

Assessment of New York City Natural Gas Market Fundamentals and Life Cycle Fuel Emissions

Prepared for:

New York City Mayor's Office of Long-Term Planning and Sustainability

Submitted by:
ICF International
9300 Lee Highway
Fairfax, VA 22031

[This page is intentionally left blank.]

TABLE OF CONTENTS

TABLE OF EXHIBITS

[This page is intentionally left blank.]

Executive Summary

In April 2011, the City of New York passed regulations phasing out the use of highly polluting No. 6 and No. 4 fuel oil. The City simultaneously launched the NYC Clean Heat program[1], which strives to achieve a 50 percent reduction in fine particulate matter (PM 2.5) emissions from buildings burning these types of oil by the end of 2013 by transitioning buildings to the cleanest fuels (ultra-low sulfur No. 2 oil, biodiesel, steam, or natural gas) as quickly as possible.

This report addresses two topics of interest in the implementation of this program. The first part of this report (Sections 2 through 4) provides ICF's outlook for the natural gas market in the Northeast and New York City in order to put in context the impact of converting residential and commercial boilers that currently use heavy fuel oil (*i.e.*, No. 6 and No. 4 fuel oil) to natural gas. The analysis first examines the North American gas market, presenting ICF's view of future gas supply and demand and the pipeline infrastructure to support the future supply and demand growth. The report then conducts similar analyses of the gas markets in the Northeast and New York City. The analysis is based on ICF's modeling of the North American gas market with its Gas Market Model® and reflects ICF's April 2012 Base Case forecast.

The second part of the report (Section 5) analyzes the life-cycle greenhouse gas (GHG) emissions of fuel oil, natural gas and biofuels. In 2007, as part of the comprehensive agenda for sustainability and long-term growth, *PlaNYC,* New York City committed to reduce citywide GHG emissions by 30 percent by 2030, and municipal GHG emissions by 30 percent by 2017. Understanding the GHG emission impacts of fuel conversions from heavy oil to cleaner fuels is critical in this context.

Other potential environmental impacts associated with natural gas production--including possible groundwater pollution, waste disposal, and air emissions—are important considerations and areas of active research by industry participants, NGOs, state governments and federal agencies. Given the rapidly evolving science and regulatory environment, analyzing these potential upstream impacts was beyond of the scope of this study.

Natural Gas Market Assessment

The future environment for the U.S. and Canadian natural gas market is one where both natural gas demand and production grow robustly. As we exit the recession, total gas demand will be led by growth in gas demand in the power sector. With the recent development of new supplies of natural gas from shale formations, North American production will be able to keep pace with growth in demand at gas prices that are both moderate, compared to recent history, and at levels sufficient to support supply growth.

The major development in North American gas markets has been the growth of shale gas production. Today, over half of the known North American gas resources are made up of shale resources, with the largest source of shale gas in the Northeast being the Marcellus Shale and Utica Shale formations underlying the Appalachians. Growth in shale gas and other unconventional resources will drive North American gas supply over the forecast period. Because of the abundance of shale gas resources, gas prices will be moderate over the forecast period when compared to recent history.

[1] More information on this program can be found at: www.nyc.gov/cleanheat. The City of New York also issued new regulations to curb fine PM and NOx pollution in 2011. These new regulations are separate from the NYC Clean Heat Initiative and are found in Chapter 2 of Title 15 of the Rules Governing the Emissions from the Use of No. 4 and No. 6 Fuel Oil in Heat and Hot Water Boilers and Burners, see, http://www.edf.org/documents/11725_NYC-clean-heat-rule-F_DEP_04_21_11_A.pdf .

Marcellus Shale gas production will have a significant effect on pipeline flows across the United States and in the Northeast. With large resources so close to markets, shale gas development in the Northeast will displace supplies from the region's traditional sources of gas, the Gulf Coast and Canada. By the end of the forecast period, ICF believes that over 80 percent of the physical gas going to New York City will be shale gas from nearby areas.

Approximately 57 percent of New York City's energy use is fueled by natural gas, either directly through on-site combustion to heat and cool buildings, or indirectly through the use of gas at power plants to generate electricity.[2] Two large gas local distribution companies (LDCs) serve New York City, Consolidated Edison Company of New York, Inc. (ConEd) and National Grid USA (NGrid).[3] In 2009, they delivered about 462 billion cubic feet (Bcf) of gas or an average of 1.3 billion cubic feet per day (Bcfd) to their customers. Meeting peak day demand is the critical design challenge for LDCs, which they achieve through a combination of supply contracts on pipelines and short-term peak-shaving facilities that can store gas for use during peak periods. The New York LDCs have substantial capacity on long haul transmission pipelines into the region. By using the supply capacity on these transmission lines, supplemented by peak-shaving facilities on their systems, the LDCs are able to meet peak day sendout in the City of approximately 2.5 Bcfd.

Without taking into account the impact of gas conversions stemming from the City's heavy oil regulations, both LDCs expect growth in their peak-day sendout requirements of about 1.1 percent per year, as well as growth in total deliveries of less than one percent per year. Both LDCs will require pipeline capacity and distribution facility enhancements to meet growing winter peak day demand.

The City's phase-out of heavy oil is expected to increase these growth rates. ICF estimates that the conversion of all No. 4 and No. 6 oil boilers to natural gas would result in the incremental gas use shown in Exhibit ES-1.

Exhibit ES-1: Boiler Conversion Impact on Gas Use (000 Dth[4])

	Annual	Average per day	Peak Day
Conversion Total	77,776	213.0	746.0
ConEd	69,289	189.8	664.4
NGrid	8,487	23.2	81.6

Source: Conversion and fuel estimates provided by New York Department of Environmental Protection (NYDEP); gas use estimates by ICF.

The average per day impact of these potential conversions represents a 16 percent increase and the peak day impact represents a 30 percent increase, over the forecasts described above. The conversions would constitute a 58 percent increase in peak day load for ConEd and a six percent increase in peak day load for NGrid.[5] Lesser conversion levels would result in smaller, but still significant, increases in the LDCs' peak day requirements.

[2] New York City Mayor's Office of Long-Term Planning and Sustainability.
[3] National Grid also serves Long Island and upstate New York.
[4] One therm is the heat content of 100 cubic feet of gas or approximately 100,000 Btu. A dekatherm (Dth) is 10 therms or approximately 1 million Btu or 1 MMBtu.
[5] This is in the increase in non-power peak day load as gas-fired power generation is offline on peak winter day sendout conditions.

ICF's analysis indicates that the increases stemming from conversions from heavy oil to natural gas, when added to other growth forecast by the LDCs, will require additional upstream gas supply capacity, including new pipelines, as well as infrastructure improvements within the LDCs' service territories to meet peak day responsibilities. While we expect that conversions from heavy oil will take place over the next decade, which may moderate their short-term impact on gas supply system needs, locally and upstream, the length of the implementation term does not change the overall conclusion regarding the effects of conversions to natural gas and the associated system needs.

Analysis of Life Cycle Emissions for Oil and Natural Gas

While natural gas is generally acknowledged to have the lowest air emissions of any fossil fuel at the point of combustion, a more complete environmental assessment must evaluate the emissions created to produce and deliver each fuel in addition to the emissions at the point of use. This broader emissions assessment is known as a "life-cycle analysis" (LCA) and the total emissions throughout the production and delivery steps are known as the "life-cycle emissions". Life-cycle emissions of GHGs from fossil fuels are an important environmental consideration due to the global impacts of GHGs.

There has been a lot of interest in life-cycle emissions of natural gas since the first half of 2011 due to the increased production of shale gas and to changes in the U.S. Environmental Protection Agency's estimates of methane emissions from oil and gas production, especially shale gas. A study from Cornell University created concerns by estimating that the GHG emissions from shale gas production were significantly greater than those for coal. However several subsequent studies project that GHG emissions from shale gas are much lower than coal and on the order of 11 percent higher than for conventional gas. When compared to GHG emissions from coal in the production of electricity, both conventional and shale gas are estimated to produce significantly lower emissions – approximately 36 percent to 47 percent lower than from coal.

Using the information from these studies, and adjusting for the future gas supply mix for New York City and local emission and transportation factors, this study estimates lifecycle emissions of 71 kg CO_2e/MMBtu for natural gas delivered to New York City customers. It also estimates the GHG life-cycle emissions for No. 2 and No. 6 fuel oil delivered to New York City customers. Accounting for boiler efficiency, it estimates that natural gas has life-cycle GHG emissions 20 percent lower than fuel oil per unit of energy delivered to customers. It also finds that soy-based biofuel would be an environmentally beneficial addition to the heating fuel mix.

There is continuing work on the estimation of GHG emissions from shale gas production. The collection of better data on these emissions will allow for better characterization of the emissions. There are also federal and proposed state regulations that would require reductions of these emissions starting in 2012. Such regulations will result in life-cycle emissions for shale gas that are lower than those calculated in the second half of this report.

In sum, this study concludes that converting No. 6 fuel oil boilers in New York City to cleaner fuels, including natural gas, will create significant GHG reductions.

1. Introduction

1.1 Report Overview

This report provides ICF's outlook for the natural gas market in New York as well as providing a life-cycle analysis of GHG emissions from heating fuels in New York City. The purpose of the analysis in the first portion of this report (Sections 2 to 4) is to provide context for the potential effects of the City's regulations phasing out heavy oil on gas supply and demand, and on associated infrastructure needs. The analysis in the latter half of this report (Section 5) focuses on life-cycle emissions of various heating fuels.

Natural Gas Market Assessment

The analysis begins (Section 2) with the North American gas market, presenting ICF's view of future gas supply and demand and the pipeline infrastructure to support the future market. We describe how market developments will change the flows of gas around the country. We also provide a forecast of natural gas prices at Henry Hub.[6] Our forecast runs from 2010 to 2030.

The next section of the report (Section 3) parallels the first section, focusing on the Northeast. This section is more specific on the impacts of Marcellus Shale gas production on Northeast markets, in both the evolving sources of gas for the region and its effect on pipeline flow patterns. We provide a forecast of gas prices centered on downstate New York (Transco Zone 6 New York). We also present basis relationships to other hubs around the region.

The fourth section specifically addresses New York City. Approximately 57 percent of New York City's energy use is fueled by natural gas, either directly through on-site combustion to heat and cool buildings, or indirectly through the use of gas at power plants to generate electricity. We provide an overview of the market structure and then present ICF's forecast of demand, the sources of supply into the City and the impact on pipeline flows to and around the City. We also compare the estimate of the amount of gas needed to supply conversions from fuel oil and compare this to the infrastructure serving the City, but not the infrastructure within the City.

We also provide an appendix with more discussion of the Marcellus Shale development.

Analysis of Life Cycle GHG Emissions for Heating Fuels

This analysis begins with an overview of recent information on the life-cycle emissions of natural gas. Interest in the life-cycle emissions of natural gas increased during the early part of 2011 due to the increased production of shale gas and the release of new information by the U.S. Environmental Protection Agency (EPA) on the GHG emissions from the production, processing and delivery ("upstream emissions") of natural gas production generally, and shale gas in particular.[7] One study, by Howarth *et al.* from Cornell University,[8] was partially based on this new information and suggested that the life-cycle GHG emissions of natural gas are much higher than previously thought. That study created concerns over the potential benefits of gas conversions. In response to those concerns, this analysis reviews other recent analyses of the

---

[6] Henry Hub is located in southern Louisiana in the major gas production area and serves as a proxy for the national price of natural gas.

[7] EPA (2010). Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry. Background Technical Support Document.
http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf

[8] Howarth, Robert; Renee Santoro; and Anthony Ingraffea, "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations," Climatic Change Letters, DOI: 10.1007/s10584-011-0061-5.

issue and compares the life-cycle GHG emissions of natural gas, fuel oil and biofuel for residential and commercial applications.

The assessment of New York gas life-cycle emissions is linked to the projection of future sources of gas consumed in the City. The primary data source for the analysis is the detailed National Energy Technology Laboratory (NETL) study, which calculates the gas LCA for a variety of sources of natural gas production and delivery.[9] The NETL study assumes well completion emissions 20 percent higher than the EPA inventory estimate and assumes only 15 percent mitigation of emissions from well completion, which is much lower than the EPA estimates of current emissions. The NETL assumptions are also lower than the requirements under the regulations proposed by the New York State Department of Environmental Conservation (NYSDEC)[10] and proposed EPA New Source Performance Standard (NSPS)[11] regulations regarding reduced emission completions (REC) or flaring for most shale gas wells. Therefore, our LCA estimate is quite conservative. The NETL data were modified to reflect conditions specific to New York City (sources of gas, proximity to sources, etc).

The assessment of life-cycle emissions from oil was based on the results of the 2009 ICF report entitled “Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water”[12]. This 2009 report developed the petroleum LCA factors for a detailed life-cycle analysis of heating oil delivered to various U.S. regions, including New York/New Jersey. The 2009 ICF report results were combined with the CO_2 emissions from the combustion of oil itself to determine the total life-cycle GHG emissions for fuel oil in New York City.

Lastly, life-cycle emissions from biofuels were assessed since New York City has a requirement for two percent biofuel content in heating oil. The life-cycle analysis used in this case comes from the same ICF report used for the analysis of emissions from oil combustion, the 2009 ICF report, “Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water.” The primary biofuel reference in the 2009 ICF report is a report from the National Renewable Energy Laboratory[13] (NREL), which is a widely cited reference on life-cycle emissions for biofuel.

[9] Skone, T.J., “Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production”, National Energy Technology Laboratory, U.S. Department of Energy, DOE/NETL-2011/1522. October 2011.
[10] NYSDEC. "High Volume Hydraulic Fracturing Proposed Regulations" , 2012. http://www.dec.ny.gov/regulations/77353.html.
[11] U.S. EPA, “Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews”, 76 FR 52738.
[12] ICF International. “Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water”, 2009. Prepared for the Consortium of State Oil Heat Associations.
[13] John Sheehan, et al., “Life Cycle Inventory of Biodiesel and Petroleum Diesel for Use in an Urban Bus”, National Renewable Energy Laboratory, May 1998.

2. U.S. and Canadian Natural Gas Market Outlook

In this section, we first discuss the outlook for U.S. and Canadian gas demand by sector. Next, we present the forecast of U.S. and Canadian natural gas supply. The third part of the section discusses implications of the changes in gas supply for pipeline flows across North America and the Northeast. The final section discusses our projected gas prices.

The analysis is based largely on ICF's Gas Market Model (GMM®). The GMM is a large, sophisticated supply and demand equilibrium model of the North American gas market. The model has detailed representations of regional supply with data on production costs, ultimate recoverable reserves, decline rates by well, and total production capabilities. The demand module represents the gas consuming sectors, price elasticities, technology trends, and alternative fuel cost. The model equilibrates over a large pipeline network that connects supply regions with demand regions. Pipeline links reflect pipeline capacity and costs of moving gas, including fuel costs. GMM® forecasts gas prices at about 120 market locations, including Henry Hub, and major locations around New York. The model also forecasts gas flows, sources of supply, consumption by sector by node and region. A more lengthy description of GMM® is found in Appendix B.

ICF produces four quarterly GMM® Base Cases per year. These represent our collective and official outlook for the North American gas market. These Quarterly updates address national trends but do not include local programs. Therefore, potential impacts and effects of New York City's heavy oil phase-out are not reflected in the following discussion of the GMM baseline analysis, but they are addressed separately in this report. This study is based on ICF's April 2012 Base Case.

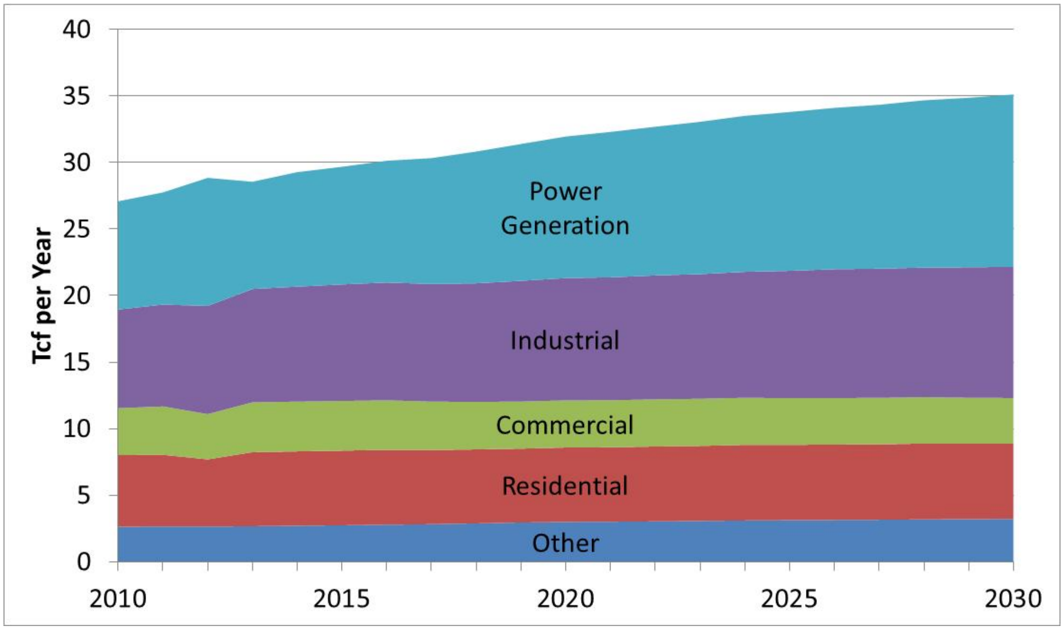
ICF forecasts that U.S. and Canadian demand for natural gas will grow robustly. As we exit the recession, total gas demand will be led by growth in the power sector. Due primarily to new shale gas supplies, North American production will be able to keep pace with growth in demand at gas prices that are both moderate, compared to recent history, and at levels sufficient to support supply growth.

2.1 Demand Outlook

The ICF Base Case projects substantial growth in gas use over time. U.S. and Canadian natural gas use are anticipated to grow from 27 trillion cubic feet (Tcf) in 2010 to 35 Tcf in 2030, an average growth rate of about 1.3 percent per year (Exhibit 2-1). About 60 percent of the total growth in gas use, or 4.8 Tcf, is projected to occur in the power generation sector, where gas-fired generation increases significantly over time.

Growth in gas demand for power generation is driven by a number of factors. In the past fifteen years, there have been 280 GW of new gas-fired generating capacity built in the U.S. and Canada, and much of that capacity is underutilized and readily available to satisfy incremental electric load growth. Historically, electricity demand has been positively related to Gross Domestic Product (GDP), although the relationship changes over time due to generally increasing energy efficiency across the economy and the effect of targeted energy efficiency programs. Prior to the recession, demand for electricity in the U.S. and Canada was growing at about 2 percent per year. Over the next twenty years, although GDP is forecast to grow at 2.6 percent annually, electricity demand growth is expected to average only about 1.3 percent per year. This assumed growth rate is approximately 25 percent lower than the pre-recession historical growth rate, mainly due to widespread implementation of energy efficiency measures. The assumed growth rate for the New York area is even lower than the national value at 0.6 percent per year, as a result of its more mature market and the effectiveness of its energy efficiency policies. Even at a lower growth rate, annual electricity sales in the U.S. are expected to increase to approximately 4,800 terawatt-hours (TWh) per year by 2030. This is about a 30 percent increase over the 2010 level of about 3,700 TWh per year.

Exhibit 2-1: U.S. and Canadian Gas Consumption by Sector



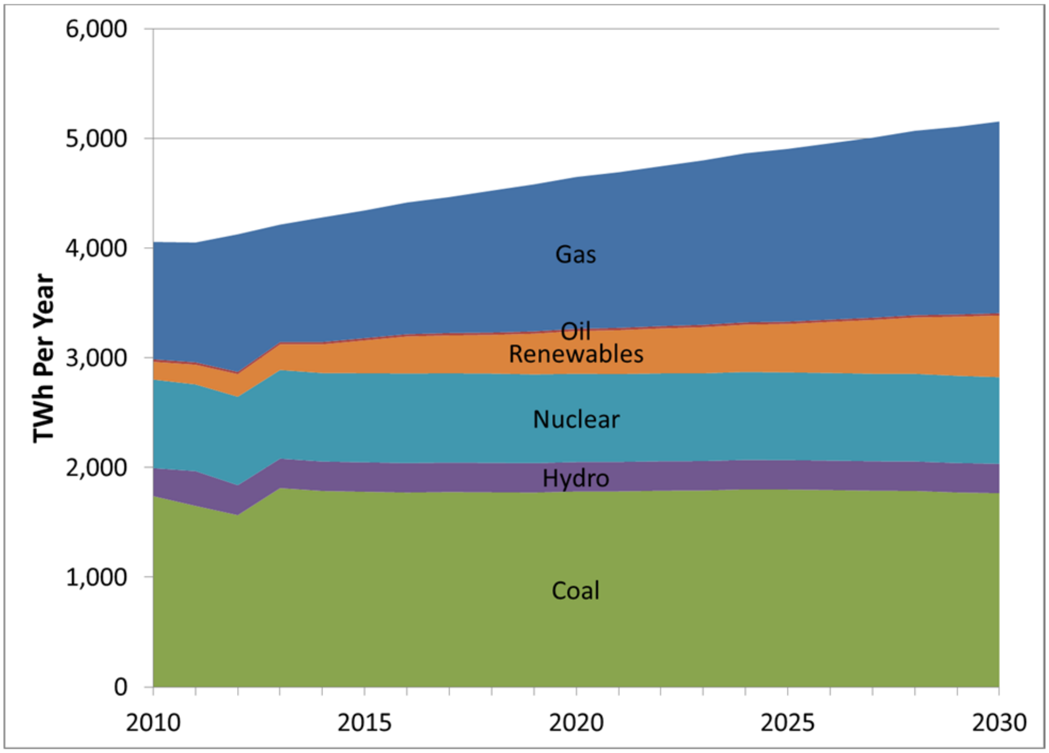
Source: ICF GMM® April 2012.

The expanding use of natural gas in the power sector is driven in part by environmental regulations such as the Cross State Air Pollution Rule. The ICF Base Case assumes that all current air quality regulations and rules continue to apply. Because ICF assumes that all current state renewable portfolio standards are met, renewable generation grows at a rapid pace, but it remains a relatively small portion of total generation. The ICF Base Case also assumes that new EPA regulation of hazardous air pollutants lead to the retirement of about 50 GW of coal capacity by 2020. In addition to these regulations, ICF's Base Case also assumes that a Federal cap-and-trade system to control CO_2 emissions is implemented towards the end of this decade, although the anticipated CO_2 allowance prices are not so high as to have a major impact on power markets. We also assume existing nuclear units have a maximum lifespan of 60 years, which results in a few nuclear retirements by 2030, but has a more significant impact thereafter.

The ICF Base Case forecasts U.S. gas use for power generation to increase from about 23 percent of total generation in 2010 to 32 percent of total generation by 2030 (Exhibit 2-2). This growth in gas generation and the accompanying growth in gas consumption are the primary drivers of gas demand growth throughout the forecast period.

