The Declining Role of Natural Gas Power in New England

Detail and Technical Accompaniment

June 2020

Description

In "The Declining Role of Natural Gas Power in New England: A Comparison of Costs and Benefits", Acadia Center contrasted two scenarios that describe how New England's power grid could evolve in the coming decade. To perform the comparison, Acadia Center developed a model of generating capacity in New England to explore how that capacity could be used to meet the region's energy, reliability, and climate goals under different assumptions about the role of new natural gas power plants and supply infrastructure. The goal of the analysis was to ask whether continuing to build gas infrastructure in the future would yield the best outcome, or whether the benefits of alternatives like wind and solar bolster the case for New England to leave natural gas – or "fossil gas" – behind as soon as possible.

This is a technical accompaniment to that report. It includes additional technical information about data sources, with some added results for each of the two main scenarios presented in the "The Declining Role of Natural Gas Power in New England" brief. Acadia Center developed this technical accompaniment for the curious reader who is familiar with the electricity sector and seeks additional information not provided in that brief. This accompaniment does **not** comprise a full description of modeling methodology or an exhaustive bibliography of data sources used throughout the analysis.

Inputs and Assumptions

Energy Supply in Two Scenarios

Acadia Center modeled two scenarios that explore how different electricity supply choices could meet New England's energy, capacity and renewable energy goals by the year 2030. The "Business-as-Usual" scenario extrapolates current energy supply conditions and state renewable procurement laws, assuming no further policy actions are taken by states or by ISO New England (ISO-NE) to change New England's resource mix[1]. Meanwhile, the "No New Gas" scenario is meant to demonstrate an alternative to conventional gas-fired generation, bearing in mind that some fossil gas power plants are already scheduled to be built and connected to the grid in coming years. Table 1 categorizes the major assumptions for each scenario into those pertaining to electricity generation capacity and pertaining to fossil gas supply infrastructure.

[1] For brevity in this report, Acadia Center uses the term "New England" interchangeably with the ISO-NE control area. This is only an approximation, since some Northern counties in Maine are not part of the ISO-NE grid.

acadiacenter.org • info@acadiacenter.org • 207.236.6470 ext. 001

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Table 1: Description of generating capacity and gas transmission infrastructure assumptions and data sources in each scenario.

Scenario	Electric Generating Capacity	Fossil Gas Supply
Business-as-Usual	• Includes all existing capacity in the year 2018 and planned capacity additions from the US Energy Information Administration (EIA)[i], ISO-NE's latest capacity auction[ii] and distributed solar forecast[iii], as well as any direct procurement of resources by states. • To continue meeting the grid's projected energy and capacity needs through 2030, small amounts of additional capacity may be added before 2024, with much larger amounts after 2024 (the end of ISO-NE's most recent forward capacity procurement period, the 14th Forward Capacity Auction). Technology options include fossil gas and oil, wind and solar (including solar and battery hybrid systems), small hydro, waste-to-energy (including landfill gas and municipal solid waste) and biomass.	• Planned fossil gas pipelines or infrastructure upgrades are completed on schedule, adding an additional 387 million cubic feet per day of fossil gas supply[iv] from Tennessee Gas Pipeline Company's (Kinder Morgan) 261 Upgrade Projects, Atlantic Bridge Phase 2, Iroquois Enhancement, Westbrook Xpress Phase 2, and Portland Xpress Phase 3. • After these infrastructure investments are made, projections of winter and summer fossil gas prices in New England are brought closer to nationally averaged winter and summer prices.
No New Gas	• Like Business-as-Usual, includes all existing and planned capacity in New England (including **planned** fossil gas from the 14th Forward Capacity Auction). • Like Business-as-Usual, new capacity may be added to meet the grid's energy and capacity needs through 2030. However, no additional **unplanned** fossil gas capacity may be added. Larger annual additions of renewable energy are permitted instead.	• No fossil gas infrastructure projects proceed. No investment costs are incurred, and the price of fossil gas delivered to New England's electric generators is forecasted based on historical trends from New England. No amount of harmonization with national gas prices takes place.

To assess the two alternatives, Acadia Center modeled electricity production, capacity, costs, and greenhouse gas (GHG) emissions from generators within the ISO-NE grid forward of and behind-the-meter (BTM), as well as imported electricity and demand resources[2]. In order to calculate these outputs in each scenario year through 2030, Acadia Center used LEAP, or the Long-range Energy Alternatives Planning system[v], to conduct dispatch and capacity expansion calculations, selecting the lowest-cost mixture of energy (in megawatt-hours, MWh) and

[2] ISO-NE defines three main types of demand resource, one of which is energy efficiency (on-peak demand resources). Acadia Center performs all demand and system load calculations net of energy efficiency, which means that energy efficiency is not considered a separate resource for this analysis.

capacity (in megawatts, MW) that meets all modeling constraints during the scenario period. Electricity transmission constraints or network upkeep costs are not included in this analysis.

