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ResearchReport

Barriers to Increasing Connecticut's Natural Gas Supply

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Issue

Are there obstacles to increasing Connecticut's natural gas supply and, if so, what are they?

Summary

Yes, there are obstacles to increasing Connecticut's natural gas supply at each stage of the supply chain. The largest obstacle to increasing natural gas production is the fact that, due to Connecticut's geology, it has minimal natural gas resources that are highly unlikely to be developed. The New England region is also geologically unable to store natural gas underground for use during periods of peak demand (U.S. Energy Information Administration, *State Profile: Connecticut*). Therefore, this report focuses on obstacles to expanding the transmission and distribution aspects of the natural gas supply chain.

Obstacles to increasing transmission capacity into Connecticut, and New England more broadly, include:

1. securing federal and state approval for transmission facilities, which may entail authorization from multiple states and agencies during a changing regulatory landscape;

2. court approval for acquiring land by eminent domain, if needed;

The Natural Gas Supply Chain

The natural gas supply chain can be divided into four segments:

- **Production**
  Natural gas is withdrawn from wells and delivered through gathering pipelines to processing plants
- **Transmission**
  Large quantities are pumped through wide-diameter transmission pipelines to large industrial customers, power plants, and to distribution centers
- **Underground storage**
  Underground reservoirs (e.g., salt caverns or depleted gas fields) store amounts for later use
- **Distribution**
  The gas is delivered to end-use customers through a network of smaller pipes owned by the local distribution companies or stored in the form of liquefied natural gas

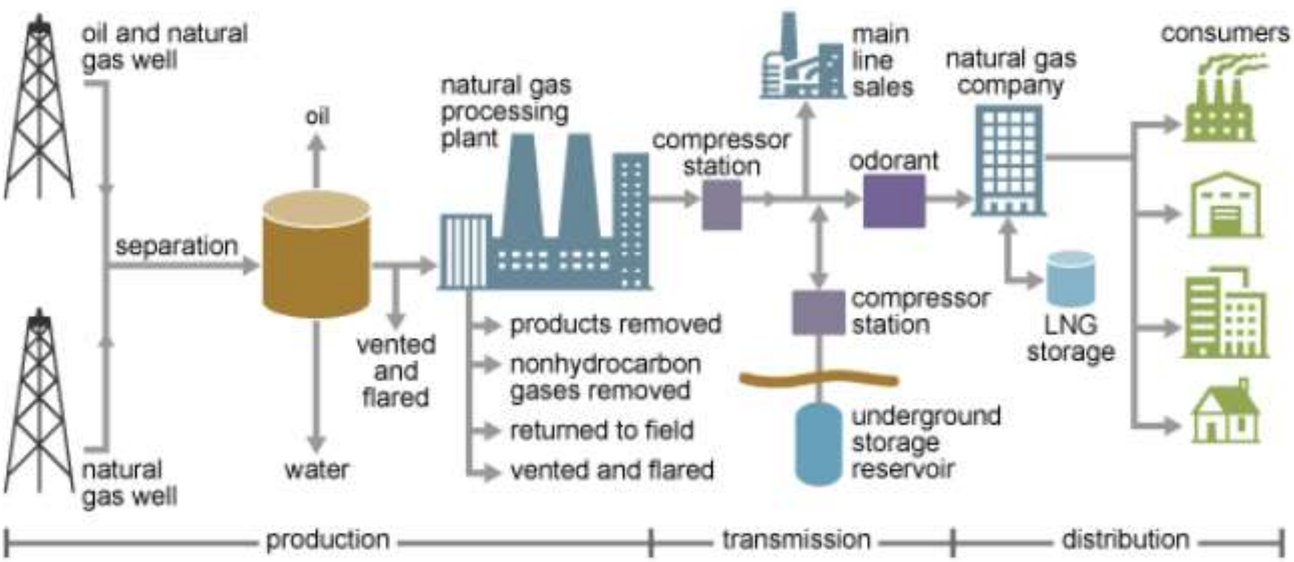
3. public pushback; and

4. securing sufficient capital and customers to justify the significant capital outlays required, particularly in light of uncertainties regarding the region's future energy mix and policies aimed at electrification.