Growth of gas demand in other sectors will be much slower than in the power sector. Residential and commercial gas use is affected by both population growth and efficiency improvements, which lead to lower per-customer gas consumption. For these sectors, ICF forecasts an overall growth rate of only about 0.1 percent per year on average. Gas use by natural gas vehicles (NGVs) is included in the commercial sector. The ICF Base Case assumes that the growth of NGVs is primarily in fleet vehicles (*e.g.*, urban buses), so vehicular gas consumption is not a major contributor to total demand growth.

Exhibit 2-2: Projected U.S. Electricity Generation by Type



Source: ICF GMM® April 2012.

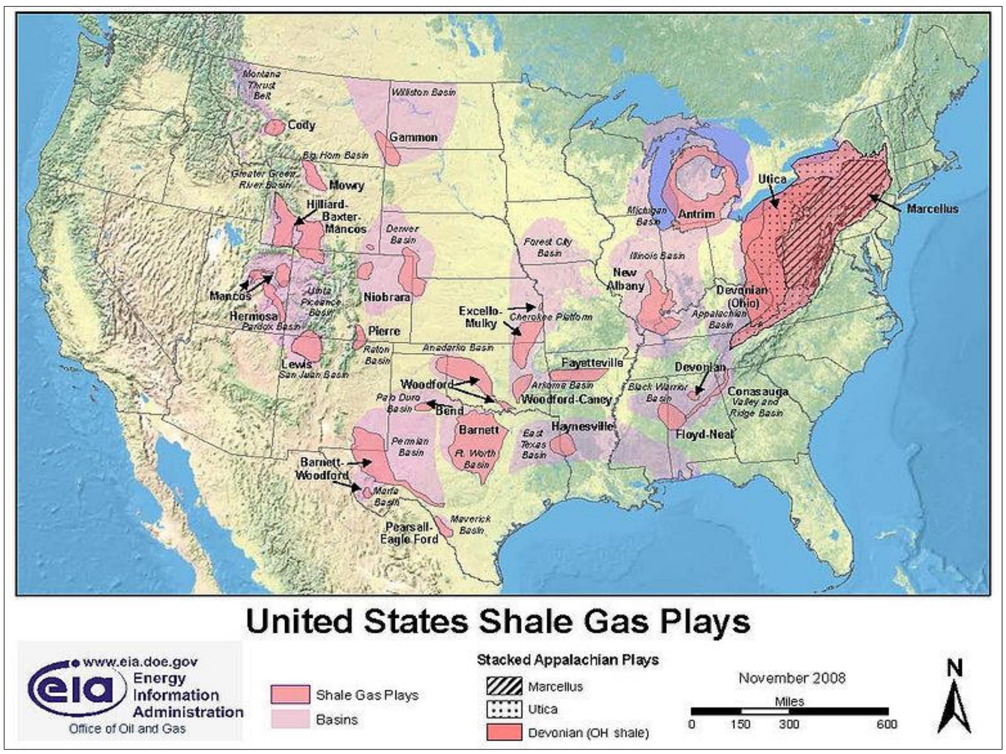
While gas consumption in the industrial sector is projected to increase, much of the increase in the next two years is a post-recession recovery in demand. Longer term, a large share of the industrial gas demand increase is from the development of the Western Canadian oil sands. Overall, the growth in industrial sector gas demand in the ICF Base Case is small, as reducing energy intensity (*i.e.*, energy input per unit of industrial output) remains a top priority for manufacturers.

2.2 Supply Outlook

The key trend in the natural gas industry in recent years has been the growth of North American resources and gas supply due to the technological advances in the recovery of gas from shale formations. Producers have understood for a long time that shales contain significant amounts of gas. But it has only been in the last decade that technologies have advanced to be able to access this gas. These technologies are now widely applied and include horizontal drilling that allows wells to follow the shale bands and have greater contact with the shale rocks. Advanced techniques for hydraulic fracturing the shale create pathways for the gas to migrate to the well bore. Chemicals in the fracturing water help to facilitate the flow of gas into the well bore. Because of these stimulation techniques and the need to manage the environmental impacts of production, individual wells in the shales are rather expensive, often ranging between $3 million and $5 million per well. Nevertheless, the production rates from individual wells are also much greater than their conventional counterparts. The potential environmental effects of shale gas production on air and water have raised concerns and are prompting new regulatory actions at the state and federal level. While regulatory action may result in some limitations on drilling in some sensitive areas and some added costs of production, these effects are factored into the GMM® baseline.

Shale formations are widely distributed across North America (Exhibit 2-3). The earliest developments, where the advanced stimulation techniques were first employed, are in the Barnett Shales around Dallas and Fort Worth, Texas. Other prolific shale formations are in Louisiana (Haynesville), Arkansas (Fayetteville), Texas, Oklahoma, the Rocky Mountains, and Western Canadian Sedimentary Basin (WCSB – encompassing Alberta and parts of British Columbia). Among the largest formations, accounting for almost half of the total shale resource, is the Marcellus Shale, which underlies large parts of Pennsylvania, West Virginia, and New York, and the Utica Shale which underlies the Marcellus Shale and extends farther west into Ohio, north into New York, and south to Tennessee.

Exhibit 2-3: Shale Gas Resources in the United States



Source: EIA. Office of Oil and Gas. November 2008.

North America has abundant remaining resources for natural gas, with over 300 Tcf of proven gas reserves and a total of nearly 4,000 Tcf of gas resources remaining to be developed with current exploration and production technologies (Exhibit 2-4). Over half of the resources come from shale gas formations. The Eastern Interior region shown in Exhibit 2-4 includes 986 Tcf of shale. Of this amount, about 728 Tcf is in the Marcellus Shale formation and an estimated 207 Tcf is in the Utica Shale formation.

ICF's resource estimate is based on a "bottom-up" assessment of detailed geological data, development feasibility factors, and well recovery and production profiles. ICF has extensively evaluated North American shale gas production and has concluded that some published estimates of the resources, including the latest USGS estimate adopted by the U.S. Energy Information Administration, are on the low side of the potential resource range. The USGS estimate, which is based on a probabilistic assessment of gas resources, incorporates production assumptions that are conservative when compared to actual well data obtained by the State of Pennsylvania and other sources. Nonetheless, although the latest USGS estimate is lower than ICF's estimate, it is 40 times higher than the previous USGS estimate, indicating significant growth in the resource assessment. Several other independent resource estimates are similar to ICF's estimate.[14]

Exhibit 2-4: U.S. and Canadian Natural Gas Resource Base

U.S. and Canada Natural Gas Resource Base[1]

(Tcf of Economically Recoverable Resource, Assuming Current E&P Technologies)

	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resource	Shale Resource[2]
Alaska	7.7	153.6	161.3	0.0
West Coast Onshore	2.3	24.6	27.0	0.3
Rockies & Great Basin	66.7	388.3	454.9	37.9
West Texas	27.6	47.7	75.3	17.5
Gulf Coast Onshore	70.1	684.7	754.8	476.9
Mid-continent	37.0	205.0	241.9	133.9
Eastern Interior [3,4]	18.6	1053.7	1072.3	986.1
Gulf of Mexico	14.0	238.6	252.5	0.0
U.S. Atlantic Offshore	0.0	32.8	32.8	0.0
U.S. Pacific Offshore	0.8	31.7	32.5	0.0
WCSB	60.4	664.0	724.4	508.8
Arctic Canada	0.4	45.0	45.4	0.0
Eastern Canada Onshore	0.4	15.9	16.3	10.3
Eastern Canada Offshore	0.5	71.8	72.3	0.0
Western British Columbia	0.0	10.9	10.9	0.0
US Total	**244.7**	**2,860.6**	**3,105.3**	**1,652.5**
Canada Total	**61.3**	**807.6**	**868.8**	**519.1**
US and Canada Total	**306.0**	**3,668.1**	**3,974.1**	**2,171.6**

1. ICF updated its gas resource assessment in December 2011; while these regional totals may not fully reflect the current assessment, the U.S./Canada economically recoverable resource is similar.
2. Shale Resource is a subset of Total Remaining Resource
3. Eastern Interior includes Marcellus, Huron, Utica, and Antrim shale.
4. Reference case assumes drilling levels are constant at today's level over time, reflecting restricted access to the full resource development.

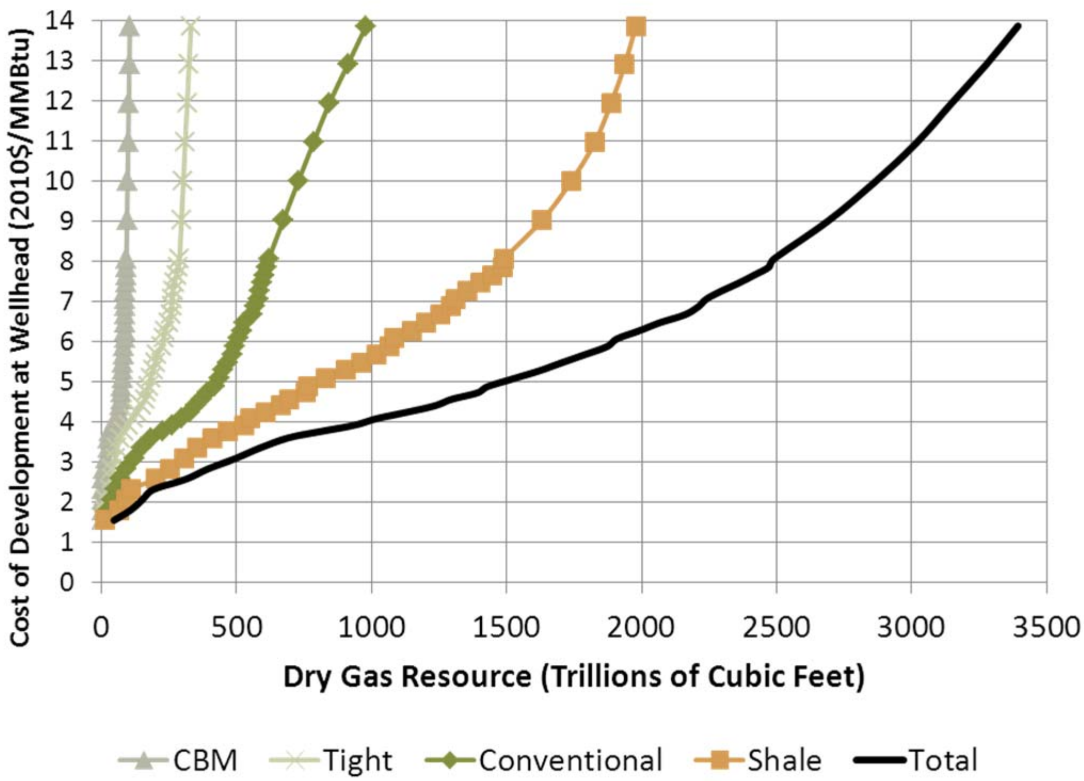
Source: ICF Estimates.

Exhibit 2-5 presents the gas supply curves for the ICF Base Case. The gas supply curves show the incremental cost of developing different types of gas resource, as well as for the resource base in total. Shale gas, tight gas, and coal bed methane are collectively referred to as

[14] Puko, Timothy. "New figures on shale gas optimistic", Pittsburgh Tribune-Review, March 20, 2012.

"unconventional" gas resources.[15] Based on our analysis of the resource base and drilling costs, ICF has estimated that there is 1,500 Tcf of gas in the U.S. and Canada that can be developed at a wellhead cost of $5 per million British thermal units (MMBtu) or less. Of that 1,500 Tcf that can be developed at $5/MMBtu or less, about 800 Tcf is shale gas.

Exhibit 2-5: U.S. and Canadian Natural Gas Supply Curves



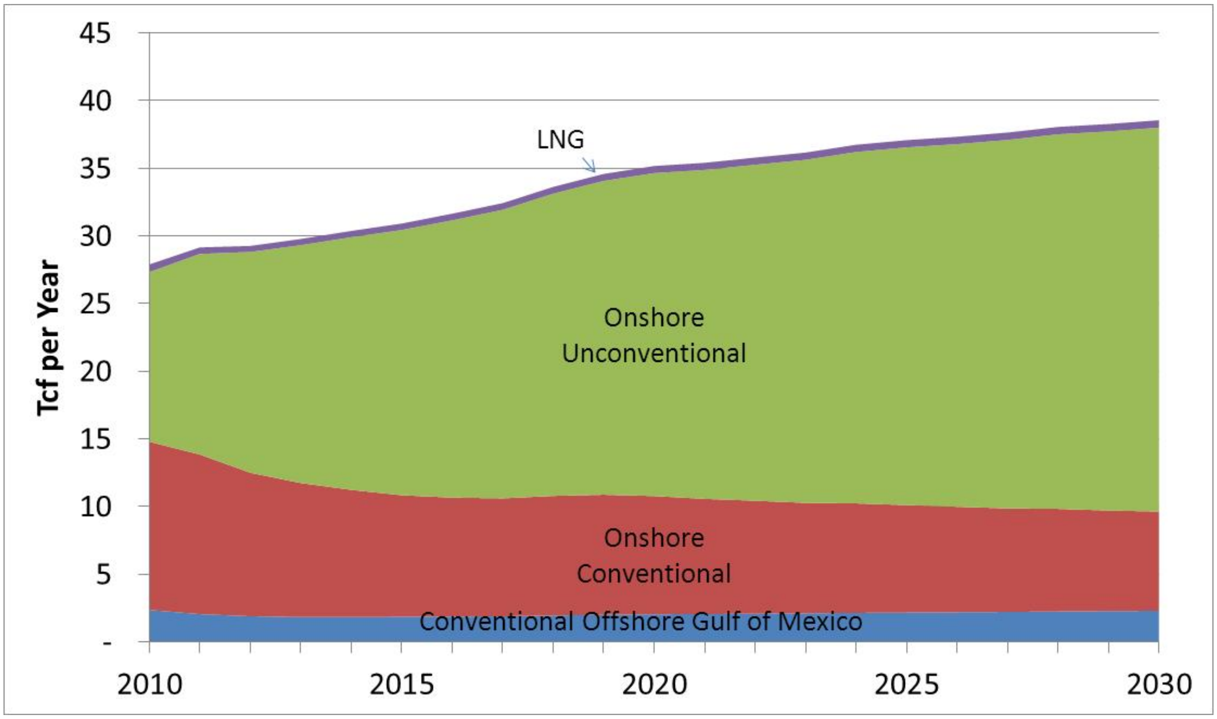
Source: ICF Estimates.

The market growth that we project places upward pressure on gas prices. However, since there is so much resource available at relatively low prices, gas prices are only expected to grow modestly. ICF projects U.S. and Canada gas production to grow from about 27 Tcf in 2010 to over 38 Tcf by 2030, an average annual growth rate of 1.7 percent per year (Exhibit 2-6). All of this growth is anticipated to come from unconventional production while conventional onshore production is expected to decline by about two Tcf, and offshore production in the Gulf of Mexico is expected to remain at current levels. Liquefied natural gas (LNG) imports are expected to comprise less than two percent of total North American supplies, although LNG remains important for the New England market, particularly in peak winter months when pipeline capacity into New England can become constrained. The April ICF Base Case assumes three LNG export terminals will export LNG from North America: the Kitimat terminal in British Columbia, and two facilities located on the U.S. Gulf Coast. Overall, unconventional gas production, dominated by shale, will become the base source of natural gas for the United

[15] Unconventional refers to production that requires some form of stimulation within the well to produce gas. Conventional wells do not require stimulation.

States. Many of the conventional supplies will become the marginal sources of gas supply in the future.

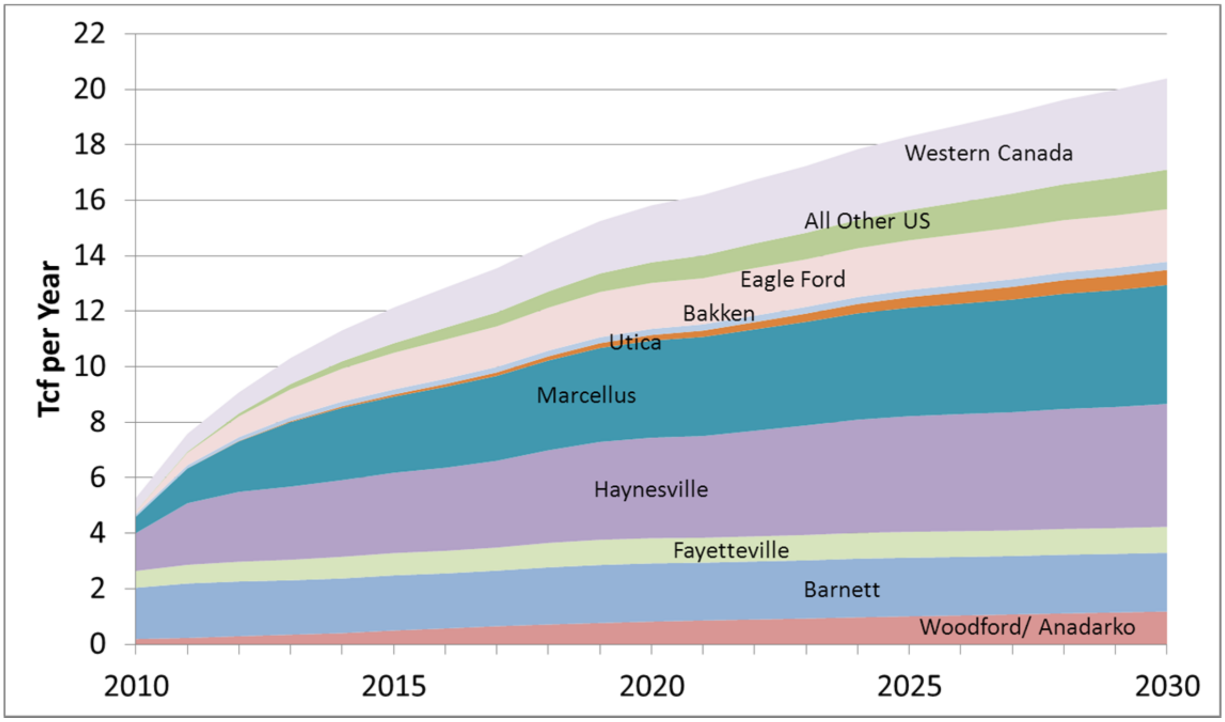
Exhibit 2-6: Projected U.S. and Canadian Gas Supplies



Source: ICF GMM® April 2012.

Production from the U.S. shale formations will grow from about 5 Tcf in 2010 to about 20 Tcf by 2030 (Exhibit 2-7). As noted above, the major shale formations in North America are located in the Northeast U.S. (Marcellus and Utica), the Mid-continent (Barnett, Woodford, Fayetteville, and Haynesville), south Texas (Eagle Ford), and western Canada (Montney and Horn River). The Bakkan Shale, which spans parts of North Dakota and Montana, is primarily an oil formation but also has significant amounts of natural gas. There are other shale formations in the U.S. that have not yet been evaluated or developed for gas production.

Exhibit 2-7: Projected U.S. and Canadian Shale Gas Production



Note: Haynesville production includes production from other shales in the vicinity, *e.g.*, the Bossier Shale.
Source: ICF GMM® April 2012.

2.3 Pipeline Flows

As regional gas supplies and demand continue to evolve and shift over time, there are likely to be significant changes in interregional pipeline flows. Exhibit 2-8 shows the projected changes in inter-regional pipeline flows from 2010 to 2030 in the ICF Base Case. The map shows the United States divided into Census Regions, with New York City in the Middle Atlantic Census Region. The Middle Atlantic Census Region also is where the Marcellus Shale gas production is located. The arrows show the changes in gas flows over the pipeline corridors between the Census Regions between the years 2010 and 2020, where the gray arrows indicate increases in flows and red arrows indicate decreases (blue arrows show LNG import and export locations and volumes if listed).[16]

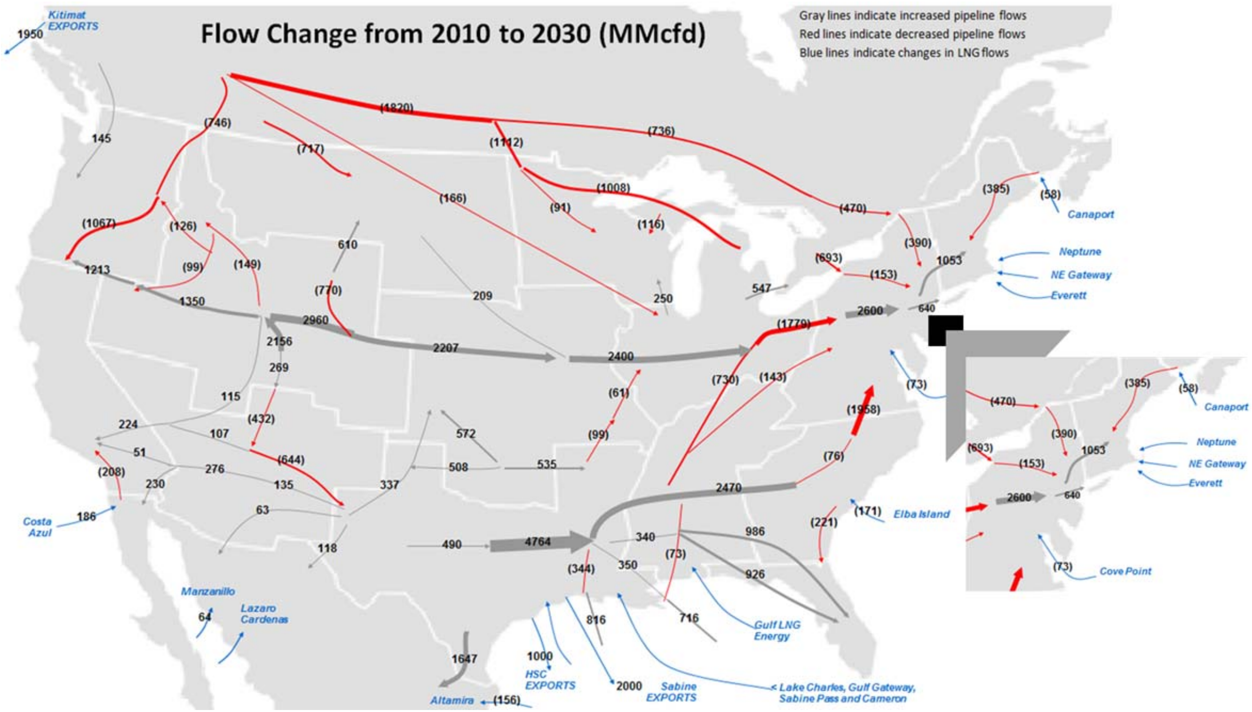
This map illustrates how four gas supply developments will drive major changes in North American gas flows.