Energy dispatch calculations were conducted on a pseudo-hourly basis in each year, ensuring that both load and annual renewable energy requirements from states' Renewable Portfolio Standards (RPSs) are met. This pair of constraints is enforced in each of twenty-four hours of an average weekday and twenty-four hours in an average weekend day, in each season. In addition, the highest demand found in each separate hour across the whole season is assembled to create an additional group of twenty-four hours, composed of peak demands for each particular hour. This configuration of dispatch periods allows Acadia Center to represent the system's peak hourly load, without incurring the computation penalties of modeling each individual hour of each year. Within each period, different resources are used to produce energy subject to their availability. Dispatchable resources are assumed to be unavailable some of the time for maintenance, while intermittent wind, solar and hydro exhibit seasonal and/or diurnal variability calculated from the National Renewable Energy Laboratory (NREL) PVWatts Tool[vi], NREL's Wind Toolkit[vii], and historical monthly hydroelectricity production[viii]. Total energy dispatched in each season is then calculated by repeating each representative weekday or weekend day for as many weekday/weekend days as needed, before adding the twenty-four seasonal peak hours.

In addition to the power plants that already exist, planned capacity additions are included (see Table 1 for a short description of planned capacity), as well as planned retirements or any other retirements that would be expected based on a plant's construction year and expected number of operating years. To define new capacity beyond these planned generators, capacity expansion calculations are carried out within the model to ensure that the system's installed capacity requirements are met in each year through 2030. Acadia Center's model is heavily constrained from adding large amounts of capacity before 2024, because it is unlikely that new large power plants would be added before then unless they are planned. But after 2024, larger amounts of capacity can be added in each year. Capacity requirements in each year ensure that the ratio of ISO-NE's installed capacity requirement[ix] to forecasted summer peak load is preserved. As peak load increases in the model, so too does the capacity requirement, which triggers the software to add new capacity.

Energy Supply Prices

Since Acadia Center's model meets capacity and energy needs using the lowest-cost mix of resources, assumptions about installation, maintenance and fuel costs are especially important in this study. Of the many different cost assumptions and forecasts used, the capital costs of generating technologies and the delivered price of fossil gas are among the most important. The capital costs of major electricity production technologies are drawn from estimates in public literature, which for newly constructed plants are then amortized over the expected lifetimes of the assets. For gas delivered to power generators in New England, Acadia Center developed four price forecasts that are used across the two scenarios: during and outside the winter and autumn space heating season, and with and without infrastructure upgrades listed in Table 1. Higher gas prices that do not account for these infrastructure upgrades are used for the No New Gas scenario, reflecting the continuation regional supply limits that contribute to higher prices. In the Business-as-Usual scenario, prices are partially harmonized with the US national average. Capital costs and gas prices are summarized in Figure 1 and Figure 2, respectively.

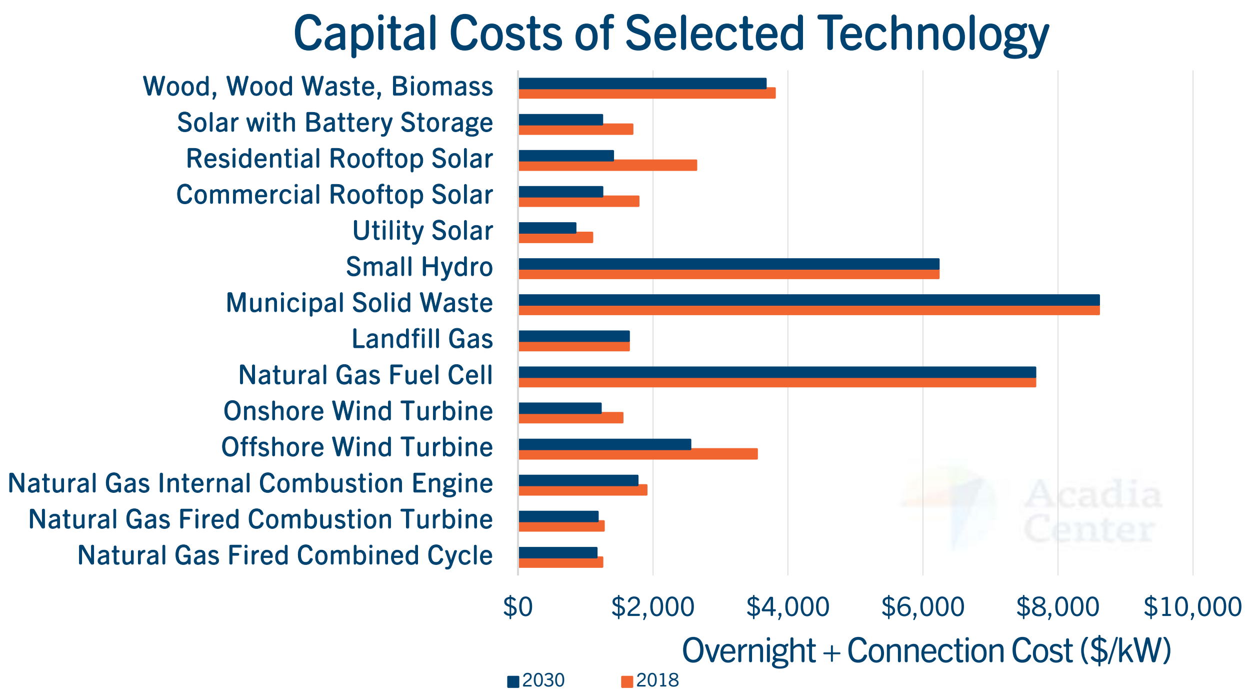

Figure 1: Capital costs for overnight construction for a selection of major technology options considered in this study, including estimated grid connection costs. Current and expected future costs are drawn primarily from NREL's Annual Technology Baseline[x], supplemented using those provided by the EIA[xi]. Values presented in this chart, as with all prices shown throughout this report, are expressed in real 2017 US dollars using historical consumer price indices[xii].

