing was combined with its DSM and Transportation Electrification Plan filings in an effort to streamline programmatic planning and funding.

<sup>1</sup> Decision C26-0371, Proceeding 25A-0220G. 2026.

[https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=1066304](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1066304)

<sup>2</sup> COPUC. 2026. “Colorado Public Utilities Commission Concludes Deliberations on Xcel Energy’s Gas Rate Increase Proposal.” Colorado Public Utilities Commission. Accessed on July 15, 2026.

<https://puc.colorado.gov/press-release/colorado-public-utilities-commission-concludes-deliberations-on-xcel-energys-gas-rate>

<sup>3</sup> Decision C26-0371, Proceeding 25A-0220G. 2026. Page 33.

[https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=1066304](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1066304)

## 2.4 Illinois

### 2.4.1 Summary

Illinois has deregulated retail electricity and natural gas markets and has historically not required integrated resource planning by utilities. In 2023, the Illinois Commerce Commission (ICC) created a new requirement for Long-Term Gas Infrastructure Plans (LT-GIPs) and launched a multi-year “Future of Gas” proceeding to explore integrated gas-electric distribution planning, data needs, and possible legislative changes. Following litigation, the LT-GIP mandate was struck down by the Illinois Appellate Court, which ruled that utilities are not required to file LT-GIPs. Nicor nonetheless filed an LT-GIP, which proved useful in the company’s 2025 rate case to evaluate proposed infrastructure spending and discuss improvements in Nicor’s evaluation of non-pipeline alternatives. The ICC’s Future of Gas workshops are expected to continue through 2026, alongside a consultant “Pathways” study and pilot-project work, with the ICC to later pursue formal rulemaking or legislative recommendations.

### 2.4.2 Context

Illinois has deregulated the retail electricity and natural gas markets.<sup>1</sup> This means that investor-owned natural gas and electric utilities own and maintain the physical delivery infrastructure for energy and offer retail customers a default supply service option, and Alternative Retail Electric Suppliers and Alternative Gas Suppliers may compete with IOUs to provide the supply of energy.<sup>2</sup> Electric supply sold by an IOU is not selected by the IOU, but rather procured by the Illinois Power Agency (IPA) through an annual Electricity Procurement Plan that secures power for the supply-eligible customers of the major IOUs.<sup>3</sup> While the IPA performs a supply-procurement function for eligible default-service electric customers, it is not a comprehensive integrated electric resource planning process.

Most electricity and natural gas customers in Illinois are served by IOUs. ComEd is electric-only, Ameren and MidAmerican are combined utilities, and Nicor Gas, Peoples Gas, North Shore Gas, Consumers Gas, and Liberty Gas are natural gas-only.<sup>4</sup> Several smaller regulated utilities operate across the state, including Consumers Gas, Illinois Gas, Liberty Gas, and Mt. Carmel Public Utility Company (both electric and natural gas), for a total of four electric IOUs and nine natural gas IOUs. All other Illinois customers get their electric and/or gas service from publicly owned and operated utilities, including municipalities and cooperatives. ComEd and Ameren are the largest IOUs, with the former serving 4 million electric customers, including the Chicago metropolitan area,<sup>5</sup> and the latter serving 1.2 million electric customers and over 800,000 gas

<sup>1</sup> The 1997 Electric Service Customer Choice and Rate Relief Law restructured the market to allow for consumer choice of electric supply in IOU territories (220 ILCS 5/16-101).

<sup>2</sup> State deregulation of both electric and natural gas supply allows retail and commercial customers of IOUs to choose their supplier (i.e., ARES and/or AGS) but still receive delivery through the infrastructure of their local utility (which is not applicable for customers of municipal electric utilities and rural electric cooperatives, or publicly-owned utilities, that must receive both delivery and supply from their local utility).

<sup>3</sup> Under 220 ILCS 5/16-111.5B, each Illinois utility procuring power must provide the IPA with an annual assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan.

<sup>4</sup> CUB. 2022. *The Facts on Municipal and Cooperative Utilities*. Citizen’s Utility Board, Chicago, IL. <https://www.citizensutilityboard.org/wp-content/uploads/2022/09/Municipal-Co-op-Factsheet.pdf>

<sup>5</sup> Exelon. 2026. “ComEd: An Exelon Company.” Exelon Corporation. Accessed on July 15, 2026. <https://www-stg.exeloncorp.com/companies/comed>

customers.<sup>1</sup> As of May 2025, about 20% of ComEd residential customers and 43% of Ameren residential customers elected an alternative supplier.<sup>2</sup>

Except for MidAmerican Energy, which appears to have mostly overlapping gas and electric service territories (see Figure 8), the electric IOUs have overlapping service territories with multiple gas utilities. ComEd's electric service territory overlaps with four gas IOUs (Peoples Gas, Nicor Gas, North Shore Gas, and Ameren). Ameren's electric service territory substantially overlaps with its own gas service territory, which can be helpful for coordinating planning. However, it also has small overlaps with Nicor Gas, Liberty Gas, Illinois Gas, and Consumers Gas. Ameren, Nicor, Peoples Gas, and North Shore Gas are the largest gas IOUs in the state, and as such, have been the focus of stakeholder interest in more transparent and comprehensive natural gas planning.

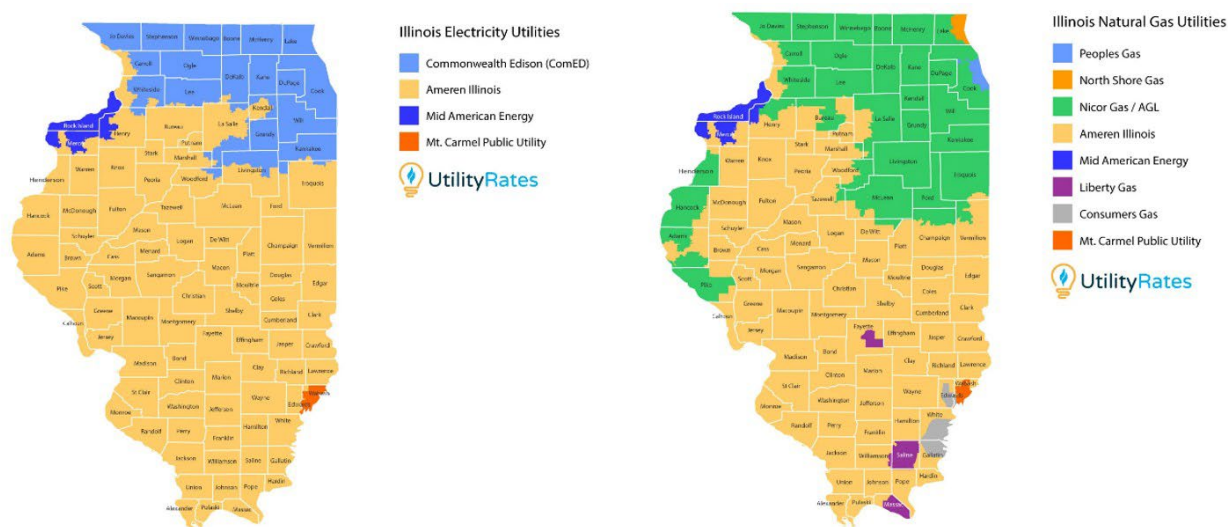


Figure 8: Illinois Electricity and Natural Gas Utilities Service Area Maps. Note: Illinois Gas is not pictured, but serves Richland, Lawrence, and Jasper Counties.<sup>3</sup>

In 2021, Illinois enacted Public Law 102-0662, which set a goal of 100% carbon-free electricity by 2050 and required utilities (ComEd and Ameren) to file detailed, long-term “Multi-Year Integrated Grid Plans” with the ICC.<sup>4,5</sup> While the law prescribed certain requirements related to electricity supply, it did not contain similar or analogous requirements for the natural gas

<sup>1</sup> Ameren Illinois. <https://www.ameren.com/-/media/illinois-site/files/media-resources/ameren-illinois-overview.pdf>

<sup>2</sup> CUB. 2025. “Grim Milestone: CUB review of state data finds ComEd, Ameren residential customers have lost more than \$2B to alternative power suppliers over the last decade.” Citizens Utility Board, August 11, 2025. <https://www.citizensutilityboard.org/blog/2025/08/11/grim-milestone-cub-review-of-state-data-finds-comed-ameren-residential-customers-have-lost-more-than-2-billion-to-alternative-power-suppliers-over-last-decade/>

<sup>3</sup> UtilityRates. Illinois Electricity and Natural Gas Utilities Service Area Maps. Accessed July 1, 2026. <https://www.utilityrates.com/illinois>

<sup>4</sup> Sippert, E. 2022. “Revitalizing Illinois’ Power Grid: Where We Are.” Environmental Law & Policy Center. July 25, 2022. <https://elpc.org/blog/revitalizing-illinois-power-grid-where-we-are/>

<sup>5</sup> ICC. 2026. “2022 Multi-Year Integrated Grid Plan Workshops.” Illinois Commerce Commission. Accessed on July 16, 2026. <https://icc.illinois.gov/informal-processes/multi-year-integrated-grid-plan-workshops>

system. The ICC noted that “Identifying how ... gas and electric systems can adapt to meet the state’s policy goals, and what specific actions should be taken to achieve them, will be an important task for the Commission moving forward.”<sup>1</sup>

It is in this context that the ICC, in issuing its Final Orders on November 16, 2023, in general rate cases for the state’s four largest natural gas IOUs (Ameren, Nicor, Peoples Gas, and North Shore Gas), introduced a new regulatory requirement for utilities to submit LT-GIPs. The Final Orders also called for a “Future of Gas” Proceeding to consider the data and policies needed to support integrated planning between the natural gas and electric sectors, looking beyond the first iteration of LT-GIPs. The ICC highlighted a historical lack of comprehensive natural gas system data to evaluate infrastructure and reliability needs, which led to the denial of \$240 million in collectively requested rate increases across the four utilities in 2023 (ICC Docket Nos. 23-0066 through -0069). Ultimately, following litigation, the Illinois Appellate Courts found the LTGIP requirement to be unlawful, standing in violation of the administrative rulemaking requirements of the Illinois Administrative Procedure Act.<sup>2</sup> Accordingly, the natural gas utilities are not required to submit LT-GIPs.

### 2.4.3 Planning Frameworks

Natural gas utilities have historically not been required to conduct long-term planning in Illinois. The LT-GIP requirements, as envisioned, would increase transparency into natural gas system reliability and infrastructure needs and concerns. The ICC envisioned that LT-GIPs would include:

- Public disclosure of 5-year action plan investments (i.e., list of proposed system expenditures and investments), describing the lowest societal cost gas distribution system investments necessary to meet customer demand and comply with public policy objectives.
- Distribution mapping that identifies areas of constraint and risk and the location of planned projects.
- Demonstration that the proposed program(s) or project(s) will minimize rate impacts on customers.
- Scenario and sensitivity analysis to test the robustness of the utility’s portfolio and investments under various parameters.
- Filing every two years starting July 1, 2025.

Following the ICC’s 2023 rate case orders, Ameren filed a Petition for Review to the Fifth District Appellate Court, which subsequently vacated the Commission’s directive that Ameren file a LT-GIP, effectively removing the binding requirement for all the utilities. Nicor opted to file a full LT-GIP by the ICC’s original deadline. North Shore Gas and Peoples Gas filed a Motion to Stay on March 17, 2025, citing concerns over the legal validity of the LT-GIP requirement and their ability to meet its deadline; no LT-GIPs have been submitted by either utility to date. The

<sup>1</sup> Adams, A. 2023. “Advocates hail regulatory ‘earthquake’ as state slashes requested gas rate increases.” *The State Journal Register*. November 17, 2023. <https://www.sj-r.com/story/business/energy-resource/2023/11/17/illinois-commerce-commission-regulators-cut-gas-rate-increase-requests/71616362007/>

<sup>2</sup> See *Nicor Gas v. Commerce Comm’n*, 2025 IL App (3d) 240093; *Ameren Illinois v. Commerce Comm’n*, 2025 IL App (5th) 240014, *North Shore Gas v. Commerce Comm’n*, 2026 IL App (2d) 240350-U.

ICC is evaluating Nicor's plan and the other utilities' long-term capital spending plans in the standard rate case processes for each utility.

The ICC's 2023 Final Rate Case Orders also called for a "Future of Gas" proceeding to:

- Conduct a multi-stakeholder investigation of the gas system to explore the issues involved with shifting off the gas distribution system.
- Develop actionable recommendations to guide the ICC's future policies and actions, especially with respect to the development of a future integrated (electric & gas) distribution planning framework.
- Propose any legislative changes that might be necessary.

The Future of Gas proceeding is a two-phase process involving collaborative workshops that integrate stakeholder perspectives, assess impacts across short-term (present through 2035), medium-term (2035–2045), and long-term (post-2045) horizons, and identify practical solutions. Both phases are managed by an independent, third-party facilitator contracted by the ICC. Phase 1 workshops, which were conducted from April 1 to August 31, 2024, assessed topics critical to the future of natural gas, identifying priority issues for Illinois' energy sector, including the need for integrated planning between natural gas and electric systems, with emphasis on understanding considerations unique to dual fuel vs. single fuel utilities. Stakeholders noted that legislative action may be necessary to clarify requirements for natural gas utilities as a precursor to developing a framework or pathway for holistic planning.

Phase 2 workshops, scheduled from September 1, 2024, through December 2026, will a) revisit issues identified in Phase 1, b) examine pilots for innovative energy solutions and scenarios or pathways for the state's natural gas system, and c) propose regulatory or legislative solutions.

During Phase 2, ICC Staff solicited proposals for pilots related to new approaches or technologies for improving natural gas service that could be included in natural gas companies' long-term gas infrastructure plans, such as geothermal solutions.<sup>1</sup> Following the pilot development, the ICC opened a proceeding related to pilots—Docket No. 26-0067—which examines questions on the implementation of pilot projects related to the Future of Gas.

The current part of Phase 2 ("2C – Proposals") aims to identify potential legislative and regulatory solutions to the issues highlighted throughout the workshops.<sup>2</sup> In parallel, the ICC has hired a consultant to conduct a "Pathways" study to help resolve disagreements between stakeholders regarding data and the role of natural gas in Illinois' future.

#### 2.4.4 Planning Methodologies

Of the four natural gas utilities subject to the ICC's 2023 Final Rate Case Orders, only Nicor filed an LT-GIP by the originally-proposed July 2025 deadline. Nicor's plan indicates a preference for a hybrid portfolio approach (e.g., energy efficiency and weatherization programs, alternative gases, and new technologies), although preferred non-pipeline alternative pathways and relative costs and benefits of alternatives were not clearly defined, as noted in stakeholder review. Additionally, Nicor's first-ever filing received scrutiny over the limited data transparency

<sup>1</sup> Staff received 103 pilot ideas which was narrowed and refined down to 10 ideas through a working group process.

<sup>2</sup> ICC. 2026. "Future of Gas Workshop – Phase C." Illinois Commerce Commission. Accessed on July 16, 2026. <https://icc.illinois.gov/programs/Future-of-Gas-Workshop-Pilot2C>

in the company's scenario planning methodologies and calculation assumptions used in infrastructure planning.

Nicor's LT-GIP was discussed and debated in the company's 2025 rate case, which was decided in November 2025. The ICC was able to use information provided in the LT-GIP to evaluate proposed spending in the rate case. Nicor had proposed infrastructure spending to bring operating pressures into compliance with Federal standards. The commissioners noted that Nicor's LT-GIP contained data showing that the utility had ample time left to achieve compliance and the spending was not necessary.

The non-pipeline alternative analysis in Nicor's LT-GIP was also discussed within the rate case, with stakeholders arguing that the company's assessment of alternatives was not robust. The ICC pointed to the Future of Gas proceedings as the venue for broader discussion around non-pipeline alternative approaches but agreed with stakeholders that Nicor did not consistently evaluate alternatives and that doing so is an important part of prudent system planning. Looking forward, the ICC encouraged Nicor to "amend its capital planning processes such that the company can show its consideration of alternatives to traditional pipeline investments, including repairs, relining, and NPAs."<sup>1</sup>

#### 2.4.5 Remaining Issues

There is continued legal uncertainty surrounding ICC's authority to mandate natural gas planning requirements. While the ICC cannot require utilities to file LT-GIPs in individual company rate orders, it remains unclear whether it has the authority to make administrative rules of general application requiring LT-GIPs. As conversations about the future of natural gas evolve, there has also been limited clarity or understanding on how (or if) LT-GIPs should interact with other energy planning requirements, such as multi-year integrated grid plans, the Illinois Power Agency's Long-Term Electricity Procurement Plan, or the multi-agency Resource Adequacy Report.

