The Northeast Gas Association (NGA) is pleased to present this periodic update on market characteristics and recent developments in the Northeast region of the United States. This paper summarizes key features of the natural gas system in New England, New Jersey, New York, and Pennsylvania, and then reviews several current market issues.

This paper has been updated in mid-July 2020 in the midst of the Coronavirus pandemic impacting the United States and the global community. The health crisis has already had a major impact on public health and the economy. Since we are still in the midst of this pandemic, its full impact on public health, the economy, and energy markets is still to be fully understood. This paper to a great extent presents a snapshot in time, reflecting the market view principally from 2019 and early 2020. The outlook for the current year as a result of COVID-19 remains uncertain. For energy markets, the immediate impact is on reduced demand, production and prices. The question is, as for the whole economy—how long will this last, and when will a steady recovery begin?

Meanwhile, we extend our hope for good health and safety to all.

MARKET BACKGROUND

Population and Economy

The Northeast region comprises the nine states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. The composite population is 56.1 million (17.1% of the U.S.). Total state domestic product for the region is $4.3 trillion (20% of the U.S. total).

Regional Natural Gas Market

The nine-state region has 13.8 million natural gas customers (18.4% of the U.S. total of 74 million). Total annual gas sendout on the regional gas system is 4.1 trillion cubic feet (Tcf), or 15% of U.S. total consumption (measured in volumes delivered to consumers).

Primary Energy

Natural gas represents 29% of the primary energy consumption of the six New Eng-
land states, 36% of New Jersey, 36% of New York, and 34% of Pennsylvania, compared to the national average of 31% (based on U.S. EIA data, 2018).

**Gas Customers**
New England has 2.8 million natural gas customers. Residential customers total 2.5 million; commercial and industrial customers number over 280,000.

New Jersey has 3 million natural gas customers. Residential customers total 2.8 million; commercial and industrial customers number about 250,000.

New York has 5 million natural gas customers. Residential customers total 4.5 million; commercial and industrial customers number about 410,000.

Pennsylvania has 3 million natural gas customers. Residential customers number 2.8 million; commercial and industrial customers number 245,000.

Natural gas remains the leading home heating fuel: in New England it is 39.9%, followed by fuel oil (35%); in New Jersey, 75%, followed by electricity (13%); in New York, 60%, followed by fuel oil (20%); and in Pennsylvania, 51%, followed by electricity (24%), and fuel oil (16%).

**Consumption/Sendout by Sector**
Total annual sendout in New England is 900 billion cubic feet (Bcf), in New Jersey about 760 Bcf, in New York about 1,320 Bcf, and in Pennsylvania about 1,110 Bcf (2018 EIA annual data).

In New England, gas consumption by end-use sector is 24% residential, 24% commercial, 13% industrial, and 40% power generation. In New Jersey, it is 32% residential, 22% commercial, 8% industrial, and 37% power generation. In New York, it is 37% residential, 25% commercial, 6% industrial, and 31% power generation. In Pennsylvania, it is 21% residential, 11% commercial, 19% industrial, and 45% power generation.

In New England, the gas distribution company, or LDC, design day demand is 4.8 Bcf per day, in New Jersey over 4 Bcf/d, and in Pennsylvania 5 Bcf/d. In New York State, gas system peak demand is 7.8 Bcf/d. While winter is still the peak season for demand, the increasing use of gas for power generation has led to higher demand in summer months.

*The U.S. interstate natural gas pipeline system includes 300,000 miles of transmission pipeline, according to the U.S. PHMSA. The EIA map on the left illustrates the extensive system.*
The 9 Northeast states have close to 14 million gas customers, about 18% of the U.S. total.

Electric Generation Sector

Based on annual fuel mix and generator applications in the queues at ISO-NE, NYISO, and PJM, natural gas remains one of the leading current and projected fuel sources for electricity generation. In New England, natural gas represents 49% of current regional electric capacity, in New Jersey 67% (in-state generation), in New York, over 50%, and in Pennsylvania, 42%.

Regional Market: Gas Supply Sources

Domestic resources account for 90% of the natural gas consumed in the U.S. The balance is imported from Canada, and a small share is imported in the form of liquefied natural gas (LNG).

Net imports as a percentage of total natural gas consumption in the U.S. totaled 8% in 2011, but dropped to about 2.5% in 2016. “The U.S. became a net natural gas exporter on an annual basis in 2017 for the first time in almost 60 years,” according to the EIA.

Historically, the Northeast has relied on three supply areas: Gulf Coast U.S., Canada, and imported LNG. Throughout the last two decades, supply areas expanded to include Rockies/Midcontinent gas and eastern Canada. For the Northeast, the most significant supply change is the development of the Marcellus and Utica Shale gas basins in Appalachia and Ohio. Marcellus/Utica production is resulting in new delivery points and new pipeline infrastructure. Appalachian production reached 32 Bcf/d in early 2020. Exports from Canada to the Eastern U.S. have fallen from 2.8 Bcf/d in 2007 to 0.8 Bcf/d in 2019, because of Marcellus and Utica shale gas availability.

LNG imports into the U.S. were 53 Bcf in 2019, substantially lower than the high point of 771 Bcf a decade earlier. The Everett LNG facility outside Boston imported 35 Bcf in 2019, which represented about 67% of total U.S. imports.

LNG imports play a critical role in helping gas utilities in the Northeast region meet winter peak day requirements; for example, LNG provides about 27% of New England utilities’ peak day requirements. Canaport in New Brunswick, Canada delivered 18 Bcf to the regional market in 2019. The offshore Northeast Gateway terminal imported about 5 Bcf in early 2019.