- First, the growth in Marcellus Shale gas production in the Middle Atlantic Census Region will displace gas that once was imported into that region from other regions, hence the red arrows entering the Middle Atlantic Census Region from points north (Canada), west (Ohio), and South (West Virginia and North Carolina). In effect, the Middle Atlantic Census Region becomes a major producer of gas and consumers there, including New York City, will use more gas from within the region and less from outside the region. The latter is an important point: gas will continue to flow into the Middle Atlantic Census Region from other regions, just at lower levels. Gas will continue to flow through the

[16] This section focuses on high-level trends for North American pipeline flows; changes in pipeline flows for the Northeast and New York City are explored in more detail in the sections that follow.

Middle Atlantic Census Region into New England (the gray arrow), some of which will be Marcellus production, but also gas from the other sources (Canada, the south and southwest).

Exhibit 2-8: Projected Change in Inter-regional Pipeline Flows from 2010 to 2030



Source: ICF GMM® April 2012.

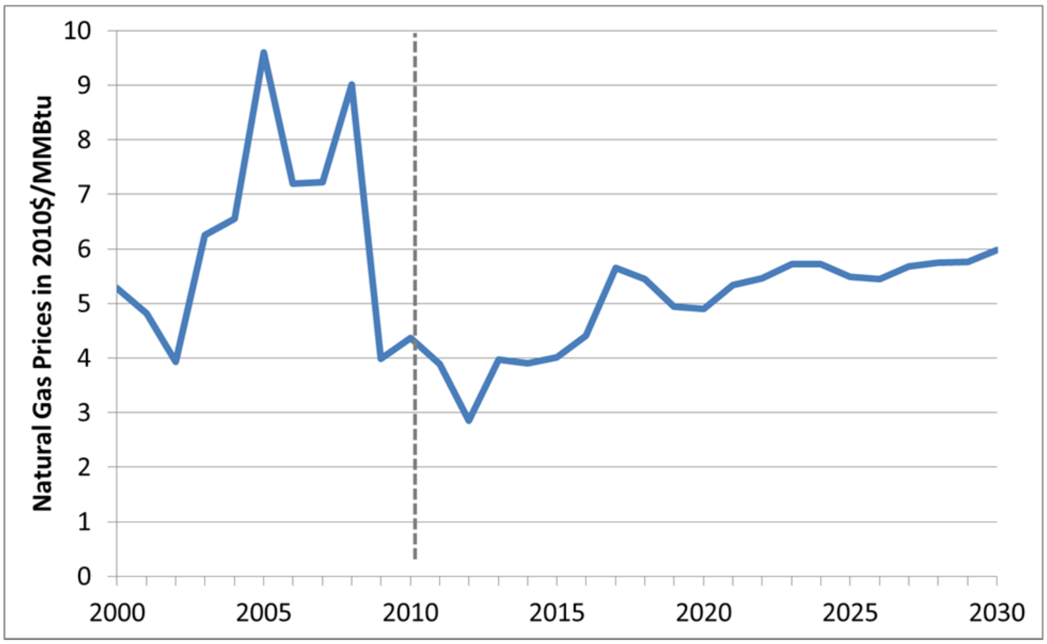
- Second, the large increases in flows eastward from the West South Central Census Region (Texas, Louisiana, and Arkansas) are due to growing shale gas production in this region. However, most of this gas is consumed in the East South Central Census Region (Mississippi, Alabama, Tennessee, and Kentucky) and South Atlantic Census Region (Florida to North Carolina) where demand is strong. The Marcellus gas production in Middle Atlantic Region means that less of the gas from the West South Central Census Region is needed in New York and the other Middle Atlantic states.
- Third, gas flows out of western Canada are projected to decrease because conventional gas production in Alberta will decline and gas demand growth in western Canada will keep more gas in the Western provinces. The planned Kitimat LNG export terminal in British Columbia also will draw off gas supply once it begins to export LNG.
- Fourth, pipeline flows both east and west will increase out of the Rocky Mountains with the growth in production there and the expansion of pipelines out of the Rockies.

The ICF Base Case assumes some level of LNG imports will continue in the Gulf Coast, as well as through Cove Point, Maryland, and into New England. However, ICF also assumes North American LNG exports will total 5 bcfd by 2020. ICF assumes three terminals will export LNG from North America: Kitimat (starting in 2016) at 2 bcfd, and Sabine Pass (starting in 2015) at 2 bcfd, and a Houston Ship Channel facility (starting in 2016) at 1 bcfd. Therefore, by 2016, LNG exports are greater than LNG imports, and North America becomes a net exporter of LNG.

2.4 Gas Price Forecast

With growing gas demand and increased reliance on new sources of supply, the ICF Base Case forecasts higher gas prices from current levels. Nevertheless, as Exhibit 2-5 showed, the cost of producing shale gas moderates the price increase. We do not expect gas prices to return to pre-recession levels. In the ICF Base Case, gas prices are expected to increase gradually, climbing from less than $3/MMBtu in late 2011 to about $6/MMBtu by 2030 (in 2010 dollars, Exhibit 2-9). This gradual increase in gas prices supports development of new sources of supply, but prices are not so high as to discourage demand growth. Gas prices throughout North America are expected to remain moderate, similar to the forecast shown in Exhibit 2-9 for Henry Hub. However, in some regions other market dynamics will influence regional prices. Implications for the Northeast are presented in the next section.

Exhibit 2-9: Annual Average Natural Gas Price at Henry Hub in 2010$/MMBtu



Source: ICF GMM® April 2012.

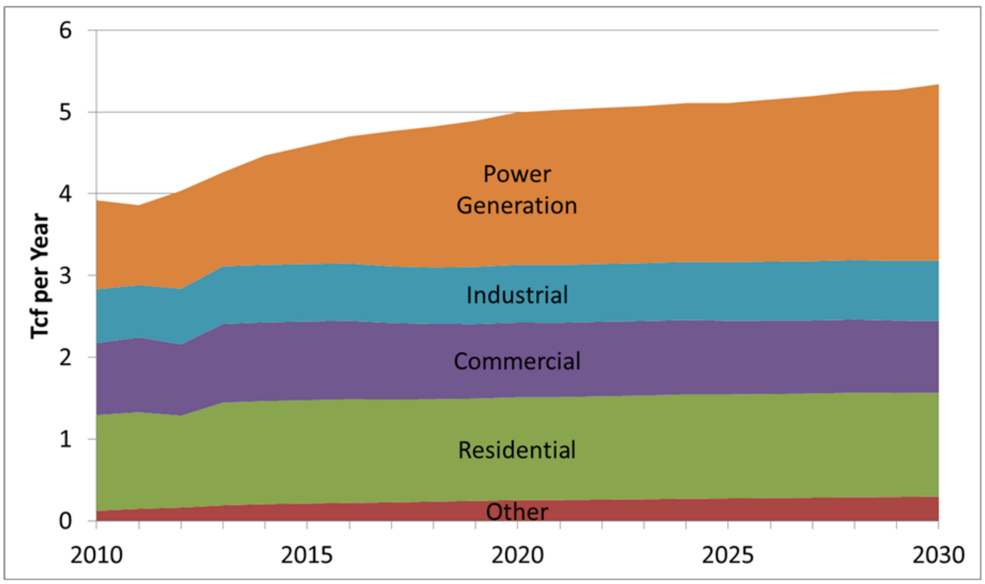
3. Northeast Gas Market Outlook

In the ICF Base Case, the future environment for the Northeast[17] natural gas market is one where both supply and demand are growing. Gas demand growth in the region is anticipated to be strong, mostly led by growth in power generation use. Gas production in the region is expected to grow at a rapid pace, as both the Marcellus and Utica Shale continue to be developed. This will have a major effect on pipeline utilization and flows as some traditional pipeline supply from the Gulf Coast and Canada are displaced. Gas prices in the Northeast will trend moderately upward, following the general trend in North American prices. In this section, we discuss the growth in demand by sector for the Northeast. Then, we discuss the supply outlook and gas transportation trends that will be affected. We also provide our projections for Northeast gas prices.

3.1 Demand Outlook

In the ICF Base Case, total gas consumption within the Northeast is projected to grow from about 3.9 Tcf in 2010 to 5.3 Tcf in 2030 (Exhibit 3-1). This is a growth rate of about 1.6 percent per year, which is similar to the growth rate for the entire U.S. and Canadian gas market. Of this total growth, almost 75 percent is attributable to the power sector from the expanded use of natural gas-fired generating facilities.

Exhibit 3-1: Northeast Gas Consumption by Sector

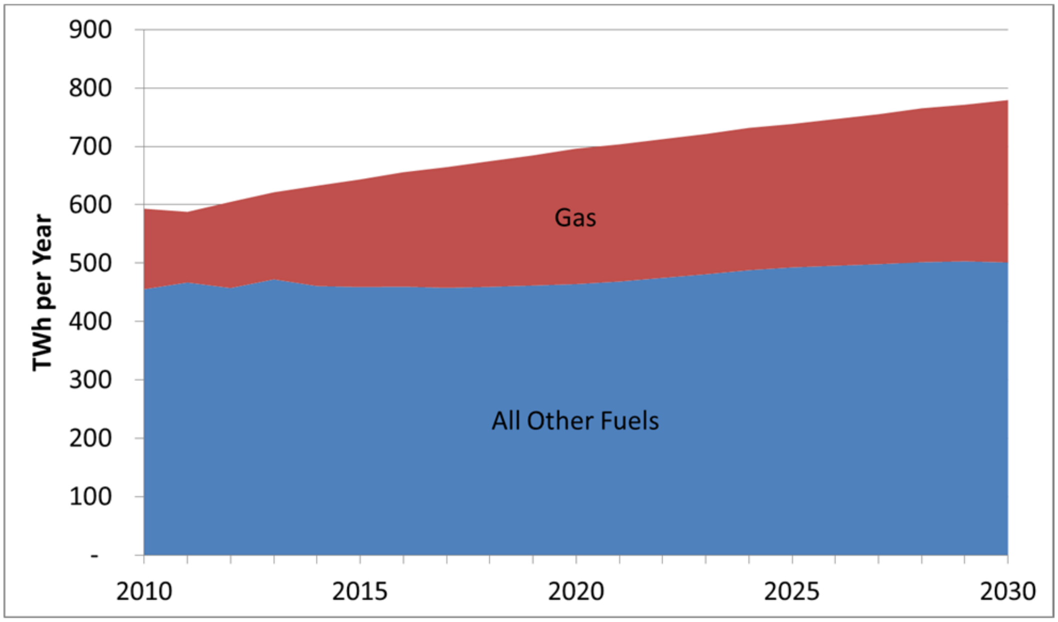


Source: ICF GMM® April 2012.

This increased consumption is caused by increasing electricity demand, environmental regulations, and public policies that disfavor other fuel sources (*i.e.,* coal and nuclear). Total electricity generation in the area is projected to grow from 600 TWh per year in 2010 to 780 TWh per year by 2030 (Exhibit 3-2), a 30 percent increase. At the same time, coal-fired generation is expected to decline, with the result that ICF forecasts gas-fired generation to increase from 140 TWh per year in 2010 to 290 TWh per year by 2030.

[17] In the context of this section, "Northeast" refers collectively to New York, New England, New Jersey, and Pennsylvania but we also include gas supply from West Virginia and eastern Ohio to capture the full extent of the Marcellus and Utica Shale formations.

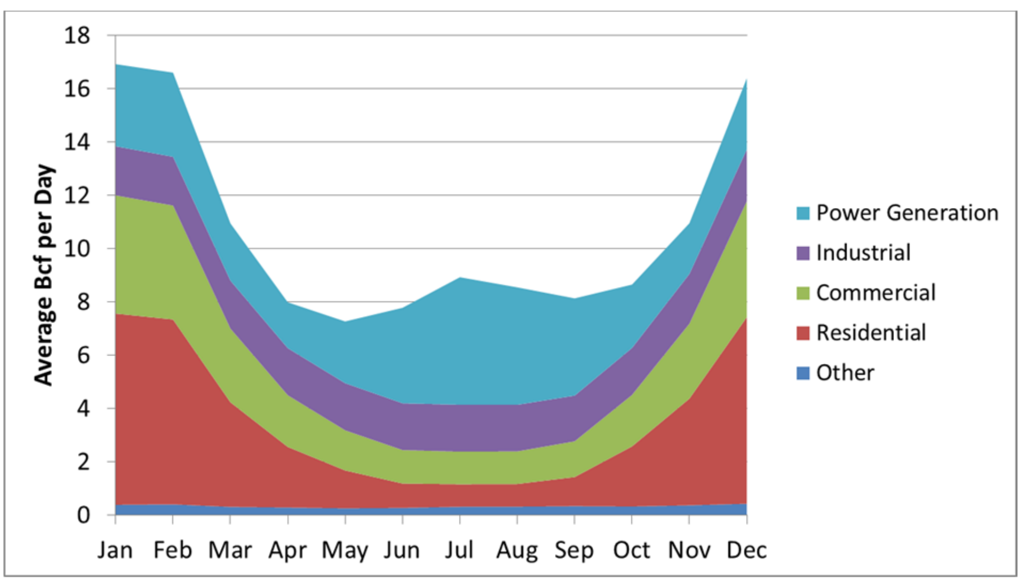
Exhibit 3-2: Northeast Generation by Type, TWh per Year



Source: ICF GMM® April 2012.

Gas demand in the Northeast has a significant seasonal swing, with an average winter load that is about 10 Bcfd above an average spring or fall load (Exhibit 3-3). Variations in residential and commercial gas use account for the vast majority of the seasonal swing, as winter space heating needs comprise most of the demand in these sectors. Winter weather has dramatic impacts on heating load, and can create significant demand spikes in the wintertime, leading to pipeline capacity limitations, reliability concerns, and increased price volatility. Unlike residential and commercial gas use, industrial gas demand is fairly constant, with little seasonal variation. However, industrial gas use is also the smallest sectoral component of Northeast gas demand.

Exhibit 3-3: Northeast Monthly Gas Demand by Sector, 2010



Source: Energy Information Administration (EIA): Form EIA-857, and Form EIA-923,"Power Plant Operations Report."

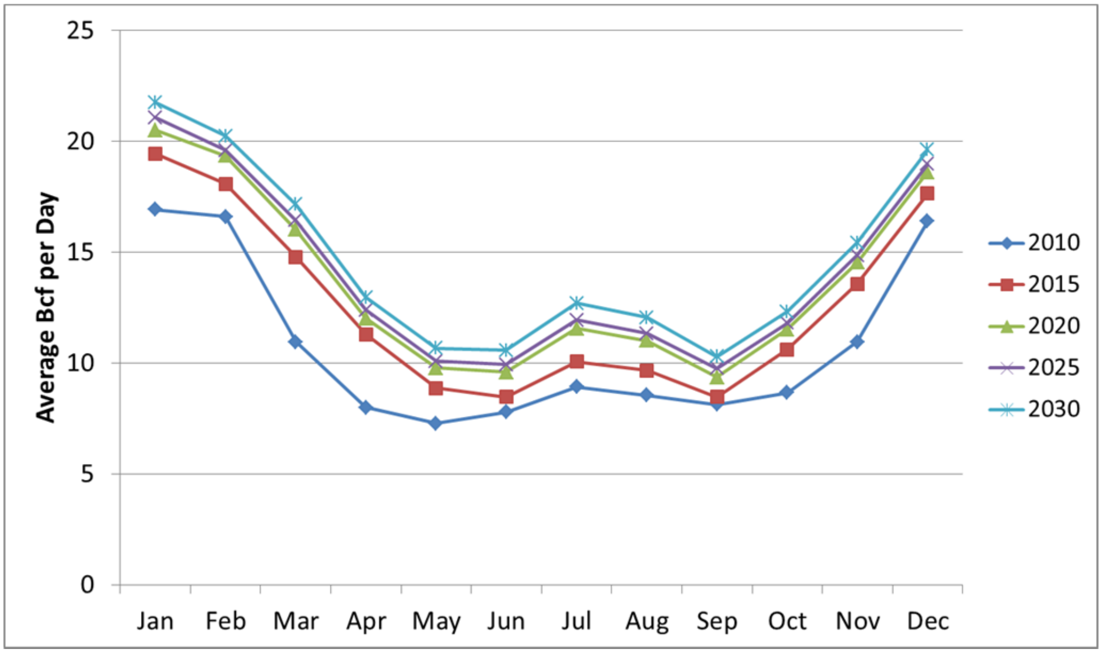
In contrast to the residential and commercial sectors, power generation gas use has peak periods in both the winter and summer, with a somewhat greater peak in the summer when electricity load is at its peak due to air conditioning requirements. While average summer gas loads are well below the winter averages, the impact of extremely hot weather on electricity demand or outages at a large coal or nuclear power plant can cause a significant spike in summertime gas use. Such demand spikes can lead to increased pipeline capacity limitations, reliability concerns, and increased price volatility in the Northeast generally, including New York City specifically.

The seasonal gas demand pattern for the Northeast shifts over the forecast period (Exhibit 3-4). Due to increases in gas-fired generation, gas demand in the summer months is expected to increase more quickly than in the winter; however, the peak gas demand period remains in the winter months. As peak seasonal demand grows over time, pipeline capacity serving the Northeast will become increasingly constrained. Growth in seasonal gas demand will be driven demographics, economic growth and by conversions from fuel oil to natural gas. The ICF Base Case assumes about half of the buildings in the Northeast currently using No. 2 fuel oil as their primary fuel will convert to natural gas by 2030. This forecast does not capture conversions to natural gas stemming from New York City's phase-out of heavy oil.[18]

Residential and commercial gas consumption in the Northeast will grow comparatively more than in the U.S. as a whole. The Northeast has a higher percentage of residential and commercial buildings using No. 2 fuel oil for heating, and conversions of these buildings are a significant component of demand growth in these sectors. Industrial gas use comprises a relatively small portion of Northeast gas consumption, and should remain flat through 2030.

[18] As noted above, the ICF Base Case does not include the effects of New York City's efforts to phase-out heavy oil due to its local impact and as yet uncertain outcome for gas consumption. The ICF Base Case forecast does include distillate fuel oil conversions, which are a significant trend affecting regional gas use.

Exhibit 3-4: Northeast Monthly Gas Demand, 2010 though 2030



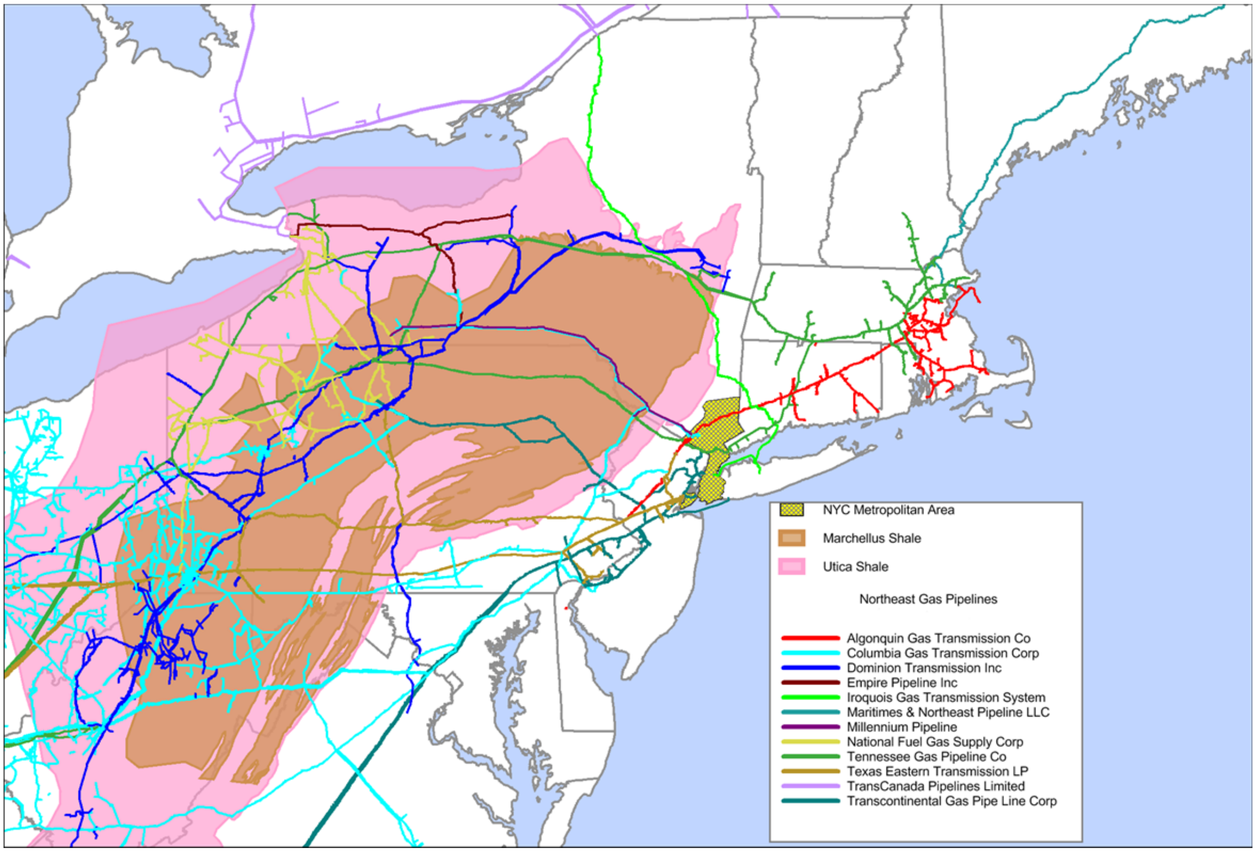
Source: ICF GMM® April 2012.

3.2 Supply Outlook

Historically, gas demand in the Northeast was satisfied mostly by gas supplies from the Gulf Coast (both onshore and offshore), the Mid-continent production areas (including from the shale formations in those areas), and Western Canada. The Northeast is subject to higher prices and volatility than other regions of the country due to pipeline capacity limitations, often caused by severe weather. Fuel costs for moving gas long distances on the interstate pipeline network also contribute to gas price increases.

The growth in Marcellus Shale gas production has major implications for the Northeast in general and New York City in particular. As shown in Exhibit 3-5, the Marcellus Shale gas resources lie under the major pipelines that supply natural gas to the Northeast from the south and west. The size of those resources, as shown in Exhibit 3-6, and their location are expected to result in a major shift in the composition of the sources of supply for the Northeast.

Exhibit 3-5: Northeast Area Pipelines and Shale Resources



Note: The pipelines listed above are of the major suppliers to New York City.
Source: ICF GMM® April 2012.

Exhibit 3-6 shows the changes in gas supply for the Northeast resulting from the development of the Marcellus Shale. In the ICF Base Case, the amount of gas coming from distant supply sources over long-haul pipelines declines substantially because this gas is replaced by production from the Marcellus Shale. By 2030, 80 percent of the total Northeast gas demand of 5.4 Tcf is met from Marcellus Shale production. By contrast, Western Canadian supply drops from 20 percent of total Northeastern supply in 2005 to under 2 percent in 2030. Gulf Coast and Mid-continent conventional supplies decline in similar patterns. Nevertheless, these sources will continue to be a key part of Northeastern supply, albeit at the margin.