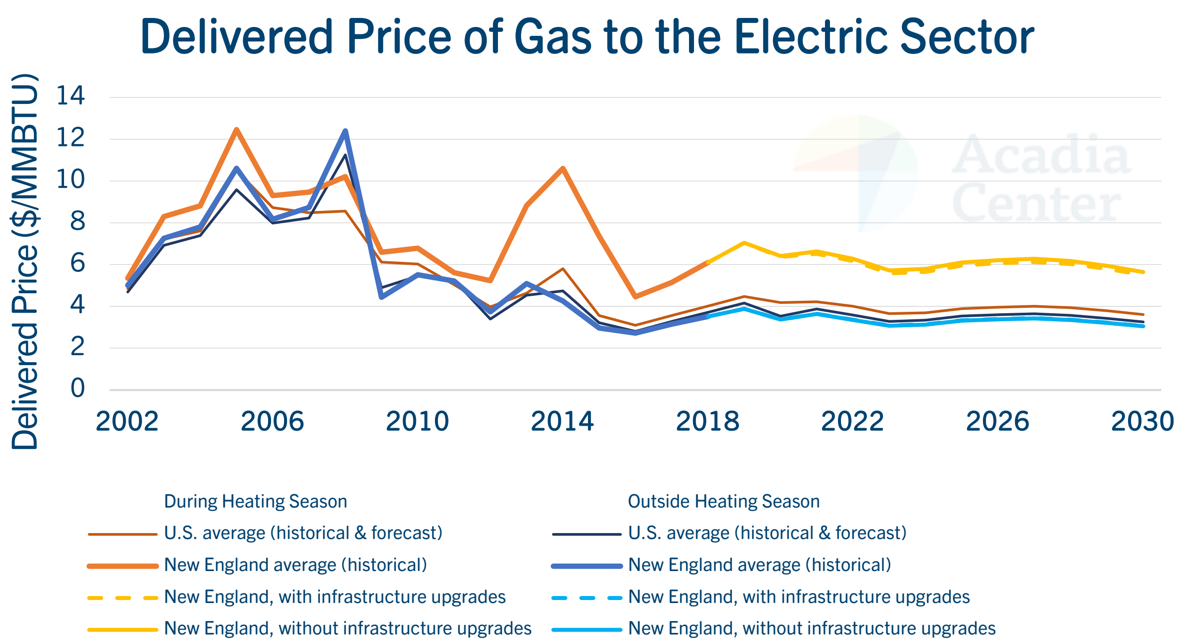

Figure 2: Historical and forecasted fossil gas prices for electric sector consumers, both in New England and averaged across the country. Seasonal price differences were derived from monthly Henry Hub spot price[xiii] and futures quotes[xiv], with prices for the New England electric sector from the EIA[xv] (historical) and the Annual Energy Outlook[xvi] (future). Acadia Center adjusted these price forecasts to estimate price impacts of including or excluding an additional 387 million cubic feet per day of fossil gas supply[xvii].

Energy Demand

To make the comparison as objective as possible, the two energy supply scenarios were evaluated against the same electricity demand forecast for the whole ISO-NE region. The forecast, shown in Figure 3, is one in which the recent decline in energy demand is reversed, as transportation and building heating needs become increasingly electrified. To be consistent with recent work[xviii] that foresees electricity demand doubling by midcentury, Acadia Center used a forecast that puts less emphasis on efficiency and demand response than other recent forecasts like ISO-NE's annual energy forecast[xix] (and Acadia Center's own EnergyVision 2030 baseline scenario[xx]) which show approximately flat electricity demand this decade. This demand trajectory is chosen to avoid underestimating the need for electricity, including from fossil gas.

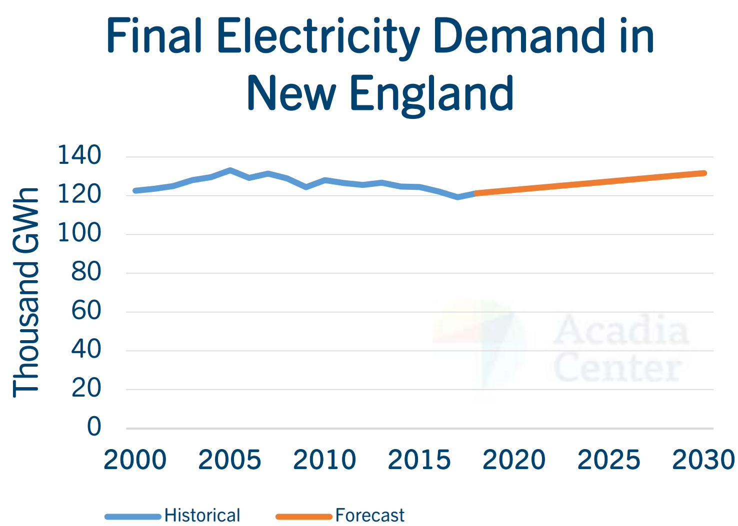

Figure 3: Final electricity demand in New England, net of energy efficiency, but gross of transmission losses and BTM electricity production. Forecasted electricity demand from NREL's Electrification Futures Study[xxi].