Pipeline and LNG Deliverability

New England

New England has 2,698 miles of gas transmission pipeline, according to the U.S. Department of Transportation / Pipeline and Hazardous Materials Safety Administration (PHMSA).

New England is the site of three import terminals for LNG, two of which are operational. The onshore terminal in Everett, outside of Boston, is owned by Exelon (Constellation). LNG is delivered by tanker to the terminal which has storage capacity of 3.4 Bcf. The terminal has pipeline interconnections as well as connections with a major gas utility and a major power plant. LNG is also transported to multiple LDCs’ satellite storage tanks from trucks that fuel at the Everett facility. The terminal’s vaporization capability is 715 MMcf/d; it also has daily sendout by truck of another 100 MMcf/d.

The offshore Northeast Gateway facility (near Cape Ann, MA) is owned by Excelerate Energy. It can receive LNG cargoes and inject the revaporized gas into Enbridge’s HubLine pipeline system. After several years of inactivity it brought 2.6 Bcf in 2015 and 2.3 Bcf in 2016, but none in 2017 or 2018. In early 2019, the facility brought in just under 5 Bcf to meet cold weather demand.

The offshore Neptune LNG facility owned by ENGIE (also near Cape Ann, MA) was completed in 2010. It has been inactive since its start-up, and is presently offline.

Canaport LNG (located across the Maine border in Saint John, New Brunswick) is owned and operated by Repsol and Irving Oil. It can deliver up to 1 Bcf/d into the Brunswick Pipeline, which connects with the Maritimes & Northeast Pipeline, which then can transport the volumes into New England. Since its inception, it has delivered over 430 Bcf into the regional market. Canada’s National Energy Board noted in March 2017 that “Canaport is a peak demand serving facility with deliveries increasing during the winter months in response to cold temperatures.”
New Jersey

New Jersey has 1,570 miles of gas transmission pipeline. The interstate pipeline companies serving New Jersey are: Algonquin Gas Transmission, Columbia Gas Transmission, Tennessee Gas Pipeline Co., Texas Eastern Pipeline Co., and Transcontinental Gas Pipe Line Corp. The LDCs utilize local LNG storage for peak day support.

New York

New York has 4,592 miles of gas transmission pipeline. The pipeline companies serving New York State are: Algonquin Gas Transmission, Columbia Gas Transmission, Dominion Energy Transmission, Empire State Pipeline Co., Iroquois Gas Transmission System, Millennium Pipeline Company, National Fuel Gas Supply Co., North Country Pipeline, Stagecoach Gas Services, Tennessee Gas Pipeline Co., Texas Eastern Pipeline Co., and Transcontinental Gas Pipe Line Corp. New York also has gathering systems such as Laser Pipeline. LNG is utilized by two local utilities in the New York City and Long Island areas. The LNG is received from the pipeline in vapor form and then liquefied. New York has no LNG import facility.

Pennsylvania

Pennsylvania has 10,345 miles of gas transmission pipeline. The pipeline companies serving Pennsylvania are: Columbia Gas Transmission, Dominion Energy Transmission, National Fuel Gas Supply Co., Tennessee Gas Pipeline Co., Texas Eastern Pipeline Co., and Transcontinental Gas Pipe Line Corp. LNG is utilized by two LDCs, and produced by the affiliate of another utility for sale into the regional energy market.

Regional Production

The Northeast region, a major consumer of natural gas and a high-priced energy market, is a center of U.S. natural gas production. Historically, the region had only limited natural gas production in New York and Pennsylvania. (There is no gas resource production base in New Jersey or New England.) With the advancement of hydraulic fracturing and the development of the Marcellus resource base, the Northeast has become a significant area of natural gas production. Appalachian production, centered in Pennsylvania, Ohio, and West Virginia, reached close to 33 Bcf/d in early 2020. Pennsylvania’s annual production grew
to 6.9 Tcf in 2019 (compared to 0.6 Tcf in 2010); it is the second-largest state producer of natural gas in the U.S.

Interstate pipeline companies serving the Appalachian region continue to add interconnects from area producers. Several projects have been completed and others are in development to bring this gas to market (while others face siting challenges, an issue discussed further below).

While there is a shale gas resource in New York, use of the hydraulic fracturing process is not permitted per state regulation announced in late 2014. New York State does allow conventional drilling production. Total annual state output was 11 Bcf in 2019. The state’s conventional production has steadily declined since 2007, when annual production totaled 55 Bcf.

There is some limited conventional production in eastern Canada.

Gas from offshore Nova Scotia was produced for two decades from the Sable Offshore Energy Project, but production ceased at the end of 2018. In February 2019, Canada’s NEB noted: “The Maritimes will transform from being an exporter of natural gas to being an importer of natural gas from the U.S.”

A gas production field in New Brunswick, the McCully field of Corridor Resources, which began production in 2007, provides small amounts of gas for delivery into the Maritimes & Northeast Pipeline.

Regional Storage

Storage is a critical part of the natural gas supply and delivery chain. The Northeast region has considerable underground storage, notably in Pennsylvania (8.2% of the U.S. total). Underground storage in New York is about 2.6% of the U.S. total. The geology of New Jersey and New England is not suitable for underground gas storage.

LNG is an important part of the storage portfolio. Total LNG storage capacity in New York is 3.2 Bcf, in New Jersey about 4 Bcf, in Pennsylvania 6.7 Bcf, and in New England 16 Bcf on the LDC system and another 3.4 Bcf at the Everett import terminal. The Canaport LNG facility has 9.9 Bcf of storage. LNG is also produced and supplied by companies in Québec and Pennsylvania.