Exhibit 3-6: Supply Sources for the Northeast Gas Market (Bcf)

	2005	2010	2015	2020	2025	2030
Total Northeast Gas Demand	4,084	3,945	4,684	5,083	5,195	5,396
Amount sourced from:						
Northeast (Marcellus & Utica Shales)	511	1,026	2,833	3,515	3,938	4,325
Southeast	88	83	38	55	51	49
Midwest	40	32	5	5	4	4
Mid-Continent Conventional	252	198	89	86	62	53
Rockies	72	119	27	39	30	39
Gulf Onshore Conventional	446	169	89	54	38	28
Gulf/Mid-Continent Shale	779	1,404	1,196	998	787	642
Gulf Offshore	621	167	65	38	24	16
Western Canada	811	426	45	69	70	65
Eastern Canada	87	78	95	35	11	4
U.S. East Coast LNG	351	187	163	163	163	163
Canaport LNG	0	54	37	25	14	8
Gulf Coast LNG	27	5	2	2	1	1
	2005	**2010**	**2015**	**2020**	**2025**	**2030**
Supply sources as percent of total:						
Northeast (Marcellus & Utica Shales)	12.5%	26.0%	60.5%	69.2%	75.8%	80.1%
Southeast	2.2%	2.1%	0.8%	1.1%	1.0%	0.9%
Midwest	1.0%	0.8%	0.1%	0.1%	0.1%	0.1%
Mid-Continent Conventional	6.2%	5.0%	1.9%	1.7%	1.2%	1.0%
Rockies	1.8%	3.0%	0.6%	0.8%	0.6%	0.7%
Gulf Onshore Conventional	10.9%	4.3%	1.9%	1.1%	0.7%	0.5%
Gulf/Mid-Continent Shale	19.1%	35.6%	25.5%	19.6%	15.2%	11.9%
Gulf Offshore	15.2%	4.2%	1.4%	0.7%	0.5%	0.3%
Western Canada	19.9%	10.8%	1.0%	1.4%	1.4%	1.2%
Eastern Canada	2.1%	2.0%	2.0%	0.7%	0.2%	0.1%
U.S. East Coast LNG	8.6%	4.7%	3.5%	3.2%	3.1%	3.0%
Canaport LNG	0.0%	1.4%	0.8%	0.5%	0.3%	0.1%
Gulf Coast LNG	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%

Source: ICF GMM® April 2012.

3.3 Pipeline Flows

The changes in sources of gas lead to changes in pipeline flow patterns. To accommodate these changes, pipelines in the Northeast have been adding pipeline capacity and proposing expansions. Exhibit 3-7 lists the major expansions proposed and planned as announced by the pipeline companies. We have highlighted in bold the expansions that will directly serve the New York City market. Many of the other expansions are designed to expand regional access to Marcellus production without adding new capacity into New York City. Capacity expansion is expressed in millions of cubic feet per day (MMcfd), based on announced volumes. One expansion (Alqonquin AIM) is yet to be determined (TBD). Likewise, the dates for in service are based on pipeline statements.

Exhibit 3-7: Northeast Pipeline Expansions Through 2027

Rest of Northeast US Planned Expansions Pipeline - Expansion Name	Area	Capacity (MMcfd)	Planned In Service	Status
Algonquin - AIM Project	*Algonquin compression*	*TBD*	*Nov-14*	*E*
Tennessee Gas Pipeline - Northeast Supply Diversification	*Marcellus supply Z4 to Z5 and Z6*	*250*	*Nov-12*	*B*
Dominion Transmission - Appalachia Gateway	*West Virginia to Oakford PA*	*484*	*Sep-12*	*A*
Dominion Transmission - Northeast Expansion	*SW PA to Leidy*	*200*	*Sep-12*	*B*
Dominion Transmission - Marcellus 404 Project	*West Virginia*	*300*	*Nov-12*	*A*
Dominion Transmission (For Tenn NSD Project) - Ellisburg-to-Craigs	*Ellisburg PA to Craigs NY*	*150*	*Nov-12*	*B*
Dominion Transmission - Tioga Area Expansion	*Tioga, Potter, Clinton, and Greene Counties*	*270*	*Nov-13*	*D*
Texas Eastern - TEAM 2012	*Interconnects OH, WV, PA*	*200*	*Nov-12*	*A*
Texas Eastern - TEAM 2014	*OH, WV, PA Looping & Compression*	*1400*	*Nov-13*	*E*
Spectra -TETCO - Algonquin - NJ-NY Expansion	*Linden NJ to Staten Island NY and new connection to ConEd in Manhattan*	*800*	*Nov-13*	*C*
National Fuel - Northern Access	*Potter Co PA to Niagara*	*320*	*Nov-12*	*B*
National Fuel - Line N 2012 Expansion	*Along Western PA border*	*150*	*Nov-12*	*C*
National Fuel/Empire - Central Tioga County or (TCE2)	*Tioga PA Interconnect to TGP*	*260*	*Sep-13*	*E*
National Fuel - West to East Phase 1 & 2	*Overbeck PA to Leidy*	*425*	*Oct-13*	*E*
Tennessee Gas Pipeline - Northeast Supply Diversification	*Marcellus supply Z4 to Z5 and Z6*	*250*	*Nov-12*	*B*
Tennessee Gas Pipeline - MPP Project	*Z4 with backhaul to Z1-Z3*	*240*	*Nov-13*	*D*
Tennessee Gas Pipeline - Northeast Upgrade Project	*Line 300 to Interconnects with NJ Pipelines*	*636*	*Nov-13*	*C*
NiSource & UGI - PennStar Pipeline	*Leidy area to Corning NY*	*500*	*2013*	*E*
Millennium Pipeline - Minisink Compression	*Corning to Ramapo mainline*	*150*	*Nov-12*	*D*
Millennium Pipeline - Neversink Compression Replacement	*Corning to Ramapo mainline*	*525*	*2014*	*E*
Williams Transcontinental - Bayonne Lateral	*14" lateral and oil line conversion in NJ*	*250*	*Apr-12*	*F*
Williams Transcontinental - Northeast Connector	*St195 SE PA to Rockaway Deliv Lateral - National Grid NYC*	*100*	*2014*	*E*
Williams Transcontinental - Northeast Supply Link	*Northern NJ and Leidy Line looping and compression*	*250*	*Nov-13*	*D*
Williams/Dominion - Keystone Connector	*REX Clarington OH to Transco St195 SE PA*	*1000*	*2014*	*E*
Williams - Atlantic Access	*SW PA Marcellus to Transco St195*	*1800*	*Dec-15*	*E*
Iroquois Gas Transmission - NYMarc	*Sussex NJ to Pleasant Valley NY*	*500*	*Nov-14*	*E*
Central New York Oil & Gas - Marc I Hub Line	*Bradford PA (Tenn) to Lycoming Co PA (Transco)*	*550*	*Nov-12*	*A*
EQT Midstream - Sunrise Project	*WV and West PA*	*430*	*Jul-2012*	*A*
Dominion Transmission - Marcellus Gathering Enhancement	*West Virginia Gathering and Hasting Plant Exp.*	*50*	*Sep-2012*	*A*
DTE Energy - Bluestone Gathering	*Susquehanna PA to Broome NY (Millennium)*	*250*	*Jun-2012*	*A*
National Fuel Gas Supply - Trout Run Gathering	*Lycoming Co PA*	*466*	*Jun-2012*	*A*
Boardwalk/Southwestern Energy - Marcellus Gathering	*Susquehanna and Lackawanna PA to Tenn*	*275*	*Jul-2012*	*A*
Crestwood Midstream/ Mountaineer Keystone - Tygart Valley Pipeline	*NE WV Randolph Co to Columbia Gas Trans*	*200*	*Dec-2012*	*E*
NiSource - Big Pine Gathering	*SW PA, Butler, Indiana, Armstrong, and Westmoreland Counties*	*425*	*Dec-2012*	*E*

A FERC Approved and Under Construction
B FERC Approved
C Filed with FERC, Favorable Environmental Impact Statement but waiting on FERC Approval
D Filed with FERC
E Potential Expansion either announced or had open season but not yet filed with FERC
F Bayonne Lateral is authorized to start service as of April 5th, 2012.

Source: ICF, compiled from industry announcements.

A total of 7.3 Bcfd of new pipeline capacity is projected in or near the Marcellus Shale production areas through 2014. Of this, 2.3 Bcfd is directly connected to Marcellus Shale production and another 2.6 Bcfd moves gas further downstream to congested markets near the East Coast, including the New York City region. About 1 Bcfd would improve movement of gas to export points located near Niagara to carry gas into Canada. Another 2.9 Bcfd of generic expansions are assumed between 2018 and 2027 to support market growth, for a total of 10.2 Bcfd of added pipeline infrastructure. From this chart, about 1.15 Bcfd of new capacity would be built to delivery points that can serve New York City (consisting of the highlighted Spectra, Williams NE Supply Link, and Williams NE Supply Project in the table above).

Exhibit 3-8 illustrates the gas balance for the Northeast in the ICF Base Case for 2010, 2020 and 2030, exclusive of net storage injections. The exhibit also shows the rate of change in gas consumption and sources of supply. Overall growth in consumption in the Northeast averages 1.6 percent per year through 2030, with New York City consumption growing at a slightly lower rate. Increased production from the Marcellus Shale will result in a net reduction in flows into the region from other areas, as Marcellus gas displaces other supply sources.

Exhibit 3-8: Gas Balance for the Northeast[19]

	Flows in Bcfd			Compound Annual Growth Rate	
	2010	2020	2030	2010-2020	2010-2030
Total Northeast Consumption	***9.20***	***11.93***	***12.67***	2.6%	1.6%
NYC Consumption	1.85	2.06	2.14	1.1%	0.7%
Total Northeast Production	***1.95***	***8.32***	***10.13***	15.6%	8.6%
LNG Imports	***0.44***	***0.44***	***0.44***	-0.1%	-0.1%
Net Pipeline Imports	***6.90***	***3.34***	***2.23***	-7.0%	-5.5%
Midwest	3.15	2.04	1.24	-4.2%	-4.5%
Mid-Atlantic	1.87	1.14	1.01	-4.8%	-3.0%
Canada	1.89	0.17	-0.02	-21.6%	-

Source: ICF GMM® April 2012.

Currently, most of the capacity on the pipelines serving the New York City region is held by the LDCs. The remainder is held by gas marketers and power generators. As the LDCs' peak day requirements increase, they will need to seek expansion capacity on the pipelines and/or add additional peaking facilities to accommodate growth. Several of the pipelines have proposed expansions into the region – Transco and Texas Eastern (Spectra) have proposed large pipelines into northern New Jersey and New York. Liberty LNG is also proposing an offshore LNG terminal to feed into the region.

3.4 Gas Price Forecast

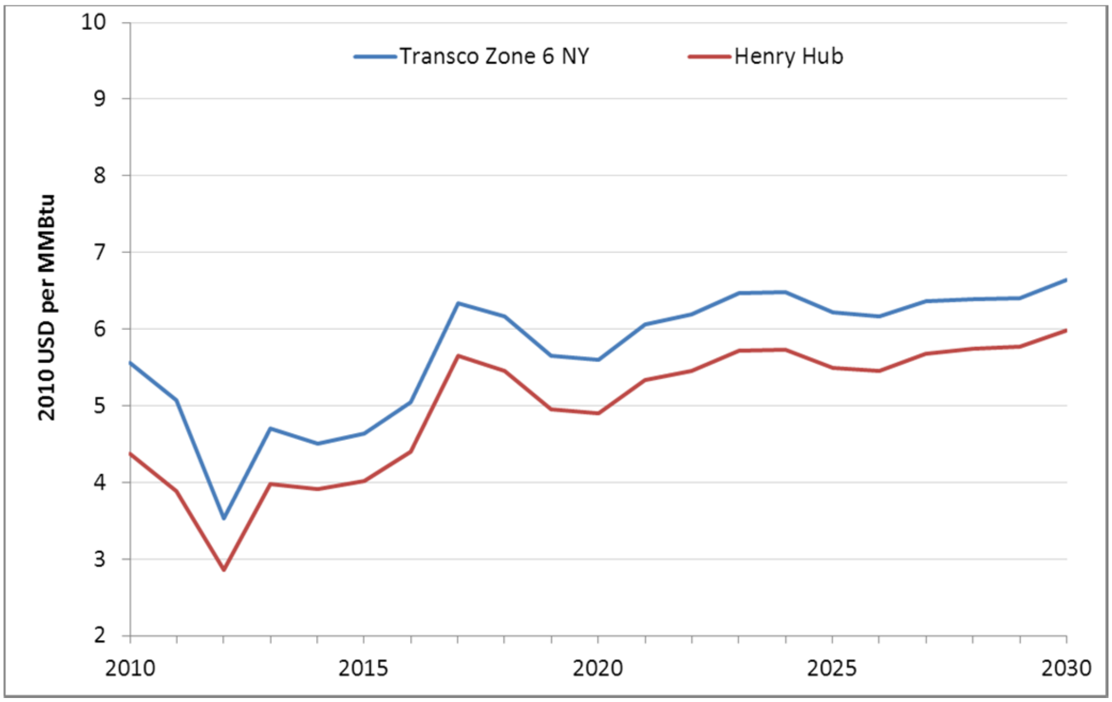
ICF's forecast of gas prices for Henry Hub is shown in Exhibit 2-9 and again below in Exhibit 3-10 in real 2010 dollars. For comparison purposes, Exhibit 3-9 includes Transco Zone 6 NY prices.[20] The forecast shows prices delivered to New York City rising from \$5.50/MMBtu in 2010 to about \$6.50/MMBtu by 2030. Through 2020, prices are expected to stay under

[19] This gas balance does not include the effect of conversions from the Clean Heat program.
[20] The Transco Zone 6 New York is a trading hub adjacent to Manhattan at the northern end of the Transco pipeline in Northern New Jersey. Therefore, the Transco Zone 6 pipeline price is a reasonable proxy for the NYC gas price. Prices at locations other than the Henry Hub are often quoted in terms of an increment or decrement to the Henry Hub price. (The difference in price from Henry Hub also is referred to as the "basis" from Henry Hub.) Because of the costs of transportation from Louisiana to New York, New York gas prices normally are higher than Henry Hub gas prices.

$7.00/MMBtu. Compared to recent history, this is a rather moderate price outlook. The relative price stability is attributable to the increase in shale production nationwide and in the Northeast.

As also shown in Exhibit 3-9 and in more detail in Exhibit 3-10, the price difference (or basis) between Henry Hub and Transco Zone 6-NY narrows in 2014-17 and through around 2020 as more gas is produced in the Northeast from shale resources. The basis indicates both the cost of transporting gas from one hub to another and the supply/demand balance at each hub. The basis between Henry Hub and Transco Zone 6-NY is an indication of the degree of capacity constraint on the pipelines between the two regions. An increase in the basis indicates increasingly constrained capacity on the pipelines, such as would occur when there is high demand in New York City.

Exhibit 3-9: Gas Price Forecast, 2010-2030 (2010$)



Source: ICF GMM® April 2012.

Exhibit 3-10 also shows ICF's forecast of the basis between Transco Zone 6-NY and various other hubs associated with Marcellus Shale production, another Northeast market hub, and Henry Hub. (Prices at these points are subtracted from Transco to show the cost of transporting gas to NYC.) The Marcellus Shale hubs (Dominion, Columbia, Lebanon, and Leidy) show a lower basis to Transco Zone 6-NY after 2015 when many of the pipeline expansions enter service.

Exhibit 3-10: Basis between Transco Zone 6 NY and Other Hubs (2010$/MMBtu)

	Average in 2010 USD/MMBtu				
	2006 to 2010	**2011 to 2015**	**2016 to 2020**	**2021 to 2025**	**2026 to 2030**
Transco Zone 6 NY	**7.53**	**4.49**	**5.76**	**6.28**	**6.40**
Basis from					
Dominion South Point	0.82	0.57	0.47	0.52	0.47
Lebanon	0.82	0.61	0.49	0.55	0.50
Henry Hub	1.17	0.76	0.69	0.74	0.67
Columbia Appalachia	0.93	0.65	0.54	0.59	0.54
Tennessee Z5	0.24	0.05	0.02	0.02	0.01
Texas Eastern M3	0.33	0.30	0.17	0.20	0.17
Leidy	0.82	0.56	0.48	0.53	0.48

Source: ICF GMM® April 2012.

The Spectra and Williams expansions into Transco Zone 6-NY, which also interconnect with New York City LDCs, will alleviate gas pipeline constraints and reduce gas prices in the region relative to Henry Hub. This is seen in the Henry Hub basis decline between 2011-2015 when the pipelines are presumed to go into service in 2014 and the period 2016-2020 when they are fully operational. Thereafter, as consumption in New York continues to grow, the Henry Hub basis starts to increase.

4. New York City Gas Market Outlook

4.1 Market Structure

ConEd supplies gas to Manhattan and the Bronx, and parts of Westchester and Queens. NGrid supplies gas to Brooklyn, Queens, and Staten Island as well as Long Island. In 2010, total gas consumption in New York City was approximately 472 Bcf. Of this amount, 287 Bcf was provided by ConEd and about 185 Bcf was provided by NGrid.

Exhibit 4-1 shows the number of customers in New York City served by each LDC. The number of residential customers in the City increased between 2005 and 2009 (latest year of data) by almost 30,000. Current peak day demand for ConEd is estimated to be approximately 1.15 Bcf.[21] For NGrid, peak day demand in New York City is estimated to be about 1.38 Bcf.[22] Combined, total peak day requirements for firm sales and transportation loads are about 2.9 Bcf. The conversion of heavy fuel oil users to natural gas users is not included in this estimate of peak day requirements and will thus increase the peak day requirements for the LDCs.

Exhibit 4-1: Utility Customers by Type - 2005 & 2010

	2005	2010
ConEd		
Residential	934,272	939,586
Commercial	120,593	122,432
Industrial	56	46
Total	1,054,921	1,062,064
NGrid		
Residential	1,120,046	1,158,412
Commercial	44,997	41,634
Industrial	827	3,622*
Total	1,165,870	1,203,668
Total (New York City)	2,220,791	2,265,732

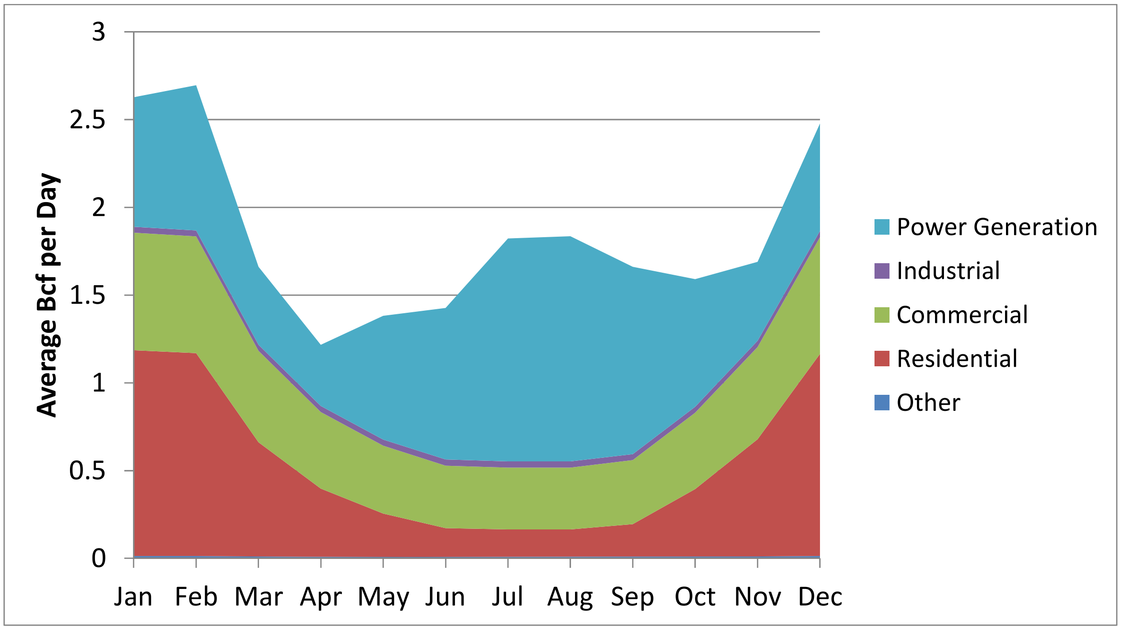
Note: Electric power generators not included. *NGrid reclassified some commercial loads as industrial. The sum of commercial and industrial load is fairly stable over the period, which is reasonable.
Source: EIA. "176 Custom Report (User-defined)." Natural Gas Annual Respondent Query System (EIA-176 Data through 2010). Release Date: November 2011.

The usage pattern for natural gas in the New York City region is similar to that for the entire Northeast. (See Exhibit 4-1). Residential and commercial consumption dominate in the winter heating season months and decline substantially in the summer months. Electric power generation peaks in the summer months. Exhibit 4-1 shows the dominance of gas use for power generation in the summer months. While substantial amounts of gas are used for power generation in winter, many of the power generation loads are interruptible and have dual-fuel capability. Therefore, they are interrupted to meet firm gas demand on winter peak days and

[21] Source. ConEd 2010 Annual Report.
[22] Source. National Grid U.S. Enterprise Wide 5 Year Distribution System Reinforcement and Reliability Plan (2010).

have a lesser overall impact during the winter months. Exhibit 4-2 shows the New York City monthly gas demand by sector.

Exhibit 4-2: New York City Monthly Gas Demand by Sector, 2010



Note: This includes NGrid's Long Island load as well as ConEd's loads outside the city.
Source: ICF GMM April 2012.

As shown on Exhibit 4-3, there is an extensive interstate pipeline network around New York City. ConEd and NGrid are directly connected to several pipelines at various points in their service territories and also have capacity on several other pipelines through upstream connections. The interconnection points with the City are at Staten Island (Transco and Tetco), Manhattan (Transco), and the Bronx (Iroquois). The Tennessee and Algonquin pipelines are interconnected with ConEd facilities in Westchester. Deliveries are made to the LDCs at city-gate stations where the distribution pipes meet the interstate pipelines. The LDCs also transport gas across their service territories for redelivery to each other. For example, ConEd receives volumes from Tennessee that it redelivers to NGrid. Transco, Texas Eastern and Tennessee are directly linked into Marcellus Shale gas production in Pennsylvania.