Additionally, a federal law essentially blocks New England liquid natural gas (LNG) import terminals from receiving domestically produced natural gas.

In the past, Connecticut created an initiative aimed at encouraging natural gas transmission pipeline companies to increase their capacity into the state and region by limiting some of the financial risk of the expansion. Generally, it sought to increase and guarantee demand at the distribution level by (1) encouraging new natural gas customer conversions and (2) having the state, in conjunction with other New England states, conduct a procurement process for long-term contracts for natural gas resources to supply natural gas-powered electricity generators. However, the multi-state procurement process did not occur once a court overruled Massachusetts' participation in it, and the Public Utilities Regulatory Authority (PURA) cancelled the customer conversion program in 2022 finding, among other things, an insufficient number of new customers enrolled in the program to justify the level of ratepayer subsidies that were needed to continue it.

Diagram 1: Elements of the U.S. Natural Gas Supply Chain



Source: U.S. Energy Information Administration (EIA)

Table of Contents

Expanding Transmission Capacity 4

FERC Approval (Interstate Pipeline Projects) 5

State Approval (Intrastate Projects) 7

Court Approval for Eminent Domain 8

Public Perception 9

Securing Capital and Customers 10

Firm vs. Intermittent Contracts 10

Liquefied Natural Gas 11

Global Demand 11

Shipping Obstacles 11

Connecticut Initiative to Encourage Expansion 12

Distribution Expansion Plan 12

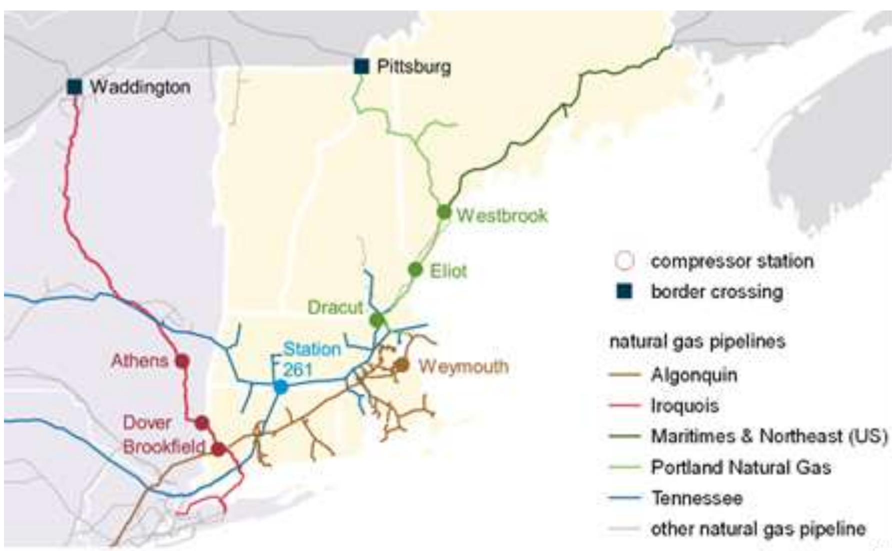
Multi-State Procurements 13

Expanding Transmission Capacity

The natural gas transmission system includes both interstate pipelines (generally those that go beyond the borders of a single state) and intrastate pipelines, as well as compressor stations along the way that maintain pressure and flow. The federal government has primary authority over interstate pipeline infrastructure (including compressors) and the state has authority over intrastate pipeline infrastructure.

This results in multiple layers of approvals being required to expand transmission capacity, potentially posing obstacles at each stage, including opportunities for public opposition, that can slow down or derail a project. Even if a project has the necessary regulatory authorizations, the developer often needs to secure land rights for the project, which may entail court approval. Furthermore, securing financing to construct infrastructure may be difficult without confidence in the strength of long-term demand. But local distribution company (LDC; e.g., CT Natural Gas or Eversource) demand can be difficult to predict (see, e.g., “Connecticut’s Distribution Expansion Plan” below) and the largest natural gas takers (electric generators) typically do not enter into long term capacity agreements.