Recent System Enhancements

In 2019, several interstate pipeline projects were completed and entered service:
Another key supply point for the region is liquefied natural gas (LNG). The region has three operating import facilities, two in MA and one in New Brunswick, Canada. Nationally and regionally, LNG imports are down, as U.S. domestic production is on the increase. LNG remains especially important to New England for peak days. This photo is of an LNG tanker delivery to Everett during a snowstorm in March 2019.

Photo source: Everett LNG

Enbridge: “Lambertville East”  
Millennium: “Eastern System Upgrade”  
PNGTS: “Portland XPress” [phase 2]  
PNGTS: “Westbrook” [phase 1]  
Transco: “Rivervale South to North”  
Transco: “Gateway Expansion Project.”

Several other projects experienced permitting delays, however, and some others were withdrawn in the first half of 2020 (refer to the section on Infrastructure Siting Challenges and Regulatory Delays).

Planned Infrastructure Enhancements

The Northeast region’s natural gas industry plans several infrastructure projects in the near-term to meet growing market demand. The natural gas system remains constrained at several points on its natural gas system, especially into New England and southern New York/Long Island. Several gas utilities in the region have implemented moratoria on new customer connections, citing supply and delivery limitations.

New supplies and infrastructure would ease constraints, mitigate regional price disadvantages, and increase regional natural gas capacity, deliverability, flexibility, and reliability. NGA posts updates on proposed projects at:

http://www.northeastgas.org/pipeline_expansion.php

Challenges for new projects include siting, environmental concerns, and securing market position. Contract commitments in New England remain a vexing market issue, as the largest consuming sector, power generation, is constrained by the complex economic structure of its wholesale electricity market. Local natural gas utilities have tried to invest in incremental pipeline projects to meet system expansion and reliability needs.

LNG is another supply option for the market in general and for gas LDCs.
The interstate pipeline system in the Northeast accesses supplies from multiple sources. The pipelines also can access storage at different points along their systems, including local storage in Pennsylvania and New York. With prolific production underway in Appalachia, these pipeline operators are undertaking numerous projects to add facilities to bring these new supplies to local markets in the Northeast and elsewhere, changing traditional flow patterns.

MARKET ISSUES

Supply Outlook

U.S. production reached new heights in 2019, a 10% increase over 2018 levels.

As of March 2020, EIA was forecasting that U.S. dry natural gas production would average 95 Bcf/d for 2020, up 3% from the 2019 record. But a month later, in April, the EIA had already adjusted the annual outlook in response to the COVID-19 outbreak. EIA as of July is now forecasting that dry natural gas production will average 89.2 Bcf/d for 2020. In July, EIA noted that “The April 2020 decline in natural gas production was the largest monthly decrease since Hurricane Isaac-related shut-ins in August 2012...The declining market led oil and natural gas operators to shut-in wells and limit the number of wells brought online, lowering the output for the major oil- and natural gas-producing regions.” (While
most producing states saw declines in April, production that month actually increased in Louisiana and Pennsylvania.

The U.S. resource base for natural gas nevertheless remains extensive even as the virus is seriously impacting near-term production conditions in the wake of the economic contraction.

In September 2019, the Potential Gas Committee (PGC) at the Colorado School of Mines released its 2018 biennial report, Potential Supply of Natural Gas in the United States. The assessment reported that the U.S. possesses a technically recoverable natural gas resource potential of 3,374 Tcf, which is the highest resource evaluation in the PGC’s 54-year history. The future supply of domestic natural gas continues to increase due to the emergence and advancement of key technologies that unlock gas production from reservoirs such as shale formations.

Canada, which has considerable natural gas reserves, remains an important energy partner, although its share of the U.S. natural gas market is expected to decline over the long-term. In its December 2019 report, Canada’s Energy Future 2019, the Canada Energy Regulator (CER) projected that natural gas production will increase steadily over the next decades, with the power generation market and LNG exports as key market drivers.

Increased domestic production in the U.S. affects LNG imports. LNG imports into the U.S. are substantially lower than a decade ago, and the focus for the U.S. gas market has shifted from imports to exports. Several LNG import facilities on both coasts and especially in the Gulf are adding liquefaction facilities so that they can export LNG to the world market. In 2019, the U.S. exported far more LNG (1.8 Tcf) than it imported (53 Bcf), a trend that will continue.

One example of the new dynamic is Dominion’s Cove Point facility in Maryland; long an import facility, it recorded its first export shipment in 2018. In July 2020, EIA noted that “gross exports of U.S. LNG averaged 5.0 Bcf/d in 2019. EIA expects LNG exports will increase to 5.4 Bcf/d in 2020 and 7.3 Bcf/d in 2021.”

With the Northeast delivery system still constrained at certain points, regionally based LNG facilities are expected to continue to help ease bottlenecks and increase supply and delivery options.

Efficiency Initiatives

The Northeast states continue to be leaders in per capita energy efficiency.

The Northeast region is a recognized national leader in per capita energy efficiency. A 2019 report by the American Council for an Energy Efficient Economy (ACEEE) noted that $1.4 billion was invested in natural gas efficiency programs nationwide in 2018 (latest data). Over 40% ($572 million) of the national total was invested in the nine Northeast states alone.
ACEEE stated that efficiency opportunities exist in multiple sectors: “While the roots of natural gas efficiency programs lie within residential markets, there are now programs serving multiple types of natural gas customers – from homeowners to large industries….Programs may target specific technologies that use natural gas, such as furnaces, water heaters, boilers, and cooking equipment, or they may target the systems and facilities that are served by natural gas technologies. Improving the thermal envelope of buildings is one example of programs that address whole buildings.”