In the Nicor rate case, stakeholders requested that the ICC open a rulemaking on the Company's line extension policy, rather than wait for the Future of Gas proceeding to address the issue. Instead, the ICC chose to require Staff to issue a report on all Illinois utilities' line extension policies, including analysis of the cost and miles of service lines and mains extended through the policies and how those costs related to the benefits provided to all ratepayers. The final report contains a list of findings and recommendations that the ICC may consider as next steps.<sup>2</sup>

#### 2.4.6 Next Steps

When Phase 2 of the Future of Gas proceeding wraps up at the end of 2026, the facilitator will deliver a final report, the consolidated legislative proposals, and Pathways study to the ICC. It is expected that the ICC will then open dockets to develop administrative rules or deliver ideas to the legislature for consideration.

<sup>1</sup> ICC. 2025. "Document for 25-0055." p. 80. Illinois Commerce Commission. Accessed on July 16, 2026. <https://icc.illinois.gov/docket/P2025-0055/documents/373246> page 80

<sup>2</sup> ICC. 2026. *Illinois Gas Utilities Line Extension Policies Review*. Illinois Commerce Commission Staff Report. <https://icc.illinois.gov/docket/P2025-0055/documents/381030/files/668989.pdf>

## 2.5 Massachusetts

### 2.5.1 Summary

Massachusetts has a complex utility landscape, with three investor-owned electric utilities, five investor-owned natural gas utilities, and dozens of municipal providers whose overlapping service territories complicate coordinated planning. Recent regulatory action by the Department of Public Utilities (DPU) requires natural gas and electric utilities to develop integrated planning processes, requires electric utilities to participate in natural gas planning, and requires natural gas utilities to file new five-year plans that show how they will meet demand, use pilots, comply with policy goals, and analyze non-pipeline alternatives as a condition of recovering natural gas infrastructure investments. Eversource and National Grid are leading efforts to align data and planning methods and are piloting projects like networked geothermal. DPU decisions on the new natural gas utility plan filings are anticipated in the second half of 2026.

### 2.5.2 Context

Massachusetts has three investor-owned electric and five IOU natural gas utilities. In addition, there are 41 municipal electric utilities, of which four are also municipal natural gas providers. As with several other states, the geographic landscape is complex, with the electric service territories of the three IOUs overlapping in places with their own natural gas company and elsewhere with other natural gas IOUs. In addition, some natural gas IOU service territories overlap with municipal electric utilities.

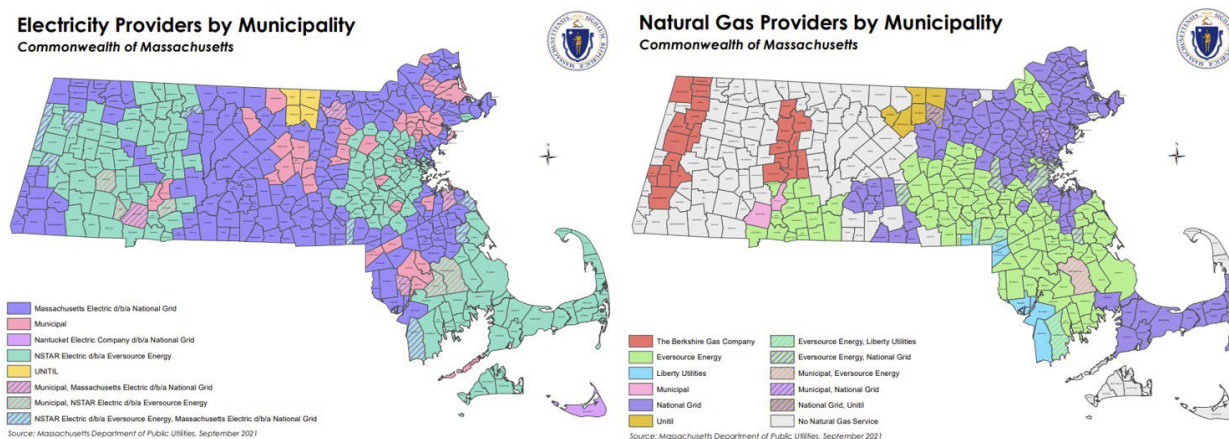


Figure 9: Massachusetts Electricity and Natural Gas Utility Service Areas.<sup>1</sup>

Eversource and National Grid are the two largest dual-fuel utilities in the state and have significant complexity to manage as they integrate natural gas and electric planning. In their electric service territories, both will need to coordinate with multiple natural gas IOUs. As natural gas utilities, both overlap with municipal electric providers, their own electric service territory, and each other's electric service territory.

Massachusetts electric utilities are distribution-only and therefore do not conduct resource planning. The companies are required to file Electric Sector Modernization Plans (ESMPs)

<sup>1</sup> EOTSS. 2021. "Maps of Service Areas." Executive Office of Technology Services & Security. <https://ma-eeac.org/wp-content/uploads/Appendix-B-Maps-of-Service-Areas.pdf>

outlining their plans for necessary grid infrastructure improvements in the next 5–10 years based on electric demand forecasts. Since 2014, natural gas utilities have been required to file Gas System Enhancement Plans (GSEPs) to address the aging natural gas energy infrastructure in the state. Subsequent legislation changed the requirements for GSEPs to ensure that utilities fully consider alternatives to standard pipe replacements.

The DPU, which regulates local distribution companies (LDCs, or natural gas utilities) and electric distribution companies (EDCs, or electric utilities), issued an order in December 2023 that set in motion a number of activities related to integrated natural gas/electric planning.<sup>1</sup> The DPU announced that it would be examining, among other things, line extension policies for natural gas companies, revenue decoupling mechanisms, accelerated depreciation, and customer affordability. The order requires electric utilities to participate in the LDCs' natural gas planning processes. The LDCs and EDCs are directed to work together to develop a joint natural gas and electric planning process. In addition, the DPU itself has taken steps to enhance the state's integrated planning by creating a new division with this focus.<sup>2</sup>

In 2022, the legislature allowed natural gas utilities to begin developing thermal energy networks, which further increased the imperative for joint planning.

### 2.5.3 Planning Framework

The December 2023 order requires the LDCs to file plans every 5 years (Beginning April 1, 2025) demonstrating how they will satisfy customer demand, use pilots to assist in identifying investment alternatives, and meet state policy requirements. Those plans were filed by the LDCs and docketed in DPU 25-40 through DPU 25-44/45 and are in the formal adjudicatory process at the DPU. See Table 1 for select key dates.

These plans were required to contain an analysis of non-pipeline alternatives as a condition of recovering investment in natural gas infrastructure. The utilities proposed a framework for analyzing NPAs in their initial plan filings. Under the 20-80 order, natural gas LDCs are also required to coordinate directly with their corresponding electric company to identify at least one specific community that can be shifted to electric heat pumps or thermal energy.

More broadly, the utilities are in various stages of developing integrated energy planning (IEP) approaches. Eversource and National Grid are furthest along in implementing internal steps to break down silos that previously kept natural gas planning and engineering separate from electric.

<sup>1</sup> DPU 20-80-B. Order on Regulatory Principles and Framework. December 6, 2023. <https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file/iadhaj?Kc28B1RUJcyf7TDOLTzteGFJ0i oKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMINqhcSkxPf0qUr1gASPKrYE1qejevbf677PtCVStUd HoHpEGELGLGjR+ZpYgt>

<sup>2</sup> DPU. 2025. "DPU Creates Division of Clean Energy and Resilience Engineering." January 15, 2025. Accessed on July 16, 2026. <https://www.mass.gov/news/dpu-creates-division-of-clean-energy-and-resilience-engineering>

Table 1: Key Dates in Massachusetts' Integrated Planning Processes

| Date             | Proceeding                        | Event                                                                                                                        |
|------------------|-----------------------------------|------------------------------------------------------------------------------------------------------------------------------|
| December 6, 2023 | DPU 20-80                         | Order 20-80-B issued, formalizing expectations and requirements for natural gas and electric utilities                       |
| August 28, 2024  | DPU 24-10                         | Order refines expectations for an integrated energy planning process.                                                        |
| Winter 2024      |                                   | IEP Working Group established by utilities                                                                                   |
| April 1, 2025    | DPU 25-40 through DPU 25-44/25-45 | All natural gas LDCs submit new plans, including non-pipes framework and integrated planning process                         |
| August 26, 2025  | DPU 25-40 through DPU 25-44/25-45 | Memorandum requesting comments regarding legal issues associated with the obligation to service by the natural gas companies |
| TBD              | DPU 25-40 through DPU 25-44/25-45 | Final DPU decisions                                                                                                          |

#### 2.5.4 Planning Methodologies

This section focuses on the approaches of Eversource and National Grid. Both companies have begun aligning data on the natural gas and electric distribution networks in parts of their service territories where they provide both natural gas and electric service. For example, when a segment of pipeline is identified as needing a replacement through the GSEP analysis, both companies use a process to assess the electric distribution system in that area for its current ability to absorb new electric load, thus enabling a coordinated planning approach. Within this coordinated planning, a point of contention centers on what analysis should occur when the electric system is identified as needing an upgrade.

None of the LDCs have yet to defer or replace the need for natural gas pipeline infrastructure by using the utilities' proposed draft non-pipeline alternative framework. However, Phase 1 of Eversource's Framingham Networked Geothermal Pilot is complete, which is measuring grid impacts, emission impacts, and customer bill savings across 26 buildings. The pilot is already demonstrating the benefits of close natural gas/electric utility coordination. All of the EDCs now have a heat pump electric rate; Framingham pilot customers now experience cost savings with this rate. The data collection phase of the Pilot will continue through August 2027. Eversource hopes to expand the geothermal grid through the "Flagg Loop" expansion, which would add another 27 buildings to the grid. National Grid has proposed a demonstration program for shifting targeted natural gas customers to electric heat pumps, but the plan and approach have run into disagreements with stakeholders regarding whether the utility is required to provide natural gas service to customers who want to remain on the natural gas system.

Both National Grid and Eversource conduct load forecasting for their natural gas and electric service territories using distinct sets of assumptions. This means that the customer technology adoption trends assumed in the utilities ESMPs are not necessarily the same as in their natural gas planning process. This could result in the same customers being modeled as both full natural gas heating and full electric heating customers, when in reality, there will be one primary heating system with a possible backup. On the one hand, the utilities point out that they must ensure that they can reliably meet customer load, and planning conservatively by assuming customers are connected to the system will enable their planning process to lead to the right investments to do so. On the other hand, advocates and state agencies have pointed out that diverging sets of forecasting assumptions can result in an over-estimate of both electric and natural gas system needs and inefficient use of capital resources.

### 2.5.5 Remaining Issues

Many of the issues being discussed in Massachusetts are currently up for debate within dockets 25-40 through 25-45, which deal with the natural gas utilities' plans in response to Order 20-80. One of these is the question of how to encourage or require more coordinated planning between electric and natural gas systems, particularly when the two systems are operated by different companies. Some stakeholders suggest that the state ought to establish a state-protected data clearinghouse for distribution system and customer data, so that different utility companies can access information about other systems needed in order to jointly plan. Other suggestions related to integrated planning include requiring iterative planning loops between the two systems and linking cost recovery of natural gas system investments, which occurs through the GSEP, to the utilities' existing IEP. All of these options face some opposition, including from the LDCs.

Another active area of debate centers around the natural gas utilities' historical "obligation to serve," with different parties having different interpretations of the legal requirement. The obligation to serve is a fundamental part of monopoly utility service, which may be called into question if the shift to electric end-uses means terminating natural gas delivery for existing customers. Historically, this obligation has meant that natural gas utilities must provide safe, adequate, and reliable service to any customer in their service territory who requests it, and they cannot refuse service to a home if it is located within a reasonable distance of a natural gas main. They also cannot shut off a customer's service just because maintaining the system is getting more costly. Some parties are arguing that the utilities' obligation is "fuel neutral," and would allow reliable heating and thermal energy service to be provided via several different means in addition to supplying natural gas as a commodity. The natural gas utilities view the obligation to serve in line with the historical precedent, arguing that customers already connected to the natural gas system have the right to remain connected if they wish.

Another issue is whether the GSEPs and the associated cost recovery mechanisms are still needed and appropriate mechanisms for the Commonwealth. Legislators are concerned that the accelerated cost recovery mechanism within the GSEP is directly contributing to affordability challenges and are debating whether the program should be altered or terminated entirely. In addition to discussions surrounding the planning methods identified above, the DPU has heard testimony and received briefings on issues related to the authority of the DPU to require the utilities to conduct iterative planning between ESMPs and natural gas system plans, and the best role for networked geothermal in meeting the state's thermal energy needs.

### 2.5.6 Next Steps

The next major development will be the DPU's decisions in dockets 25-40 through 25-45. In the second half of 2026, the DPU is expected to decide whether to accept, modify, or reject the companies' filed plans. The DPU may also rule on whether the natural gas utilities' obligation to serve should be interpreted more broadly than its historical interpretation, potentially leading to mandatory decisions to shift customers to some other form of thermal service, such as networked geothermal or electric heat pumps. Regulators may also make changes to the GSEP process if they determine that it ought to be more closely coordinated with the utilities' new plans.

In October 2026, the LDCs will submit their next annual GSEP for replacing leak-prone pipes. This will be an opportunity to examine the LDCs approach to potential non-pipes alternatives, specifically whether any new non-pipeline alternatives have been identified.

## 2.6 Minnesota

### 2.6.1 Summary

Minnesota's largest energy providers are Xcel Energy for electric and CenterPoint Energy for natural gas, with overlapping service territories in the Minneapolis-St. Paul area. Though electric system planning is well established in Minnesota, natural gas resource planning requirements have only existed since 2024 following Winter Storm Uri and subsequent regulatory investigations. Xcel Energy's first natural gas IRP, filed in July 2026, responds to the new regulatory requirements and includes scenario analysis, non-pipeline alternative analysis, and documents the company's efforts to coordinate with CenterPoint Energy in their overlapping service territory. Questions remain over the alignment of assumptions and forecasts across natural gas and electric planning and how pilots and dual-energy heating strategies will translate into scalable resource choices in future natural gas IRPs. The PUC's decision on Xcel's natural gas IRP is expected in mid-to-late 2027, with CenterPoint set to file in July 2027 and Minnesota Energy Resources Corporation in July 2028.

### 2.6.2 Context

Xcel Energy is the largest electric utility in the state in terms of the number of customers and serves the Minneapolis-St. Paul metro area. There are two other investor-owned electric utilities (Minnesota Power and Otter Tail Power), 50 electric cooperatives, and 120 municipal electric utilities. There are 33 municipal natural gas utilities, but the largest metro area (Minneapolis) receives natural gas service largely from an investor-owned gas-only company, CenterPoint Energy. CenterPoint is Minnesota's largest natural gas utility, serving nearly 900,000 customers in more than 260 communities.<sup>1</sup> Xcel Energy is the second-largest natural gas utility with 430,000 customers statewide. Some of these customers are within Xcel's electric territory as well—St. Paul and the eastern metro area are served by Xcel for both electric and natural gas. Thus, natural gas/electric coordination in the densest part of the state is partly an inter-company exercise between Xcel Energy's electric system and CenterPoint's natural gas system, and partly a within-company exercise at Xcel.

Minnesota has an established, mature electric IRP process. Xcel's 2024–2040 electric IRP sets out its plan for meeting customer electricity demand over the next 15 years.<sup>2</sup> Natural gas planning, by contrast, was historically internal and informal. After the natural gas price spikes experienced during Winter Storm Uri, the Minnesota PUC found that the natural gas utilities did not act prudently to protect ratepayers from extreme price increases and directed the creation of a stakeholder group to examine changes to natural gas supply planning. Subsequently, in October 2024, the Minnesota PUC established planning requirements for the three largest natural gas utilities.<sup>3</sup>

<sup>1</sup> CenterPoint Energy. 2024. "CenterPoint Energy continues to invest in the safety, reliability and resilience of its natural gas system to benefit customers." November 25, 2024. <https://investors.centerpointenergy.com/news-releases/news-release-details/centerpoint-energy-continues-invest-safety-reliability-and>

<sup>2</sup> PUC. 2026. "Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan (IRP)." Accessed on July 16, 2026. <https://mn.gov/puc/activities/economic-analysis/planning/xcel-energy-irp/>

<sup>3</sup> Minnesota PUC. Docket No G-008, G-002, G-011/CI-23-117 and Docket No G-999/CI-21-565. October 28, 2024. <https://efiling.web.commerce.state.mn.us/documents/%7B10C8D392-0000-CD32-9AA3-0C989AB58883%7D/download?contentSequence=0&rowIndex=42>

In addition to the natural gas IRP requirements, Minnesota's legislature and PUC have established other tools related to integrated natural gas and electric planning.

The Natural Gas Innovation Act (NGIA, passed in 2021, allows natural gas utilities to submit five-year plans to the Minnesota PUC to invest in pilot programs testing innovative technologies and fuels, including biogas, renewable natural gas, power-to-hydrogen, power-to-ammonia, carbon capture, strategic electrification, district energy, and innovative efficiency.<sup>1</sup> Xcel's NGIA plan was approved in January 2026, and it is currently working to develop the pilots approved therein (see Table 2).