Diagram 2: Natural Gas Interstate Infrastructure in New England



Source: U.S. EIA

As shown in Diagram 2 above, three interstate pipeline systems bring natural gas to Connecticut: (1) the Algonquin, (2) the Iroquois, and (3) the Tennessee. Two other interstate pipeline systems bring natural gas into New England but not Connecticut directly: the Maritimes & Northeast and the Portland Natural Gas Transmission. In addition, a revived proposal to run a new pipeline, the

Constitution Pipeline, from the Marcellus Shale to the latter two existing pipelines is currently being considered (see below).

FERC Approval (Interstate Pipeline Projects)

Under the federal Natural Gas Act, developers seeking to build interstate natural gas pipelines need authorization from the Federal Energy Regulatory Commission (FERC) (15 U.S.C. § 717 et seq.). Depending on the project, the developer may also need to secure approvals with other federal offices, such as the Department of Transportation, Environmental Protection Agency, and Advisory Council on Historic Preservation. FERC is generally considered the primary federal regulatory body for these projects, though.

Specifically, developers must get a certificate of public convenience and necessity, indicating FERC has determined the pipeline "is or will be required by the present or future public convenience and necessity" (15 U.S.C. § 717f(e)). According to the Congressional Research Service (CRS), FERC exercises this authority in accordance with its own regulations and the guidance of its own certification policy (i.e. its 1999 policy statement, clarifying statement, and further clarifying statement; the commission recently rescinded its 2022 draft policy guidance). However, FERC generally considers the need for the project, which is shown, in part, through "precedent agreements" (contracts with future customers for the capacity). In the past, it has also considered a project's potential impact on pipeline competition, the possibility of overbuilding, subsidization by existing customers, avoiding the unnecessary use of eminent domain, and other considerations.

As part of its determination, FERC must also conduct an environmental analysis, in accordance with the National Environmental Policy Act (NEPA), to evaluate the environmental consequences of the project in coordination with other federal agencies. It will also evaluate site alternatives and communicate with landowners and the public.

Administration Changes. According to CRS, FERC's review of siting applications for these kinds of projects has been the subject of controversy and litigation, especially with respect to its consideration of environmental impacts, project need, and environmental justice concerns. There has been concern by some that the application review process, in part due to these reasons, is costly, time-consuming, and uncertain for all parties involved.

This year, the current federal administration has taken steps to lower the regulatory threshold for approving these projects (see President Trump "Executive Order 14156 Declaring a National Energy Emergency" (in particular § 3, directing agencies with infrastructure siting authority to use their existing emergency approval authority to help expedite energy and infrastructure projects and to facilitate the transportation of energy in and through New England); FERC: "FERC Revises NEPA Procedures to Make Permitting More Efficient." June 30, 2025; and FERC: "FERC Takes Action to Remove Barriers to Building Natural Gas Facilities." June 18, 2025.)

It is currently unclear how these changes at the federal level will impact the ability of transmission pipeline projects to expand capacity. At an industry conference the Northeast Energy and Commerce Association hosted this year, the managing director at RBN Energy (an energy market research and consulting firm), reportedly stressed that, despite changing political attitudes around gas expansion, key barriers to addressing New England's gas constraints remain—in particular difficulties financing projects, which are discussed below.

State Approval of Interstate Transmission Projects. Interstate projects may need to seek approval from multiple states' regulatory authorities. Although the Supreme Court has held (in *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988)) that the Natural Gas Act preempts state laws pertaining to interstate gas pipelines (giving FERC near plenary authority over siting and eminent domain for these pipelines), other federal statutes give states authority to block projects that would endanger the quality of their water, air, or coastal zones.

For example, under the Clean Water Act (CWA), if a proposed project FERC is considering could result in discharges into navigable waters (i.e. waters of the United States), the applicant must get "section 401 certification" from the certifying authority (generally the applicable state or states), attesting that the discharge will comply with state water quality standards approved by the Environmental Protection Agency, among other criteria (33 U.S.C. § 1341(a)). The state may grant, grant with conditions, deny, or waive the certification. If a state denies certification, generally FERC must deny the project's application (CRS: "*Clean Water Act Section 401: Overview and Recent Developments*." Feb. 7, 2025). In Connecticut, the Land and Water Resources Division within the Department of Energy and Environmental Protection (DEEP) administers the section 401 certification process.