Both annual and hourly demands are forecasted, for each of the pseudo-hourly dispatch periods introduced earlier. Acadia Center's estimate of hourly load in each year comes from interpolating between ISO-NE's 2018 hourly system load[xxii] and NREL's hourly load projection for the year 2030.

Findings

Capacity and Energy Production

Over the next ten years, which is roughly the time spanned by this analysis, the two scenarios do not diverge sharply. With long-lived assets like power plants and few significant retirements scheduled by 2030, the regional grid transforms gradually. Unless final energy demand increases significantly more than is proposed in Figure 3, much of the capacity that will be added through the middle of the decade is already committed. In both scenarios, total system capacity grows moderately, with offshore wind and solar PV comprising most of the newly added capacity, especially in the latter half of the decade. Table 2 provides an overview of installed capacity in 2018 and 2030 under both scenarios, for major categories of electric generators. Cumulative capacity additions are also shown (retirements can be inferred from the table but are not shown).

Table 2: Total nameplate capacity, and capacity additions, of major power generation technologies and other resources across New England, in each scenario. Supply resources shown include the implied nameplate capacity of BTM PV, as well as intertie capacity with neighboring grids in New York, Québec, and New Brunswick.

Technology	Capacity in 2018 (MW)	Capacity Added 2019 - 2030 (MW)		Capacity in 2030 (MW)	
		Business-as-Usual	No New Gas	Business-as-Usual	No New Gas
Nuclear	4,075	-	-	3,405	3,405
Coal	959	-	-	214	214
Natural Gas	17,985	3,288	2,220	19,919	18,851
Oil Products	6,948	22	22	6,058	6,058
Wind	1,371	9,033	9,922	10,398	11,288
Biogas, Biomass, Waste-to-Energy	1,706	816	1,065	2,079	2,328
Hydro, *including pumped storage*	3,730	154	249	2,750	2,845
Solar, *including hybrid battery systems*	2,830	6,731	7,587	9,561	10,417
Batteries	30	971	971	999	999
Demand Response, *excluding efficiency*	3,615	847	847	4,463	4,463
Imports	5,101	3,145	3,145	8,101	8,101
Total	48,350	25,007	26,030	67,945	68,968

In large part, the expansion of renewable capacity seen above in both scenarios is driven by existing requirements that states meet more and more of their electricity needs using renewable sources. While there are differences in each states' RPS targets and which resources may qualify under them, to model the whole grid, Acadia Center calculated a regional average renewable requirement of 45% of energy provided in 2030, under which newly- or recently-built wind, solar, small hydropower, some waste-to-energy technologies, some biopower, and some imports may qualify. With these targets and pre-existing capacity commitments included in both scenarios, there is a relatively narrow band of opportunity to effect additional changes to the grid before 2030. Capacity is dispatched to produce electricity in qualitatively similar ways, shown below by resource type in Figure 4.