The Energy Conservation and Optimization Act (ECO Act), passed in 2021, modernized the Conservation Improvement Program and allows utilities to count fuel switching toward energy savings goals when it reduces source energy on a fuel-neutral basis.

The Minnesota PUC opened a Future of Gas investigation (Docket G-999/CI-21-565) in 2021 to evaluate changes to natural gas utility regulatory and policy structures.<sup>2</sup> The topics discussed to-date include the appropriate use of dual-energy heating systems (electric heat pumps with natural gas back-ups to manage extreme winter peak demands) and thermal energy networks.

### 2.6.3 Planning Framework

The new natural gas IRP framework (established in October 2024 in Docket 23-117)<sup>3</sup> is the primary venue for discussion on integrated planning. The framework requires natural gas utilities to file IRPs every three years, with a ten-year planning horizon and a five-year action plan (see Table 2). Xcel must file first by July 1, 2026, followed by CenterPoint in 2027 and Minnesota Energy Resources Corporation (MERC) in 2028. Plans must include high, medium, and low forecasts of future demand over a 10-year period. The Minnesota PUC will approve, modify, or reject the IRPs.<sup>4</sup>

The framework requires natural gas utilities to work with electric utilities in their respective service territories to understand how customer energy choices may affect the demand for natural gas. The PUC acknowledged this will be difficult because a natural gas utility may overlap multiple electric territories and gave natural gas utilities discretion to determine the breadth and depth of their engagement with electric companies. The utility approaches to coordinated planning are still to be determined.

Non-pipeline alternative analysis, called "Expansion Alternatives Analysis (EAA), is required under the framework. Each utility must compile a list of all forecasted capacity-expansion projects over a \$1 million cost threshold for the next five years (maximum ten projects), then select two to three for a full analysis of whether alternatives can meet the need. The EAA assesses whether an alternative resource would be more appropriate than system expansion

<sup>1</sup> Minn. Stat. § 216B.2427. <https://www.revisor.mn.gov/statutes/cite/216B.2427/pdf>

<sup>2</sup> Minnesota PUC. Docket G-999/CI-21-565.

<https://efiling.web.commerce.state.mn.us/documents?doSearch=true&dockets=21-565&documentId=&onBehalfOf=&content=&receivedFrom=&receivedTo=>

<sup>3</sup> Minnesota PUC. Docket No G-008, G-002, G-011/CI-23-117 and Docket No G-999/CI-21-565. October 28, 2024. <https://efiling.web.commerce.state.mn.us/documents/%7B10C8D392-0000-CD32-9AA3-0C989AB58883%7D/download?contentSequence=0&rowIndex=41>

<sup>4</sup> Zitelman, K. 2025. *Long-Term Planning among Regulated Natural Gas Utilities*. National Association of Regulatory Utility Commissioners. May 2025. <https://pubs.naruc.org/pub/B3E9420C-9813-1958-98BB-C5387B4E2A9C>

and must consider non-gas alternatives. Routine maintenance, safety, integrity, and reliability investments are excluded from the non-pipeline alternative requirement.

In a June 2026 decision within the Future of Gas docket, the Minnesota PUC directed Xcel Energy to evaluate dual-energy heating models in the upcoming natural gas IRP.<sup>1</sup> These models use high-efficiency heat pumps for heating during the majority of the year, and switch to natural gas heating infrastructure only during the winter peak coldest hours.

**Table 2: Timeline of Minnesota Key Filings and Decisions Related to Long-Term Gas Planning**

| Date         | Proceeding                                | Event                                                    |
|--------------|-------------------------------------------|----------------------------------------------------------|
| Jul 23, 2021 | Future of Gas (G-999/CI-21-565)           | Docket opened                                            |
| Jun 26, 2021 | Natural Gas Innovation Act (NGIA) enacted | Minn. Stat. § 216B.2427                                  |
| Oct 28, 2024 | Gas IRP framework (23-117)                | Planning requirements established in the Framework order |
| Jan 5, 2026  | Xcel NGIA (G-002/M-23-518)                | Plan approved (13 projects, \$55M)                       |
| Jul 1, 2026  | Xcel natural gas IRP (26-168)             | First natural gas IRP filed                              |

## 2.6.4 Planning Methodology

Xcel Energy is the only utility that has begun the natural gas IRP process. After a series of stakeholder workshops, the company filed on July 1, 2026.<sup>2</sup>

### 2.6.4.1 Forecasting

Xcel includes forecasts of customer count, annual throughput (sales), and design day peak hour natural gas demand, along with relevant assumptions, in its natural gas resource plan, consistent with Minnesota PUC requirements.<sup>3</sup> Interactions with the electric system were explicitly considered within each of these forecasts; for example, assumptions about customer adoption of electric technologies directly informed the projected per-customer usage and customer counts over time. Xcel does not explicitly link the forecasting assumptions in the natural gas IRP with completed or planned load forecasts in the company's electric resource or distribution system plans; however, the company's natural gas IRP Preferred Plan is consistent with its proposed Electric and Natural Gas Energy Conservation and Optimization (ECO)

<sup>1</sup> Minnesota PUC. 2026. "Minnesota PUC Tightens Natural Gas Extension Rules, Pushes Efficiency Standards." St. Paul, MN, June 5, 2026.

<https://content.govdelivery.com/accounts/MNPUBUC/bulletins/41aa86a>

<sup>2</sup> Xcel Energy. Filing re: Docket NO. G002/RP-26-186. July 1, 2026.

<https://efiling.web.commerce.state.mn.us/documents/%7B803A209F-0000-CA1C-8977-5E0629E26077%7D/download?contentSequence=0&rowIndex=54>

<sup>3</sup> The "design day" peak hour is a long-term planning concept that models the forecasted highest possible volume of natural gas demand required under the most extreme winter weather conditions on a single day.

Triennial Plan, filed in June 2026,<sup>1</sup> indicating a level of consistency regarding customer demand forecasting across multiple Xcel plans.

#### 2.6.4.2 Non-pipeline alternatives

An EAA is required for capacity expansion projects identified in the natural gas IRP. Xcel identified nine capacity expansion projects needed to address forecasted system constraints, which were then subjected to an EAA screening process and quantitative scoring and prioritization. The screening process included assessing each project for two criteria: (1) the project's required in-service date was 2028 or later, allowing time for alternatives implementation, and (2) the project is located within the company's electric service territory, which it states will enable coordinated evaluation of natural gas and electric system impacts.<sup>2</sup> Projects that did not meet both of these criteria were eliminated from EAA consideration. Three out of nine capacity expansion projects met those criteria and were then subject to a full EAA.

Xcel's proposed EAA framework assesses EAA portfolios for their feasibility in avoiding, reducing, or delaying the need for capacity expansion projects by considering the technical, feasible, and achievable potential of each portfolio. For projects that advance beyond this "potential analysis", Xcel then performs a cost-benefit analysis to compare the relative cost-effectiveness of the EAA portfolio against the traditional natural gas infrastructure project.

Only one of the three EAA portfolios that were subject to the full assessment resulted in a lower cost than the proposed capacity expansion project. The portfolio would require up to 50 residential customers in central Minnesota to electrify their heating systems and over 300 customers in the same area to participate in a natural gas demand response program. Xcel states that this poses some key feasibility questions and that it intends to conduct customer research and work with stakeholders in assessing the feasibility of this portfolio before deciding whether to recommend moving forward with the EAA portfolio in a filing with the Minnesota PUC in early 2027.<sup>3</sup>

#### 2.6.4.3 Coordinated planning

Xcel's natural gas IRP Preferred Plan relies on a "Resource Level Analysis" that evaluates supply-side and demand-side resource options together within a single analytical framework. The company states that this enhances transparency, supports more informed trade-off analysis, and enables the company to construct a coordinated, dual-energy approach that "recognizes the complementary roles of natural gas and electric system."<sup>4</sup>

<sup>1</sup> Xcel Energy. Filing re: Docket NO. E,G022/CIP-26-110. June 15, 2026. <https://efiling.web.commerce.state.mn.us/documents/%7BA0D2CC9E-0000-C616-97DB-7751A0B37645%7D/download?contentSequence=0&rowIndex=11>

<sup>2</sup> Xcel Energy. Filing re: Docket NO. G002/RP-26-168. July 1, 2026. Page 148. <https://efiling.web.commerce.state.mn.us/documents/%7B803A209F-0000-CA1C-8977-5E0629E26077%7D/download?contentSequence=0&rowIndex=54>

<sup>3</sup> Xcel Energy. Filing re: Docket NO. G002/RP-26-168. July 1, 2026. Page 161. <https://efiling.web.commerce.state.mn.us/documents/%7B803A209F-0000-CA1C-8977-5E0629E26077%7D/download?contentSequence=0&rowIndex=54>

<sup>4</sup> Xcel Energy. Filing re: Docket NO. G002/RP-26-168. July 1, 2026. Page 2. <https://efiling.web.commerce.state.mn.us/documents/%7B803A209F-0000-CA1C-8977-5E0629E26077%7D/download?contentSequence=0&rowIndex=5> page 2

Additionally, Xcel is at varying stages of coordination with other utilities, as discussed in its proposed 2027-2029 ECO Plan.<sup>1</sup> Xcel proposes to ensure that all of its customers—whether natural gas, electric, or combination—are able to receive the same rebate for undertaking energy efficiency or fuel switching actions, which it states will require consistent incentives across service territories. Xcel and CenterPoint Energy are collaborating on technical assumptions and incentive levels for their shared customers.

#### **2.6.4.4 Response to Winter Storm Uri**

Xcel subjected each of the five portfolio configurations in the natural gas IRP to a Winter Storm Uri stress test to examine how these portfolios would respond to a severe supply-side disruption. The results reflect additional savings that are attributable to demand-side measures during a low-probability, high-impact event.

#### **2.6.5 Remaining Issues**

The natural gas IRP framework requires Xcel (electric) and CenterPoint (natural gas) to coordinate, but the exact approach is still being determined. Like other jurisdictions and utilities, the forecasts of future demand for electricity and natural gas have not historically been based on identical input assumptions. Parties have been encouraging Xcel and the Minnesota PUC to align those assumptions to ensure that aligned forecasting informs infrastructure planning on both systems.

As the NGIA pilots begin generating data and lessons learned, which technologies move into full-scale funded programs or into the natural gas IRP resource mix will be a recurring decision point. Relatedly, Xcel has experience with evaluating non-pipeline alternatives in its natural gas infrastructure planning process in Colorado, which the company and stakeholders have been focused on learning from.

#### **2.6.6 Next Steps**

Following Xcel's natural gas IRP filing in July 2026, the Minnesota PUC will receive stakeholder and company comments. A decision is expected in mid-to-late 2027. The Future of Gas (CI-21-565) proceeding will continue to address broader natural gas regulatory issues. CenterPoint and MERC will file their first natural gas IRPs in July 2027 and July 2028, respectively.

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<sup>1</sup> Xcel Energy. Filing re: Docket NO. G002/RP-26-168. July 1, 2026. Page 7.  
<https://efiling.web.commerce.state.mn.us/documents/%7BA0D2CC9E-0000-C616-97DB-7751A0B37645%7D/download?contentSequence=0&rowIndex=11> page 7

## 2.7 New York

### 2.7.1 Summary

New York's deregulated natural gas and electricity markets are served by many utilities, but most customers rely on large IOUs for energy delivery. In 2019, the state set strict economy-wide emissions limits, which, combined with ongoing utility-initiated natural gas connection moratoria and limited transparency in natural gas infrastructure planning, prompted the Public Service Commission (PSC) to require more formal natural gas planning. In the 2022 order, the PSC created a statewide natural gas system planning process requiring the largest natural gas utilities to file long-term plans every three years, prioritizing non-pipe alternatives, competitive solicitations, shareholder incentives, and a "no infrastructure" scenario analysis. The PSC found multiple shortcomings in the initial utility filings, especially around defining true "no infrastructure" options, selecting preferred pathways, and improving forecasting and optimization, which the utilities are currently working to address. New filings are expected in late 2026 and 2027.

### 2.7.2 Context

New York has deregulated electricity and retail natural gas markets, allowing consumers to choose who provides their energy supply—either their utility or a third-party supplier.<sup>1</sup> These third-party suppliers sell electricity and/or natural gas to customers using the transmission or distribution system of a utility. New York is served by 56 electric utilities, which are comprised of 7 investor-owned and 49 municipally owned utilities (see Figure 10), as well as 19 natural gas utility companies. Most New Yorkers are served by investor-owned, combination utilities, represented heavily by the so-called "Joint Utilities," which consist of Central Hudson Gas and Electric (CHG&E), Consolidated Edison (ConEd), National Grid, New York State Electric and Gas (NYSEG), Orange and Rockland Utilities, Inc., and Rochester Gas and Electric (RG&E). The Joint Utilities deliver energy to over 13 million customers.<sup>2</sup> While several of these combination utilities supply both natural gas and electricity to a subset of their customer base, as with the other states discussed here, there are pockets of New York where services are provided by different companies.

<sup>1</sup> DPS. "How to Shop for Energy Services." New York State Department of Public Service. Accessed on July 16, 2026. <https://dps.ny.gov/how-shop-utility-services>

<sup>2</sup> Joint Utilities of New York. 2026. "About the Joint Utilities of New York." Accessed on July 16, 2026. <https://jointutilitiesofny.org/about/who-we-are>

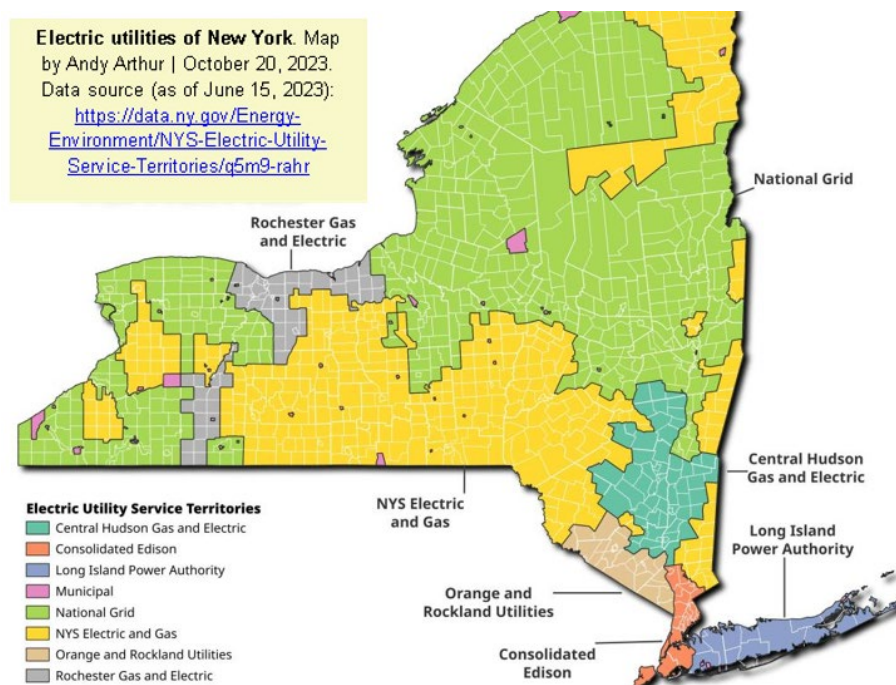


Figure 10: Service Territories of Electric Utilities in New York.<sup>1</sup>

For example, in New York City, Con Edison provides electric distribution services to all five boroughs (~3.6 million customers) but is the natural gas distribution company only to Manhattan, the Bronx, and parts of Northern Queens (~1.1 million customers). National Grid owns and operates the natural gas system in the rest of the city (see Figure 11).<sup>2</sup>

<sup>1</sup> Andy Arthur. 2023. "Electric Utility Service Territories." Accessed on July 16, 2026. <https://andyarthur.org/p/147449>

<sup>2</sup> City of New York. *A Stronger, More Resilient New York*. Report by the New York City Special Initiative for Rebuilding and Resiliency (SIRR). New York: City of New York, 2013. Chapter 6, pg 109-110. [https://www.nyc.gov/assets/sirr/downloads/pdf/Ch\\_6\\_Uilities\\_FINAL\\_singles.pdf](https://www.nyc.gov/assets/sirr/downloads/pdf/Ch_6_Uilities_FINAL_singles.pdf)