Similarly, the federal Clean Air Act (CAA) gives states permitting authority over certain projects, including compressor stations, that may emit air contaminants. And, if a project would impact the state's coastal zone, the federal Coastal Zone Management Act (CZMA) generally requires state certification that the project will be consistent with the state's federally approved coastal management plan (42 U.S.C. § 7401 et seq. and 16 U.S.C. § 1456(c)(3); see also Jason Bressler. "Blocking Interstate Natural Gas Pipelines: How to Curb Climate Change While Strengthening the Nation's Energy System." *Columbia Journal of Environmental Law*, Jan. 17, 2019).

However, state authority under these laws is not unchecked; their decisions are subject to federal administrative and judicial oversight and review. State denials under the CWA and CAA are appealable to the U.S. Court of Appeals (15 U.S.C. § 717r(d)) and the Secretary of Commerce can overturn denials under the CZMA (16 U.S.C. § 1456(c)(3)(B)).

State Approval (Intrastate Projects)

FERC jurisdiction does not extend to intrastate transportation or local distribution of natural gas. Those are subject to state regulation.

Connecticut Siting Council. The Connecticut Siting Council has jurisdiction over siting intrastate fuel transmission facilities, including gas transmission lines with a design capability of less than (a) 200 pounds per square inch gauge pressure or (b) 20% of its specified minimum yield strength (CGS § 16-50i(a)(2)).

Generally, developers must apply to the council for a certificate of environmental compatibility and public need ("certificate") to construct, maintain and operate a facility (CGS § 16-50k). (In certain circumstances, developers may instead apply for a declaratory ruling, which is generally a shorter and less expensive process) The council's statutory charge is to balance a proposed facility's public need or benefit with its effects on the state's natural environment at the lowest reasonable cost to consumers.

To get a certificate, a transmission facility developer must, among other things:

1. pay a filing fee to the council, ranging from $1,250 to $25,250 (depending on the project's estimated construction cost) and a municipal participation fee of $40,000 (or $80,000 if the proposed location is in more than one municipality) (CGS § 16-50*l*(a) and Conn. Agencies Regs. § 16-50v-la);

2. consult with the host municipality's legislative body, chief elected official, and state legislators on the proposed site and alternative sites and provide them with certain information (CGS § 16-50*l*(f));

3. submit an application to the council with information the law specifies, including on estimated costs, the need for the project, rights-of-way needed, the environmental effects, expected benefits, and abutting landowners (CGS § 16-50*l* and Conn. Agencies Regs. § 16-50j-59; see also the council's application guide); and

4. during a public hearing, formally present its exhibits and be subject to cross examination by the council, parties, and intervenors (CGS § 16-50m and the council's website).

The council may grant, grant with conditions, or deny a certificate. For fuel transmission lines, it must do so within 12 months from when the application was filed (CGS § 16-50p(a)(2)). By law, the council cannot approve an application unless it makes certain findings (e.g., a public need exists and that any adverse environmental impacts are not sufficient to deny it). Additionally, the council may not approve a fuel transmission line unless it finds the location will not pose an undue hazard to persons or property along the area the line would traverse (CGS § 16-50p(a)(3)(e)).

Any party may appeal a council decision on a certificate or amendment to Superior Court, in accordance with the Uniform Administrative Procedures Act (CGS §§ 16-50q & 4-183).

Other Connecticut Approvals. The state approvals required for a natural gas transmission project vary based on the nature of a proposed project. In the past, projects have been required to get from DEEP:

1. water diversion permits from the Bureau of Water Protection and Land Reuse (CGS § 22a-365);
2. air emission permits (Title V and as a new source) from the Bureau of Air Management;
3. coastal permits from the Bureau of Water Protection and Land Reuse (CGS §§ 22a-28 et seq. & 22a-359 et seq.);
4. general permits for the discharge of stormwater and dewatering wastewater from construction site activities (CGS § 22a-430b); and
5. a threatened and endangered species consultation and clearance, based on the Natural Diversity Data Base map, from the Bureau of Natural Resources.

In the past, projects have also had to have a historic preservation act consultation with the state historic preservation offices as well as a coastal site plan review with the municipal planning and zoning commission, pursuant to the Connecticut Coastal Management Act (CGS § 22a-90 et seq.)