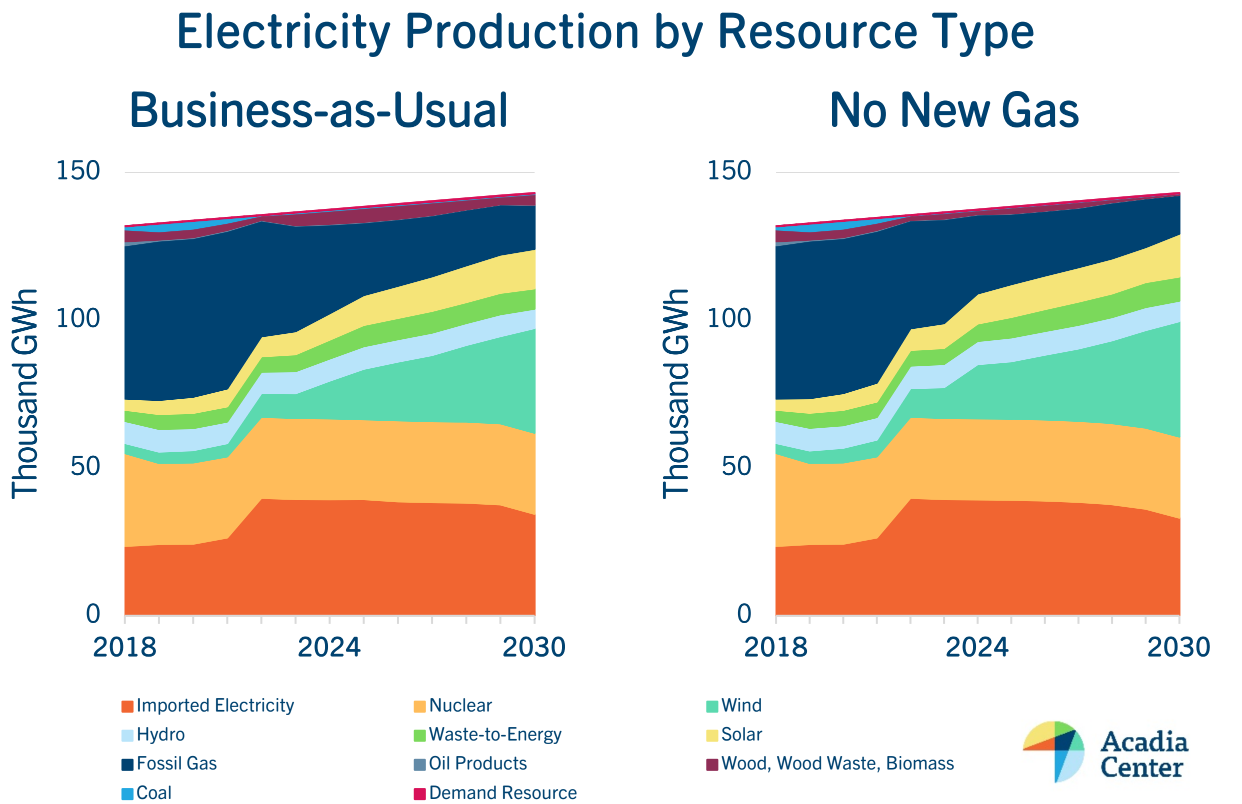

Figure 4: Electricity production by fuel or resource type in each year, under both scenarios. The category labeled waste-to-energy includes all forms of landfill gas, anaerobic digestion and municipal solid waste incineration, and the solar category includes all forward- and behind-the-meter solar, including solar integrated with battery energy storage. Very small amounts of energy produced through demand resources come from ISO-NE's active demand response.

A key feature of both scenarios seen in Figure 4 is that electricity produced from fossil gas declines significantly by 2030 compared to today, both in magnitude and as a percentage of the overall energy mix. In estimating the declining use of fossil gas capacity, Acadia Center's modeling also accounted for the relative contributions of each technology during each modeled dispatch period. Figure 5 shows that by 2030 in the No New Gas scenario, even during summer, the majority of load is met using imports, nuclear, wind and solar, despite the scenario retaining enough fossil gas capacity to meet half of the system's power requirements during the summer peak.