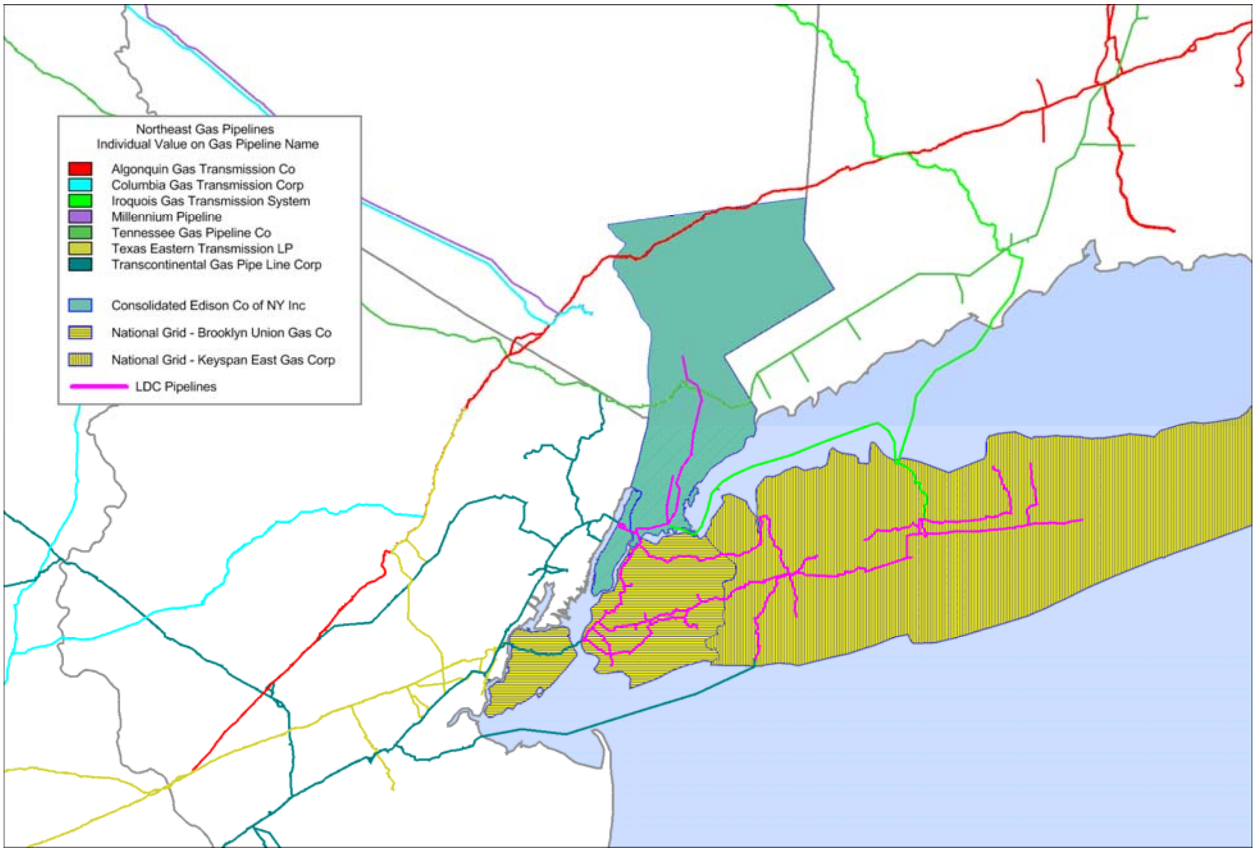
The LDCs meet their firm demand on peak days with a combination of contracted capacity on the interstate pipelines that deliver to the city-gates, peak shaving facilities[23], and interrupting customers taking interruptible service.

The major sources of gas supply to the City are through the interstate pipelines. There are a number of other shippers that have firm capacity on the pipelines. Exhibit 4-4 is a matrix showing the firm shippers on all of the major interstate pipelines that deliver into the New York City region. Besides the ConEd and NGrid, there are 19 other shippers who have pipeline capacity into the region and can supply New York City. One of these, Orange and Rockland Utilities, Inc. (O&R), an affiliate of ConEd, operates a joint portfolio with ConEd so some of its capacity is available to ConEd. NGrid's divisions also operate jointly to "share" pipeline

[23] Peak shaving facilities are facilities that store natural gas (in cryogenic liquefied form) or propane for use on peak demand days when the local demand is greater than can be supplied from the interstate pipelines. Both LDCs have several peak shaving facilities distributed around the metro area.

capacity. Other shippers include gas marketers (*e.g.*, Hess), generating facilities (*e.g.*, TC Ravenswood); these shippers may release capacity to the LDCs for some periods of the year. Other LDCs, such as Washington Gas Light Co. and New Jersey Natural Gas Co., may exchange capacity with ConEd and/or NGrid. The total of all capacity into the New York City region delivery points is 2.9 million decatherms per day (Dth/d).[24] The combination of capacity sharing by affiliates, released capacity, exchanges, and the redeliveries of gas across the New York City facilities' pipeline network complicates the task of determining how much pipeline capacity is available to meet market peak day requirements for each of the LDCs.

Exhibit 4-3: Schematic of Pipelines In and Around New York City



Source: ICF and Ventyx. This schematic approximates the service territories of the LDCs. ConEd, for example, serves some wards in Queens and NGrid-LI serves the Rockaways and Queens.

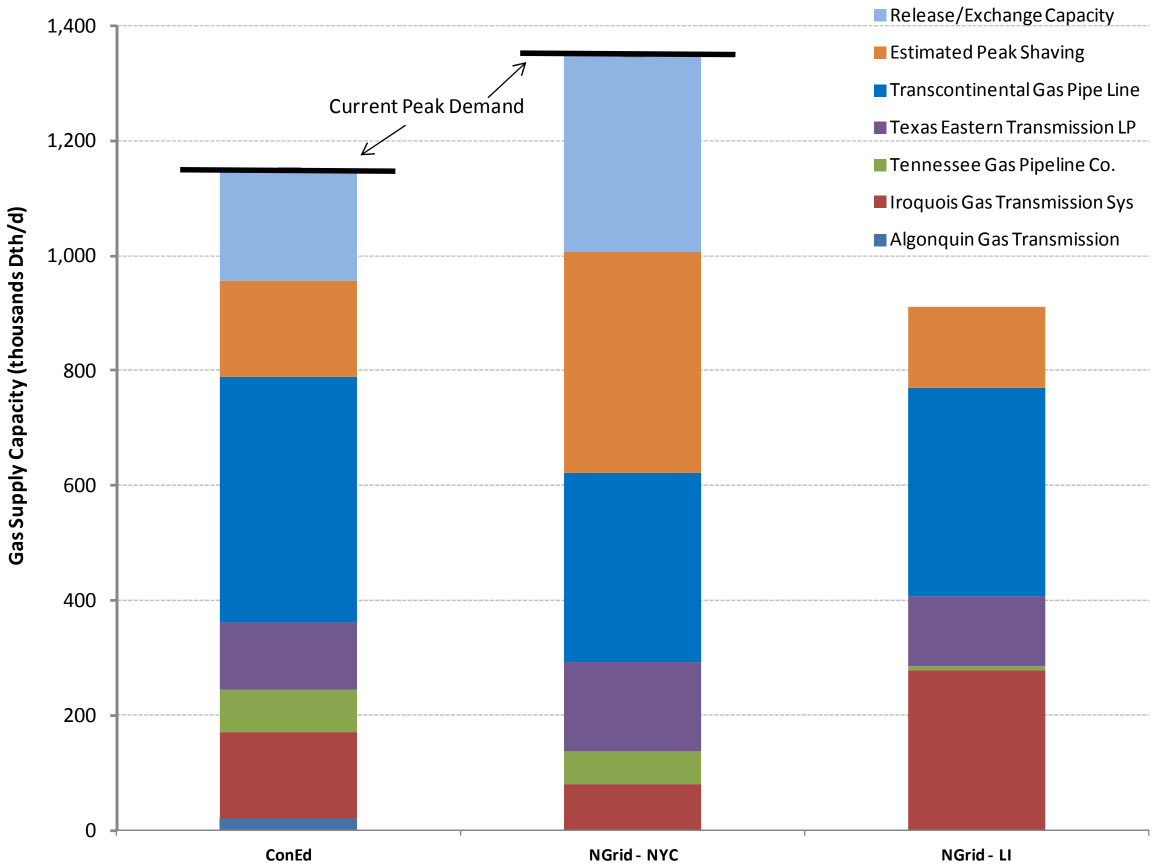
[24] Pipelines measure contract delivery capacity in decatherms, which is the equivalent of one million Btu (MMBtu). One million Dth is approximately one Bcf.

Exhibit 4-4: Firm Pipeline Transport Capacity into the NYC Region (Q4 2011) in Dth

Contract Shipper	Transco Z6 Cntrcts	TETCo M3 NY Cntrcts	Iroquois Z2 NY Cntrcts	Tenn Z5 NYC Cntrcts	Algonquin NYC Cntrcts	All Pipes
BROOKLYN NAVY YARD COGEN. PARTNERS, LP			25,548			**25,548**
CONNECTICUT NATURAL GAS CORPORATION			5,000			**5,000**
CONOCOPHILLIPS COMPANY			10,117			**10,117**
CONSOLIDATED EDISON COMPANY OF NEW YORK INC	**426,751**	**118,245**	**150,234**	**74,293**	**20,000**	**789,523**
EMERA ENERGY SERVICES, INC.					6,676	**6,676**
HESS CORPORATION	20,873		30,000	11,000		**61,873**
IBERDROLA RENEWABLES			50,000			**50,000**
INERGY GAS MARKETING, LLC				90,000		**90,000**
KEYSPAN GAS EAST CORPORATION D/B/A NATIONAL GRID	**363,719**	**121,488**	**277,760**	**7,720**		**770,687**
MPS MERCHANT SERVICES, INC.		30,000				**30,000**
NEW JERSEY NATURAL GAS COMPANY		110,559	5,468			**116,027**
NEW YORK POWER AUTHORITY	30,840					**30,840**
NJR ENERGY SERVICES COMPANY	5,000		35,000	3,000		**43,000**
NRG POWER MARKETING LLC		3,500				**3,500**
ORANGE AND ROCKLAND UTILITIES INC				66,143		**66,143**
RRI ENERGY SERVICES, LLC		50,000				**50,000**
TC RAVENSWOOD, LLC			60,000			**60,000**
THE BROOKLYN UNION GAS COMPANY D/B/A NATIONAL GRID NY	**330,126**	**153,088**	**80,936**	**57,822**		**621,972**
UGI ENERGY SERVICES INC.				18,000		**18,000**
VIRGINIA POWER ENERGY MARKETING, INC.			20,000			**20,000**
WASHINGTON GAS LIGHT COMPANY	50,000					**50,000**
YANKEE GAS SERVICES COMPANY			8,115			**8,115**
New York City Delivery Contracts	**1,227,309**	**586,880**	**717,513**	**327,978**	**26,676**	**2,886,356**
			Capacity not held by NYC utilities			**704,174**

Exhibit 4-5 presents ICF's comparison of the available capacity for both ConEd and NGrid with the peak day requirement. (We include NGrid-LI to show the other pipeline capacity into the NYC region.) ConEd has a peak day sendout capacity of about 1.15 million Dth, enough for its peak day requirements. This sendout capacity consists of the pipeline capacity shown in Exhibit 4-4 of 790,000 Dth plus its peak shaving capacity of about 166,000 Dth. ConEd also has access to O&R capacity as well as released capacity agreements with some shippers and perhaps some exchange agreements with other shippers. NGrid-NY has a peak day requirement of 1.38 million Dth. This is met with pipeline capacity shown in Exhibit 4-5 of 622,000 Dth plus its peak shaving capacity of about 385,000 Dth, with the balance supplied by released and other sources of capacity, including NGrid-LI which has about 770,000 Dth of pipeline capacity and and peak shaving capacity of around 140 MMcfd.

Exhibit 4-5: Sources of NYC LDCs' Peak Day Capacity (Q4 2011) in Dth



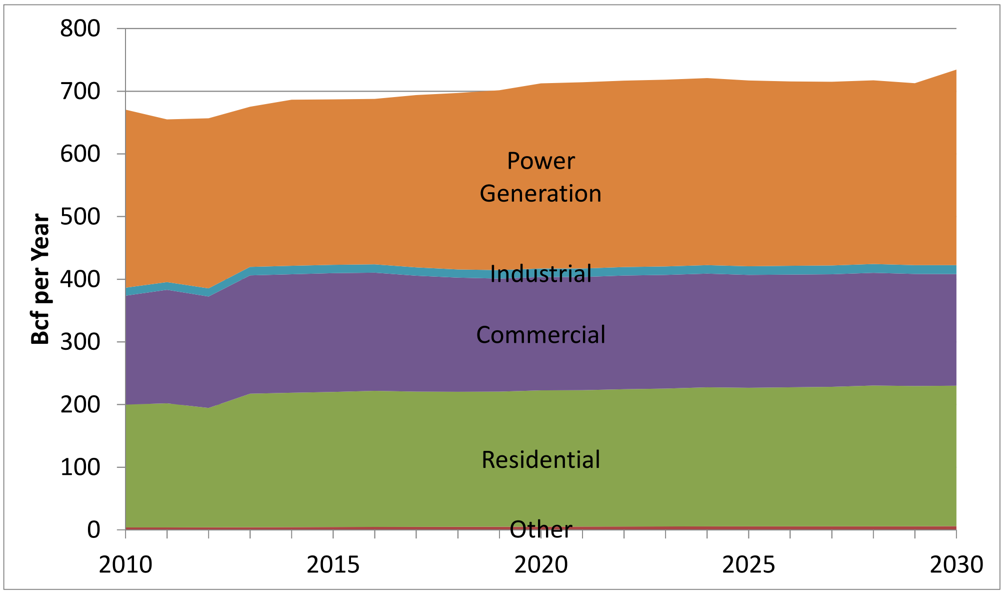
Note: *Tennessee volumes to NGrid are delivered through ConEd.*
Source: Interstate pipelines' Index of Customers.

4.2 Demand Outlook

The ICF Base Case forecasts that gas demand in downstate New York will grow slower than the rest of the Northeast.[25] The Base Case growth assumptions take into account population growth, economic growth, and No. 2 fuel oil conversions. (The Base Case does not include the effect of fuel conversions from heavy oil to natural gas, and it is not included in our growth rate.) As shown in Exhibit 4-6, over the next 20 years, total gas demand in the New York City region is forecast to grow by about 100 Bcf (about 0.27 Bcfd), from 670 Bcf in 2010 to about 770 Bcf in 2030. This is an annual growth rate of approximately 0.8 percent per year. While much of the forecasted market growth will be in electric power generation, there will also be increases in residential and commercial gas demand, but at lower rates.

[25] ICF's model has a single demand node for downstate New York that includes New York City, Long Island, and Westchester, Orange, and Rockland counties.

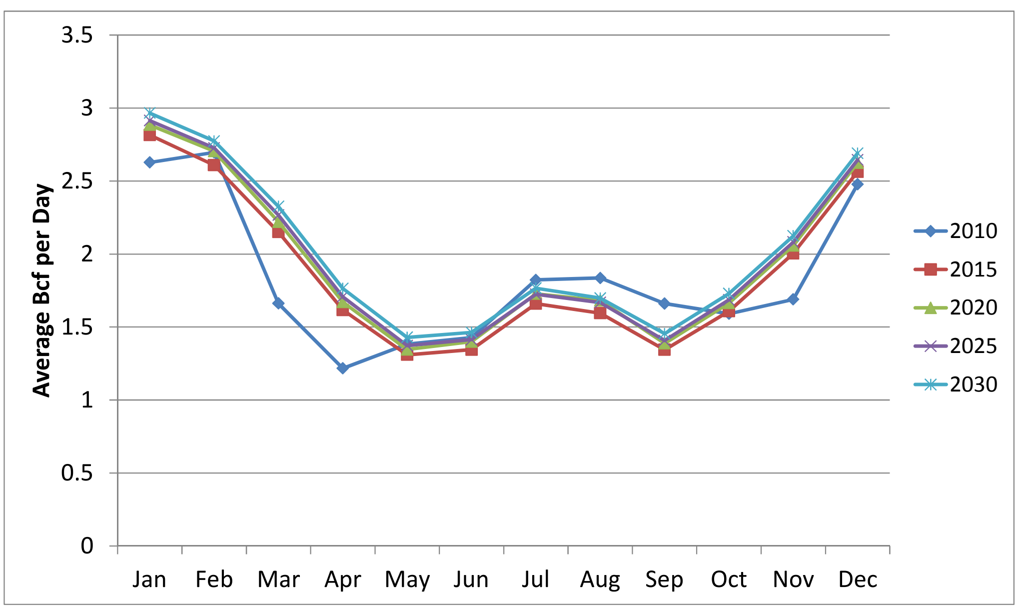
Exhibit 4-6: Forecast of Annual NYC Region Gas Demand – Bcf/yr (2010-2030)



Source: ICF GMM® April 2012.

Exhibit 4-7 shows the monthly pattern of gas demand growth over the forecast period for the entire New York City region. The monthly pattern resembles the pattern shown for 2010 in Exhibit 4-2. Although similar to the historical pattern, there is a flattening out of peak power demand in the summer over the forecast period and a growing winter month demand over the same period. This reflects growing residential and commercial (*i.e.*, weather dependent) loads. ConEd in its 2010 Annual Report has forecast design day peak demand growth of 1.1 percent per year for the next five years.

Exhibit 4-7: Forecast of Monthly Gas Demand for NYC Region, 2005-2030



Source: ICF GMM® April 2012.

NGrid's Five Year Distribution System Reinforcement and Reliability plan forecasts peak day growth also at about 1.1 percent per year. Using the same growth rate for both companies, the peak day demand in 2015 would be 2.64 Bcf. These growth rates are 0.3 percent higher than ICF's forecast growth rate. Note that none of these growth rates incorporate the increased gas usage stemming from New York City's phase-out of heavy oil.

4.3 Supply Outlook

ICF forecasts major shifts in the sources of gas supply for the New York City region as a consequence of the growth of Marcellus Shale gas production. As shown in Exhibit 4-8, northeastern supplies, including Marcellus Shale and Utica Shale production, increase from 13 percent of New York City supply in 2005 to 88.5 percent by 2030. The next largest source of gas, at only slightly more than 10 percent of the total supply, would be shale gas from the Gulf Coast and Mid-Continent regions. New York City will see major declines in gas imports from Western Canada, as well as gas from off-shore Gulf of Mexico. LNG supplies also should decline substantially as LNG imports fall in the face of shale gas output. The forecast in Exhibit 4-8 assumes expansion of gas pipeline capacity into the region and the alleviation of pipeline constraints as a result of the expansions.

The major implication for New York City of this shift in supply is development of pipeline infrastructure to serve the region. As shown in Exhibit 3-7, there will be major additions of gas pipeline capacity to deliver Marcellus Shale gas into the North American gas pipeline grid. This will result in changes to pipeline flows feeding into ConEd and NGrid.

The two pipelines most relevant to New York City are Transco and Texas Eastern. While Transco's mainline (MD to PA) shows relatively constant flows over the forecast period and has no expansion plans, the line to Leidy is being expanded to increase gas throughput. Similarly, Texas Eastern shows major expansions into the New York City area from eastern Pennsylvania, and large increases in pipeline flow. The other pipeline serving the area with large flow increases is Tennessee's 300 line into New Jersey.

The pipelines that historically have brought gas into the New York City area from Canada will experience major decreases in throughput into the region and lower load factors. Iroquois' Waddington interconnection and Tennessee's Niagara interconnection experience major decreases in throughput, but both pipelines will receive gas from other sources and continue to supply New York City. The negative and extremely low-flow numbers on the Tennessee Niagara interconnect are a result of reverse flows into Canada during some months of the year. (In 2015, the annual flow balance is negative – i.e., Tennessee flows most of the time into Canada.) Growth in throughput on Algonquin, a major supplier to New England, increases with additional receipts in New Jersey that bypass New York City and flow into New England.

In addition to the increased regional capacity, there will also need to be additions to the pipeline links that bring gas into New York City itself in order to meet peak demand and this will be exacerbated by the increased demand from conversion of heavy oil boilers.

Exhibit 4-8: Sources of Natural Gas Supply for NYC Region (Bcf)

	2005	2010	2015	2020	2025	2030
Total Downstate NY Gas Demand	660	680	705	729	727	742
Amount sourced from:						
Northeast (Marcellus & Utica Shales)	86	207	525	604	645	679
Southeast	15	14	5	6	5	4
Midwest	5	5	0	0	0	0
Mid-Continent Conventional	37	30	9	7	4	3
Rockies	10	16	2	2	1	1
Gulf Onshore Conventional	82	34	14	6	4	2
Gulf/Mid-Continent Shale	119	215	129	92	62	44
Gulf Offshore	126	40	13	7	4	3
Western Canada	95	61	1	2	1	1
Eastern Canada	10	16	2	0	0	0
U.S. East Coast LNG	69	41	4	3	1	3
Canaport LNG	0	0	0	0	0	0
Gulf Coast LNG	5	1	0	0	0	0
Supply sources as percent of total:						
Northeast (Marcellus & Utica Shales)	13.1%	30.5%	74.5%	82.9%	88.7%	91.5%
Southeast	2.3%	2.1%	0.8%	0.8%	0.7%	0.6%
Midwest	0.7%	0.7%	0.0%	0.0%	0.0%	0.0%
Mid-Continent Conventional	5.7%	4.4%	1.3%	1.0%	0.6%	0.4%
Rockies	1.5%	2.4%	0.2%	0.3%	0.1%	0.2%
Gulf Onshore Conventional	12.5%	5.0%	1.9%	0.9%	0.5%	0.3%
Gulf/Mid-Continent Shale	18.0%	31.6%	18.3%	12.6%	8.5%	6.0%
Gulf Offshore	19.2%	5.9%	1.9%	0.9%	0.5%	0.4%
Western Canada	14.4%	9.0%	0.2%	0.2%	0.1%	0.2%
Eastern Canada	1.5%	2.4%	0.2%	0.0%	0.0%	0.0%
U.S. East Coast LNG	10.4%	6.0%	0.6%	0.4%	0.2%	0.4%
Canaport LNG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Gulf Coast LNG	0.8%	0.2%	0.1%	0.0%	0.0%	0.0%

Source: ICF GMM® April 2012.

4.4 Impact of Heavy Oil Boiler Conversion

The current estimated consumption of No. 6 and No. 4 fuel oil subject to the City's phase-out mandate is approximately 77.8 million Dth per year. Taken on an average daily basis, the additional demand associated with a full conversion to natural gas would average about 213,000 MMBtu of incremental gas load that ConEd and NGrid would have to meet. The more significant increase would be on peak day requirements.[26] Based on the assumption that firm peak day sendout is about 3.25 times the average daily throughput, the implied peak day

[26] The estimate of the gas required is based on a strict conversion with no allowance for increased efficiency due to boiler replacement that may result from shifting from oil to gas. In the near term, many conversions may rely simply on burner replacements but over time there may be efficiency gains as older boilers are replaced, thus reducing the potential gas consumption below this projected level.

addition from the conversions could be about 746,000 MMBtu. The increase in peak demand would be more pronounced on ConEd, where 89 percent of the increase in gas use from conversions is expected to occur. For ConEd, the impact is expected to be up to a 58 percent increase in gas consumption on a peak day. In Exhibit 4-9 we estimate the implied average day and peak day consumption resulting from the boiler fuel conversion. Most of the increase in gas requirements will accrue to ConEd.

Exhibit 4-9: Boiler Conversion Impact (000 Dth)

	Annual	Average per day	Peak Day
Conversion Total	77,776	213.0	746.0
ConEd	69,289	189.8	664.4
NGrid	8,487	23.2	81.6

Source: Conversion and fuel estimates provided by New York Department of Environmental Protection (NYDEP); gas use estimates by ICF.