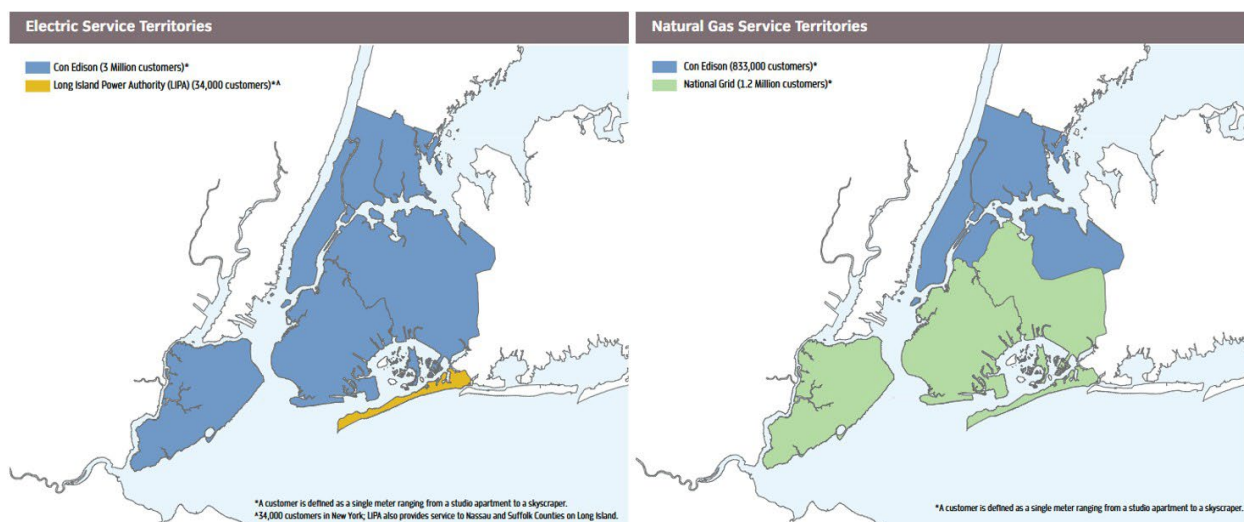


Figure 11: Electric and Natural Gas Service Territories in New York City.<sup>1</sup>

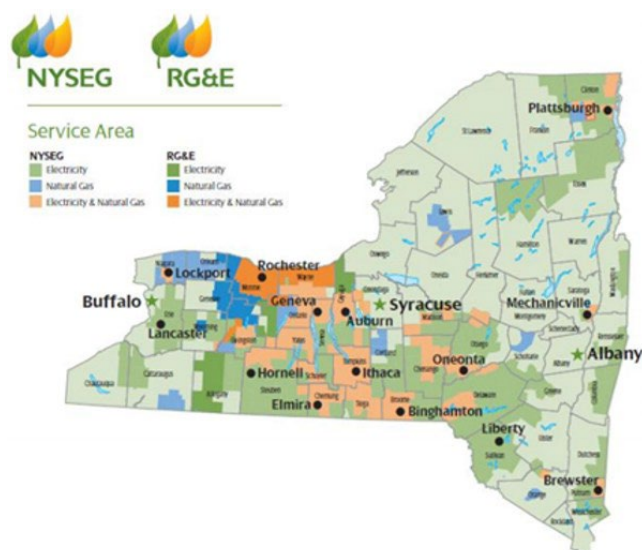


Figure 12: NYSEG and RG&E New York Service Territories<sup>2</sup>

NYSEG and RGE (both subsidiaries of Avangrid) serve significant portions of upstate New York, but with a patchwork of service territories (see Figure 12) that intersect with each other, National Grid's electric service territory, Central Hudson's Gas and Electric's service territory, Orange and Rockland's electric territory, and National Fuel Gas's natural gas territory.

In 2019, New York passed Senate Bill S6599, establishing an economy-wide emission reduction target of 40% below 1990 levels by 2030 and 85% below 1990 levels by 2050.<sup>3</sup> This initiated a

<sup>1</sup> City of New York. *A Stronger, More Resilient New York*. Report by the New York City Special Initiative for Rebuilding and Resiliency (SIRR). New York: City of New York, 2013. Chapter 6, pg 109-110. [https://www.nyc.gov/assets/sirr/downloads/pdf/Ch\\_6\\_Utilities\\_FINAL\\_singles.pdf](https://www.nyc.gov/assets/sirr/downloads/pdf/Ch_6_Utilities_FINAL_singles.pdf)

<sup>2</sup> NY Grid CONNECT. 2026. "Introduction to NYSEG and RG&E." Accessed on June 15, 2026. <https://gridconnect.nyserda.ny.gov/nygc-home/utility-profiles-information/nyseg-rge/>

<sup>3</sup> Enacted as the Climate Leadership and Community Protection Act (CLCPA), under SB S6599-A/A8429.

discussion on the role of natural gas within New York's current and future energy landscape. In Case 20-G-013, the PSC ordered LDCs to file locational supply and demand analyses, as well as proposals to manage moratoriums and address areas of supply and demand imbalance. The precursory planning requirements were created in response to utility-imposed moratoria on new natural gas customer service connections (driven by ongoing reliability issues) and a historical lack of transparency in natural gas infrastructure planning. In tandem with these requirements, Commission staff were also directed to file a proposal for modernizing natural gas planning consistent with the newly established legislative targets. In 2021, a staff proposal was submitted, with recommendations that LDCs file long-term, 20-year plans on a three-year cycle, with opportunity for stakeholder engagement and iteration, as well as evaluation by an independent third-party consultant.<sup>1</sup>

In addition to these regulatory actions, in December 2025, the New York legislature repealed residential natural gas line extension allowances (known as the “100-foot rule”).<sup>2,3</sup> Residential customers seeking new natural gas connections will now need to cover the associated costs, rather than have them paid for by other ratepayers.

### 2.7.3 Planning Framework

Case 20-G-0131 ultimately led to the establishment of a comprehensive natural gas planning process in New York, requiring the state's 11 largest LDCs to develop long-term plans every three years.<sup>4</sup> In 2022, the PSC published its Order Adopting Gas System Planning Process under Case 20-G-0131, setting requirements for LDCs to address in their long-term natural gas system plans (largely accepting the Commission staff proposal submitted in 2021).<sup>5</sup> Among the requirements, LDCs must present demand and supply forecasts that incorporate the impact of demand-side measures, energy efficiency programs, and innovative rate designs, based on a 20-year planning horizon.

The Order places a significant emphasis on non-pipe alternatives, requiring LDCs to:

- Develop a framework to assess non-pipeline alternatives, including suitability criteria, a shareholder incentive mechanism, and cost recovery details. Non-pipeline alternatives

<sup>1</sup> PSC. 2021. Notice of Stakeholder Forum and Soliciting Comments, Case 20-G-0131. February 12, 2021. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA08C40FF-D465-407A-A956-01F625BC4055%7D>

<sup>2</sup> Relates to the provision of gas service to new customers. S8417/A.8888. 2025–2026 legislative session (signed by the Governor). <https://www.nysenate.gov/legislation/bills/2025/S8417>

<sup>3</sup> Yelda, R. 2025. “New York State Removes 100-Foot Natural Gas Hookup Rule.” Natural Resources Defense Council. June 17, 2025. <https://www.nrdc.org/press-releases/new-york-state-removes-100-foot-natural-gas-hook-rule#:~:text=%22The%20repeal%20is%20a%20long%20overdue%20reform%20that,subsidize%20fossil%20fuel%20infrastructure%20for%20new%20customers.>

<sup>4</sup> DPS. Petition. Matter 23-00628, Case 23-G-0147. <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=23-G-0147&CaseSearch=Search>

<sup>5</sup> PSC. 2022. Proceedings on Cases 20-G-0131 and 12-G-0297. May 12, 2022. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={130B05B5-00B4-44CE-BBDF-B206A4528EE1}&DocTitle=Order%20Adopting%20Gas%20System%20Planning%20Process>

are subject to ad-hoc approval by the PSC,<sup>1</sup> and what constitutes a non-pipeline alternative varies by LDC.<sup>2</sup> Each company offers its own set of suitability criteria for demand and supply side resources.<sup>3</sup> Non-pipeline alternatives are acquired through competitive solicitations and evaluated based on the suitability criteria (with PSC oversight).<sup>4</sup> LDCs are also required to file a shareholder incentive mechanism worth up to 30 percent of the net benefits of the non-pipeline alternative project in their application.

- Propose solutions for meeting demand with reduced reliance on natural gas infrastructure. LDCs must include descriptions of how non-pipeline alternatives will be prioritized, as well as an assessment of a “no infrastructure” scenario for meeting natural gas supply needs without system expansion.
- File depreciation studies under three scenarios: (1) all new natural gas infrastructure is fully depreciated by 2050; (2) all natural gas infrastructure is fully depreciated by 2050; or (3) 50 percent of natural gas customers exit the system by 2040 and 90 percent exit by 2050.
- Complete annual reports outlining whether leak-prone pipes could be abandoned in favor of non-pipeline alternatives, including the location of specific segments for non-pipeline alternatives and where capital investments are needed to ensure system reliability. New York exempts projects that meet a certain safety threshold from the non-pipeline alternative requirements, defined as “immediate threats to public safety or system reliability.”

Finally, the order requires that a third-party consultant review all long-term plans to test their assumptions, validate calculations, and explore approaches from other states or countries. Case 20-G-0131 also calls for the formation of an “Avoided Cost of Gas Working Group” to refine the calculations of certain indices used in the benefit cost analysis (BCA) framework to account for differences between electric and natural gas BCAs.

#### 2.7.4 Planning Methodologies

In this section, we provide a summary of elements of the initial long-term plans of four NY utilities: ConEd, Orange and Rockland Utilities (ORU), National Grid, and Central Hudson Gas & Electric (CHG&E).<sup>5</sup>

<sup>1</sup> Strategen. 2023. *Non-Pipeline Alternatives to Natural Gas Utility Infrastructure*. Prepared for the Lawrence Berkeley National Laboratory. <https://eta-publications.lbl.gov/sites/default/files/non-pipeline-alternatives-to-natural-gas-utility-infrastructure-1-final.pdf>

<sup>2</sup> Non-pipeline alternatives cover both demand-side resources, including electrification, energy efficiency, and weatherization, and supply-side resources, including renewable natural gas, green hydrogen, and CNG injection.

<sup>3</sup> Although it varies by LDC, common criteria include proposal content, bidder experience, environmental impacts, project viability, technical reliability, safety, customer and socioeconomic impacts, scheduling, offer price, customer acceptance, and cost-effectiveness.

<sup>4</sup> LDCs are not required to divulge the weighting or relative importance of each criterion category.

<sup>5</sup> ConEd and its subsidiary, ORU, filed their initial long-term plan in Docket 23-G-0147 in November 2023. CHG&E filed its initial LTP in Docket 23-G-0676 in November 2024. National Grid filed its initial LTP in Docket 23-G-0248 in X, 2025.

### 2.7.4.1 Planning Scenarios

ConEd and its wholly owned subsidiary, ORU, presented three representative future pathways: a “reference” case reflecting the state’s legal, regulatory, and policy status at the time of planning, to inform short-term rate case funding requests; a “hybrid” case that incrementally expands upon the reference case (assumes elimination of line extension allowances and robust use of low carbon fuels, including synthetic natural gas); and a “deep electrification” case that incrementally expands upon the hybrid case.

Under the reference pathway, the two companies’ sales are stable through 2026 and then steadily decline through 2043. A similar trajectory is shown for peak natural gas demand. These are the only utilities in our set of case studies that are forecasting a decline in natural gas sales in the reference case, and this is at least partly attributed to the steps required to comply with New York City Local Law 154 and Local Law 97, which impact natural gas infrastructure in new and existing buildings in the city. With no anticipated future growth-related infrastructure investment, the companies describe all three pathways as “no infrastructure” options.

CHG&E modeled four different scenarios: a “Current Clean Agenda” case that reflects the state’s legal, regulatory and policy status at the time of planning including funding levels; a case that incorporates programs and policies to meet the requirements of Senate Bill S6599; a “No New Infrastructure” case that contains no growth-related investment; and a “Pipe Use Transformation” case that considers a transition to alternative gaseous fuels.

In its plan, National Grid presented three future scenarios: a “Reference” case that reflects the state’s legal, regulatory and policy status at the time of planning; a “Clean Energy Vision” case that reflects a hybrid approach with lowest cost to customers and the highest benefit-cost ratio; and the “Accelerated Electrification” case that expands upon the Clean Energy Vision case to increase adoption of heat pumps and throughput of alternative fuels, although at a higher cost and with a lower benefit-cost ratio.

### 2.7.4.2 Non-pipeline Alternatives

The Commission determined that the approach to a “no infrastructure scenario” of ConEd and ORU was not sufficient to meet the requirements in the Planning Order. The companies were directed to provide a no-infrastructure option in their 2027 long-term plan that meets all load growth with non-pipeline alternatives. The PSC acknowledged that there are challenges with implementing non-pipeline alternatives but directed the companies to more proactively engage with customers to create and deploy them, as outlined in comments from the third-party consultant and other parties.<sup>1</sup>

CHG&E describes the challenges with scaling up its leak-prone pipe NPA program, in which it permanently retires leak-prone pipe at no cost to customers, aimed at low saturation areas with high pipeline replacement costs. The program centers on replacing natural gas-using equipment with electric devices and covers “make ready” costs, such as electrical wiring and panel upgrades, in areas with 100% customer participation. The program resulted in per-home conversion costs of approximately \$46,000, with an average \$4,000 bonus incentive offered. CHG&E states that these costs, and the high transaction costs of recruiting customers to participate, make focusing on full abandonment of geographic areas infeasible.

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<sup>1</sup> The companies were also directed to develop and file a non-pipeline alternative deployment plan within 120 days. ConEd and ORU filed these deployment plans separately in January 2025.

In reviewing CHG&E's long-term plan, the PSC noted that the utility's preferred pathway does not meet the definition of "No Infrastructure Option" because it includes capital expenditure and does not reflect a fully non-pipeline-alternative-driven portfolio to close demand-side gaps.

#### 2.7.4.3 Integrating Natural Gas and Electric Planning in the Future

Across all of the New York LDC long-term plans, the companies, third-party consultants, other parties, and the PSC acknowledge that further work is needed to integrate natural gas and electric planning. In addition, the companies and the Commission agree that, for the foreseeable future, customers will retain natural gas-fired equipment, and those who choose to switch to electric appliances may do so in a piecemeal fashion, which will have varying impacts on the natural gas and electric systems. In the Order reviewing ConEd and ORU's long-term plan, the PSC directed the companies to include information in their next LTP addressing the impacts of increased electric load on the reliability of both systems.<sup>1</sup>

National Grid's long-term plan describes a coordinated strategy between the company's Upstate and Downstate service territories, which have different rates of growth, infrastructure needs, and customer profiles. Although the long-term plan is not an integrated plan, it is an early coordination effort, which the company is actively doing in the areas where it serves as the electric and natural gas provider.

#### 2.7.4.4 Improvements Needed in Future LTPs

The PSC also noted that ConEd and ORU did not adequately develop or present a "preferred pathway" as required. As such, the PSC directed the companies to select a preferred pathway and conduct multivariable optimization in the 2027 long-term plan. This includes a more detailed analysis of customer counts and annual use per customer, with consideration to the evolving competition between natural gas and electric appliances and impacts to the electric system from changes in natural gas use.

Much like ConEd's filing, the PSC also directed CHG&E to conduct multivariable optimization to produce planning scenarios in its next long-term plan. The PSC directed National Grid to provide additional information related to demand forecasting and explicitly list the improvements they are making to forecasting methodologies, share updates on remaining leak-prone pipe mileage, and examine the potential to decommission the Greenpoint LNG plant.

In a separate Case (24-E-0364), *In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure*, the PSC directed the Joint Utilities<sup>2</sup> to integrate the granular electric system forecasts being developed in that case into future planning cycles, sales forecasts, natural gas planning work, and rate cases.<sup>3</sup>

<sup>1</sup> PSC. 2024. Order Regarding Long-Term Natural Gas Plan and Requiring Further Actions. 23-G-0147, p. 52. September 20, 2024.

<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={30831092-0000-CC1F-A4BA-BA05427FE6C6}&DocTitle=Order%20Regarding%20Long-Term%20Natural%20Gas%20Plan%20and%20Requiring%20Further%20Actions>

<sup>2</sup> In this case, "Joint Utilities" refers to Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., National Grid, New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, and Orange and Rockland Utilities, Inc.

<sup>3</sup> PSC. 2024. Order Adopting Modified Proactive Planning Framework. 23-G-0147, p. 26, <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80185E99-0000-CF1D-A57E-F4A6874B79D5}&DocTitle=Order%20Adopting%20Modified%20Proactive%20Planning%20Framework>

### **2.7.5 Remaining Issues**

The PSC declined to approve all submitted long-term natural gas plans, signaling a desire for further refinement and alignment with the state's policies. The natural gas long-term plan is not an integrated energy plan. There are a few recommendations from the third-party consultant for creating an integrated plan, including a suggestion to establish a new workstream within the natural gas planning proceeding dedicated to coordinated planning that advances state goals and to investigate a framework for consistency in supply-demand forecasts in future planning.