Court Approval for Eminent Domain

Developers may need to secure the rights to use land on which a transmission project will be sited, which may cross hundreds of miles in the case of pipelines. The Natural Gas Act and state law authorize pipeline developers who have received a certificate of public convenience and necessity from FERC to use eminent domain to acquire the necessary right-of-way easements (the right to use the property) if it cannot negotiate a voluntary agreement with a landowner. The developer would need to initiate legal proceedings in court to condemn the land and for the court to determine just compensation to the property owner (15 U.S.C. § 717f(h) and CGS §§ 16-263 to 267; see also FERC: *Landowner Topics of Interest*).

Connecticut state law similarly provides a process by which applicants who have been granted certification from the Siting Council may initiate a condemnation proceeding in state court (CGS § 16-50x).

Public Perception

According to CRS, these proposals have faced greater public scrutiny and become increasingly controversial over the last decade. Many pipeline permit applications have faced significant challenges during permit application reviews and been the subject of protracted litigation at both the state and federal levels. Opponents, including environmental groups and affected communities along pipeline routes, have objected to these projects principally on the grounds that they may negatively impact the environment, disproportionately impact disadvantaged communities, and promote continued U.S. dependency on fossil fuels.

According to reports in the *Newstimes* and *CT News Junkie*, Connecticut's Brookfield compressor station (an interstate transmission facility owned by Iroquois), and its subsequent expansion for which DEEP recently issued a draft permit, faced extensive pushback from the public. Environmental Groups opposing the project also expressed concerns about its location near a middle school and health implications of exposure to air emissions from it.

Constitution Pipeline

The Williams Companies recently announced it is seeking approval to build a 135-mile pipeline project, called the Constitution Pipeline, which would transport natural gas from Marcellus Shale to upstate New York (Schoharie County) and connect with the existing Tennessee and Iroquois pipeline systems. If approved by federal and state regulators, Williams projects the pipeline could be in service by April 2028.

This proposal is not new. FERC first issued a certificate of public convenience and necessity for the pipeline in 2014, but the New York State Department of Environmental Conservation declined to issue it a water quality permit at that time, and the project was shelved. However, this year, the federal government has expressed support for the project's revival and it has been reported that state governors have been considering the matter. Financial obstacles may remain, though, with some sources suggesting that to make the project worth it, developers would need to build a larger network throughout the region but the economics of it may be challenging.

Proposed Constitution Pipeline (red line)

Securing Capital and Customers

Insufficient Firm Capacity Contracts. Because new interstate pipeline infrastructure comes with high capital costs that are recovered over long time periods, developers are often hesitant to invest the significant capital needed for infrastructure expansion without first having long-term contracts for the pipeline capacity in place. These agreements are also often a vital component of pipeline financing as it may represent the main revenue source for the project to service its debt.

Firm vs. Intermittent Contracts

Firm capacity contracts give holders ("shippers") the right to transport an agreed daily quantity of gas, and their orders must be filled regardless of market or weather conditions. Holders pay to reserve capacity irrespective of whether they actually use it.

Intermittent contracts (or interruptible contracts) are less expensive, but holders' supply orders can be delayed or cancelled if orders from higher-priority, firm customers need to be filled.

However, the largest users of natural gas in the state (electricity generators, which account for approximately 56% of the state's total natural gas consumption) largely do not enter long-term firm contracts. Since power plant usage can be highly variable, they typically purchase gas through short-term intermittent contracts in a competitive, deregulated auction market. A study, prepared as part of a series prepared for the Department of Energy in 2019, cites the unwillingness or inability of merchant power generators to enter into long-term contracts necessary to support pipeline capacity as an obstacle to new infrastructure deployment.

Local distribution companies (or gas utilities), on the other hand, are typically the largest subscribers. They generally procure enough firm contract capacity to meet the peak demand of their retail customers (e.g., heating for residential and commercial buildings). They assume little financial risk by entering these long-term contracts because, as revenue-regulated utilities, they can pass procurement costs on to ratepayers.