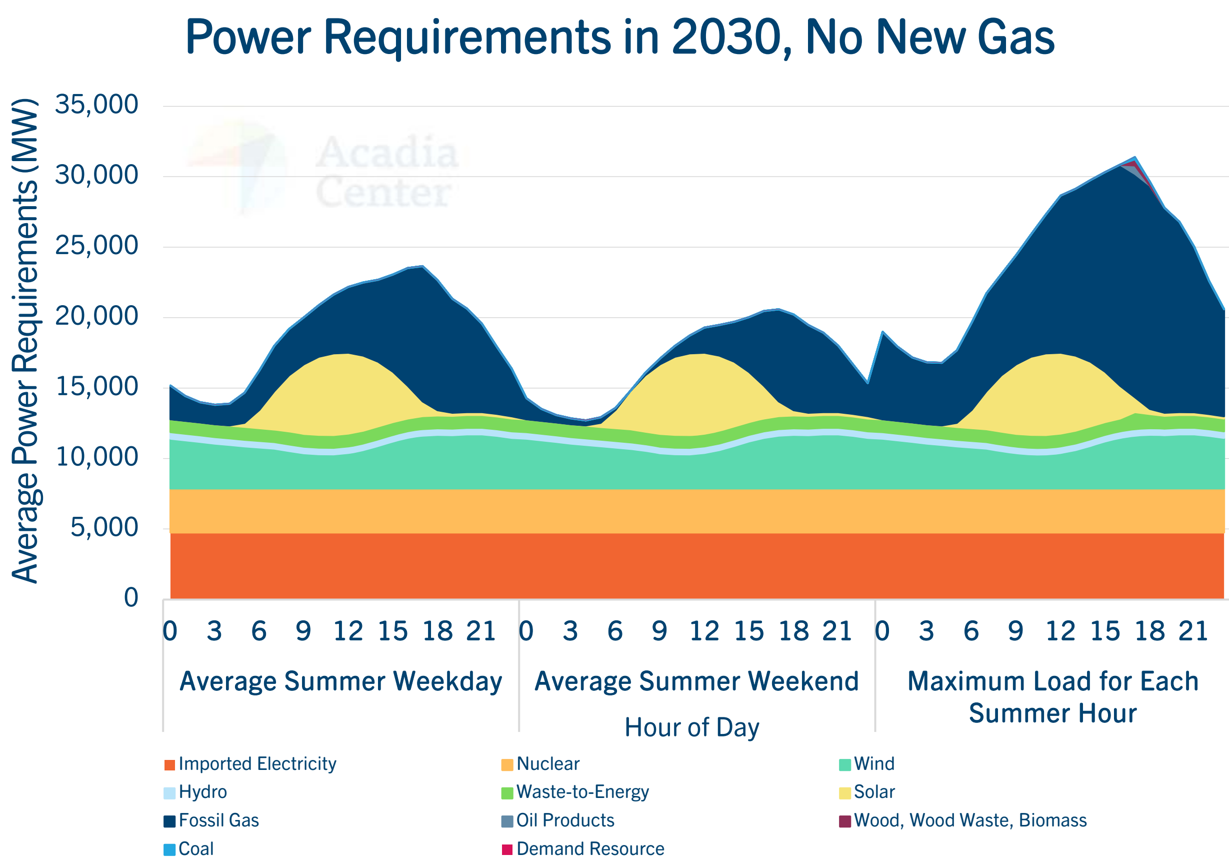

Figure 5: Power requirements in 2030, for each hour during an average summer weekday and weekend day. The rightmost portion of the chart shows the additional twenty-hour hours that are the "peak seasonal hours" for summer, representing the highest load for that hour across the whole summer season. Power requirements are gross of BTM PV, and net of energy efficiency.

Even though, in its modeling, Acadia Center ensured a minimum level of reserve capacity, it does not consider ancillary service markets for system reliability or sub-hourly ramping needs, nor does it conduct a stochastic assessment of resource intermittency. Instead, residual fossil gas capacity on the grid in 2030, together with battery energy storage and other supply (or demand-side) technologies, is assumed to be sufficient for whatever reliability or ramping needs may arise.

Costs and Savings

One important element of Acadia Center's comparison is to contrast the costs, or savings, that could occur under one scenario or the other. For insight into this, Acadia Center began by calculating the average system-wide operating cost[3], during peak and off-peak hours separately, for each scenario's final year.

[3] In this report, operating cost is defined using the variable components of the levelized cost of electricity, averaged over a period of choice. In the case described in Figure 6, Acadia Center presents operating costs averaged over peak hours and outside of peak hours.

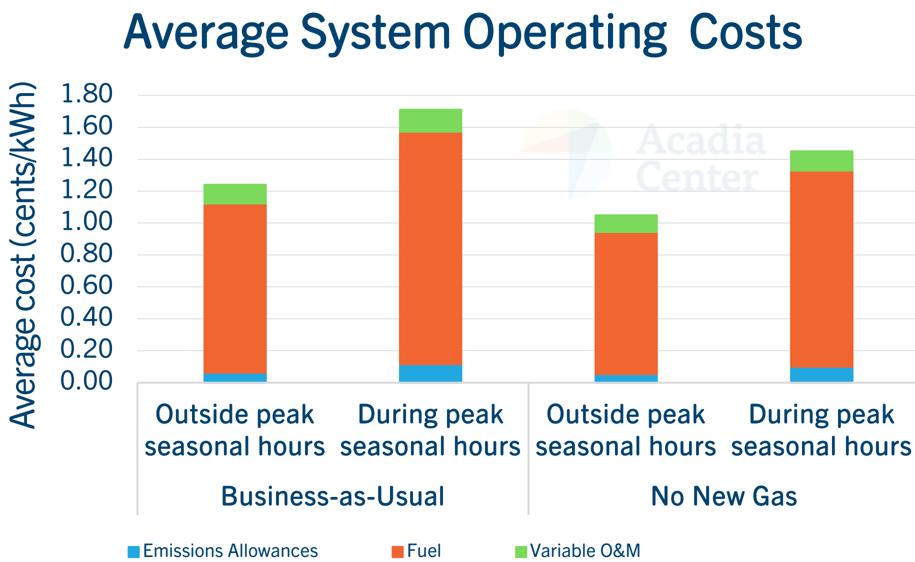

Figure 6: Average operating costs for each scenario in 2030. Costs are averaged over two different periods: peak seasonal hours, and all other hours that are not peak seasonal hours (weekday and weekend day hours, as described earlier in this document). Three types of costs are included in the operating cost, covering fuel purchases (fuel, in the chart legend), variable operation and maintenance (variable O&M), and the expected costs of GHG emission allowances under the Regional Greenhouse Gas Initiative[xxiii] (emissions allowances).

Figure 6 shows that the cost of production is higher during periods of high demand, because increasingly expensive generators are needed to serve load. It also shows that a grid that relies more on zero energy cost renewables, such as that of the No New Gas scenario, exhibits lower running costs. This result holds even when accounting for the higher delivered cost of fossil gas in the No New Gas scenario. A more complete comparison of costs between the two scenarios (shown in Figure 7) includes the costs of building and maintaining plants, as well as the investment requirements for additional fossil gas pipelines.