It is unlikely that all of the boilers currently using heavy oil will convert to natural gas. The No. 6 boilers are to be converted by 2015 and the No. 4 boilers by 2030, so gas conversions will be taking place over at least the next decade. It is difficult to predict the number of years over which any specific percentage of heavy oil users will convert their boilers to natural gas or No. 2 oil. Certainly, the City's heavy oil regulations, in combination with the NYC Clean Heat Initiative and the benefits that are available thereunder will motivate conversions in the next three to five years. The price disparity between natural gas and fuel oil is likely to be another significant motivating factor for expeditious conversions. That is, while natural gas prices are forecast to remain relatively stable, fuel oil prices are expected to continue to increase, making the conversions more economic.

Exhibit 4-10 shows a range of scenarios that demonstrate the impact of different levels of conversion on each LDC's peak day sendout. The 100 percent conversion scenario is provided to bound the potential impacts, even though it is unlikely that all heavy oil users will convert to natural gas. It also shows the impact of 50 percent and 75 percent conversion scenarios, and the cumulative potential impact of the conversions on each LDC's peak day sendout.

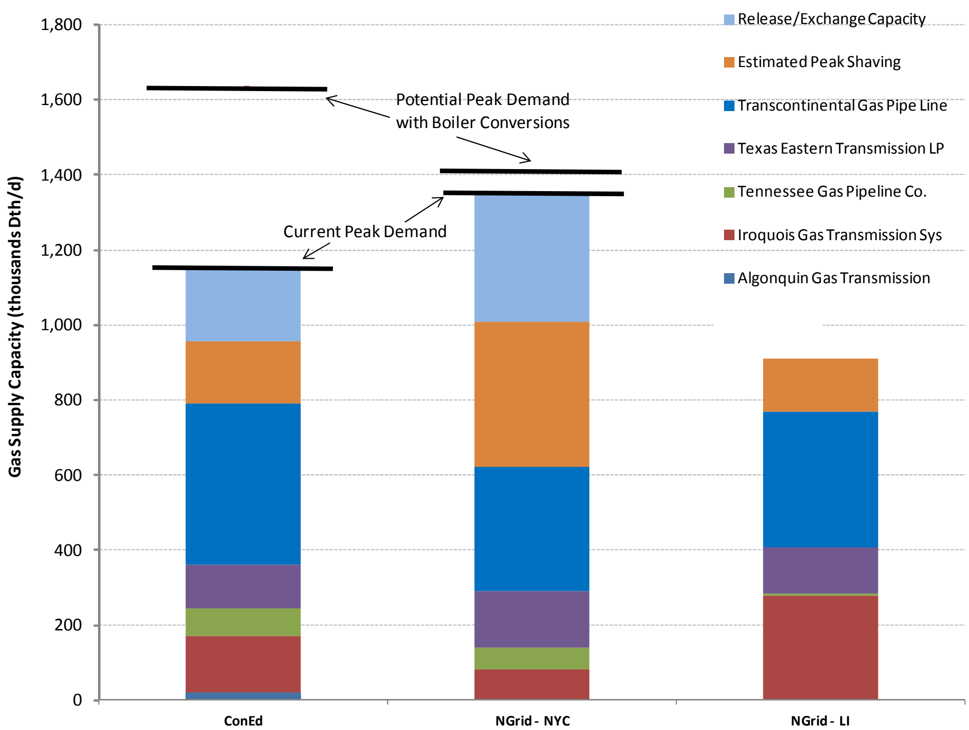
Exhibit 4-10: Potential Annual Impact of Boiler Conversions (MMcfd)

	ConEd			NGrid		
Percent Conversion	Ave. Day	Peak Day	Percent Increase in Peak Day	Ave. Day	Peak Day	Percent Increase in Peak Day
25%	34.6	124.8	14%	4.4	15.4	2%
50%	69.2	249.6	29%	8.8	30.7	3%
75%	103.9	374.4	43%	13.2	46.1	5%
100%	138.5	499.2	58%	17.6	61.5	6%

In each scenario, each LDC would ultimately see substantial increases in peak day responsibilities. LDCs design their systems and contract for pipeline capacity to meet peak day requirements. Increases in gas use on the peak day require additional delivery capabilities both into the LDCs from outside sources of supply and enhanced delivery capability within the LDC's distribution systems.

As noted above, ConEd has pipeline capacity contracts totaling approximately 790,000 Dth/d and NGrid has approximately 622,000 Dth/d. The peak day requirements of both LDCs are already estimated to be greater than their existing pipeline capacity into New York City, with the remaining load met by peak shaving capacity within the City, released/exchanged capacity from other shippers on the pipelines, and interruption of interruptible customers. The increase in peak day demand will exacerbate the tightness of the LDCs' gas supply capacity and place added pressure on the need for the LDCs to increase the combined pipeline capacity under their control. The increased capacity from the pipelines proposed by Williams and Spectra (see Exhibit 3-7) would satisfy at least some of the LDCs' increased peak needs arising from the fuel oil conversions. Exhibit 4-11, shows the amount of additional peak day capacity that would be needed to meet the incremental demand if all heavy oil boilers were converted to natural gas.

Exhibit 4-11: Peak Gas Demand Impact of Potential Heavy Oil Boiler Conversions

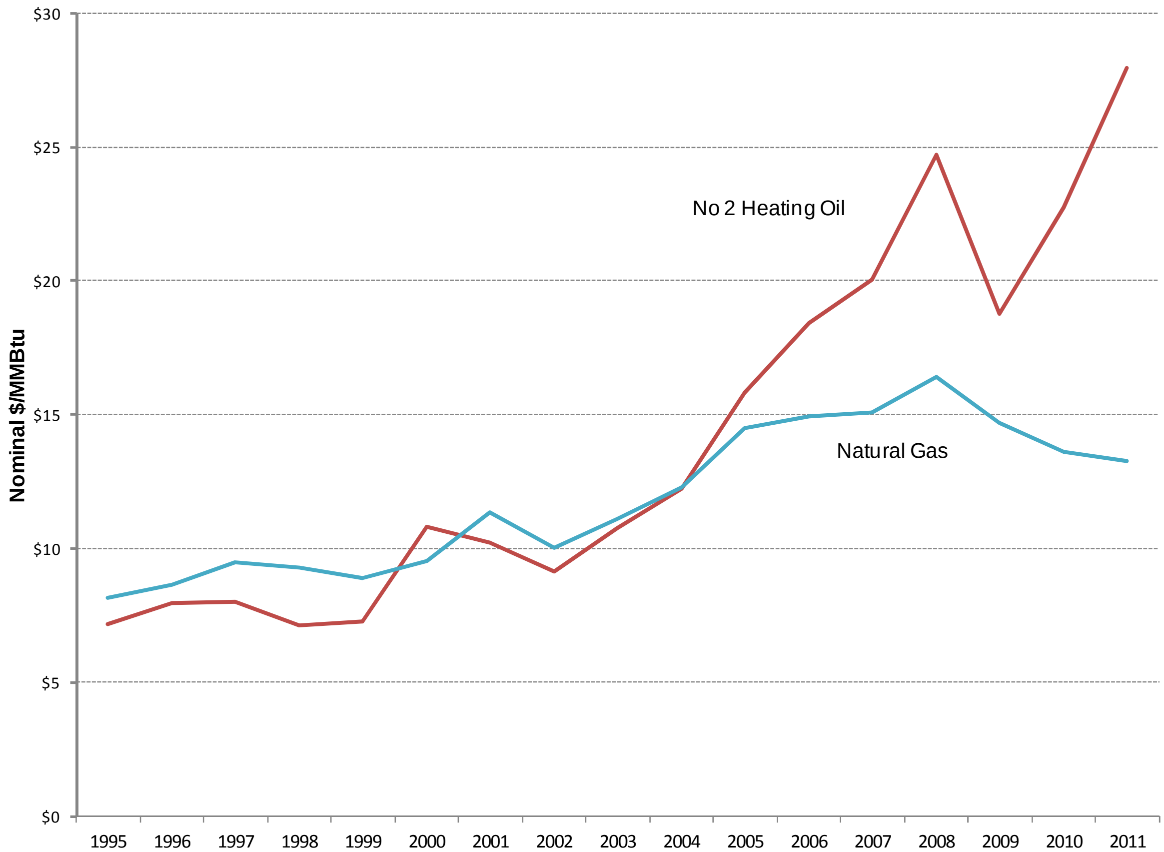


Source: ICF estimate from interstate pipeline data, LDC peak day data, and NYDEP.

4.5 Oil and Gas Prices

Exhibit 4-12 shows the historical trend of residential heating oil and natural gas prices in New York State. Gas prices were slightly higher than No. 2 oil prices for most years from 1995 through about 2004. Since then, oil prices have increased significantly while gas prices have leveled off, with gas approximately half the price of oil in 2011.

Exhibit 4-12: New York State Average Residential Heating Oil and Natural Gas Prices – 1995 - 2011

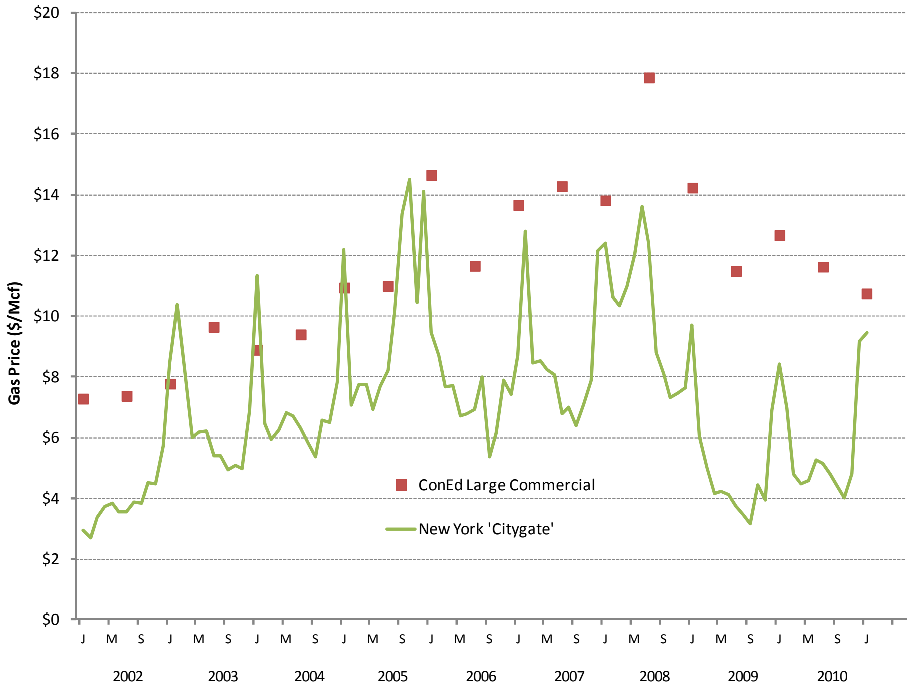


Source: U.S. Energy Information Administration.

The commodity price of natural gas is only one part of the cost of gas to consumers. The other primary component is the delivery cost. The LDCs purchase gas through a portfolio of long and short-term contracts, so that the cost of gas to the LDC does not precisely track the spot market for gas. Exhibit 4-13 provides a history of several indicators of commercial gas prices for NYC. One line is the price of the gas commodity at the end of the pipelines supplying New York City (taken as the higher of Transco Zone 6-NY and Iroquois Gas Transmission Zone 2 prices). The points show the cost of gas delivered to ConEd Large Commercial customers at each point in time. The chart shows that the cost of the gas commodity is about half to two thirds of the ConEd price to customers. It also shows that the ConEd price generally tracks the commodity price of gas. Therefore, we would expect the current downward trend and generally stable trajectory of gas prices to be reflected in the price of gas delivered to consumers.

The New York City LDCs, in particular ConEd, will need to invest in additional pipeline capacity, peak shaving facilities and/or distribution infrastructure to meet increased demand for widespread conversion of heavy oil boilers, which will affect their cost of service. The timing of these investments will also have a significant effect on how they are reflected in consumer costs. ICF has not evaluated the impact of the need for additional peak day sendout capability on the cost of service; however, we would expect the overall price trend for delivered gas prices to generally track the commodity gas price.

Exhibit 4-13: ConEd Commercial Gas Rates and City Gas Prices, 2002-2010



Source: New York Public Service Commission. Typical Customer Bill Information. Gas Commercial. July and January 2002 to 2011.

5. Life-Cycle Analysis

5.1 Life-Cycle Analysis Overview

Life-cycle analysis (LCA) covers a variety of methodologies and levels of detail. A "bottom up" LCA calculates the emissions for each step of the life cycle for a specific product. The bottom up LCA provides a great deal of specificity and detail, but is not easily applied to the overall national emissions of a fuel. A "top down" LCA uses national level data to calculate the average emissions for a fuel. This approach provides a national average value but does not provide insight into the performance of specific processes or steps in the production, transportation or use of a fuel. In addition, some LCAs analyze the production (extraction), processing, transportation and distribution of a fuel, while others also address the emissions from the production of the equipment used for these steps. In order to provide a comprehensive assessment, this study includes both bottom up and top down analyses of natural gas production.

The primary greenhouse gases (GHGs) to be addressed by this study are:

- CO_2: The primary GHG emissions produced from the combustion of fossil fuels. CO_2 gas is also present in oil and gas as it comes out of the well and is released during processing.
- Methane (CH_4): The primary constituent of natural gas. CH_4 is emitted through fugitive emissions (*i.e.*, unintentional leakage such as from compressor seals and valve packing) and venting (*i.e.*, intentional releases such as from pneumatic devices or when equipment is taken out of service for maintenance) that occur throughout the production, processing and transportation of natural gas.

Each GHG has different characteristics and different effects on climate change. In order to compare them, we use a factor called the global warming potential (GWP), which relates each GHG's effect to that of CO_2, which is assigned a GWP of 1. The GWP is a function of the gas' climate forcing potential (its effect on atmospheric warming) and its lifetime in the atmosphere. The international standard for GWPs is established by the Intergovernmental Panel on Climate Change (IPCC).

CO_2 has a long life in the atmosphere – on the order of hundreds of years. For this reason, the primary GWPs are established on a 100-year basis. Methane has a stronger climate forcing effect than CO_2 but has a shorter lifetime in the atmosphere (10 to 15 years). On a 100-year basis, methane is assigned a GWP of 25 by the IPCC[27]. This means that one ton of methane has the same effect as 25 tons of CO_2 over 100 years.

The IPCC also establishes 20-year GWPs. Some analysts believe that the 20-year GWP is more appropriate to use for short-lived GHGs like methane, especially to show the potential benefits of short-term mitigation options for these GHGs. Because methane is more potent over its shorter life, the IPCC 20-year GWP for methane is 72.

Most projections estimate that the largest growth area for natural gas consumption in the U.S. will be in the electric power sector. Much of this growth relates to the replacement of coal-fired power plants with cleaner, gas-fired power plants. Therefore, the major focus of recent LCAs

[27] Intergovernmental Panel on Climate Change, "2007 IPCC Fourth Assessment Report (AR4)". 2007. http://www.ipcc.ch/publications_and_data/ar4/syr/en/contents.html.

has been on the comparison between life-cycle emissions of natural gas and coal for electricity generation. While natural gas has much lower combustion emissions than coal, it has higher upstream methane emissions and that has been a key focus of the analysis. Within New York City, most power plants already use natural gas as their primary fuel source. Therefore, natural gas consumption is expected to grow primarily due to the conversion of boilers from heavy fuel oil to natural gas. Accordingly, this study provides both a comparison of gas to coal and gas to fuel oil.

5.2 Oil, Gas and Coal Production Overview

Oil and natural gas are produced from wells. Most oil wells produce natural gas (associated gas) with the oil. There are also wells that produce only gas (non-associated gas). The equipment for drilling these wells is primarily powered by large diesel engines, and the associated vehicles are also predominantly diesel-fueled. Raw gas (including methane) is vented at various points during the production process. In some cases, the gas may be flared or recovered for sale. Flaring gas produces CO_2, but the emissions are lower than the GWP-weighted emissions of the methane that would otherwise be released. In both oil and gas production, water and hydrocarbon liquids are separated from the product stream at the wellhead. This process may involve some fuel combustion and can also involve some venting and/or flaring of methane.

About 60 percent of U.S. oil consumption is imported – 20 percent from Canada and Mexico and the other 40 percent from other sources. Only about 12 percent of natural gas is imported, and most of that, about 11 percent, is from Canada. Only one to two percent is LNG imported from other countries.

For the last 100 years, domestic oil production has been primarily in the Southwest (Texas, Arkansas, Oklahoma), the Gulf of Mexico, California, and Alaska. Domestic gas production has been mostly in the Southwest, Gulf of Mexico, and the Rockies. More recently, the focus of new natural gas development has been in the extraction of gas from shale formations. Shale is a sedimentary rock composed of compacted mud, clay and organic matter. Over time, the organic material can produce natural gas and/or petroleum, which can slowly migrate into formations where it can be recovered from conventional oil and gas wells. The shale rock itself is not sufficiently permeable to allow the gas to be economically recovered through conventional wells; that is, gas will not flow sufficiently freely through the shale to a well for production.

Gas from shale formations is recovered by hydraulically fracturing the shale rock to release the gas. This involves pumping water at high pressure into the well to “fracture” the shale, creating small cracks that allow the gas to flow out. The pumping is powered by large diesel engines that create CO_2 emissions. When the water “flows back” out of the well, methane is entrained and may be vented. Due to the high GWP of methane, this can be a large source of GHGs. For these reasons, the increased production of shale gas is a potential source of increased GHG emissions. The initial shale gas formations to be developed were in the Southwest, but development has started now on the Marcellus shale formation which underlies New York, Pennsylvania and parts of Maryland and West Virginia.

Although some gas is pure enough to go directly into a pipeline, most gas is transported by pipeline to gas processing plants. The gas processing plants remove gaseous impurities as well as hydrocarbon liquids that are used for fuel (propane) or feedstocks (ethane, butane). The raw gas content varies widely among different gas formations. One of the gaseous impurities found in the raw gas is CO_2. This "formation" CO_2 is vented at the gas processing plants and is a source of GHG emissions along with the combustion emissions from the plants.

From the gas processing plants, gas is transported long distances by interstate pipelines. The vast majority of the compressors that move the gas through the pipelines are fueled by gas; a small share is powered by electricity. Gas compression creates three types of GHG emissions: CO_2 from the operation of the compressor engines, fugitive methane emissions, and vented methane emissions. Leakage from the pipelines themselves is very small. The final step of delivery for residential and commercial customers is delivery by an LDC. The primary source of emissions during the delivery stage is leakage from pipes, valves and meters. This is especially true for older systems that have cast iron distribution mains.

Like natural gas, crude oil produced in North America is transported primarily by pipelines. Some of the crude oil consumed in this country is brought to the U.S. by ship. Crude oil is processed in a refinery to separate it into different petroleum-based products. This is similar in concept to natural gas processing, but all crude oil must be refined and the processing is much more complex and energy intensive. There are significant combustion emissions and process emissions of CO_2 in the refining process. After refining, the products are brought to market by pipeline, rail, barge and truck. Some products are blended by local distributors before being delivered to consumers, mostly by truck. All of these transportation and delivery stages result in CO_2 emissions.

There are fewer steps in the production and processing of coal. Coal is produced from underground mines (40 percent) and surface mines (60 percent). In underground mines, most of the mining equipment is driven by electricity. In surface mines, the equipment runs on diesel fuel or electricity. Coal formations contain methane, which is released when the coal is mined. The methane content varies among different coal formations but is generally higher for underground mines than for surface mines. Underground mines use ventilation to remove the methane, and, in some cases, recover it for use or flare it to reduce GHG emissions. Coal is transported to consumers (*e.g.,* power plants) primarily by rail, with a small portion moved by truck or barge.

5.3 Natural Gas and Coal LCA

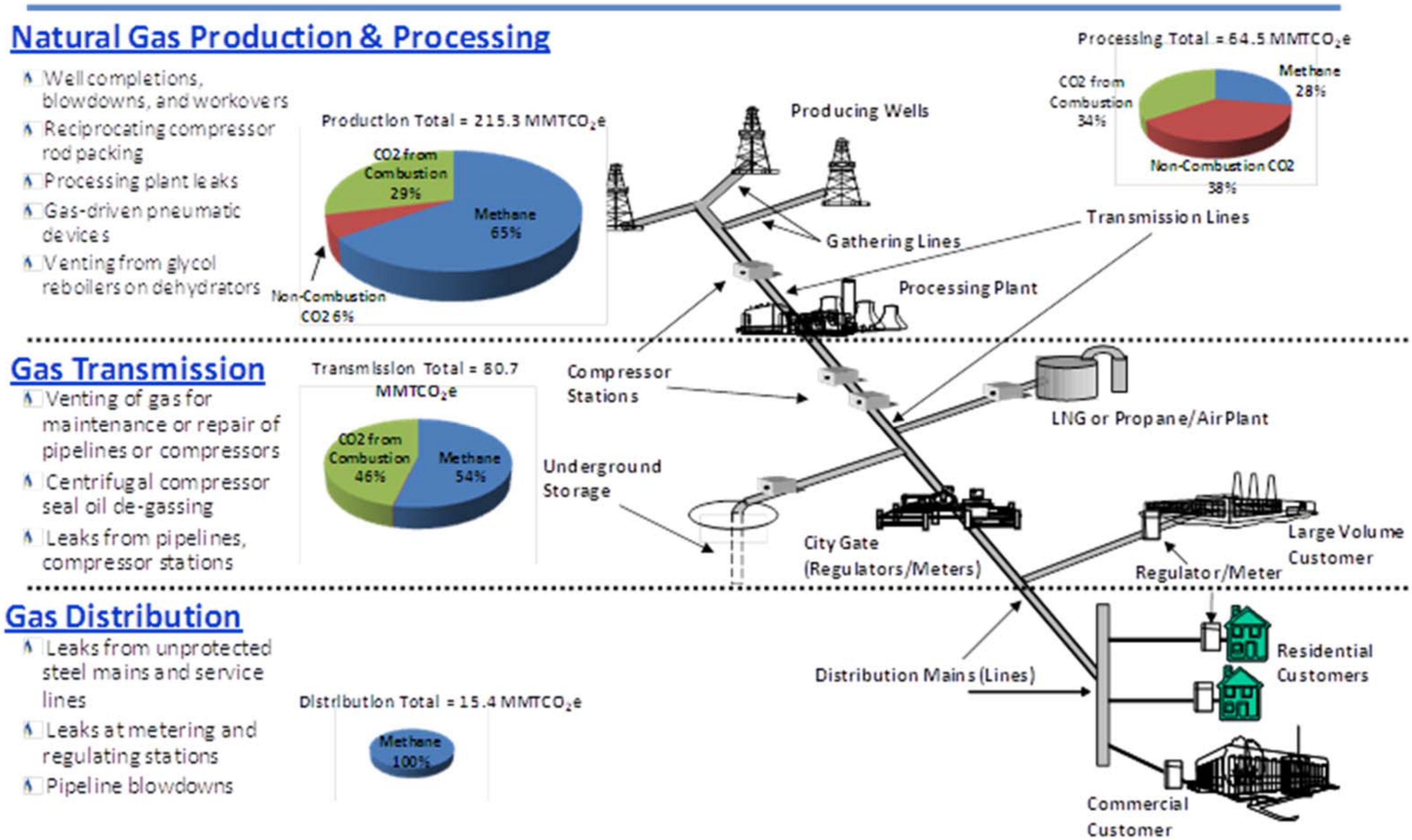
The major sources of upstream GHG emissions from natural gas production and delivery are CO_2 from the equipment used to drill the wells and process and transport the gas, and from fugitive and vented emissions.