Risk of Stranded Assets. According to industry experts, potential investors may hesitate to invest in pipeline infrastructure given the risk that their costs might not be recovered if, for example, demand for natural gas transportation services fell in future years because of a declining natural gas share in the energy mix. (This risk is sometimes referred to as a "stranded asset risk.") (CRS: *Natural Gas Reliability: Issues for Congress*. July 15, 2024; see also Jon Lamson. "New Pipelines Unlikely for New England, Experts Say." *RTO Insider*, July 16, 2025, and Miriam Wasser. "Why a New Gas Pipeline into New England May (or May Not) Lower Energy Bills." *WBUR*, Aug. 21, 2025).

Factors that have been cited as contributing to these uncertainties include:

1. the future energy mix due, in part, to federal and state investments in renewables and legal mandates to meet greenhouse gas reduction goals;

2. the potential for New England states' heating electrification initiatives to reduce demand for natural gas (some cities and states, such as New York, have partially banned new natural gas hookups, as well); and

3. global market conditions that have led domestic gas producers to increasingly liquefy and export their gas to take advantage of increased foreign demand and prices in the short term (EFI Foundation. The Future of Natural Gas in a Low-Carbon World, April 2024).

Liquefied Natural Gas

When natural gas is cooled at a liquefaction facility, it condenses into a liquid that can be transported by truck or ship, stored in large-volume above-ground tanks for use in peak-shaving facilities, and re-gasified as needed. LNG imports help to meet natural gas demand in New England when transmission capacity is constrained. (The U.S. EIA estimated that on peak demand days, imported LNG can contribute up to 35% of New England's natural gas supply.) However, several factors can impede access to LNG, including (1) global demand for LNG and (2) a federal law that, in effect, prevents direct shipments of domestic LNG to New England's import terminals.

Global Demand

The transportability of LNG enables it to be sold internationally. As a result, LNG imported into New England on a spot basis needs to compete with global prices. This makes LNG susceptible to price swings in response to global weather conditions, geopolitical disturbances (like Russia's invasion of Ukraine and COVID-19), and other market factors.

Shipping Obstacles

The Merchant Marine Act of 1920, a section of which is known as the "Jones Act," is a federal law generally aimed at promoting and maintaining a strong American merchant marine for economic and national security reasons. It requires any vessel carrying goods from one U.S. port to another to be built, owned, and primarily operated by U.S. citizens or permanent residents (46 U.S.C. § 50102). However, according to CRS, the U.S. does not currently build LNG tankers. This means that U.S. terminals can export LNG to other countries, or receive imports from other countries, but cannot receive LNG from other parts of the United States.

This poses an obstacle for New England as domestic LNG (e.g., from export terminals in Maryland) cannot be shipped directly to its LNG import terminals. Without Jones-compliant LNG tankers, domestically produced LNG must first be shipped to a foreign terminal (e.g., a Canadian terminal in New Brunswick) and transferred by a foreign LNG tanker or come to New England via the Maritimes and Northeast Pipeline or by truck. According to EIA, the Everett Marine Terminal in Massachusetts received about 87% of total U.S. LNG imports in 2023, all by LNG carriers from Trinidad and Tobago and a small amount from Jamaica.

Connecticut Initiative to Encourage Expansion

As discussed above, natural gas infrastructure developers are generally reluctant to build out capacity without some assurance that a sufficient long-term demand exists to make their significant investment worth it. In the mid-2010s, several New England states attempted to address this mismatch in supply and demand through initiatives to (1) build out their natural gas distribution infrastructure (i.e. in-state pipelines, owned by LDCs, that receive gas from interstate transmission pipelines and distribute it to retail customers) and (2) hold multi-state procurements for long-term capacity contracts (which electricity generators typically do not enter). These plans essentially intended to develop an increased, long-term demand with the expectation that the associated costs would be spread amongst a larger number of ratepayers, attracting further investment in supply capacity.

Connecticut's plan ended in 2022 after PURA found, among other things, that the distribution expansion plan did not garner the expected number of new natural gas customers and the program was overly subsidized by ratepayers. New Hampshire, Maine, and Masschusetts also developed plans with a similar aim, although the details varied.

Distribution Expansion Plan

In 2013, the state's *Comprehensive Energy Strategy* reported that, according to Connecticut gas companies (i.e. LDCs), the interstate pipeline infrastructure was insufficient to bring new gas supplies to the New England market, but interstate pipeline companies would expand their facilities if Connecticut committed to expanding the use of natural gas and allowed LDCs to enter into longer term capacity contracts. Subsequently, PA 13-298 required the state's natural gas companies to submit a natural gas infrastructure expansion plan for PURA's approval.