### **2.7.6 Next Steps**

At the time of writing, the utilities are taking PSC-directed follow-up actions to address specific issues and improve their planning processes. Several utilities are in the process of implementing natural gas demand response programs and developing more detailed non-pipeline alternative deployment plans. The next round of long-term plans is expected to commence in a staggered fashion, with ConEd and ORU filing in November 2026, National Fuel Gas filing in late 2026, and other utilities filing in late 2027.

## 2.8 Québec

### 2.8.1 Summary

Rather than being legislatively- or regulator-driven, Québec's natural gas and electric coordination began with a voluntary commercial partnership between two separate utilities, the electric Crown corporation Hydro-Québec and the province's dominant natural gas distributor, Énergir. The dual-energy program, which is overseen by the Régie de l'énergie (the utility regulator), automatically switches buildings to natural gas heating when temperatures drop below -12°C, avoiding the need for new winter peak investments on the electric system. Hydro-Québec makes volume-based compensatory payments to Énergir, though this financial structure has sparked ongoing legal and regulatory appeals regarding how those costs are passed to ratepayers. The legal challenges are happening in parallel with the program itself, which has continued to operate, and the province's own formalized long-term natural gas-electric planning, which began in 2025 following the passage of Bill 69.

### 2.8.2 Context

Québec's electricity and natural gas providers are regulated by the Régie de l'énergie (Québec Energy Board, analogous to a state PUC in the United States), an economic regulatory tribunal that sets rates and conditions of service for electricity transmission and distribution and natural gas distribution, and approves utility investment projects.

Hydro-Québec is the default electricity distributor and supplier for the majority of the province, and is a vertically integrated, low-cost-hydro Crown corporation (state-owned enterprise). Its generation fleet is almost entirely hydropower, and the primary operational constraint is winter peak demand on the coldest days. Ten municipal electric distributors and one cooperative also fall under the Régie.<sup>1</sup>

Énergir is an IOU and the largest natural gas distributor, providing 97% of Québec's natural gas to 210,000 customers over 11,000 kilometers of distribution pipeline.<sup>2</sup> A unique aspect of Québec's natural gas usage is that the majority is for commercial heating and industrial operations, rather than residential heating. Roughly 75% of residential customers heat their homes with electricity, the highest rate of electric home heating in Canada. This characteristic of residential energy use in Québec, and the resulting concerns about winter electric peak, is a central driver of natural gas and electric planning coordination.

Historically, Hydro-Québec and Énergir planned their systems independently because they are structurally separate and serve different roles. More recently, however, the separate companies have been pursuing system planning coordination through a negotiated commercial agreement. It is worth emphasizing that the coordinated planning efforts in Québec were utility-initiated, rather than being imposed through regulatory action, as is the case with most of the other examples. There was no province-level, mandated natural gas-electric planning until Bill 69 in 2025 (discussed below).

<sup>1</sup> EnergyRates.ca. "Hydro-Québec." Accessed on July 17, 2026. <https://energyrates.ca/fr/quebec/hydro-quebec/>

<sup>2</sup> Énergir. "Diversified Business." Accessed on July 17, 2026. <https://energir.com/en/about/the-company/who-we-are/our-activities>

### 2.8.3 Planning Framework

The framework for coordinated planning originated in the joint Énergir–Hydro-Québec commercial agreement, which is a dual-energy, 20-year project to convert natural gas-heated buildings to a dual electricity-and-gas system. The program is focused on converting customers to a dual-energy system rather than electric-only to help alleviate electric grid constraints during winter peaks. The utilities filed the agreement with the Régie to have one financial principal approved: that the cross-utility compensation could be factored into each distributor's revenue requirement for rate-setting.

In 2022 (Decision D-2022-061), the Régie granted the application, reasoning that the dual-energy scenario would have markedly less impact on Hydro-Québec customers' rates than an all-electric scenario, and that the cross-utility payments were necessary to ensure rapid deployment of the offer.<sup>1</sup> The program is estimated to have no impact on Hydro-Québec customers' rates until 2025, and a cumulative impact of about 1.43% by 2030, while the cross-utility payment would cover 80% of Énergir's revenue shortfall, leaving Énergir customers with about a 0.9% cumulative impact.<sup>1</sup>

In 2025, the legislature institutionalized coordinated planning through Bill 69, the *Act to ensure the responsible governance of energy resources*.<sup>2</sup> Its central instrument for coordination is the “Plan de gestion intégrée des ressources énergétiques” (PGIRE)—an integrated energy-resource-management plan. It is being developed by the Ministry of Economy, Innovation and Energy in collaboration with Hydro-Québec and the other electricity and natural gas distributors, and is envisioned to serve as a 25-year strategic energy plan.

Bill 69 is broad and controversial in its own right, also allowing the government to cap Hydro-Québec's residential rate increases and removing Hydro-Québec's obligation to procure electricity through a public bidding process.<sup>3</sup>

### 2.8.4 Planning Methodology

The dual-energy agreement between the companies is operationalized through Hydro-Québec's dual-energy tariff, “Rate DT.” A participating building keeps its natural gas furnace and adds electric heating (typically a heat pump). Electricity is used for heating most of the time, but the building switches to natural gas automatically on the coldest days. Énergir describes the design goal as shifting about 70% of a building's natural gas heating to hydroelectricity while reducing the impact on winter peaks, allowing Hydro-Québec to avoid additional investments to meet peak demand.<sup>4</sup> The utility incorporates projections of the program's impact within its resource

<sup>1</sup> D-2022-061 Decision Summary. May 19, 2022. [https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4169-2021/doc/R-4169-2021-A-0065-Dec-Som-2022\\_07\\_06.pdf](https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4169-2021/doc/R-4169-2021-A-0065-Dec-Som-2022_07_06.pdf)

<sup>2</sup> Assemblée nationale, June 7, 2025. <https://www.assnat.qc.ca/fr/travaux-parlementaires/projets-loi/projet-loi-69-43-1.html>

<sup>3</sup> Bill 69 as sanctioned, 2025 c. 24. Assented to June 7, 2025. [https://www.publicationsduquebec.gouv.qc.ca/fileadmin/Fichiers\\_client/lois\\_et\\_reglements/LoisAnnuelles/en/2025/2025C24A.PDF](https://www.publicationsduquebec.gouv.qc.ca/fileadmin/Fichiers_client/lois_et_reglements/LoisAnnuelles/en/2025/2025C24A.PDF)

<sup>4</sup> Énergir. 2026. “What is dual energy?” Accessed on July 17, 2026. <https://energir.com/en/business/dual-energy>

adequacy forecasts, which show that the program allows it to avoid the need to build at least 2 GW of additional grid capacity.<sup>1</sup>

The switchover between electric and natural gas heating is governed by a preset outdoor temperature—current program materials put it around  $-12^{\circ}\text{C}$ —enforced through a sensor that Hydro-Québec installs along with a new meter.<sup>2,3</sup> Under Rate DT, electricity for heating is inexpensive above the temperature threshold but jumps sharply below it: a third-party analysis of Hydro-Québec's April 1, 2025 rates put it at roughly 4.96 ¢/kWh above the  $-12^{\circ}\text{C}$  threshold versus about 29.0 ¢/kWh below it.<sup>2</sup>

Customers are recruited to the program with significant subsidies and a long-term commitment. Grants cover up to 80% of the cost of buying and installing the new electric equipment, co-funded by Hydro-Québec, Énergir, and the Québec government—for example, financial assistance of about \$7,300 for Énergir customers and \$6,800 for Enbridge Gaz Québec customers for a detached, semi-detached, or row house.<sup>4</sup> In return, participants must commit to Hydro-Québec's Rate DT for 10 years, with fees for early termination and obligations that follow the property on sale.<sup>5</sup> Phase 1 targets Énergir's residential customers (including converting natural gas water heaters to electric); a later Phase 2 is aimed at commercial and institutional customers.<sup>6</sup>

Because adding the heat pumps lowers Énergir's natural gas sales while raising Hydro-Québec's supply costs, Hydro-Québec pays Énergir annually based on the actual volumes of natural gas converted to electricity, estimated at \$85 million in 2030.<sup>6</sup> Hydro-Québec argues that it saves its customers money by avoiding additional grid investments.

Rather than a regulator-mandated non-pipe alternatives analysis, the "method" in this case is a jointly engineered customer product (Rate DT plus the automatic switch) that uses natural gas as a targeted peak resource and electricity as the base load. This makes the Quebec example distinct from the others in this paper. The volume-based payment from one utility to another to equalize rate impacts is also unusual, and, as discussed below, has been a controversial feature.

## 2.8.5 Remaining Issues

In the 2022 Régie de l'énergie decision authorizing the cross-utility payments, one commissioner dissented on the basis that he did not believe the Régie had the authority to

<sup>1</sup> Séguin, H. and A. Bigouret. 2023. "Hybrid heat in Québec: Energir and Hydro-Québec's collaboration on building heat decarbonization." *Canadian Climate Institute*. April 14, 2023. Accessed on July 17, 2026. <https://climateinstitute.ca/publications/hybrid-heat-in-quebec/>

<sup>2</sup> Construction Renovation Québec. "Dual-energy guide." Accessed on July 17, 2026. <https://www.constructionrenovationquebec.com/tarif-bi-energie-dt-est-ce-vraiment-rentable-de-garder-le-gaz-pour-les-grands-froids/>

<sup>3</sup> Klimfax 2026. "Dual-energy electricity and natural gas." Accessed on July 17, 2026. <https://www.klimfax.com/en/grants/dual-energy-program/>

<sup>4</sup> Hydro-Québec. 2026. "Dual energy for sustainable decarbonization." Accessed on July 17, 2026. <https://www.hydroquebec.com/residential/energy-wise/offers-to-save/dual-energy-offer.html>

<sup>5</sup> Enbridge Gas Québec. 2026. "What is Dual Energy?" Accessed on July 17, 2026. <https://enbridgegaz.com/en/residential/existing-customer/exploring-dual-energy/>

<sup>6</sup> Régie. 2022. D-2022-061 Decision Summary. [https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4169-2021/doc/R-4169-2021-A-0065-Dec-Som-2022\\_07\\_06.pdf](https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4169-2021/doc/R-4169-2021-A-0065-Dec-Som-2022_07_06.pdf)

recognize the general ratemaking principle as requested by Hydro-Québec.<sup>1</sup> Consumer and environmental groups sought review of D-2022-061, arguing the Régie had no authority to let Hydro-Québec socialize Énergir's compensation across electricity ratepayers.<sup>2</sup> In 2023, the Régie's review decision partially altered the compensation mechanism by ruling that Hydro-Québec cannot raise the rates of all its customers to pay Énergir.<sup>3</sup> This decision has since been overturned by the Québec Superior Court and escalated to the Québec Court of Appeal. Despite the ongoing legal controversy over whether payments to Énergir are costs that Hydro-Québec can pass on to customers, the dual-energy program continues to operate due to separate provincial government funding that has allowed customer-facing grants to continue.

An ongoing area of debate centers on whether the dual-energy program is the cheapest way for Hydro-Québec to manage winter peak constraints. A 2022 study found that this approach would cost enrolled customers more than electric heating with heat-storage technology.<sup>4</sup> Hydro-Québec markets peak-management technologies that could provide a similar system value to the natural gas backup furnaces.

## 2.8.6 Next Steps

Decision D-2022-061 required the companies to file the results of a planned review in five years—i.e., around 2027—with a possible revisiting of the cross-utility payment principle and its method if the Régie sees fit.<sup>1</sup> The companies must also file annual reports on the deployment of the program to the regulator.

Under Bill 69, the government's integrated energy-resource plan, which is currently under development, is the forum where natural gas-electric coordination will now formally play out.<sup>5</sup>

<sup>1</sup> Régie. 2022. D-2022-061 Decision Summary. [https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4169-2021/doc/R-4169-2021-A-0065-Dec-Som-2022\\_07\\_06.pdf](https://www.regie-energie.qc.ca/fr/participants/dossiers/R-4169-2021/doc/R-4169-2021-A-0065-Dec-Som-2022_07_06.pdf)

<sup>2</sup> Fiset, M-C. 2022. "Plusieurs demandes de révision de la décision controversée de la Régie de l'énergie sur la biénergie." *Greenpeace*. June 21, 2022. Accessed July 17, 2026. <https://www.greenpeace.org/canada/fr/blog-des-volontaires/53317/plusieurs-demandes-de-revision-de-la-decision-controversee-de-la-regie-de-lenergie-sur-la-bienergie/>

<sup>3</sup> Equiterre. "Hydro-Québec ne pourra augmenter les tarifs pour compenser Energir." February 23, 2023. <https://www.equiterre.org/en/articles/cdp-revision-decision-bienergie-hydroquebec>

<sup>4</sup> Le Devoir. 2022. "Lentente entre Hydro-Québec et Energir contestée devant la Régie de l'énergie." October 26, 2022. Accessed on July 17, 2026. <https://www.ledevoir.com/actualites/societe/767555/l-lentente-entre-hydro-quebec-et-energir-contestee-devant-la-regie-de-l-energie>

<sup>5</sup> Coalition Avenir Québec. 2025. "Adoption du projet de loi n°69 pour accélérer le développement énergétique et économique du Québec." June 9, 2025. Accessed July 17, 2026. <https://coalitionavenirquebec.org/fr/blog/2025/06/09/le-gouvernement-adopte-le-projet-de-loi-n-69-pour-accelerer-le-developpement-energetique-et-economique-du-quebec/>

## 2.9 Rhode Island

### 2.9.1 Summary

In Rhode Island, a single IOU, Rhode Island Energy (RIE), provides nearly all electric and natural gas service statewide and is the state's only regulated natural gas utility, creating a strong opportunity for fully integrated gas-electric planning. The state's core demand-side and capital investment deferral planning framework is known as Least Cost Procurement (LCP), which applies to both electric and natural gas supply. LCP requires a combined, three-year System Reliability Procurement (SRP) plan that screens non-wires and non-pipes alternatives and uses a jurisdiction-specific "Rhode Island Test" that accounts for cross-fuel costs and benefits. In practice, SRP screening has not yet produced many integrated portfolio proposals. Unresolved questions include how to allocate costs for demand-side measures that affect both systems and whether continued large natural gas capital additions are prudent given the state's legally enforceable emissions limits. Ongoing regulatory proceedings, including required LCP filings and an active base rate case, are expected to shape future planning.

### 2.9.2 Context

Rhode Island is unusual in that a single IOU provides the large majority of both electric and natural gas distribution service statewide, regulated by the Rhode Island PUC. RIE owns the electric distribution network for the entire state, except for two small municipal systems (Pascoag Utility District and Block Island Power Company), and is the sole regulated natural gas distribution company for the entire state. In rural areas where RIE does not provide natural gas, delivered fuels such as fuel oil and propane are alternative heating fuels and supplied by private companies.<sup>1</sup>

Because it owns both the natural gas and electric networks, this case study focuses solely on RIE. This situation presents a unique opportunity for a statewide holistic approach to integrated natural gas and electric planning.

A defining operational constraint is the aging, leak-prone natural gas distribution system. An E3 analysis found that replacement of leak-prone pipe required over the next decade under the Infrastructure, Safety, and Reliability (ISR) program, plus expected reinvestments, causes the natural gas annual revenue requirement to nearly double by 2050 in a reference scenario.<sup>2</sup> A second constraint is localized capacity: the Aquidneck Island natural gas system suffered a significant outage in early 2019, and RIE has since been required to develop a targeted solution for natural gas supply constraints there (discussed below).

Rhode Island has long-standing planning requirements, including a Least Cost Procurement (LCP) framework that has applied to electric utilities since 2006 and natural gas utilities since 2011. The LCP dictates that the utility conduct System Reliability Procurement (SRP) for meeting or mitigating natural gas and electric system needs with localized, cost-effective alternatives. This means analyzing both non-wires and non-pipes solutions.

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<sup>1</sup> E3. 2024. "Rhode Island Investigation into the Future of the Regulated Gas Distribution Business." Docket 22-01-NG. p. 18, <https://www.ethree.com/wp-content/uploads/2024/06/Docket-22-01-NG-E3-Technical-Analysis-Report.pdf>

<sup>2</sup> R.I. Gen Laws § 42-6.2-2. 2021 Act on Climate. <https://webserver.rilegislature.gov/Statutes/TITLE42/42-6.2/42-6.2-2.htm>

Rhode Island Energy is also required to file annual investment strategies, known as the ISR plan, for funding capital projects and maintaining the reliability of both the natural gas and electric systems. Because Rhode Island has some of the oldest natural gas infrastructure in the country, the natural gas system ISR has focused on replacing cast iron and steel natural gas mains. The challenges posed by rapid increases in spending under the natural gas ISR program are one motivating factor for better coordination of planning across utility systems.