Price Trends

The key variables in natural gas price formation are: demand growth, the state of the national economy, production levels, storage levels, weather, and alternative fuel prices.

The natural gas price trend in this new era of domestic production continues to be positive for both consumers and the entire U.S. economy. In July 2008 natural gas commodity prices reached $13.50/MMBtu (and oil hovered close to $150 a barrel), whereas in 2019 the average natural gas commodity price was around $2.50/MMBtu.

In the first half of 2020, natural gas prices at the U.S. Henry Hub benchmark reached record lows, according to EIA, which noted in July: “The average monthly Henry Hub spot price in the first six months of the year was $1.81 per million British thermal units (MMBtu). Monthly prices reached a low of $1.63/MMBtu in June, the lowest monthly inflation-adjusted (real) price since at least 1989. Prices started the year low because of mild winter weather, which resulted in less natural gas demand for space heating. Beginning in March, spring weather and the economic slowdown induced by mitigation efforts for the coronavirus disease 2019 (COVID-19) contributed to lower demand, further lowering prices.”

Given the size of the domestic supply resource base, it is projected that the natural gas price bandwidth will stay relatively stable and moderate. However, short-term volatility reflecting delivery constraints and weather will continue to affect regional markets.

EIA has projected an average commodity spot price of around $1.93 per MMBtu in 2020 (as of July), but that the average price will rise in 2021 as production cutbacks continue during the COVID-19 situation.

Winter Challenges

The back-to-back winters of 2013-14 and 2014-15 set new records for both
pipeline and gas utility sendout. The consistent cold weather tested regional energy delivery systems and resulted in significant energy price volatility. FERC’s 2013-14 winter assessment noted that “during each of these cold events, customers who had firm transportation capacity on natural gas pipelines generally managed to secure natural gas deliveries.”

After two mild winters, an historic cold snap tested the system once again, in late 2017/early 2018. From December 26, 2017 to January 7, 2018 the region experienced an extended and intense cold period (Boston had 15 consecutive days with minimum temperatures below normal.) The natural gas system performed extremely well throughout. The New England gas utilities set three new collective peak records in the first week of January 2018, with an all-time peak at close to 4.4 Bcf on January 6. In New Jersey and New York, most gas utilities hit new record sendouts. The growth in new customers and the extreme cold weather contributed to the high demand. LNG inputs into the system from both the Everett and Canaport terminals were critically important. Interstate pipeline operators performed reliably. System restrictions, such as operational flow orders, were in place to keep the system in balance throughout the period.

The high demand, record cold and system constraints did result in considerable short-term price volatility: spot prices hit extremely high levels, including a record on the Transco system in New York. While the Midwest price rose as high as $6.50/MMBtu on January 5, 2018, the spot price was $83 in Boston and $140 in the New York City area.

Natural gas utility customers in the region are largely shielded from spot market price volatility thanks to gas utilities’ firm contract arrangements for pipeline capacity and storage arrangements. Market participants such as some power generators which rely on non-firm capacity are, however, subject to spot market prices and interruptions in capacity delivery according to their contract terms.

In March 2017, the EIA noted that “both the Boston and New York natural gas markets have experienced winter price spikes because of pipeline constraints during periods of peak demand. Natural gas pipeline expansion projects that were completed in recent years may have reduced, but did not eliminate, sharp price increases with anticipated cold weather.”

Air emissions from power generation in the region have declined substantially in the past decades thanks in great part to the use of cleaner-burning fuels such as natural gas.

Photo: Joseph Murphy
The two most recent winters—of 2018/19 and 2019/20 - were marked by generally moderate weather and less severe volatility. Again, points of constraint in the Northeast leave the region subject to higher-than-average volatility during periods of cold weather and high demand.

The situation in the summer months is less challenging, although pipeline maintenance work can affect the regional market.

**Gas and Electric Power Generation**

The regional power generation fleet, already highly reliant on natural gas, is positioned to remain so for many years. Combined-cycle technology (CCT) has made the natural gas power plant the energy system of choice for the last two decades. CCT’s advantages over other conventional fuel types include higher efficiency, lower heat rates, shorter construction lead times, and reduced air emissions.

The Northeast states’ commitments to increased procurements of clean energy, notably offshore wind, is anticipated to change this profile over the next decade. Nevertheless, there is continued interest in natural gas even as renewables ramp up. In a May 2019 update on Pennsylvania, the EIA reported that natural gas is replacing nuclear and coal unit retirements: “From 2019-22, in Pennsylvania, 17 new natural gas-fired plants will be in various stages of development, bringing 8,460 MW of nameplate capacity online by 2022.”

In March 2017, PJM’s study of system reliability concluded that even with the addition of more natural gas and renewables, its system would remain reliable. The analysis identified “no limit to the amount of natural gas-fired generation that could be added to the system before it affected reliability.”

PJM’s “2019 Regional Transmission Expansion Plan,” released in February 2020, noted that “Both natural gas and solar fuels comprise 43 percent of the generation in PJM's interconnection queue...favorable fuel economics have emerged with the development of the Marcellus and Utica shale formations natural gas reserves, located in the middle of PJM's footprint.”

Meanwhile, regional retirements of non-gas units continue. In New Jersey in 2016 PSEG announced the retirement of its last two coal units, citing the competitive market pressure presented by low natural gas prices. In Vermont in 2014, En-
tergy closed Vermont Yankee, in Massachusetts in 2019, it closed its Pilgrim nuclear facility, and in New York State in 2020/2021, it will retire its Indian Point nuclear facility units. In Massachusetts in 2017, Dynegy closed the Brayton Point coal plant.