The companies' plan aimed to convert approximately 280,000 residences and businesses to natural gas over 10 years, including 85,000 "off main" conversions that would require additional cost to run main lines enabling a natural gas connection. The plan cited the cost of expansion—and determining portions of the cost to be borne by new customers, current ratepayers, and the gas companies—as a central obstacle. Ultimately, PURA approved it with modifications in 2013 (OLR Report 2014-R-0013, "Regulatory Model for Large-Scale Natural Gas Expansion Plans," provides additional details on the plan and PURA's decision).

Notably, the plan required PURA to pre-approve precedent agreements for the gas companies to purchase capacity from two proposed pipeline expansion projects that were underway (the Tennessee Gas Pipeline's Connecticut Project and the Algonquin's Incremental Market project), at a cost of $1 billion over 15 years. Under normal circumstances, PURA had not preapproved the purchase of incremental pipeline capacity contracts. But PURA noted that they were needed to make the project viable because "opportunities for capacity additions do not typically coincide with the need for capacity; capacity additions are lumpy, not normally matching the need at the time" and otherwise "forecasted demand for capacity may not materialize." The project also required capacity from an expansion of LNG facilities connected to two systems and existing capacity on the Iroquois transmission system (PURA: *Decision*, Docket 13-06-02, pp. 19-22).

Expansion Plan Wrap-Up. In 2019, PURA reviewed the plan's overall progress (Docket 20-03-16), and found, among other things, that (1) the average cost per new customer increased; (2) the companies required significant subsidies, borne by ratepayers; and (3) firm gas ratepayers paid higher costs due to the allocation of non-firm margin credits (revenue gas companies earned through interruptible and off-system sales) to expansion projects rather than back to those ratepayers, as they had previously been. PURA found in a subsequent 2020 decision that these issues persisted (OLR Report 2021-R-0169, "Natural Gas Expansion Plan," provides additional information on these decisions and cost increases).

Then, in its April 2022 evaluation, PURA issued a final decision calling for the immediate wrap-up of the program, finding that:

1. the benefits of conversions to natural gas did not outweigh the ratepayer impacts associated with the plan;
2. the prices of natural gas and oil had consistently converged instead of diverging;
3. the customer conversion rates had decreased and never achieved the projected penetration levels or those required to justify a ratepayer-subsidized program; and
4. the plan no longer furthered the state's overall climate and energy goals (PURA: *Decision*, Docket 21-08-24).

Multi-State Procurements

PA 15-107, among other things, generally allowed the DEEP commissioner, alone or in coordination with other New England states, to solicit proposals for (1) interstate natural gas transportation capacity, (2) LNG, (3) LNG storage, (4) natural gas storage, or (5) any combination of these resources. The proposals had to provide incremental capacity, gas, or storage with a firm delivery capability to transport natural gas to natural gas-fired generating facilities located in the regional electric grid's control area.

Under the act, if the commissioner found that a proposal met certain criteria (e.g., was in ratepayers' best interests) he could direct the electric distribution companies (EDCs, i.e. Eversource and United Illuminating) to enter long-term contracts with the selected providers. The EDCs would then recover their net contract costs from their ratepayers, or provide billing credits for any net revenues they made from selling the natural gas products procured under the contracts.

In 2015, the Massachusetts Department of Energy Resources proposed a similar plan to allow the state's EDCs to (1) enter into long-term contracts to procure capacity on new interstate natural gas pipelines and (2) recover their costs for the contracts through their electric distribution rates. The Massachusetts Supreme Judicial Court ruled, however, that the state's regulatory department, was not authorized to review and approve ratepayer-backed long-term contracts by EDCs for natural gas pipeline capacity (for additional details about the decision see OLR Report 2016-R-0161).

With the initiative halted in Massachusetts, and public opposition to a "pipeline tax" and natural gas expansion, DEEP did not proceed with the natural gas procurement process authorized by PA 15-107, although its authority to do so remains in statute (CGS § 16a-3j).

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