A second factor is that in 2021, Rhode Island enacted the “Act on Climate”, codified as Title 42 Chapter 6.2.<sup>1</sup> This law set mandatory, economy-wide, legally enforceable emission limits by 2050.<sup>2</sup> The limits apply to both the electric and natural gas sectors, compliance with which will necessitate close coordination between the two systems.

### 2.9.3 Planning Framework

The LCP standards are the foundational conservation, efficiency, demand-side management, and capital investment deferral planning requirements for both the natural gas and electric systems. The standards must be updated by the Rhode Island PUC at least once every three years and include requirements for both energy efficiency and SRP.

The SRP framework under the LCP Standards requires RIE to analyze potential opportunities to avoid traditional utility procurement and encourage optimal investment by the utility. SRP plans identify system needs on both natural gas and electric systems that could be addressed through non-wires or non-pipes alternatives, with the utility required to look at the electric system as a tool to mitigate constraints on the natural gas system. The SRP framework classifies system needs that fail the NWA and NPA screening criteria as needing traditional solutions, which are then proposed through the annual Electric or Gas ISR Plans.<sup>3</sup> SRP Plans are filed as a single combined electric-and-gas three-year plan, the most current of which is the 2024–2026 SRP (filed in Docket 23-47-EE).

Within the LCP framework, the cost-effectiveness of potential measures, programs, and portfolios is determined using Rhode Island's own jurisdiction-specific cost-test established in Docket 4600A.<sup>4</sup> This “RI Test” is significant because it requires an assessment of all fuel impacts, rather than electric system costs and benefits in isolation from natural gas system costs and benefits. This structure also dictates a certain level of coordination between systems.

Separately, the Rhode Island PUC opened the “Investigation into the Future of the Regulated Gas Distribution Business” docket in 2022 in response to the “Act on Climate”.<sup>5</sup> The Rhode Island PUC required RIE to fund a third-party technical analysis<sup>6</sup> and established a multi-

<sup>1</sup> R.I. Gen Laws § 42-6.2-2. 2021 Act on Climate. <https://webserver.rilegislature.gov/Statutes/TITLE42/42-6.2/42-6.2-2.htm>

<sup>2</sup> Rhode Island EXORD 23-06. State Agencies to Lead by Example and Lead on Climate. May 9, 2023. <https://governor.ri.gov/executive-orders/executive-order-23-06>

<sup>3</sup> Rhode Island PUC Docket 23-XX-EE. SRP Three Year Plan. Rhode Island Energy. November 21, 2023. [https://eec.ri.gov/wp-content/uploads/2023/09/2024-2026-srp-three-year-plan\\_final-draft-for-eermc.pdf](https://eec.ri.gov/wp-content/uploads/2023/09/2024-2026-srp-three-year-plan_final-draft-for-eermc.pdf)

<sup>4</sup> Rhode Island PUC Benefit-Cost Framework, Docket 4600A guidance, [https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4943-PIMs\\_Guidance\\_Document\\_Approved.pdf](https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4943-PIMs_Guidance_Document_Approved.pdf)

<sup>5</sup> Rhode Island PUC. Docket No. 22-01-NG. June 9, 2022. <https://ripuc.ri.gov/Docket-22-01-NG>

<sup>6</sup> E3. 2024. “Rhode Island Investigation into the Future of the Regulated Gas Distribution Business.” Docket 22-01-NG, p. 4. , <https://www.ethree.com/wp-content/uploads/2024/06/Docket-22-01-NG-E3-Technical-Analysis-Report.pdf>

stakeholder committee structure. RIE hired E3 to conduct the technical study, which was published in April 2024. A final report and order from the Rhode Island PUC is expected, but as of June 2026, have not yet been issued and the docket appears to be functionally idle. In the meantime, RIE has filed a new base rate case with requested revenue requirement increases for both the natural gas and electric systems, with direct implications for the findings in the “Future of Regulated Gas Distribution Business” docket and the future SRP and ISR plans.<sup>1</sup>

## 2.9.4 Planning Methodology

### 2.9.4.1 Non-wires and Non-pipes Alternatives

The SRP framework is the operational tool for analyzing whether non-wire/non-pipe alternatives can defer or avoid the need for traditional utility infrastructure. In practice, this has not yet resulted in proposals, indicating that integrated planning is occurring across the natural gas and electric systems. Following the most recent SRP, RIE brought specific investment proposals in separate electric and natural gas dockets—ConnectedSolutions (electric demand response, 24-06-EE), the Gas demand response Pilot (24-37-EE), and the Aquidneck Island non-pipeline alternative (25-16-NG).

ConnectedSolutions is a regional, summer-peaking demand-reduction program and was approved by the Rhode Island PUC in April, 2025.<sup>2</sup> Given that E3’s technical analysis in Docket 22-01-NG showed Rhode Island shifting to being a winter-peaking system under the scenarios that comply with state law, future proposals under the SRP may need to address winter peak needs.<sup>3</sup>

The continuation of the natural gas DR pilot was denied and the pilot was discontinued. RIE itself was not proposing pilot expansion due to low enrollment and consequent uncertainty about whether natural gas DR can mitigate capacity constraints and defer natural gas infrastructure investment, and, because of low enrollment, the company had struggled to meaningfully evaluate the benefits of the pilot.<sup>4</sup>

Separate from the SRP, RIE was required to file a plan for Aquidneck Island with the “objective of eventually eliminating the design-day peak hour capacity gap that has caused capacity constraints” on the Island.<sup>5</sup> That proposal was submitted in June 2025, but the Rhode Island PUC has not issued an order.<sup>6</sup>

### 2.9.4.2 Scenario Analysis

RIE is not required to file a joint resource plan but is required to conduct scenario analysis when evaluating non-pipeline and non-wire alternatives in the SRP process. This includes looking at

<sup>1</sup> Rhode Island PUC. Docket No. 25-45-GE. <https://ripuc.ri.gov/Docket-25-45-GE>

<sup>2</sup> Rhode Island PUC. Docket No. 24-06-EE November 26, 2025. <https://ripuc.ri.gov/Docket-24-06-EE>

<sup>3</sup> E3. 2024. “Rhode Island Investigation into the Future of the Regulated Gas Distribution Business.” Docket 22-01-NG. <https://www.ethree.com/wp-content/uploads/2024/06/Docket-22-01-NG-E3-Technical-Analysis-Report.pdf>

<sup>4</sup> Rhode Island PUC. Docket No. 24-37-EE. Order 25340, p. 2. <https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2025-05/RI%20Energy%2024-37-EE%202025%20GDRP%20Ord25340%205-7-25.pdf>

<sup>5</sup> In re The Narragansett Electric Company Aquidneck Island Gas Reliability Project, Old Mill Lane, Portsmouth, RI, Decision and Order, at 52 (May 12, 2025)

<sup>6</sup> Rhode Island PUC. Docket No. 25-16-NG. <https://ripuc.ri.gov/Docket-25-16-NG>

SRP investment options under high- and low-demand sensitivities and weather extremes. Another place where scenario analysis features heavily is in the E3 work for RIE conducted under the Future of Gas docket. E3 analyzed six scenarios and five sensitivities that each would result in compliance with state law. These scenarios demonstrated that, in order to comply with state law, heat-pump adoption over the next decade would need to be 5–10 times today's levels, natural gas throughput would decline by 45–95% by 2050, and the electric distribution system would expand significantly.<sup>1</sup> The analysis identified opportunities to significantly mitigate electric peak increases, such as hybrid electric with natural gas backup heating, or networked geothermal heating.<sup>2</sup> E3 also points out that additional research is required to quantify to what extent natural gas infrastructure projects can technically and cost-effectively be avoided in Rhode Island.<sup>3</sup>

### 2.9.5 Remaining Issues

The Rhode Island PUC has an active docket to review the LCP standards, where several issues are being debated. One is the appropriate cost recovery mechanism and process for demand-side measures that potentially impact both systems. For example, if an electric energy efficiency measure causes a reduction in natural gas usage, there is disagreement about whether the natural gas or electric customers should pay for that measure.

The SRP framework provides an analytical process for looking at non-pipeline and non-wire alternatives, but it remains to be seen whether RIE will bring forward larger-scale or jointly planned proposals. The non-pipeline alternative proposal for Aquidneck Island will be a test case for RIE's analysis.

The active base rate case (No. 25-45-GE) is illuminating some areas of continued disagreement among parties. In particular, RIE proposed a significant increase in natural gas rate base, which is controversial with stakeholders who argue that such investments cannot be found prudent by the Rhode Island PUC, given the binding restrictions in state law.

### 2.9.6 Next Steps

The next major developments will include the 2026 update to the LCP standards and RIE's subsequent SRP portfolio development. In addition, RIE's active base rate case will be an active venue for discussion on capital investment plans. Testimony has been filed and evidentiary hearings are scheduled to occur through mid-July 2026. It should be noted that the majority of natural gas infrastructure spending is discussed and approved in the ISR plans and then rolled into base rates, meaning that those annual plans will continue to be a focus for stakeholders and the regulator. The PUC's final Future of Gas report in Docket No. 22-01-NG is expected at some point, but no schedule for release has been given.

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<sup>1</sup> E3. 2024. "Rhode Island Investigation into the Future of the Regulated Gas Distribution Business." Docket 22-01-NG, p.6 & p.12, <https://www.ethree.com/wp-content/uploads/2024/06/Docket-22-01-NG-E3-Technical-Analysis-Report.pdf>

<sup>2</sup> E3. 2024. "Rhode Island Investigation into the Future of the Regulated Gas Distribution Business." Docket 22-01-NG, p.6 & p.72, <https://www.ethree.com/wp-content/uploads/2024/06/Docket-22-01-NG-E3-Technical-Analysis-Report.pdf>

<sup>3</sup> E3. 2024. "Rhode Island Investigation into the Future of the Regulated Gas Distribution Business." Docket 22-01-NG, Key Takeaways, <https://www.ethree.com/wp-content/uploads/2024/06/Docket-22-01-NG-E3-Technical-Analysis-Report.pdf>

## 2.10 Washington

### 2.10.1 Summary

Washington's utility landscape is fragmented, with three IOUs serving about 37% of the state's electric load and numerous public utility districts, cooperatives, and municipal providers creating overlapping service territories. Natural gas service is provided by four IOUs and one municipality, creating misaligned service territories that complicate integrated planning. Recent legislation and Utilities and Transportation Commission (UTC) rules have created a consolidated framework for integrated natural gas and electric system planning, called an Integrated System Plan (ISP). ISPs must align demand forecasts and scenario analysis across both fuels, identify non-pipeline alternatives, and develop an "iterative" modeling approach that analyzes both fuels together and produces a single "preferred portfolio." The ISP rules currently apply only to Puget Sound Energy (PSE), which must file by April 1, 2027. The other dual-fuel IOU, Avista, is not legally subject to the ISP statute but is voluntarily moving toward integrated planning after a January 2024 cold snap highlighted gas-electric interdependencies.

### 2.10.2 Context

Washington has different planning requirements for its IOUs. As such, following some initial state-wide context, separate case studies for PSE and Avista are presented below. Washington's three electric IOUs—PSE, Avista, and PacifiCorp—serve ~37% of the state's electric load. 24 public utility districts (PUDs), 18 cooperatives, 17 municipal utilities, and one Tribal entity serve the remainder. Electric load in Washington is served more heavily by non-IOUs than in neighboring states, creating a patchwork of jurisdictional oversight that may complicate joint planning efforts (see Figure 13).

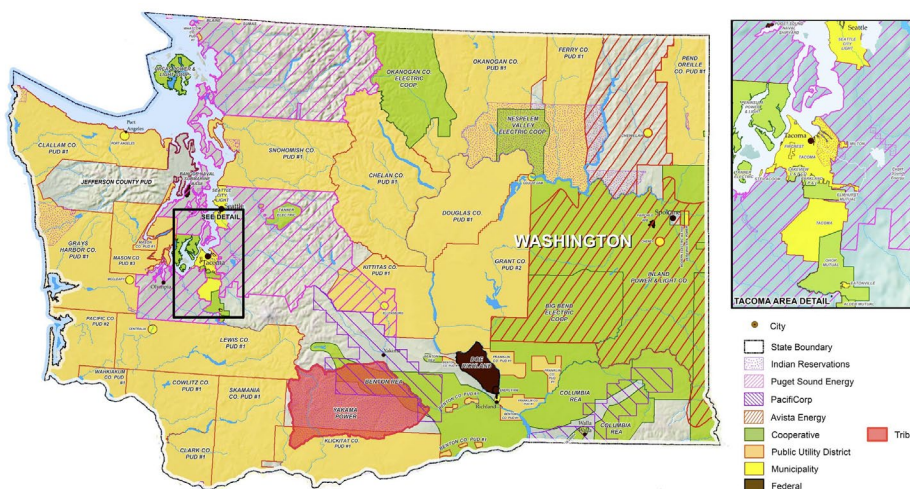


Figure 13: Service Territories of Electric Utilities in Washington<sup>1</sup>

Natural gas is provided to customers by four IOUs—Avista, Cascade Natural Gas, Northwest Natural Gas, and PSE—as well as one municipality (see Figure 14). In some parts of PSE's and Avista's natural gas service territories, the companies are also the electric provider.

<sup>1</sup> Solar Washington. 2026. "Utilities in Washington." Accessed on July 17, 2026.  
[https://www.solarwa.org/utilities\\_washington\\_state](https://www.solarwa.org/utilities_washington_state)

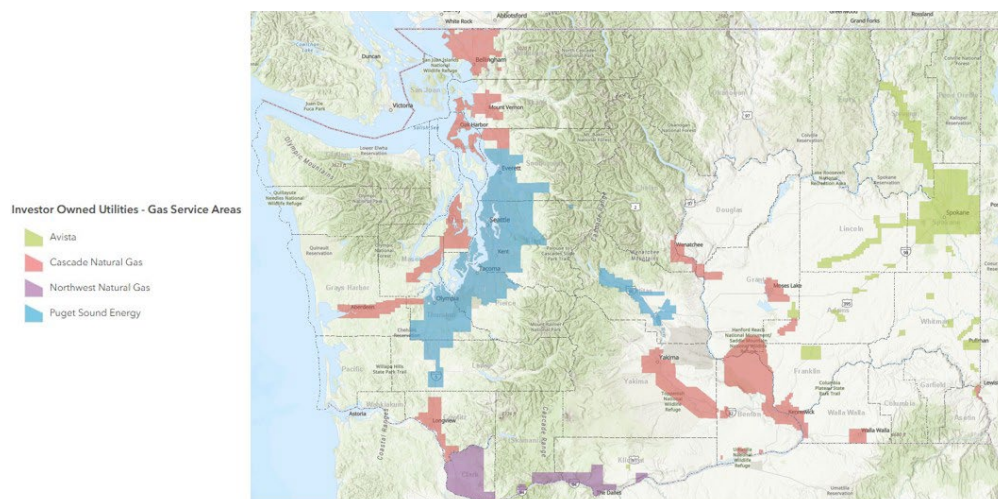


Figure 14: Regulated Natural Gas Service Areas in Washington<sup>1</sup>

In parts of PSE’s service territory, the company provides only natural gas while a public utility—e.g., Seattle City Light, Tacoma Power, or Snohomish PUD—provides the electric service. In other areas, PSE provides electric service while Cascade Natural Gas is the natural gas provider. This creates a complex landscape for conducting integrated system planning.

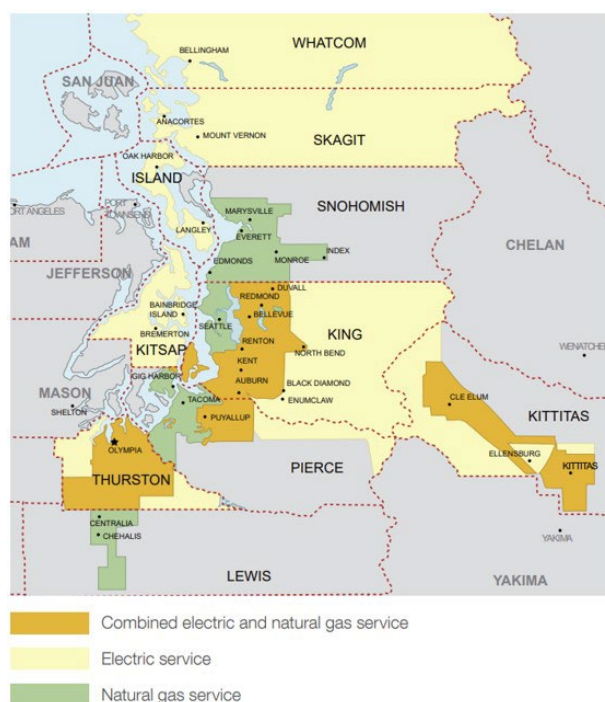


Figure 15: Puget Sound Energy Service Area Map<sup>2</sup>

<sup>1</sup> Washington Spatial Data. 2026. “UTC Regulated Natural Gas Service Areas.” Accessed July 1, 2026. <https://geo.wa.gov/maps/666d5dc97ba94dfaf61a6d791915791/explore?location=47.328056%2C-120.446947%2C8>

<sup>2</sup> PSE. 2026. “PSE Locations.” Puget Sound Energy. Accessed on July 17, 2026. <https://www.pse.com/en/Customer-Service/pse-locations-2>

Washington has a history of requiring utilities to conduct long-term planning. All electric and natural gas utilities are required to develop plans for obtaining future energy resources at the lowest reasonable cost to ratepayers. Electric utilities were required to pursue “least-cost planning” starting in 1987 and to file comprehensive resource plans every two years starting 2006.<sup>1</sup> Natural gas utilities were required to develop resource plans starting in 2001.<sup>2</sup> In 2019, the legislature adjusted requirements for electric resource planning, requiring the phase-out of the use of fossil-based resources and the creation of shorter-term action and implementation plans.<sup>3</sup>

In 2023, the legislature passed ESHB 1589, requiring the UTC to develop consolidated planning requirements and waive any commission rules necessary to facilitate an ISP. In September 2025, the UTC adopted rules to implement ESHB 1589.<sup>4</sup> At the time of writing, the ISP requirements in state law and UTC rule apply only to Puget Sound Energy, which must file its first ISP by April 1, 2027. The authors are not aware of any other similarly comprehensive integrated planning laws in other U.S. states.