The New York Independent System Operator (NYISO) noted in its May 2019 report “Power Trends 2019” that “the portion of New York’s generating capability from natural gas and dual-fuel facilities grew from 47% in 2000 to 59% in 2019….Reflecting economic and public policy investment signals, recent generation additions have primarily been natural gas-fueled in downstate New York and wind-powered in upstate.”

In 2018, new gas combined-cycle plants opened in Connecticut (805 MW, CPV Towantic plant), Massachusetts (674 MW, Salem Harbor unit), and New York (680 MW, CPV Valley Energy Center). In 2019, a combined cycle plant opened in Bridgeport, CT (485 MW), and two gas peakers totaling just over 500 MW opened in MA. In April 2020 a major gas unit (1,100 MW) in New York State became operational.

Public policy and legislative initiatives in the region are prioritizing non-fossil fuel units for new generation and encouraging electric utilities to contract for substantial amounts of offshore wind and imports of Canadian hydro. Solar also continues to make inroads behind-the-meter as its technology costs decline.

Nevertheless natural gas will continue to serve as the backbone of the power system even as the Northeast region moves toward a system more reliant on clean energy. The importance of natural gas to the region is underscored in the biennial “Regional System Plan” from ISO-NE, released in October 2019: “Natural-gas-fired generation's proportion of the system capacity mix is expected to grow from 49.5% in 2019 to approximately 54.4% by 2023 but decrease to 48.6% by 2028. Further retirements of coal and oil generators are expected over the next 10 years due to generally low natural gas prices, renewable energy additions, and pending environmental regulations. The Pilgrim nuclear plant in Massachusetts retired in 2019. Although renewable resources are anticipated to grow over the long term,
the ISO expects natural gas resources to continue to set the marginal price for wholesale electricity in most hours over the planning horizon.”

Fuel choices and power system reliability remain highly topical at national and regional/state energy forums. Fuel security and grid resilience are under review by FERC and the RTOs. The future of coal and nuclear, the adequacy of pipeline infrastructure in areas like the Northeast, the balancing of intermittent renewable resources on the system, the valuing of capacity in power markets, and the role of carbon emissions and carbon pricing, onshore connectivity, and solar acreage are complex issues. Debate will continue into 2021 and beyond as the Northeast region’s power markets evolve to reflect the changing policy and regulatory environment.

Utility System Expansions - and Limitations

Since 2012, the number of homes heating with natural gas in the Northeast region has increased by over one million (to over twelve million heating customers). U.S. Census data for 2019 indicated that the natural gas furnace remains the predominant heating choice for new home construction in the Northeast.

Gas demand has been rising due to its advantageous price, reliability, and efficiency. In New York City, a “Clean Heat” initiative led to the conversion of significant building load from oil to gas as city regulations sought to eliminate the use of #6 oil by 2020 and #4 oil by 2025. Con Edison reported the conversion of 6,500 large buildings from oil to natural gas in New York City between 2011 and 2016.

As noted earlier, rising demand and new customer additions are running up against system delivery constraints. Five utilities in Massachusetts have declared moratoria on new customer connections because of supply and delivery con-
In 2019, Con Edison and National Grid announced moratoria on new customer connections in the New York City area because of system constraints. Con Edison subsequently announced plans to secure additional pipeline capacity with both Iroquois and Tennessee Gas Pipelines, to be available, if permitted, in 2023, to address the moratorium in parts of Westchester County. Con Edison is also implementing a range of options to manage growth, from greater efficiency, to incorporating CNG, LNG and renewable natural gas, to incentives for customers who upgrade their heating equipment or install heat pumps to reduce natural gas usage. In November 2019, the State of New York and National Grid announced that the utility would lift a moratorium on new customer connections in Brooklyn, Queens, and Long Island. National Grid cited “significantly enhanced demand response; energy efficiency programs to reduce the demand for natural gas at peak times; and increasing reliance on portable compressed natural gas” as its next steps. It also agreed to spend $8 million for new energy efficiency and gas conservation measures “designed to relieve stress on the system and reduce peak-day gas usage during this two-year period.”

The actions underscore the tight supply/demand balance that exists in major parts of the region, from downstate New York to New England.

In 2019 a few communities in California and Massachusetts proposed local building ordinances to prohibit gas (and other fossil fuel) connections for new customers, citing environmental concerns and the desire for an all-electric system. In comments provided to the Cambridge, MA City Council public hearing in December 2019 as it discussed a proposed restriction on natural gas in new buildings, NGA noted that such an action would directly impact consumer choice and energy affordability for city residents and businesses. “The industry shares the City’s goal of reducing carbon emissions,” said NGA, but the pathway needs to be carefully considered for its impacts, feasibility and timing.

The utilities in the region continue to strive to meet customer demand and support reliability, affordability, and a sustainable environment and economy.

Assessing the Future Role of Natural Gas
As Interest in Decarbonization and Electrification Grows

The benefits of natural gas – lower price, lower emissions, domestic supply – contribute to continued levels of customer conversions and new customer development. The natural gas industry recognizes the interest of policymakers, regulators, customers, and the public in decarbonization.
izing the energy system as much and as swiftly as possible. Natural gas utilities have proposed various pathways to decarbonization, including greater efficiency, incorporation of renewable natural gas, and the accelerated replacement of older, more “leak-prone” system components.

Several utilities have proposed pathways that include a strategic role for natural gas. For example, Con Edison’s “Smart Solutions” proposes multiple options, including gas demand response, non-pipeline solutions, enhanced energy efficiency, gas innovation, and parallel planning for a pipeline. In April 2019 National Grid released “Delivering the Future of Heat,” which includes a program to facilitate RNG interconnections, an expanded geothermal pilot, a green gas tariff, a power-to-gas pilot project, and a hydrogen blending study. In June 2019 Central Hudson Gas & Electric issued “Powering the Path to a Cleaner Future.” The utility noted its “commitment to making investments in infrastructure and technology that cost effectively reduce carbon emissions, while continuing to provide reliable, resilient, and affordable power.” One of the central parts of its strategy is “integrating natural gas benefits.”