Exhibit 5-1 shows the emissions associated with the major natural gas process steps, based on EPA data. While these data are widely used by industry analysts, NGOs, and government agencies, there is also widespread agreement that there is significant uncertainty in the emissions estimates and a need for improved data. Some improved information will be available through implementation of the EPA Greenhouse Gas Reporting Rule and there are some independent efforts to collect additional data.[28]

The EPA produces an annual "Inventory of U.S. Greenhouse Gas Emissions,"[29] which is the official U.S. report to the IPCC on U.S. emissions. This report contains detailed information on all of the major U.S. emission sources and is therefore the basis for many other emissions

[28] The EPA's Greenhouse Gas Reporting Rule requires the gas industry to submit 2011 Greenhouse gas emissions data by September of 2012.
[29] EPA, Inventory of U.S. Greenhouse Gas Emissions And Sinks:1990 – 2009, U.S. EPA, EPA 430-R-11-005. http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf

Exhibit 5-1: Natural Gas Production and Emissions



Source: AGA, EPA, ICF Analysis.

studies. During 2010, the EPA began releasing new estimates of methane emissions associated with natural gas production. These new estimates were based on modified emissions estimates for specific processes in the gas production chain. The largest increase was for liquids unloading – the process of removing water and other liquids from the bottom of conventional gas wells. The second largest increase was related to the emissions from shale gas wells during completion. These emissions come from the methane released during the "flowback" when the water used to fracture the well is released. Previously, the EPA had assumed that all of this methane was being flared. The new estimates assume that roughly one third is flared, one third captured for sale, and one third vented. These estimates were also incorporated into the Technical Support Document for EPA's GHG reporting requirements for emissions from the oil and gas sectors[30].

Although the emission rates for some of the individual processes were increased by a factor of 100 or more, these processes make up only a small part of the total upstream GHG emissions for the gas sector. Nevertheless, after the revised estimates began to appear in EPA documents in late 2010, some analysts became concerned in early 2011 that the overall impact would be very large, resulting in high life-cycle emissions estimates for gas, especially shale gas produced through hydraulic fracturing.[31] These concerns resulted in the release of several new studies of the life-cycle emissions of natural gas and coal in 2011, which are summarized and compared below:

Howarth *et al.* (Cornell)[32] – This 2011 study from Cornell University was the first new peer reviewed study to address the LCA issue based on the new EPA data and specifically focus on shale gas production. It gained a lot of attention due to its conclusion that shale gas has higher life-cycle GHG emissions than coal, due largely to methane emissions during the extraction process.[33]

Jiang *et al.* (Carnegie Mellon)[34] – This peer reviewed study updates several earlier LCAs done at Carnegie Mellon University to specifically address the life-cycle emissions of shale gas produced through hydraulic fracturing. It finds that the life-cycle GHG emissions of shale gas are approximately 5 percent higher than the base case conventional gas case and the emissions from gas-fired electricity generation are about 42 percent lower than for conventional coal generation.

Burnham *et al.* (Argonne National Laboratory)[35] – This peer reviewed study by researchers at the Argonne National Laboratory used a variety of detailed data sources and the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) LCA model to develop life-cycle GHG emissions estimates for conventional gas, shale gas and coal-based electricity generation. Unlike other studies, this one found that the emissions from conventional gas production were slightly higher than for shale gas production, due primarily to fugitive

[30] EPA (2010). Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry. Background Technical Support Document. http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf

[31] Lustgarden, A. "Climate Benefits of Natural Gas May Be Overstated". ProPublica. January 25, 2011. http://www.propublica.org/article/natural-gas-and-coal-pollution-gap-in-doubt

[32] Howarth, R. W., R. Santoro, and A. Ingraffea. 2011. Methane and the greenhouse gas footprint of natural gas from shale formations. Climatic Change Letters, DOI: 10.1007/s10584-011-0061-5.

[33] Howarth *et al* have released a response to recent challenges to the results of the study but it contains no new data. http://216.250.243.12/shalegasghgreport.html

[34] Jiang, Mohan; W. Michael Griffin, Chris Hendrickson, Pauline Jaramillo, Jeanne VanBriesen, and Aranya Venkatesh. "Life cycle greenhouse gas emissions of Marcellus shale gas." Carnegie Mellon University and IOP Publishing, 5 August 2011: Pittsburgh.

[35] Andrew Burnham, Jeongwoo Han, Corrie E Clark, Michael Wang, Jennifer B Dunn, and Ignasi Palou Rivera. Environ. Sci. Technol., 22 November 2011.

methane emissions from liquid unloading in conventional gas production. Overall, it found that life-cycle GHG emissions from gas-fired electricity production were 36 percent lower than for coal-fired electricity production.

Hultman *et al.* (University of Maryland)[36] – This peer reviewed study from the University of Maryland compared the life-cycle emissions of conventional gas, shale gas and coal for electricity generation. It found that the GHG impacts of shale gas are 11 percent higher than those of conventional gas, and 44 percent lower than for coal.

Deutsche Bank/WorldWatch Institute[37] – This top-down LCA study explicitly looked at the effect of the revised EPA methane estimates on the life-cycle emissions from natural gas production and use. It also included adjustments for natural gas imports. It concluded that the overall effect of the EPA adjustments is an 11 percent increase in the life-cycle emissions of natural gas, with the life-cycle emissions of gas-generated electricity still about 47 percent lower than for coal-generated electricity.

National Energy Technology Laboratory (NETL)[38] – This study is a very detailed, bottom-up study of life-cycle emissions from electricity generated from conventional and shale gas from various sources compared to the life-cycle emissions from coal-fired electricity production. It is part of a series of studies on life-cycle emission from various energy sources. The study finds that life-cycle emissions from natural gas-fired electricity generation are 39 percent less than from coal-fired electricity generation.

Exhibit 5-2 summarizes the results of these studies as reported, showing the life-cycle GHG emissions of the fuel as delivered to the point of end use in kg CO_2e/MMBtu of delivered energy. Because each of the studies is evaluating a slightly different case with a different methodology, one can expect some variation. In all cases, the largest component of the natural gas emissions is the CO_2 released during the actual combustion of the fuel – 53 kg CO_2/MMBtu.

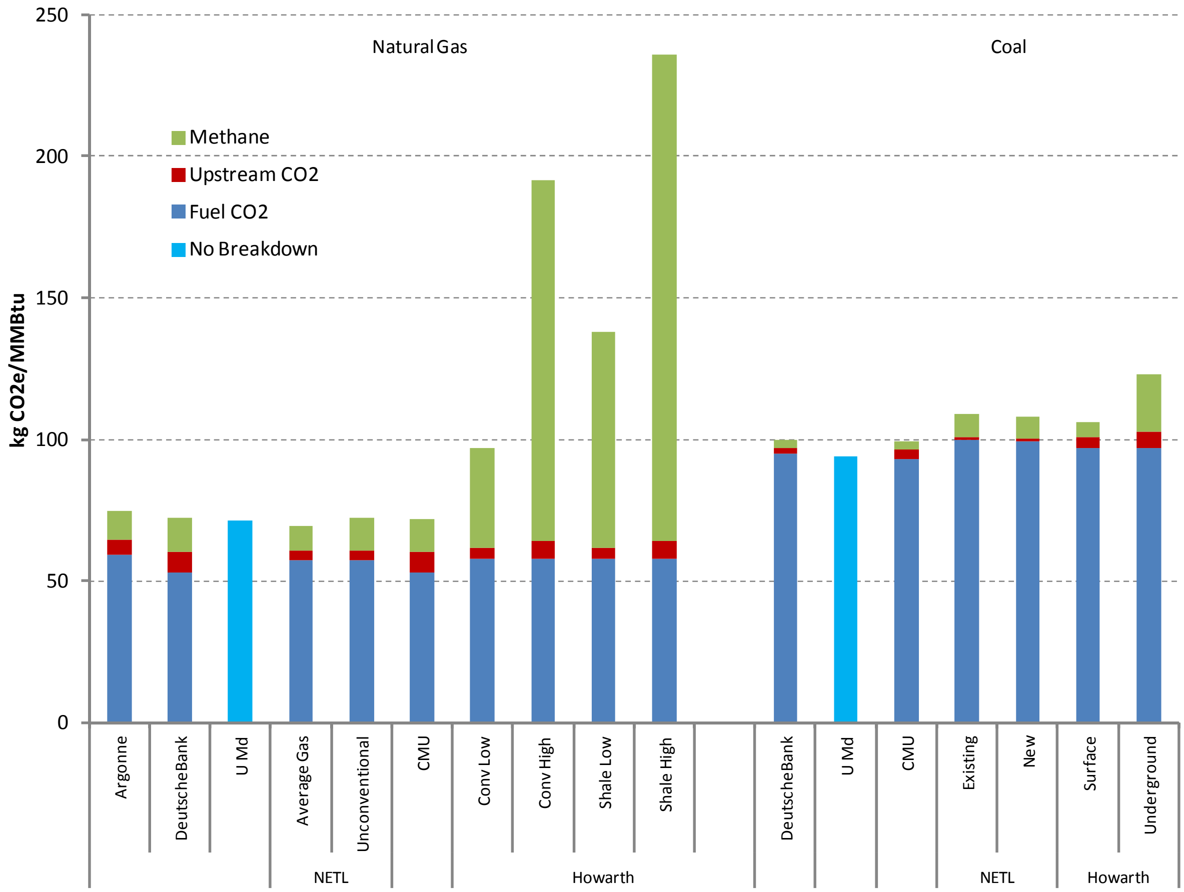
The upstream CO_2 emissions estimates from drilling engines, process equipment, pipeline compressors, and other equipment are a much smaller component, while the upstream methane emissions estimates are, in some cases, quite large due to the higher GWP of the methane. The coal LCAs show a similar pattern, with the CO_2 from combustion of the fuel comprising the largest share of the life-cycle emissions and the upstream emissions much smaller but usually dominated by the methane component.

All of the studies except the Howarth study show total life-cycle emissions for natural gas delivered to consumers ranging from 69 to 75 kg CO_2e/MMBtu (including the 53 kg/MMBtu for the gas combustion itself). The Howarth study has values two to nearly five times as high, almost entirely due to the estimates of upstream methane emissions. One reason for this difference is that Howarth used a different GWP for methane. The other studies used the standard IPCC 100-year GWP of 25. Howarth used a 20-year GWP and did not use the IPCC value of 72, but a value of 105 proposed by Shindell, *et al.*[39] This value is based on newer

[36] Nathan Hultman, Dylan Rebois, Michael Scholten and Christopher Ramig, The greenhouse impact of unconventional gas for electricity generation, Environ. Res. Lett. 6 (October-December 2011) 044008.
[37] Fulton, M, Melquist, N. Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal. DeutscheBank Climate Advisors. August 25, 2011.
[38] Skone, T.J., Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production, National Energy Technology Laboratory, U.S. Department of Energy, October 23, 2011, DOE/NETL-2011/1522.
[39] Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE "Improved attribution of climate forcing to emissions." Science 326:716–718 (2009).

research and is still being evaluated by the international scientific community. This choice alone explains much of the difference between the Howarth study and the other recent studies.

Exhibit 5-2: Comparison of Recent Studies of Life-Cycle Emissions from Natural Gas and Coal (kg CO_2e/MMBtu)



Source: Cited studies and ICF Analysis.

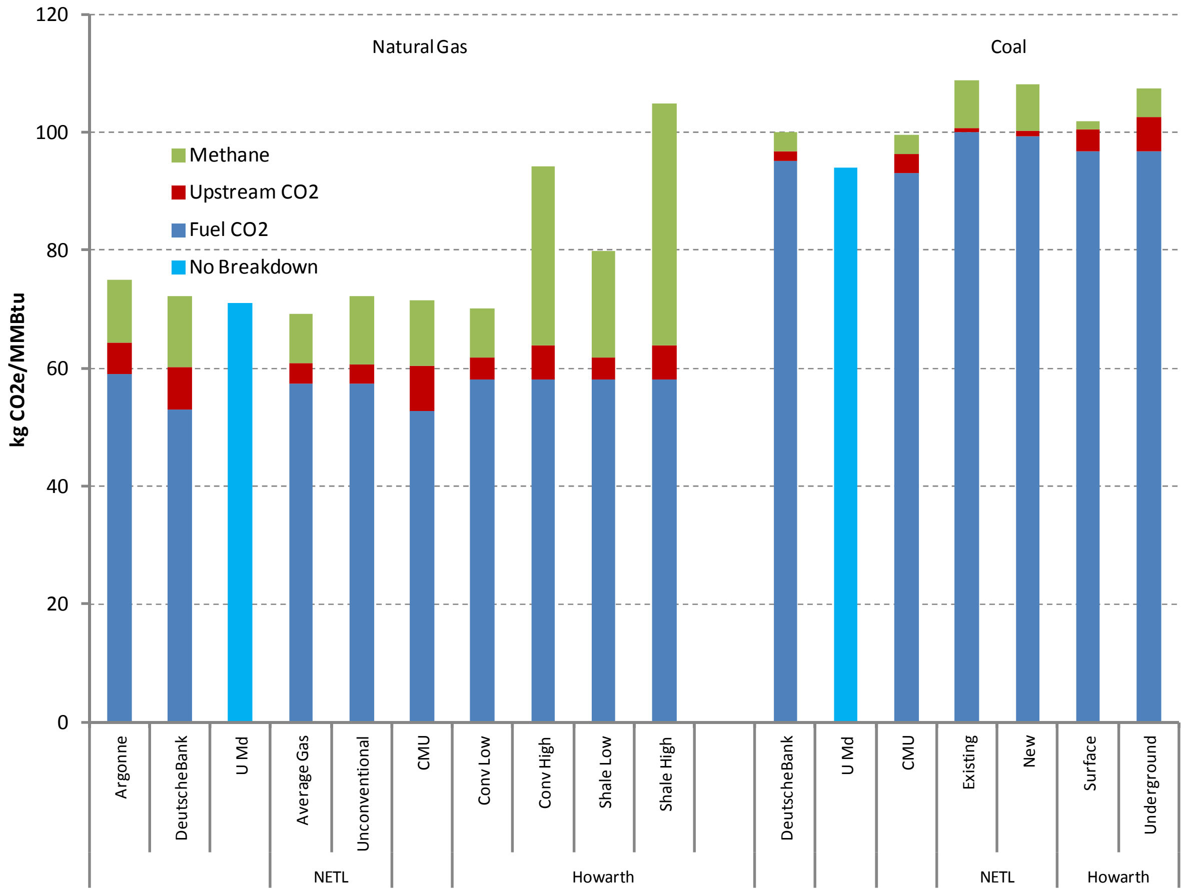
Recent research (Alvarez, *et al* Environmental Defense Fund, Princeton University, Rochester Institute of Technology and Duke University)[40] suggests an alternative analytical approach to assessing methane that explicitly evaluates its global warming effect over time rather than using the GWP approach. This report did not look at the implications of this new approach in assessing the life-cycle impact of natural gas on global warming.

Exhibit 5-3 shows the gas LCA studies all normalized to the same 100-year GWP of 25 for methane. While the Howarth values are much closer to the other studies on this basis, the shale gas values in particular are still much higher. There are several reasons for this difference. As in the other studies, the Howarth study divided the analysis into different segments. Like other researchers, Howarth used EPA inventory data for several of the segments but then chose other sources with higher values for some segments. For example, the Howarth study did not use the EPA data for the methane emissions from shale gas

[40] Ramón A. Alvarez, Stephen W. Pacala, James J. Winebrake, William L. Chameides, and Steven P. Hamburg, "Greater focus needed on methane leakage from natural gas infrastructure." Proceedings of the National Academy of Sciences, February 13, 2012. www.pnas.org/cgi/doi/10.1073/pnas.1202407109

completions (the methane released during flowback of the fracturing fluid). While the EPA has derived a value for this process in the inventory, the Howarth study derived its own higher value based on four data points.

Exhibit 5-3: Comparison of Recent Studies of Life-Cycle Emissions from Natural Gas and Coal Normalized to Methane GWP of 25 (kgCO$_2$e/MMBtu)



Source: Cited studies and ICF Analysis.

Also, the Howarth study did not, like other studies, include the potential for mitigation of the methane emissions. In particular, the completion emissions can be mitigated either by flaring or by REC. Under REC, the gas that would be vented is captured, cleaned and put into pipelines for sale. Two states, Wyoming and Colorado, require that fracturing completions capture or flare the completion emissions; other states are considering such regulations. In 2011, the EPA proposed revised NSPS for the oil and natural gas industry that will require REC or flaring for most gas wells nationally.[41] The NYSDEC has also proposed regulations for shale gas production that would require REC or flaring for most shale gas wells.[42] The assumption in the Howarth Study that there is no mitigation of completion emissions is another primary source of the difference between that study and the other studies and also seems to indicate an overestimate of methane emissions. The Howarth study also assumed higher emission factors

[41] U.S. EPA, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews", 76 FR 52738.
[42] NYSDEC. "High Volume Hydraulic Fracturing Proposed Regulations" , 2012. http://www.dec.ny.gov/regulations/77353.html Although Pennsylvania, which is home to some of the largest deposits of Marcellus Shale, has not proposed similar regulations, gas wells there would be required to follow federal regulations.

than the other studies for several other segments of the gas production chain, in particular fugitive methane from natural gas pipelines, which contributed to the higher overall estimate for both shale gas and conventional gas. In summary, the differences between the Howarth study and the other studies stem primarily from different assumptions and choices of data sources.

While additional reliable emissions data are needed for some segments of the natural gas supply chain, the consensus of the recent studies other than Howarth is life-cycle GHG emissions for natural gas-fired electricity generation of 63 to 75 kg CO_2e/MMBtu. For coal-fired electricity generation, there is even less variation. All of the studies, including the Howarth study, put this at 94 to 108 kg CO_2e/MMBtu. Thus, except for Howarth, the studies estimate that the life-cycle emissions of natural gas-fired electricity range from 36 percent to 47 percent lower than for coal-fired electricity.

5.4 Estimate of New York Gas LCA

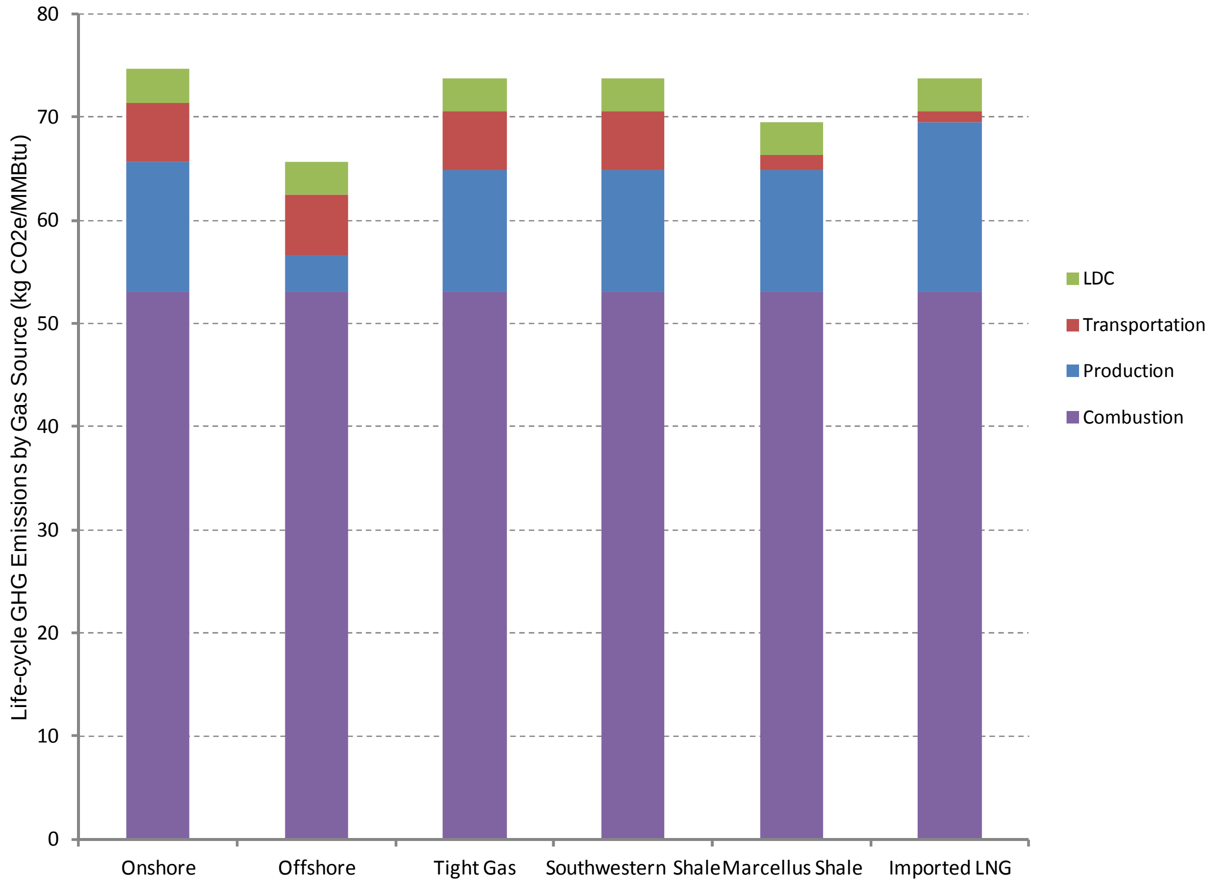
With this background on the available LCA studies, this study tailors the analysis to assess the LCA of gas boilers in New York City based on the specific gas supply and infrastructure. The primary basis for this tailored assessment is the detailed NETL study, which calculates the gas LCA for a variety of sources of natural gas production and delivery.[43] The NETL study assumes well completion emissions 20 percent higher than the EPA inventory estimate and assumes only 15 percent mitigation of emissions from well completion, which is much lower than the EPA estimates of current emissions and lower than under the proposed NYSDEC regulations and EPA NSPS regulations regarding REC or flaring for most shale gas wells. Therefore the LCA estimate for gas boilers in New York is quite conservative.

Exhibit 5-4 shows the NETL summary of upstream GHG emissions by different sources of natural gas. A category for “Marcellus Shale” was added due to the future significance of this source and the difference in emissions associated with its shorter pipeline transmission to New York City. Both tight gas and shale gas use hydraulic fracturing and therefore have high completion emissions for methane. Imported LNG has comparatively higher supply emissions due to the liquefaction and regasification processes and the transportation of the gas from other countries.