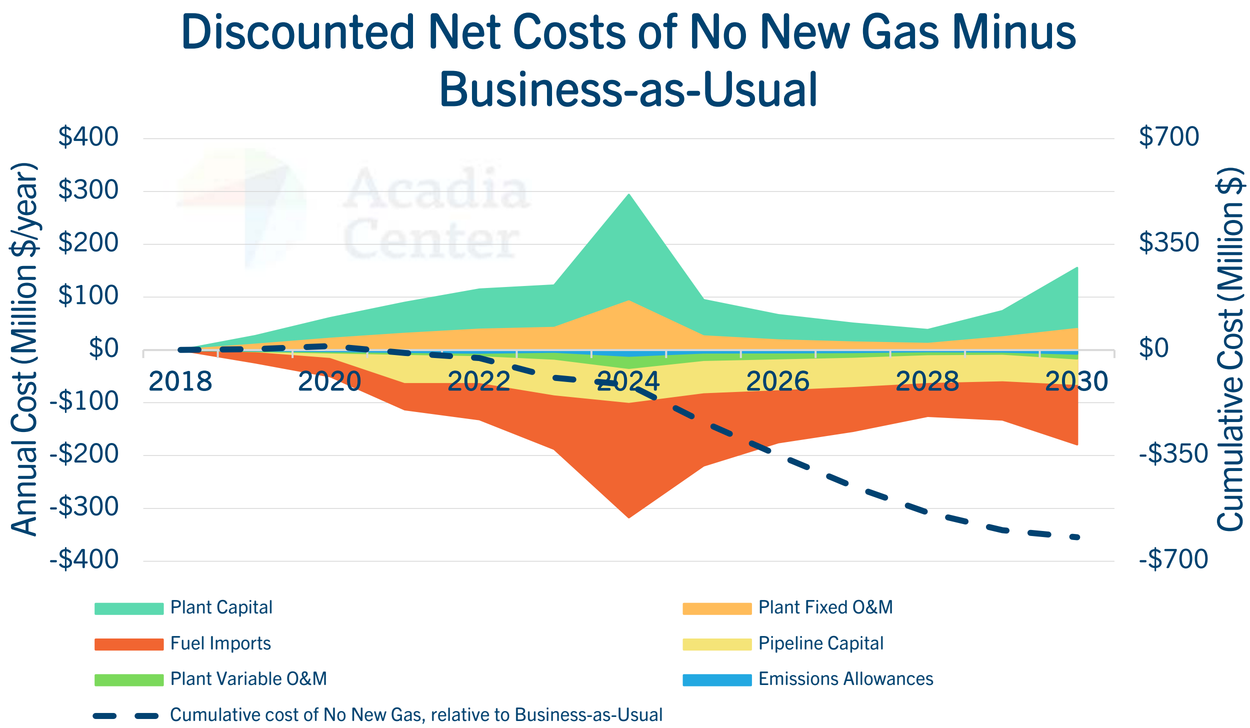

Figure 7: Annual net costs of the No New Gas scenario for each major category, having subtracted the same cost from the Business-as-Usual scenario. Positive values for plant capital and fixed operation and maintenance (fixed O&M) indicate that these costs are higher in the No New Gas scenario compared to Business-as-Usual. Negative values for all other cost types indicate that these costs are lower in the No New Gas scenario. All cost differences are then summed together for the secondary axis (right side of chart, accompanied by dotted line), which shows the cumulative cost of No New Gas, compared to Business-as-Usual. Costs displayed in present value, using a social discount rate of 5% per year.

The figure above shows that a power system with a higher penetration of renewables has higher fixed costs (capital and fixed O&M), but lower variable costs (fuel, variable O&M) than a system that is more reliant on fossil fuels. The dotted line displays the cumulative savings that would be incurred through the year 2030 under the No New Gas scenario, compared to Business-as-Usual.

Emissions and Other Co-Benefits

Moving beyond monetary costs and benefits, Acadia Center also quantified the additional savings in GHG emissions that the No New Gas scenario would unlock, and potential impacts on employment of one pathway over the other. Emissions in both scenarios are shown in Figure 8, with detail showing the source of these emissions in the No New Gas scenario.