Concurrently, several national and regional advocacy groups and consultants are promoting “strategic electrification” or “beneficial electrification” as the new overarching energy system paradigm, under which all systems – heating, power generation, and transportation – would operate via electricity, and that fossil fuels would be substantially reduced and eventually eliminated.

The costs and practicality of electrification are a concern. In mid-2018, the American Gas Association (AGA) released “Implications of Policy-Driven Residential Electrification” prepared by a cross-discipline team of experts at ICF, who assisted in the evaluation of AGA’s residential electrification policy scenarios focused on space and water heating. The report found that policy-driven electrification could be “burdensome to consumers and to the economy”; “have profound impacts and costs on the electric sector”; and be “a very costly approach for a relatively small reduction in emissions.”

ACEEE has released several studies that see value in converting homes heated with heating oil and propane to electricity, but find less value in converting natural gas homes, especially in colder climates. In a September 2018 blog post, ACEEE observed: “For the residential sector, recent ACEEE research has found that some applications (oil- and propane-heated homes and homes in the South) can meet the criteria for beneficial electrification discussed above. For these applications it can make sense to electrify the next time a heating or cooling system or water heater needs to be

A natural gas combined cycle plant in MA that went online in 2018.
replaced. But for many homes, electrification may not currently make sense and as a result, natural gas use will likely continue for decades, particularly in the North.”

In January 2019, NYSERDA released “New Efficiency: New York - Analysis of Residential Heat Pump Potential and Economics,” assessing the potential of residential heat pumps. It noted on page 55 that “generally, installations replacing natural gas have negative IRRs.” In a June 2020 report on electrification efforts at the state level, ACEE made a similar point: “In areas with high use of delivered fuels (fuel oil and propane), many programs target customers using these fuels because the economics of electrification in these situations are often better than when displacing natural gas.”

The importance of natural gas as a reliable balancing fuel for offshore wind remains generally acknowledged. In its April 2018 “National Electrification Assessment,” the Electric Power Research Institute (EPRI) noted the central role for gas in power generation over the next several decades. “Natural gas use continues to grow in all four EPRI scenarios based on its operational flexibility and an assumed cost of around $4/MMBtu…Direct gas use in industry and gas-fired electric generation grows while gas use in building heat remains relatively flat over time.” (page 42)

The growing interest in electrification and a relative ambivalence about the future role of natural gas in some policy circles was addressed in a May 2017 paper from the Natural Regulatory Research Institute (NRRI), “Questioning the Future of Natural Gas”: “A reasonable argument is that U.S. and state energy policy should encourage the use of natural gas for different uses rather than its suppression. A proper balancing of economic and environmental considerations would likely reach that conclusion. Those who advocate less natural-gas usage generally skew their finding by giving little if any weight to the economic effects….Climate change concerns should certainly be a factor in developing energy policy, but not the sole or even overriding factor.”

**Infrastructure Siting Challenges and Regulatory Delays**

Energy infrastructure has always encountered siting issues. Examples include siting wind turbines on mountain ridges or offshore, nuclear power, and electric and gas transmission.

Siting challenges for fossil fuel projects appear to have reached a new level in the U.S. and Canada in a time of growing awareness of climate change. Today’s increasing “dependence” on natural gas is viewed as an obstacle to the deployment of “clean energy.” Fossil fuels should stay in the ground and new infrastructure should be stopped, some argue, lest, once built, it remains in service for decades and restrains the use of renewables.
In the U.S., delays at the state level, particularly regarding the issuance of state water quality certificates, are adding to project costs and prolonging uncertainty. To secure federal approval, natural gas pipeline projects must demonstrate market need and financial viability, and their routes must meet environmental requirements. Contract commitments by proposed customers or shippers are essential to the process.

In 2020, several pipeline proposals were withdrawn after multiple years of navigating the permitting process, including the Constitution Pipeline, the NESE Project, and the Atlantic Coast Pipeline. The developers noted the costs of delay and the uncertainty of the regulatory process. This is disappointing news, as demand continues to be strong regionally and nationally.

The Northeast region, as a highly congested area, poses challenges for any energy development. Public policy requires all sides to weigh the costs and benefits to seek balanced and reasonable solutions.

**Environmental Considerations and Accomplishments**

Environmental issues are central to debates about energy system usage and infrastructure expansion. The natural gas industry can contribute by noting past progress and offering future solutions.

*Reductions in air emissions from power generation*

Because natural gas compares favorably to other fossil fuels regarding air emissions, it remains a favored fuel for new power generation. MIT’s June 2011 study on gas concluded that using very efficient natural gas-powered plants to replace coal-fired plants was “the most cost-effective way of reducing CO₂ emissions in the power sector” over the next 25 to 30 years. Natural gas will also play “a central role in integrating more intermittent renewable sources – wind and solar – into the electricity system because they can easily be brought in and out of service as needed.”

In 2019, the EIA reported that while energy-related CO₂ emissions in the U.S. rose in 2018, they were 12% below the 2005 levels, mostly because of changes in the electric power sector: “In recent years, the U.S. electricity generation mix has shifted away from coal and toward natural gas and renewables. The shift from coal to natural gas lowers the CO₂ emissions’ intensity because natural gas produces lower emissions per unit of energy used than coal and because natu-
ral gas-fired generators typically use less energy than coal plants to generate each kilowatthour of electricity.”