### 2.10.3 Puget Sound Energy

#### 2.10.3.1 Context

The UTC rules adopted in 2025 to comply with ESHB 1589<sup>5</sup> largely consolidate existing planning requirements into a single plan (e.g., natural gas and electric IRPs), but also contain several new planning requirements for large combination utilities.<sup>6</sup> Much of the discussion around the development of an ISP is being led by PSE as they develop the first ISP. PSE has been holding advisory group meetings to seek perspectives, broaden engagement, and collect expert technical input. Topics have included the electric and natural gas delivery systems, resource adequacy, demand forecasts, and sensitivities.

In November of 2024, Washington voters passed Initiative 2066, which would have significantly altered the requirements in ESHB 1589, namely, it would have removed specific planning provisions. The constitutionality of I-2066 was challenged in court, and in March of 2025, the initiative was ruled unconstitutional by a Superior Court. The Superior Court’s ruling has been appealed, and that appeal is pending as of the date of this writing. If the Washington State Supreme Court overturns the Superior Court’s ruling and reinstates I-2066, the planning provisions that were struck by the initiative would again be struck from state statute, and the UTC will need to conduct another rulemaking to adjust the ISP rules. Regardless of the outcome in the Supreme Court’s deliberations, the issues that are central to I-2066 are likely to continue to be discussed both within the UTC’s proceedings and more broadly in the state.

<sup>1</sup> WAC 480-100-620 and RCW 19.280.

<sup>2</sup> WAC 480-90-238.

<sup>3</sup> WA State Legislature. Chapter 19.405 RCW, <https://app.leg.wa.gov/RCW/default.aspx?cite=19.405>

<sup>4</sup> Washington UTC. Docket U-240281. General Order R-609 Order Adopting Rules Permanently. September 26, 2025.

<https://apiproxy.utc.wa.gov/cases/GetDocument?docID=260&year=2024&docketNumber=240281>

<sup>5</sup> WA State Legislature. Chapter 480-96 WAC, <https://app.leg.wa.gov/WAC/default.aspx?cite=480-96>

<sup>6</sup> “Large combination utility” is defined in the rule as “a public service company that is both an electrical company and a gas company that serves more than 800,000 retail electric customers and 500,000 retail gas customers in the state of Washington as of June 30, 2024.”

<https://apiproxy.utc.wa.gov/cases/GetDocument?docID=257&year=2024&docketNumber=240281>

### 2.10.3.2 Planning Frameworks

In summary, the UTC ISP rules require an integrated assessment and iterative analytical approach to developing an ISP, including a comprehensive assessment of both supply-side and demand/customer-side resources, a range of demand forecasts, analysis of multiple future scenarios, and the presentation of an integrated “preferred portfolio.”

These requirements necessitate an ISP development process that leads to the natural gas and electric systems being considered together. To assist with the development of the 2027 ISP, PSE has relied on the pre-existing Resource Planning Advisory Group (RPAG) to provide expert technical input. Within the RPAG, PSE proposes technical approaches to elements of the ISP, such as the cost test framework, resource adequacy modeling results, and demand forecasts, and receives feedback.

PSE’s ISP development has unfolded in parallel to the UTC’s rulemaking. The utility expects to share a draft ISP executive summary and preferred portfolio in December 2026.<sup>1</sup>

### 2.10.3.3 Planning Methodologies

The new ISP rules contain a number of comprehensive planning requirements that now apply to PSE, including:<sup>2</sup>

- Using “iterative analysis” that identifies “feedback loops between steps in the [modeling] framework and where there are opportunities for iteration, adjustments, and optimization across natural gas and electric systems.”
- Developing a “range” of 20-year forecasts, including projected customer electricity and natural gas demand and changes in the number, type, and efficiency of customer usage.
- Meeting 2% of annual electric load through conservation and energy efficiency, and 10% or more of winter and summer peak electric demand through demand response and demand flexibility.
- Using a UTC-established cost test for determining the least reasonable cost of decarbonization actions.
- Assessing non-pipeline alternatives to replacing aging natural gas infrastructure or expanding natural gas capacity.
- Providing a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the resource portfolio under various parameters.
- Developing a “preferred portfolio” and demonstrating how it represents a “portfolio approach” to system optimization across the natural gas and electric system.
- Proposing interim and specific targets that demonstrate progress toward and achievement of the planning standards and state law.

<sup>1</sup> PSE. 2026. “Resource Planning Advisory Group Meeting: 2027 ISP.” Puget Sound Energy. [https://irp.cdn-website.com/dc0dca78/files/uploaded/2026\\_0127\\_RPAG\\_Meeting\\_Final.pdf](https://irp.cdn-website.com/dc0dca78/files/uploaded/2026_0127_RPAG_Meeting_Final.pdf)

<sup>2</sup> Washington UTC. Docket U-240281. Appendix B WAC 480-96 Rules. <https://apiproxy.utc.wa.gov/cases/GetDocument?docID=257&year=2024&docketNumber=240281>

- Proposing specific actions the utility will take over the implementation period, which must represent a portfolio approach to investment plan optimization when taken together.

#### 2.10.3.4 Forecasting

Data inputs for forecasting electric and natural gas systems differ in scope and granularity. Aligning longer-term, 20-year horizon forecasts is an ongoing effort. Key assumptions for demand forecasting include the pace of customer growth, large load additions, impacts of demand-side resources, and weather. For the reference case, PSE uses the same input assumptions to produce electric and natural gas forecast results, which makes them unique among the utility approaches we reviewed. To the best of our knowledge, Avista (also operating in Washington state) is the only other combination utility in our case studies that uses the same input assumptions for natural gas and electric forecasts.

#### 2.10.3.5 Scenarios and Sensitivities

In a January 2026 RPAG meeting, PSE shared the final scenarios for the 2027 ISP. The five core scenarios all contain explicit assumptions about customer energy choices, the pace of large load interconnections, the types and sizes of customer programs, and the pace of EV adoption.<sup>1</sup>

- Reference Case: Current trends around customer energy choices, large loads, customer programs, and EV adoption continue.
- Scenario 1 (“Incentivized electrification”): adds an assumption that buildings will begin to adopt electric devices upon equipment failure and with an incentive.
- Scenario 2 (“Building electrification only”): Builds on Scenario 1 by increasing the pace of electric device adoption.
- Scenario 3 (“Enhanced electrification”) builds on Scenario 2 by adding data center and EV growth.
- Scenario 4 (“Unconstrained electrification”) builds on Scenario 3 by being more aggressive on electric device adoption assumptions.

PSE plans to assess sensitivities, which it defines as “a version of the reference scenario where one factor is changed to evaluate the impact of the change on the resulting portfolio.” For both the natural gas and electric systems, they plan to analyze sensitivities related to the requirements within Washington rule and the impacts of certain policies and emerging technologies (e.g. RNG and hydrogen). Sensitivities specific to the natural gas system will also include those related to customer energy choices, the price of natural gas, and customer sensitivity to rising bills. Sensitivities specific to the electric system will include transmission availability and customer programs.

#### 2.10.3.6 Non-pipeline Alternatives

PSE described how non-pipeline alternatives are part of the analysis they currently conduct for delivery system planning. For managing peak load on the distribution system, PSE has

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<sup>1</sup> PSE. 2026. “Resource Planning Advisory Group Meeting: 2027 ISP.” Puget Sound Energy. [https://irp.cdn-website.com/dc0dca78/files/uploaded/2026\\_0127\\_RPAG\\_Meeting\\_Final.pdf](https://irp.cdn-website.com/dc0dca78/files/uploaded/2026_0127_RPAG_Meeting_Final.pdf)

developed several alternative approaches to investing in distribution system infrastructure, including using energy efficiency, demand response, and targeted energy alternatives. However, all of these approaches are under development or being piloted and not “mature and implemented” as of yet.

### 2.10.3.7 Integrating Natural Gas and Electric Planning

PSE is adopting an innovative approach to iterative analysis between the natural gas and electric supply and distribution systems. The analysis approach requires manual iteration between the models that address natural gas supply, natural gas transmission and distribution (T&D), electric T&D, and electric supply. This is because each of the energy system areas have their own models and different requirements they must meet. The iterative approach is illustrated in Figure 16.

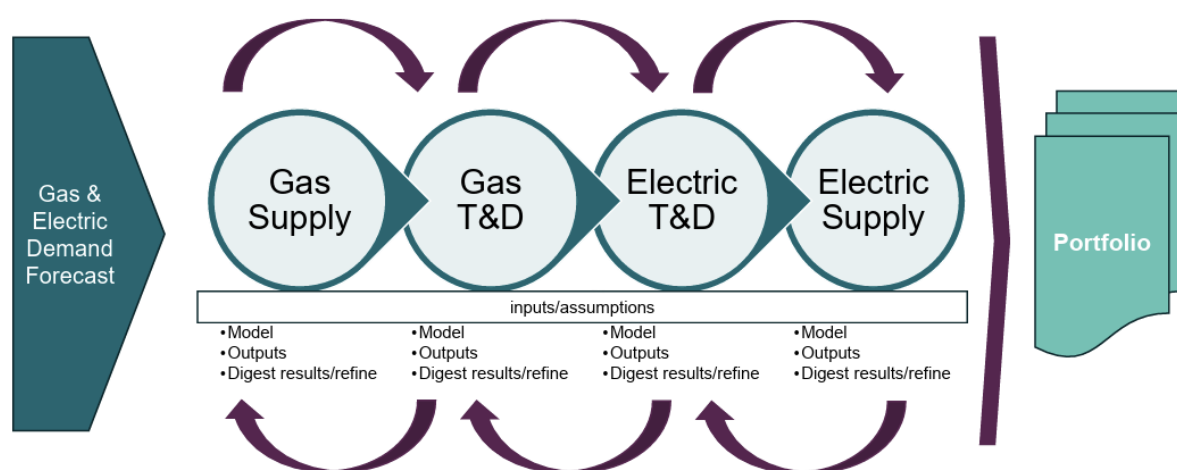


Figure 16: Puget Sound Energy's Integrated System Plan Portfolio Development Process<sup>1</sup>

A unique feature of PSE's iterative analysis for the ISP is that the inputs and assumptions are aligned across all of the models, with the demand forecasts being consistent. Once the demand forecasts for a given scenario are developed, the natural gas supply model is run to determine needs and understand how much fuel shifting between the two systems might be expected to occur. These results are then fed into the natural gas T&D analysis to determine where investments or changes should occur to be most beneficial to that system. The natural gas T&D results are communicated to the electric T&D model to explore the implied impacts and determine if there are additional electric system costs that need to be accounted for in the cost-effectiveness assessment. The electric T&D model may suggest changes to the results of the natural gas T&D outputs, after which an iteration would occur between those modeling processes. Finally, the electric supply system is analyzed to determine how the electric generation and transmission system needs to be planned to meet the expected load.

### 2.10.3.8 Remaining Issues

As of June 2026, PSE is sharing preliminary reference case results with the RPAG and the public, after which demand forecasts for various scenarios and draft results for scenarios and

<sup>1</sup> PSE. 2026. "Resource Planning Advisory Group Meeting: 2027 ISP." Puget Sound Energy. Slide 28. [https://irp.cdn-website.com/dc0dca78/files/uploaded/2026\\_0127\\_RPAG\\_Meeting\\_Final.pdf](https://irp.cdn-website.com/dc0dca78/files/uploaded/2026_0127_RPAG_Meeting_Final.pdf)

sensitivities will be shared. In the latter part of 2026, the ISP process will shift to developing a preferred portfolio.

Both the UTC and PSE state that the ISP will be iterative from one cycle to the next, and they expect methodologies and approaches to evolve as all parties gain experience with integrated planning.

Several issues may continue to be debated in future ISPs. For example, as directed by statute, the UTC established a cost test for determining the lowest reasonable cost of certain measures in an ISP, which they acknowledge may change over time. Utilities or other groups may recommend other impacts that were not initially included in the cost test analysis for future inclusion. The UTC expects that interested parties will discuss and provide input on best practices for accounting for the economic impacts of utility investments in future ISP processes.

### **2.10.3.9 Next steps**

The Washington Supreme Court heard arguments in January 2026 regarding the constitutionality of I-2066 but has not ruled as of early July 2026.

Meanwhile, PSE has filed an updated ISP work plan for the remaining plan development time, which includes nearly-monthly advisory group meetings. PSE plans to file the draft ISP executive summary along with the description of its preferred portfolio in December 2026 and its full 2027 ISP on or before April 1, 2027.

## **2.10.4 Avista**

### **2.10.4.1 Context**

Avista is a multi-state utility and is dual-fuel in Washington and Idaho. In Washington, Avista has historically been subject to the same planning requirements as the other electric and natural gas utilities.



Figure 17: Avista Utilities' Electric and Natural Gas Service Territories<sup>1</sup>

In January 2024, a significant cold snap hit the Pacific Northwest, putting strain on both the natural gas and electric delivery systems. Avista was one of many utilities that took quick action to address natural gas infrastructure outages that resulted in pipeline low pressure conditions, encourage customer conservation efforts, and adjust electric resource output to avoid even worse outages. However, Avista and many other regional entities argued that this event pointed to the need for better coordinated planning between the electric and natural gas industries to be better prepared for a similar event in the future.<sup>2</sup>

Partly as a result of the January 2024 cold snap, the company has opted to align aspects of its electric and natural gas planning into a process the company refers to as integrated system planning, even though Washington's formal ISP requirements do not apply to Avista.

Avista has created a new Integrated Planning & Clean Energy Group within the Energy Resources and Integrated Planning Department. This new group includes the electric and natural gas IRP team, transmission and distribution system planning teams, and natural gas delivery infrastructure planning. The company also consolidated their previously-separate public advisory groups for electric and natural gas IRP, along with the distribution planning advisory group. This single stakeholder group is now called the Technical Advisory Committee (TAC).

Avista is not subject to the same statutory timeline for an ISP as PSE. The company has set the following timeline for completing the integrated system planning work, and subsequently filing their electric and natural gas IRPs:

- Oct 15, 2026 – Draft Electric IRP released to the TAC
- January 1, 2027 – Final Electric IRP filed
- February 15, 2027 – Draft Gas IRP released to TAC
- April 1, 2027 – Final Gas IRP filed

<sup>1</sup> Avista. 2026. "Company Information." Accessed on July 17, 2026. <https://investor.avistacorp.com/about-avista/company-information>

<sup>2</sup> January 2024 Cold Weather Event, Report to the Northwest Power and Conservation Council, March 5, 2024. [https://www.nwccouncil.org/f/18649/2024\\_03\\_5.pdf](https://www.nwccouncil.org/f/18649/2024_03_5.pdf)

### 2.10.4.2 Planning Methodologies

Historically, capacity expansion has been conducted separately for the electric and natural gas systems. In their new integrated planning process, Avista is creating a dynamic capacity expansion model that includes both natural gas and electric systems, and also models the impacts on the energy delivery systems. Specifically, they are expanding their PRiSM model, which they have been using since the early 2000s, to include natural gas stochastic inputs. This process will be unique because the company will be doing “one solve” for the entire system, rather than the two systems individually.