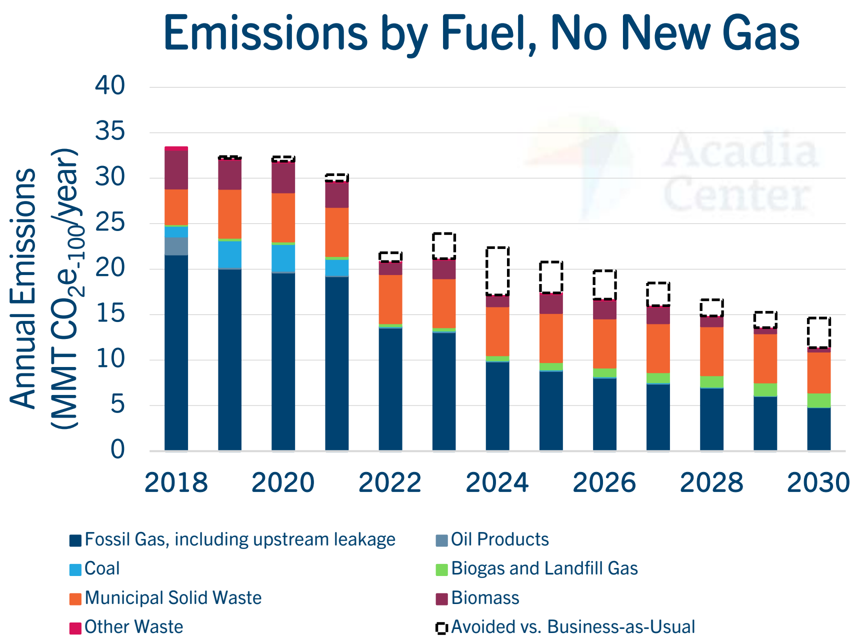

Figure 8: Annual GHG emissions associated with electricity production by different fuels in New England. Colored bars show the contribution from each fuel to emissions in the No New Gas scenario, with white bars indicating the additional emissions that No New Gas avoids, beyond the Business-as-Usual scenario. Acadia Center includes all direct combustion emissions from generators in the ISO-NE control area, calculated from the Emissions & Generation Resource Integrated Database[xxiv] (eGRID), as well as methane leakage upstream of the power plant from fossil gas storage and transmission[xxv].

Summed over the 2019 – 2030 period, the No New Gas scenario avoids an additional 26 million metric tons (MMT) of carbon dioxide equivalent, calculated using the 100-year global warming potential (GWP)[4] of methane and nitrous oxide (CO_2e_{-100}), or 27 million metric tons CO_2e_{-20}, using the 20-year GWP. Figure 9 shows GHG emissions for both scenarios divided by electricity production in each year, or the average emission factor for the ISO-NE grid.

[4] GWP is a measure of the cumulative amount of heat trapped over a specified period of time, by a pulse of GHG emissions. The amount of heat trapping is expressed in carbon dioxide-*equivalent* terms, relative to the heat trapped by the same amount of carbon dioxide. Different GHGs can have different global warming effects over the short- and long-term, and by presenting CO2e using both 20-year (CO_2e_{-20}) and 100-year (CO_2e_{-100}) time horizons, Acadia Center aims to recognize these differential effects and avoid losing important information that would be obscured by choosing one or the other unit of measurement. Charts in Figure 8 and Figure 9 provide only CO_2e_{-100}.

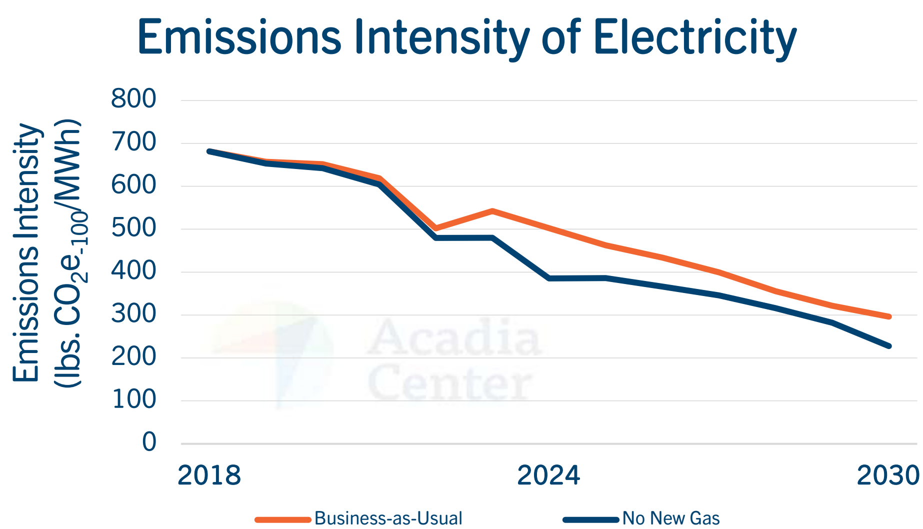

Figure 9: Average GHG emissions intensity of electricity produced in New England. Mass units of pounds (lbs.) are selected, in contrast to the metric units used earlier, for simpler comparison with ISO-NE annual emissions reporting[xxvi]. Acadia Center's emissions intensity calculations exclude imported electricity.

Acadia Center also estimated the net employment changes that could be expected under the No New Gas scenario, compared to Business-as-Usual (Table 3). Employment changes can be *direct*, resulting from the construction of new infrastructure and its operation thereafter, and they can be *indirect* (and *induced*), arising from equipment supply chains or from workers spending their wages.

Table 3: Summary of net employment benefits in the No New Gas scenario. Values given in job-years, where one job-year is equal to employment for one full-time position for one year. Where possible, Acadia Center uses NREL's JEDI model[xxvii], with other literature estimates[xxviii] as needed, for both the direct and indirect/induced employment per megawatt of installed capacity, for all major electric generation technologies considered.

Net Job-Years in No New Gas Scenario, Versus Business-as-usual		
State	Direct Job-Years	Indirect Job-Years
Connecticut	36	274
Massachusetts	2,035	2,638
Maine	558	1,632
New Hampshire	99	193
Rhode Island	841	1,164
Vermont	592	958
New England	4,160	6,858

For more information:

Taylor Binnington, Senior Policy Analyst, tbinnington@acadiacenter.org, (860) 246-7121 x203

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