At the regional level, air emission trends remain favorable. NY ISO reported in 2020 that emissions rates from its power sector dropped by 55% for CO₂, 92% for NOₓ, and 99% for SO₂ over the last two decades.

ISO-NE reported that from 2001 to 2018, total emissions from power plants in New England declined by 98% for SO₂, 74% for NOₓ, and 36% for CO₂. The ISO noted: “Several factors have played a role in the overall reduction of generator air emissions…The biggest contributor has been the region’s shift to lower-emitting, highly efficient natural-gas-fired generation. Natural gas-fired resources account for the vast majority of new generators built in New England since 1997, and they typically outcompete oil- and coal-fired generators in the marketplace to serve the region’s electricity needs.”

PJM reported substantial declines in NOₓ, SO₂, and CO₂ from 2005 to 2018 (see chart on previous page).

**Reductions of methane emissions in natural gas system operations**

The natural gas industry is cognizant of its responsibility to reduce emissions throughout its system operations. Many of NGA’s distribution and transmission company members participate in the EPA’s Natural Gas STAR Program and progress continues on this front. In 2018, Natural Gas STAR partners reported methane emissions reduction of 130.6 Bcf in the U.S., providing “cross-cutting benefits” according to EPA. Reducing pipeline leaks is of paramount interest (see section on infrastructure replacement below).

Natural gas systems in total account for about a quarter of all U.S. methane emissions, or nearly 3% of all U.S. greenhouse gas (GHG) emissions. Since 1990, methane emissions related to the U.S. natural gas system have declined by 23.7%, according to the EPA’s April 2020 national GHG inventory report. The report, reflecting 2018 data, noted: “The decrease in transmission and storage emissions is largely due to reduced compressor station emissions (including emissions from compressor and equipment leaks)....Distribution system emissions, which account for 8 percent of CH₄ emissions from natural gas systems and less than 1 percent of non-combustion CO₂ emissions, result [sic] mainly from leak emissions from pipelines and stations. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH₄ and CO₂ emissions from this stage, as have station upgrades at metering and regulating (M&R) stations. Distribution system CH₄ emissions in 2018 were 73 percent lower than 1990 levels.”
In the distribution sector, the main emphasis is to accelerate the replacement of older, potentially more “leak-prone” pipe. In 2015, a national study led by Washington State University reported that direct measurement analysis showed “decreasing methane emissions from natural gas local distribution systems in the United States.” Replacement of older pipe systems and improved leak surveys were among the reasons cited for the industry performance.

The latest GHG data from New York indicated that methane emissions related to “natural gas leakage” have declined by 20% in the last dozen years; in Massachusetts, methane emissions from natural gas systems declined by 67% since 1990.

**Shale gas development**

Development of shale gas in the U.S. continues to merit analysis and technological improvements. MIT’s June 2011 study on natural gas noted that “the environmental impacts of shale development are challenging but manageable.” An October 2011 paper by the National Regulatory Research Institute (NRRI) noted that “Based on more than one million wells drilled with fracking, however, there is little evidence that fracking directly causes groundwater contamination....[R]eports show that these incidents resulted from surface spills, poor cementing jobs in wellbores, and other operational failures.”

The Pennsylvania Governor’s Marcellus Shale Advisory Commission reported that “The primary concerns regarding hydraulic fracturing relate to surface spills of fluids, well control and lost containment of production and flowback water on the surface.” Proper procedures and oversight are necessary at all stages of the process.

The Pennsylvania DEP’s “2017 Oil and Gas Annual Report” released in August 2018 noted: “Although there is no evidence that hydraulic fracturing has resulted in a direct impact to a water supply in Pennsylvania, there are cases where related oil and gas activities have adversely affected private water supplies. DEP investigates all stray gas-related complaints and if it is determined that a water supply is adversely affected by oil and gas activities, DEP works with the responsible operator to ensure the water supply is restored or replaced.”

Other issues, such as reducing the use of diesel fuel in the production process, enhancing “green completion” in the entire production cycle to reduce emissions, and mitigating community impacts, continue to receive industry attention in Pennsylvania and elsewhere. The industry must be responsible for best practices at all times.
Related to safe operations and environmental performance is the accelerated replacement and repair of older pipeline system components (pipes constructed of bare steel or cast-iron) that are considered more “leak-prone.” The U.S. Department of Energy observed in January 2017: “Safety remains the primary policy driver for LDC pipeline and infrastructure repair programs. However, the significance of methane emissions is becoming more recognized and companies, regulators, and other stakeholders are seeking ways to incorporate emission reductions into utility programs while limiting the cost to consumers.”

PHMSA continues to urge action on repairing older, potentially more leak-prone systems. In general, due to its older systems, the Northeast states have higher levels of such distribution pipe components than the national average, but those percentages are declining as system replacement continues.

In February 2020, the National Association of Regulatory Utility Commissioners (NARUC) released an informational handbook summarizing natural gas distribution infrastructure replacement programs in 41 states and the District of Columbia. The handbook cites substantial progress in replacing aging bare steel and cast iron main miles and service counts across the U.S. in recent years, but notes as well: “However, bare steel and cast iron still account for 5.1 percent of main miles and 2.7 percent of service lines, demonstrating the need for continued action on infrastructure replacement.”

**Pipeline Safety Management and Public Awareness**

Pipeline safety is always a priority for the industry. Federal and state regulatory requirements are extensive, and recent regulations have been announced to enhance operations safety, from transmission and distribution integrity management to control room operations. While the rate of incidents is declining nationwide at gas transmission and distribution levels, “high profile, high consequence” incidents, as termed by PHMSA, have occurred in California, Pennsylvania, New York, and Massachusetts.