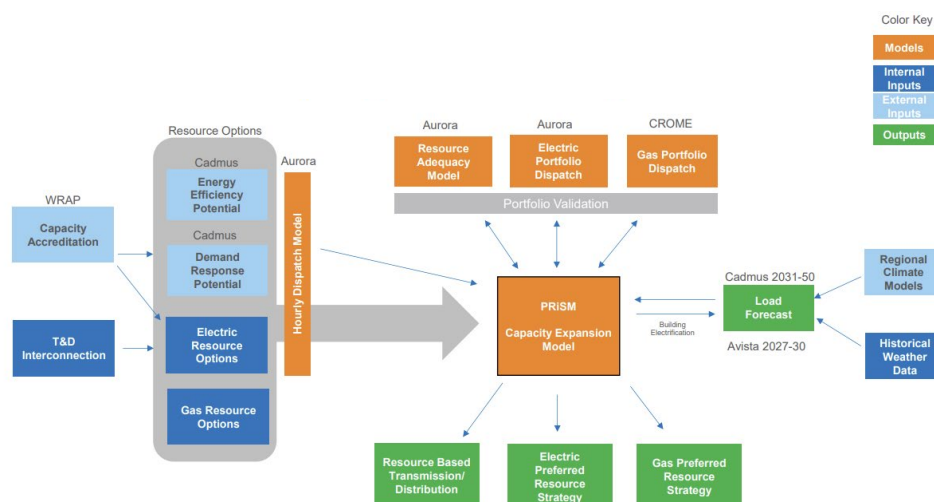


Figure 18: Avista's Integrated Natural Gas and Electric Planning Process<sup>1</sup>

In addition to developing new modeling approaches, Avista is investigating the interdependencies of natural gas and electric systems by coordinating and streamlining data and assumptions. They are including specific scenarios to analyze how changes in demand on the natural gas system translate to potential increased peak demands on the electric system. In a September 2025 public presentation, Avista stated that, moving forward, assumptions and modeling for electric and natural gas IRPs will be aligned.<sup>1</sup> However, the company still plans to file natural gas and electric IRPs separately with their various state regulators.

The UTC required Avista to conduct two non-pipeline alternative analyses on natural gas distribution projects related to customer growth for projects that exceed \$500,000 and submit those analyses no later than December 31, 2025.<sup>2</sup> Avista's submittal determined that the specific non-pipeline alternatives identified were non-viable for various reasons, including the lack of an alternative energy source for a large industrial customer.

### 2.10.4.3 Remaining Issues

Several technical issues will be addressed in the remaining planning process and TAC meetings. The company will look at areas of stress on the natural gas system and evaluate

<sup>1</sup> Lyons, J. 2025. "Introductions 2027 Electric and Gas Integrated Resource Planning." Avista. October 21, 2025. <https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2027/2027-irp-tac-2-final-presentations.pdf>

<sup>2</sup> UE-24006 and UE-24007, Corrected Final Order 08, <https://apiproxy.utc.wa.gov/cases/GetDocument?docID=1682&year=2024&docketNumber=240006>

whether they can deploy non-pipeline alternatives to meet those needs. Other stakeholders and the UTC are examining Avista's non-pipeline alternative analysis, with some pointing out that it shows that demand response programs could fully meet the safety requirements for certain pipeline upgrades.

Avista will also be working to incorporate a transmission and distribution plan into the IRPs. They will be looking at specific transmission and distribution impacts to connect the projected resources in the IRPs to the ability of the T&D systems to meet those needs. They will also develop preferred resource portfolios to address the various needs they expect on their systems.

#### **2.10.4.4 Next Steps**

Avista's 2027 IRP workplan lays out a brisk pace of advisory group meetings with draft electric and natural gas IRPs released in October 2026 and February 2027, respectively, and final electric and natural gas IRPs filed in January 2027 and April 2027, respectively.<sup>1</sup>

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<sup>1</sup> Avista. 2025. "Avista 2027 IRP Workplan." <https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2027/2027-irp-workplan-draft-12082025.pdf>

## 3.0 Summary Themes and Takeaways

This section summarizes takeaways from the above case studies, including themes that emerged across multiple jurisdictions and our observations on future actions that could address identified challenges. This section concludes with a set of initial steps toward integrated planning that we observe the entities in our case studies often take.

### 3.1 Coordinated Energy Planning Themes

There is a wide range of policy objectives, process types, and states of progress across jurisdictions and utilities that are considering the value of coordinated energy planning and grappling with the complexities of dual systems and policy objectives. However, as summarized below, this review of natural gas and electric coordinated planning across multiple states and provinces demonstrates that certain themes are emerging. These themes are often the gelling of various approaches that could lead to best practices, but are sometimes an expression of agreement that a novel challenge exists. With each theme described here, we share observations on future adjustments or updates that could help address the identified challenges.



### **Coordinating natural gas and electric planning is a nascent effort.**

Growing large loads, increasing deployment of intermittent resources, and higher frequency extreme system threats are increasing natural gas and electric interdependencies. As regulators and utilities face these new challenges, coordinated natural gas and electric planning is emerging as a promising approach. However, the case studies reveal that processes and practices are nascent and that best practices do not yet exist. Most of the early forward momentum for coordinated planning has come from legislative or regulatory action.

Some states have legislated policies that require natural gas and electric coordination. Other jurisdictions have mandates that necessitate making changes to the relative makeup of energy served by natural gas or electricity. However, all case studies include elements of general regulatory direction to improve cost efficiency of utility investments, improve system reliability, or foster greater transparency in planning and investing. Maintaining reasonable retail rates is core to utility regulators and consumer-owned utility boards, such that the foundation of coordinated multi-sector planning is driven by finding the least cost solutions for customers regardless of the policy driver.



### **Future needs**

- Establishing coordinated natural gas and electric planning processes will benefit from a preliminary examination of the values and barriers of this type of planning evolution. Such an investigation can foster a better understanding of the increased interdependence of the two sectors, and the types of values coordinated planning can assess expressed in costs savings, increased reliability, and reduced risk. An examination of this type also pulls together both natural gas and electric utilities in a single proceeding, which itself pay dividends in developing relationships across sectors.



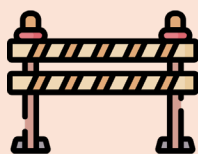
In most jurisdictions, **natural gas planning is not as robust or transparent compared to the current state of electricity planning.**

Multiple states noted that planning criteria on the natural gas side are not as well developed as within electric system planning, and the historic lack of regulatory visibility into the natural gas distribution system is making decisions about planning and investments difficult. Natural gas system planning has historically been focused on maintaining integrity and physical safety; states and utilities broadly agree that these are essential going forward, but that now a broader range of planning criteria are important. Many regulators have not consistently required utilities to provide a full range of data relating to natural gas investment options or future operations. For example, data on natural gas distribution system operations, investments, and customer end uses have generally not been sufficiently granular to support coordinated gas/electric planning. In all the case studies, except Quebec, legislative or regulatory action has begun to explore imposing new planning and visibility requirements on the natural gas sector to further efficiency, reliability, or environmental objectives.



### Future needs

- More visibility into natural gas planning will enable additional analysis of broader system values, such as resilience, performance metrics, least-cost/least-risk optimization, and policy alignment. In expanding the scope of natural gas planning, it will be beneficial to understand how broad system values have been analyzed in electric resource planning and right-size the planning criteria for the natural gas side.
- Additional data, particularly regarding the natural gas pipeline network, would enable more accurate comparisons across fuel options and a more robust alternatives analysis, potentially leading to lower costs for customers. Further exploration of enhanced data transparency will reveal both its benefits and its costs.



**Utilities and regulators have historically organized planning and operations by sector, creating institutional silos.**

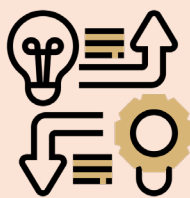
Organizational silos create institutional, regulatory, and economic barriers to conducting coordinated planning. Stand-alone natural gas utilities operate and plan their systems in isolation from the electric utility covering the same territory, and vice versa. Electric and natural gas service providers rarely have perfectly overlapped service territories and often overlap with multiple other providers, including both publicly- and privately-owned entities. When a geographic area is served by different utilities, the sharing of data, growth assumptions, and investment plans across sectors can be very difficult. Utilities with the most experience conducting integrated planning are dual fuel companies with significant overlap between their natural gas and electric territories, but even within many of those companies, the two energy operations are often kept separate. When the territory overlaps investor-owned and consumer-owned utilities, there is no shared regulatory experience, and there is virtually no visibility, cooperation, or understanding between the various systems.

Likewise, regulators themselves are frequently siloed into natural gas and electric planning teams, with little intentional collaboration or crossover. Regulatory staff are frequently assigned to one energy sector or the other, and even staff members who cover both sectors are not necessarily trained in integrated planning.



### Future needs

- Regulators may see value in encouraging utilities to increase cross-sector communication both within a dual-fuel utility and between utilities. At the same time that they are encouraging utilities to break down silos, regulators also need to address internal silos by developing internal cross-sector expertise and improving staff resources. This will be essential to advancing the best coordinated planning practices and ensuring proper regulatory oversight as utilities begin filing new types of analyses. This may require removing internal barriers to cross-team collaboration, supporting staff who may have their role redefined, and building a culture of energy planning that integrates natural gas and electric functions.
- Separate natural gas and electric planning groups within a dual-fuel utility perpetuates a lack of transparency between the sectors and leads to incompatible planning outcomes. The utilities that connect their natural gas and electric planning functions will have insight into increased natural gas and electric systems interdependencies and the potential value of increased information flow between sectors.



**Natural gas and electric planning methods are developed, refined, and deployed separately.**

Very few utilities have experience with processes or methods for analyzing the systems together. For example, forecasting electric and natural gas demand has always been done using assumptions specific to the potential future use of each fuel, without ensuring that these forecasts paint a coherent picture of future energy use in a given customer base. This is a universal topic of interest and concern within the case studies, with regulators generally desiring more consistency across natural gas and electric forecasts, particularly within the assumptions that underpin forecasts. With a few exceptions, as noted in the case studies, natural gas and electric utilities generally use conservative assumptions about future usage on their respective systems so that they can plan for providing reliable service under all plausible future consumer technology adoption scenarios. This may mean using contradictory forecasting assumptions in each sector.

Beyond forecasting, utilities rarely perform scenario and sensitivity analysis that is aligned with other utilities, meaning that potential future outcomes found within plans are difficult to compare. At the solution identification stage of planning, there is a lack of consistency in the cost-benefit analysis frameworks used by natural gas and electric system planners. This manifests itself as using different categories of costs and benefits, different methods for calculating costs and benefits, different assumptions about the impact that measures will have on the other fuel system, and different financial assumptions, such as discount rates. Some regulators are pushing for more consistency and transparency in load forecasting across energy types.



### Future needs

- Some regulators are asking for more consistency within planning methods across natural gas and electric systems. Workable planning tools and approaches that bridge the different systems will require research and collaboration to refine further alignment opportunities. Regulators and stakeholders would benefit from the development of consistent methodological approaches to forecasting and cost-benefit analysis, for example. Utilities, particularly those with both natural gas and electric planning teams, can begin to test and explore coordinated planning methods using the tools they have already deployed in their separate processes, helping to illuminate the capabilities and gaps within existing tools.



### **Agreement is lacking on the types of natural gas system**

**investments to include in joint planning.** Utilities generally prefer that

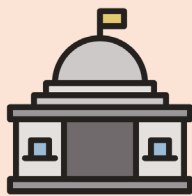
safety investments, for example, be excluded from conversations about coordinated planning, because safety investments are a priority that should not be subject to cost comparisons. Other stakeholders often disagree and desire

to see all investments compared with alternatives that could achieve the same goal. Regulators, like utilities, are often focused on the need to maintain critical natural gas infrastructure to ensure safe and reliable operation of the natural gas system. However, what qualifies an investment as related to “safety,” or otherwise makes it so immediate that it cannot be subject to an analysis of alternatives, is an area of debate in many jurisdictions.



### **Future needs**

- As methods for jointly analyzing alternatives develop, further guidance on what is “in scope” for joint planning would be useful to utilities and stakeholders. Defining what constitutes safety investments is a necessary prerequisite. Such definitions might include allowable justifications for fast-tracking those investments, such as the relative immediacy of the system need that has been identified. Clarity is also needed on the type of investments (e.g. over a certain cost threshold, or for certain types of system needs) that should be analyzed for potential alternatives in a more comprehensive planning process. Uniformly across the case studies, there appears to be agreement that useful definitions of these investment types would recognize the need for safe and secure infrastructure while applying the more expansive planning requirements to the largest feasible set of investment options.



**Some jurisdictions and utilities are required to start exploring alternatives to investments in natural gas infrastructure.** Several jurisdictions have specific statutory direction to shift consumer end-uses to electric service. This comes with special considerations relating to how to serve load at peak hours, prevent cost-shifting, and avoid unnecessary investments.

In all of these areas, coordinated planning can improve understanding of the costs and benefits of shifting load from one energy type to another. A common tool for assessing the tradeoffs between specific natural gas system investments and potential alternatives is non-pipeline alternatives. States and utilities view non-pipeline alternatives as complex and time-consuming to identify, analyze, and implement in a way that results in a cost-effective solution for customers. Many regulators are interested in NPA analysis, but the application of such analysis presents many challenges.

Some of these challenges are based in long-established utility policies, which several states are re-examining in light of the evolving relationship between natural gas and electricity service. For example, regulators are reexamining the historical “obligation to serve,” a fundamental regulatory approach dating back to the origin of utility regulation, because it complicates a utility’s attempt to deploy alternative, lower cost energy services. Any consideration of alternatives will impact the future infrastructure investment and revenue of one utility or another. The implications for bedrock rate-making policies that promote investment in the physical system and provide revenue recovery for the utility will be important to understand.



### Future needs

- Methods for deploying non-pipeline alternatives are in active development in multiple states. Greater consensus on the constituent factors of NPAs, such as thresholds for inclusion in NPA frameworks, cost-benefit calculations, and data sharing across utilities, may help streamline and accelerate NPA deployment. Collaborative efforts will be needed to realize the required improvements. Changes to regulatory policies may be necessary if NPA experience demonstrates fundamental hurdles, such as the need for 100% customer participation, as seen in a handful of states already.
- Alternative analysis will raise questions about fundamental regulatory approaches, such as socializing the cost of new infrastructure and methods for utility cost recovery. There is a need for methodical exploration of the interactions between the evolving energy system and core policy mechanisms. This, in turn, will help inform integrated natural gas and electric planning methods. Several jurisdictions are using pilots to test gas-to-electric shifting scenarios. Such pilots can help explore different models and record both successes and pitfalls.

### 3.2 Initial Steps for Jurisdictions and Utilities

Attempting to identify best practices for initiating and conducting coordinated planning can be elusive, given the differing circumstances in the surveyed jurisdictions. However, at a conceptual level, a set of initial steps can be identified. We observe that jurisdictions and utilities in our case studies often began discussions or activities with some combination of these steps. These initial steps could even be described as “no regrets” efforts that will increase regulator and public knowledge about energy systems, streamline existing processes, and promote more efficient system outcomes for customers, regardless of whether a full-scale shift to integrating natural gas and electric planning is a desired future state.

| Steps                                                                                              | Description                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
|----------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <i>Require more detailed and transparent natural gas distribution system analysis and planning</i> | Before coordinated planning with the electric system can occur, a more transparent and detailed standard of natural gas analysis and planning may be required. Many regulators do not yet require robust planning from the natural gas utility that would describe how the utility will efficiently meet customer demand, meet jurisdictional policy goals, or weigh investment alternatives. Regulators will benefit from additional information and analytical approaches that can be contrasted with the electric system. Regulators and utilities can look to jurisdictions that currently require natural gas integrated resource planning for ideas on planning frameworks or criteria. |
| <i>Coordination of demand forecasts</i>                                                            | The process of connecting natural gas and electric utility planning begins with using consistent forecasting assumptions and methodologies. This will be a longer-term process, because every utility has its own preferred approach. As an initial step, regulators could ask for, or utilities could initiate, efforts to run scenarios with their individual preferred forecasting approach and with an approach that is shared across natural gas and electric utilities.                                                                                                                                                                                                                 |
| <i>Begin collaborative conversations between utilities and customers</i>                           | Natural gas and electric utilities rarely participate in the same regulatory proceeding. While there is some familiarity between different fuel utilities, there is not a great deal of operational or system investment awareness. Even some combination utilities have a wall between functions. By encouraging conversation between utilities, regulators can foster cross-sector relationships and begin creating a common understanding, language with defined terms, and a shared set of objectives. Utilities can initiate greater coordination, both within the same company and across corporate lines, and bring learnings to the regulator and stakeholders.                       |
| <i>Enhance coordination within combination utilities</i>                                           | Requiring all utilities to use the same data sources and planning methodologies will be difficult and potentially costly, but experience in this area can be gained by combination utilities beginning efforts to streamline planning processes and make data and methodologies consistent.                                                                                                                                                                                                                                                                                                                                                                                                   |
| <i>Remove organizational silos within public utility commissions</i>                               | Regulators can organize staff so that there is greater integration between natural gas and electric staff. To the extent possible, staff expertise should be crosscutting, enabling a greater understanding of the operations of each utility type and the implications for coordinated planning.                                                                                                                                                                                                                                                                                                                                                                                             |

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