Both industry and government regulators continue to prioritize worker and contractor training, including addressing the prevalence of “third party damage” (the leading cause of incidents); the importance of “call before you dig” programs; increasing public awareness of natural gas; encouraging individuals to call utility or emergency personnel if they smell gas in the home or street; and maintaining and enhancing the physical components of the delivery system by using methods like “accelerated infrastructure replacement.”
NGA and its members continue to work on important initiatives in the areas of public awareness and new technologies. NGA introduced in recent years a “First Responder utility online safety training program” based on an award-winning program developed by National Grid.

Following the September 13, 2018 Merrimack Valley incident north of Boston which had widespread impact in three communities, Massachusetts Governor Charlie Baker led the state’s gas utilities to commit to implementing a pipeline safety management system (PSMS).

NGA is presently leading an initiative of Massachusetts and other utilities in the region to implement PSMS. The utilities and regulatory agencies are also incorporating analyses from the National Transportation Safety Board (NTSB) and PHMSA’s recommendations.

Renewable Natural Gas

Renewable Natural Gas (RNG), also known as bio-methane or biogas, is pipeline quality gas derived from biomass that is fully interchangeable with natural gas. The future natural gas network could include renewable gas from dairy farms, waste water treatment plants, landfills, and wood waste, and food waste plants.

In the Northeast there is growing interest in implementing RNG. Some examples include:
- Vermont Gas in 2018 became the first utility in the nation with a retail RNG offering.
- National Grid has been an active proponent for many years of incorporating biogas into the natural gas system.
- In fall 2018, Con Edison announced a plan to construct up to three renewable gas facilities that would convert food waste, sludge, yard, and other waste into natural gas. The projects would reduce the need for conventional natural gas by up to 7,100 dekatherms on a peak winter day.
- In fall 2018 Liberty Utilities in New Hampshire announced an RNG project to capture the gas currently being produced by decomposing organic matter at the Bethlehem, NH landfill and process it to match the chemical composition of conventional natural gas. The project is expected to provide approximately 475,000 dekatherms of RNG annually in the first 10 years of operation, all of which will be used to serve customers in New Hampshire. Liberty Utilities noted: “The supply of RNG from the Bethlehem landfill represents approximately 6% of Liberty Utilities’ total annual sales in New Hampshire. Capturing, cleaning and using this gas not only combats climate change, it also reduces emissions at the landfill.”
• In spring 2019, Summit Natural Gas of Maine announced that it will partner with the dairy industry to develop home-grown RNG by constructing an anaerobic digester in Clinton, the state’s dairy capital. Summit Natural Gas plans to match 5 percent of its Maine residential gas demand for the next year by purchasing renewable gas attributes (similar to carbon credits) at no cost to ratepayers.

In 2019, NGA and GTI released the “Interconnect Guide for Renewable Natural Gas in New York State.” The report was sponsored by and developed in coordination with several New York natural gas utilities. While developed for New York State, the report provides a guideline for RNG pipeline interconnections that will be applicable and of value throughout the U.S. and Canada. It provides a framework and technical guidance by which project developers and the local gas utility can use common core principles and a rigorous technical framework to facilitate maximizing the acceptance and introduction of RNG into the natural gas pipeline network.

Natural Gas Vehicles

Natural gas vehicles (NGVs) are a competitive alternative fuel option, especially for fleets, buses, and heavy-duty vehicles, including refuse trucks. On the environmental front, NGVs have other comparative advantages. The U.S. Department of Energy noted that “Commercially available medium- and heavy-duty natural gas engines have demonstrated over 90% reductions of carbon monoxide (CO) and particulate matter, and more than 50% reduction in nitrogen oxides (NOx) relative to commercial diesel engines.”

The market for heavy-duty vehicles remains strong especially for the bus and refuse truck sectors. Even though CNG fueling stations are being added, availability remains relatively limited in the region. UGI opened a new CNG station in 2019 in Pennsylvania, and the first CNG station in the Bronx began operations in July 2019 (incorporating RNG).

In New York, CNG “virtual pipeline” facilities have been proposed for several locations. In fall 2018, Con Edison announced plans for “the construction of two to five compressed natural gas (CNG) and liquefied natural gas (LNG) storage sites in Westchester County. The supply would reduce the need for conventional natural gas pipeline supplies by 40,000 dekatherms on peak winter days.”

Massachusetts and Pennsylvania have LNG fueling stations, and some initiatives are underway in the U.S. and Canada for “LNG highways” to establish fueling stations to facilitate truck travel. There is also some interest in using LNG as a fuel for heavy-duty trucks that travel defined routes and even for marine transportation such as ferries and cruise ships.
New Technology R&D

NGA has a significant R&D program operated by NYSEARCH. NYSEARCH has been involved with innovative projects such as pipeline sensing and guided wave technology, and continues to utilize its own testbed facility (Johnson City, NY) for advanced demonstrations. Recent success stories include the development, testing and commercialization of the Remote Methane Leak Detector (RMLD), the EXPLORER II robotics program, and tests of drones for gas company facility inspection flights. NYSEARCH is also conducting an evaluation and test program for methane emissions technology, and evaluating residential methane detector technology.

NGA has collaborated with the Gas Technology Institute (GTI) to help facilitate knowledge transfers regarding new technologies that can enhance operations, safety, efficiency, and analysis.

NGA and its members continue to support innovative advances in natural gas technology.

The Year Ahead

NGA will continue to post updates throughout the year at:

www.northeastgas.org

In conclusion, NGA wishes everyone good health and safety this year and beyond.