The gas transportation segment accounts for combustion and fugitive emissions from gas pipelines. This value was adjusted from the NETL baseline value to account for the distance to New York City. The baseline assumed a distance of 600 miles. This was doubled for sources in the mid-continent and reduced by half for the Marcellus Shale resource and by two-thirds for LNG from New England terminals. The LDC fugitive emissions were not included in the NETL study and were added here. The factor was assumed to be twice the average included in the EPA’s GHG inventory to account for the fact that the New York LDCs have older infrastructure with higher fugitive emissions. The emission factor for gas combustion (53 kg CO_2e/MMBtu) was then added to show the total life-cycle emissions. The values range from 64 kg CO_2e/MMBtu for off-shore conventional gas to 73 kg CO_2e/MMBtu for on-shore conventional gas, with gas from the Marcellus shale at 68 kg CO_2e/MMBtu. This analysis is conservative as it does not include the potential effects of new regulations requiring mitigation of all shale gas completions.

[43] Skone, T.J., “Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production”, National Energy Technology Laboratory, U.S. Department of Energy, DOE/NETL-2011/1522. October 2011.

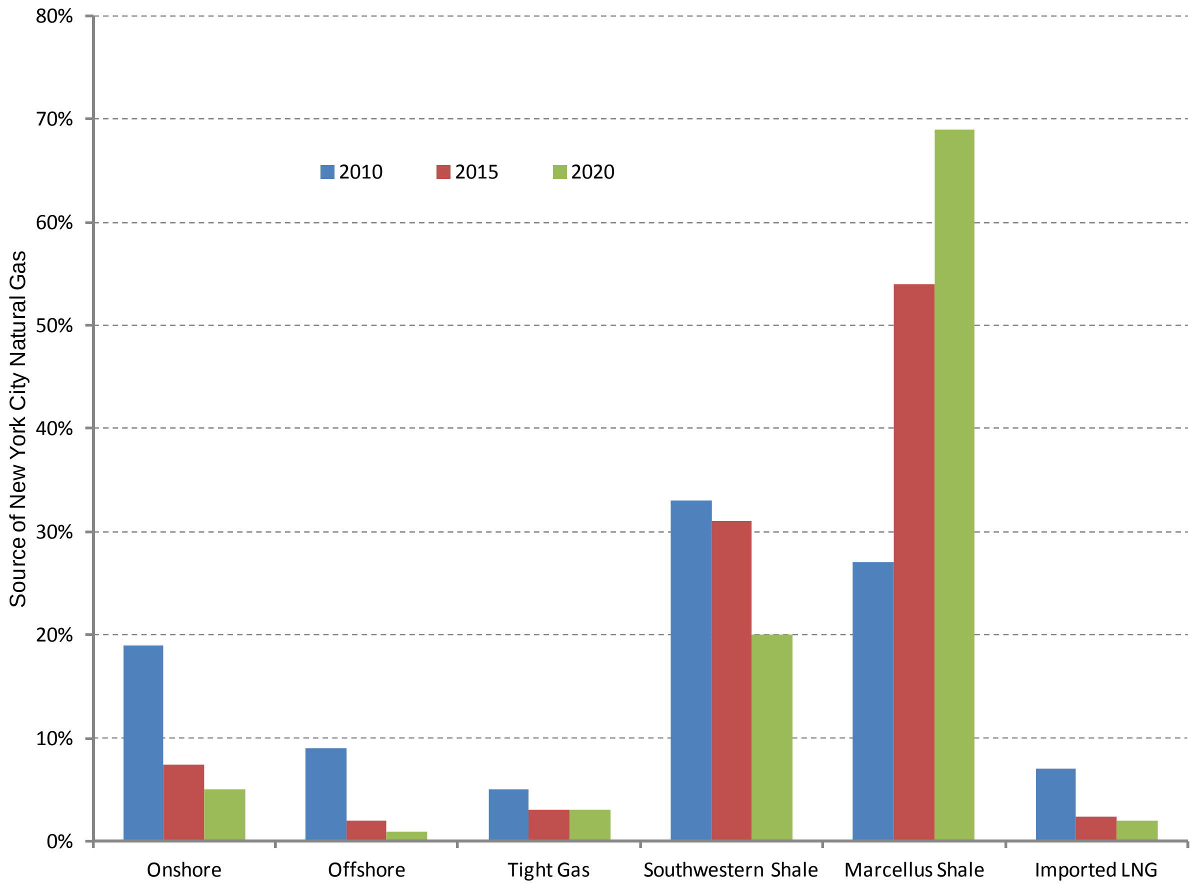
Exhibit 5-4: Life-cycle Emissions by Source of Gas (kg CO_2e/MMBtu)



Source: NETL and ICF Analysis.

The next step for this analysis was to weight these sources according to their contribution to the New York City natural gas supply. The sourcing of natural gas supply to New York City is consistent with the findings of Section 4.3 of this report. Exhibit 5-5 shows how these sources change from 2010 to 2020, with Marcellus Shale gas more than doubling from less than 30 percent of the supply to nearly 70 percent in 2020 and reducing supply from all other sources.

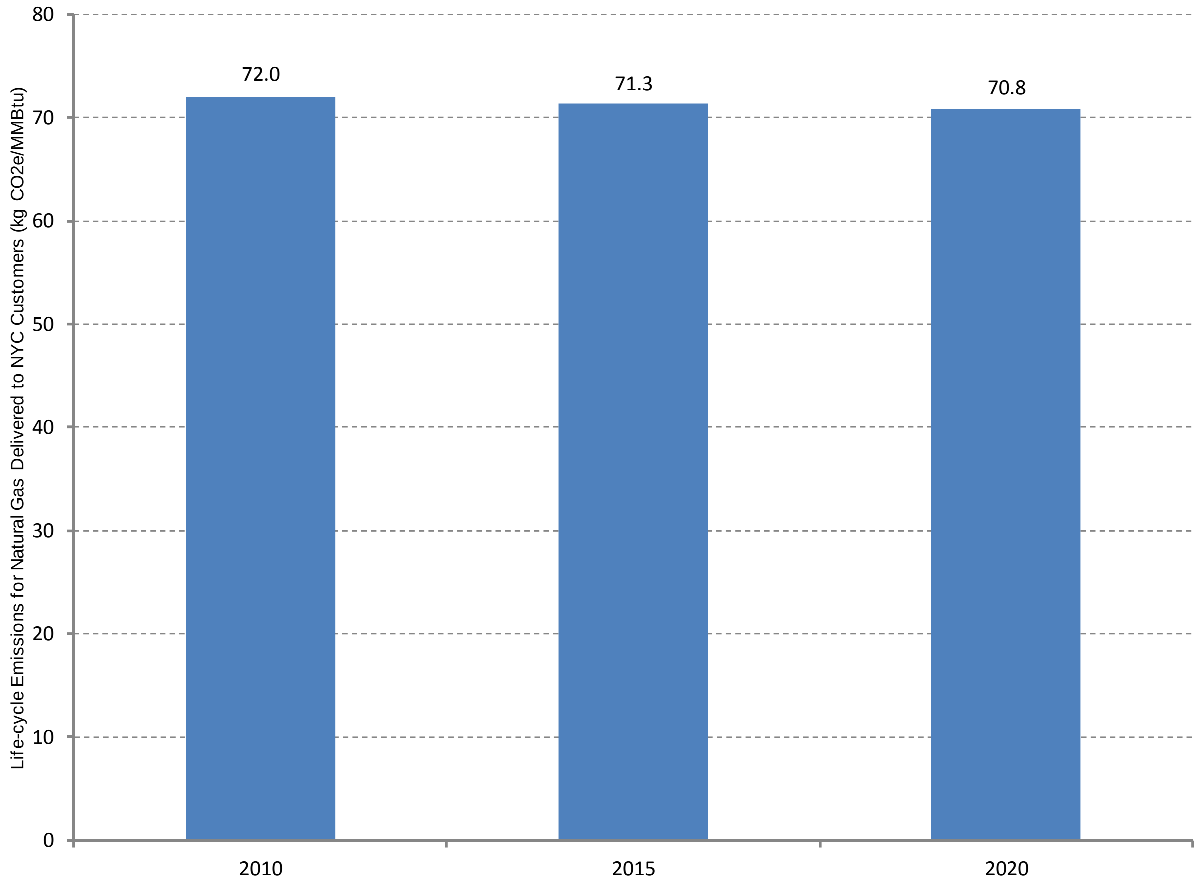
Exhibit 5-5: Sources of New York Gas Supply - 2010 to 2020



Source: ICF Analysis.

Exhibit 5-6 shows the average life-cycle emissions for natural gas supplied to New York City over time as the source of gas and the associated emissions profile change. Based on this analysis, the life-cycle emissions for gas delivered to New York City were estimated to range from 72.0 kg CO_2e/MMBtu in 2010 to 70.8 kg CO_2e/MMBtu in 2020, varying based on the sourcing of the gas and the life-cycle emissions from each source. The value declines slightly as the region shifts to natural gas from the Marcellus Shale, which has lower transportation-related emissions than gas from the mid-continent and Rockies, and away from imported LNG, which has higher upstream emissions.

Exhibit 5-6: Average Life-cycle Emissions for Natural Gas Delivered to NYC Customers (kg CO_2e/MMBtu)



Source: NETL and ICF Analysis.

5.5 Life-cycle Emissions from Oil

The extraction, processing and delivery process for petroleum products is more complex than that for natural gas. However, fugitive methane emissions during this process are much smaller than for the comparable natural gas process. Also, the petroleum process chain is well established, without any major new developments that are comparable to the development and proliferation of shale gas.

The 2009 ICF report "Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water"[44] developed the petroleum LCA factors for a detailed life-cycle analysis of heating oil delivered to various U.S. regions. The report separates the heating oil production, processing and delivery segments as follows:

- Exploration and production – Energy is consumed in the process of exploring for oil, drilling wells, bringing the oil to the surface, and in separating water, other products, and contaminants from the crude oil. The energy and emissions for exploration and

[44] ICF International. "Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water", 2009. Prepared for the Consortium of State Oil Heat Associations.

production activities are based on statistics for U.S. production. Exploration and production of imported oil, which makes up more than 50 percent of crude oil used in the U.S., is assumed to have the same energy and emissions "costs" as defined for domestic production.

- Transportation and Storage – Imported oil must be brought into the U.S. This process is primarily by ocean tanker, though there is oil that enters the country from Canada and Mexico by pipeline or rail transport. Crude oil produced in the U.S. and imports both need to be transported to refineries. This transportation is a mix of pipeline, barge, and rail from domestic production facilities and from import receiving terminals.
- Oil Refining – Crude oil is converted to home heating oil along with an entire slate of other refined products. The energy and emissions associated with oil refining are characterized. In addition, the overall energy and emissions associated with U.S. oil refining are allocated on a unit energy basis to home heating oil based on an assessment of the specific refining steps required to produce that product. There are refined products that are imported into the U.S. for delivery to storage or blending facilities. These products, refined in other countries, are assumed to have the same unit energy and emissions values as estimated for U.S. refined products.
- Bulk Shipments from Refineries – After refining, oil products are bulk shipped to storage and distribution terminals throughout the U.S. Again, these shipments include pipeline, barge, and rail shipments.
- Retail Delivery – Final distribution of home heating oil to customers is undertaken by oil delivery trucks.

The report studied the life-cycle emissions for delivery to five U.S. markets, including New York/New Jersey. Exhibit 5-7 summarizes the GHG emissions for fuel oil serving the New York City region in 2006 and 2020, except for the emissions associated with the end-use combustion of the fuel oil itself. Those emissions range from 13.3 kg CO_2e/MMBtu in 2006 to 14.1 kg CO_2e/MMBtu in 2020. There are two notable changes in the emissions estimates between 2006 and 2020 are:

- The exploration and production emissions are increased due to increased energy consumption for crude oil production from declining resources through various energy-intensive forms of enhanced oil recovery. This could also result from the use of hydraulic fracturing of shale formations to produce petroleum, which is a rapidly growing source of oil in the U.S.
- The refining emissions are increased due to the increased processing required to meet more stringent sulfur limits. Since these limits are already taking effect for New York City, the 2020 value is more appropriate to use for this study.

Exhibit 5-7: Upstream GHG Emissions for Fuel Oil (kg CO_2e/MMBtu)

	2006	2020
Exploration and Production	5.2	5.5
Transportation and Storage	1.1	1.1
Refining	6.8	7.2
Bulk Shipment from Refinery	0.0	0.1
Retail Delivery	0.2	0.2
Total Upstream Emissions	**13.3**	**14.1**

Source: ICF Analysis.

These values were derived for ultra low sulfur (ULS) No. 2 fuel oil based on the 2020 values. No. 6 fuel oil is part of the same product stream as No. 2 fuel oil up until the refining process. For the refining process, the ICF study allocates half as much energy and GHG emissions to No. 6 fuel oil as to ULS No. 2 fuel oil. Low sulfur (LS) No. 4 fuel oil in the New York City market is typically a blend of ULS No. 2 and No. 6 oil, so the LCA for it is calculated accordingly. The bulk delivery from the refinery and retail delivery is assumed to be the same for all three products. Exhibit 5-8 summarizes the results of this analysis plus the CO_2 emissions from combustion of the fuel oil itself. The heavier fuel oils have higher combustion emissions of CO_2 than the light oils but this is offset by the energy associated with increased processing required to reduce the sulfur content of the lighter oils. Therefore, ULS No. 2 fuel oil has higher upstream emissions than LS No. 4 or No. 6 fuel oils, before taking into account boiler efficiency.

Exhibit 5-8: Life-Cycle GHG Emissions for Fuel Oil in New York City (kg CO_2e/MMBtu)

	ULS No. 2	LS No. 4	No. 6
Exploration and Production	5.5	5.5	5.5
Transportation and Storage	1.1	1.1	1.1
Refining	7.2	5.4	3.4
Bulk Shipment from Refinery	0.1	0.1	0.1
Retail Delivery	0.2	0.2	0.2
Total Upstream Emissions	**14.1**	**12.3**	**10.3**
Combustion emissions	74.0	75.0	75.1
Total Life-Cycle Emissions	**88.1**	**87.3**	**85.4**

Source: ICF Analysis.

5.6 Life-Cycle Emissions for Biofuels

New York City has adopted requirements for a two percent biofuel content in heating oil. The City has an interest in expanding the use of biofuel in heating fuel as a way of reducing both conventional pollutants and GHG emissions. The direct CO_2 emissions from combustion of biofuels are typically not counted as increased (anthropogenic) CO_2 emissions because they are just the CO_2 that was absorbed by the plants from the biosphere, so there is no net increase in atmospheric CO_2. However, the upstream CO_2 content associated with transporting and processing the biofuel must be accounted for, which is the goal of LCA. The LCA here is derived from the same ICF report referenced in the last section. The primary reference for information on biofuel emissions used in that report is an NREL study from 1998.[45]

The report assumed that, in the near term, biofuel from dedicated crops will be made from soybeans.[46] The biofuel fuel cycle consists of the following general activities:

[45] John Sheehan, et al., "Life Cycle Inventory of Biodiesel and Petroleum Diesel for Use in an Urban Bus", National Renewable Energy Laboratory, May 1998. This study is a widely-cited reference on life-cycle emissions for biofuel. That said, there are multiple potential feedstocks for biofuels and many upstream emission pathways to consider, including indirect land use, which is not considered in this example. The soybean option considered here is indicative of current practice in the New York region but other options may become more common in the future.

[46] Used cooking oil is currently being collected and converted into biofuel in New York. Since much of this is soybean oil, it is reasonable to assume that the same upstream life-cycle emissions apply. If the emissions associated with the production of vegetable oil for food use are subsumed in the first use, it is arguable that they should not be included in the LCA for recycled oil converted to heating oil. Thus, the emissions associated with agriculture through crushing could be subtracted, reducing the life-cycle emissions by approximately 50%.

- Biofuel Agriculture – consisting of all of the activities associated with planting, tending, and harvesting soybeans.
- Transportation and Storage –delivering the soybeans to the crushing facility.
- Processing (Bio-refining) – consisting of crushing, which separates the raw oil from the seed meal, and refining of the oil to biofuel by a process called transesterifcation.
- Blending with Conventional or Low-Sulfur Heating Oil – the final biofuel product is generally a blend of petroleum based heating oil and biofuel.
- Retail Transportation - the transportation of biofuel to home heating customers.

The ICF Study assessed life-cycle emissions for various demand centers, including the New York/New Jersey/Pennsylvania area . For each of the demand centers, the closest soybean production locations were assumed to supply the feedstock for biofuel production. Soybean yields for the production locations were updated from the 1995 assumptions used by NREL to more recent data for the 2009 ICF study.[47] For the 2020 forecast, it was assumed that there would be evolutionary improvements in agriculture yield, processing efficiencies, and an aggressive use of biodiesel fuel in the transport operations that would result in increases in soybean yields by 20 percent. This increase was based on an analysis of the historical improvement to soybean yields over the last 20 years.

Exhibit 5-9 shows the life-cycle emissions for each of the steps in biofuel production for 2006 and 2020 and the average of the two. This study uses the average value as the basis for emissions for the next decade. The upstream emissions are estimated at 19.6 kg CO_2e/MMBtu and the GHG emissions from combustion are assumed to be zero.

Exhibit 5-9: Life-cycle Emissions for Biofuels (kg CO_2e/MMBtu)

	2006	2020	Average
Agriculture	2.9	2.4	2.6
Transport to Crusher	0.3	0.3	0.3
Crushing (Oil Extraction)	7.3	5.9	6.6
Intermediate Transport	0.5	0.5	0.5
Bio-Refining	10.5	8.4	9.4
Retail Transport	0.2	0.2	0.2
Total Upstream Emissions	**21.6**	**17.6**	**19.6**
BioFuel Combustion	0.0	0.0	0.0
Total Fuel Cycle Emissions	**21.6**	**17.6**	**19.6**

Source: ICF Analysis.

It is most likely that biofuel will be blended with petroleum-based heating oil in ratios of 2-20 percent biofuel. However, the use of pure biofuel is technically feasible with appropriate precautions in fuel handling and materials compatibility.

5.7 LCA Comparison of Heating Fuels

Based on the analysis above, Exhibit 5-10 compares the life cycle emissions of natural gas (2015 factors), fuel oils, and biofuel as delivered to New York City customers, and as delivered heat energy considering boiler efficiency.

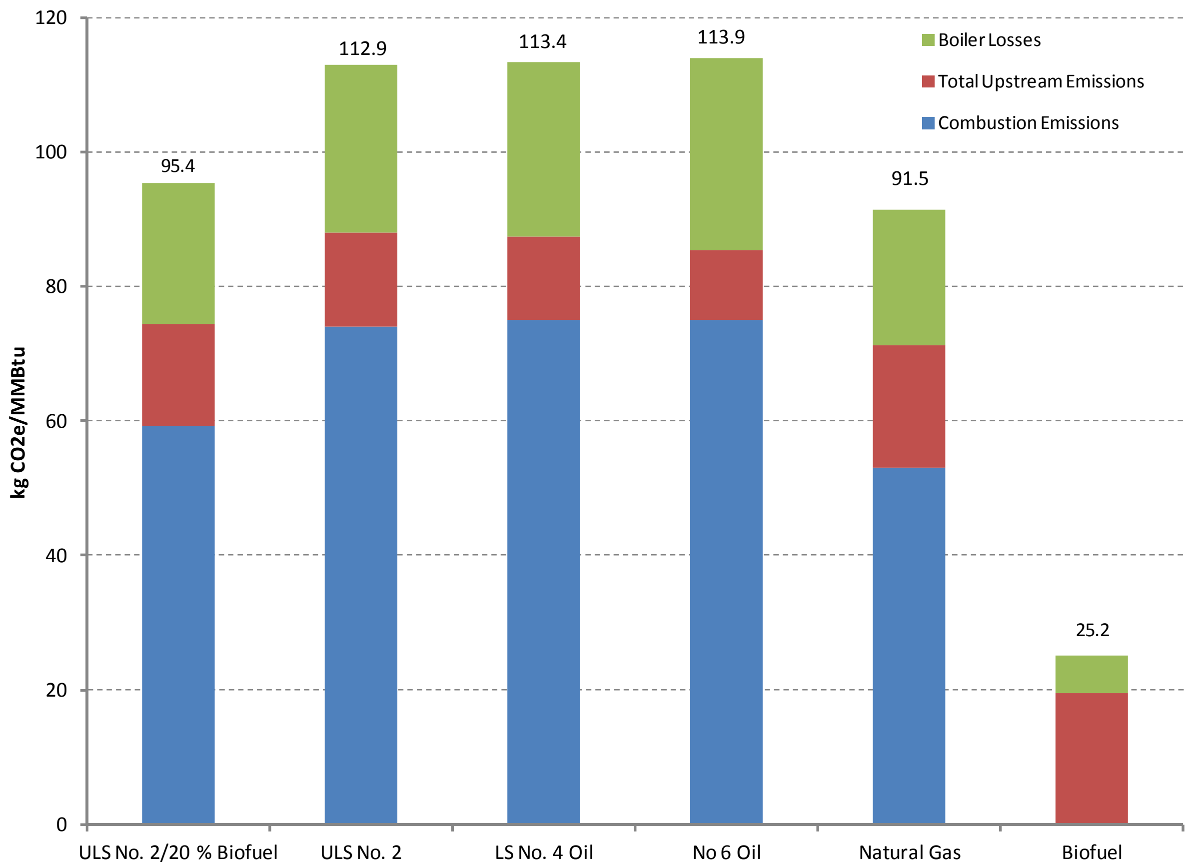
[47] ICF International. "Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water", 2009. Prepared for the Consortium of State Oil Heat Associations.

Exhibit 5-10: Total Life-cycle Emissions for Fuels Used in Boilers (kg CO_2e/MMBtu)

	ULS No.2/ 20% Biofuel	ULS No. 2	LS No. 4	No. 6	Gas	Biofuel
Total Upstream Emissions	15.2	14.1	12.3	10.3	18.3	19.6
Combustion Emissions	59.2	74.0	75.0	75.1	53.0	0.0
Total Fuel Emissions	74.4	88.1	87.3	85.4	71.3	19.6
Boiler Efficiency	78%	78%	77%	75%	78%	78%
Total Life-Cycle Emissions for Delivered Energy	95.4	112.9	113.4	113.9	91.5	25.2

Source: ICF Analysis.

Exhibit 5-11: Summary Life-Cycle GHG Emissions Comparison for Residential and Commercial Boilers in New York City (kg CO_2e/MMBtu)



Source: ICF Analysis.

6. Summary and Conclusions

6.1 Natural Gas Market Assessment

Natural gas demand and production are expected to grow robustly in the U.S. and Canada. As we exit the recession, most of the increase in natural gas demand will be from growth in natural gas-fired generating facilities. With the recent development of new shale gas supplies, and their abundance, North American production will keep pace with this growth in demand at gas prices that are moderate, compared to recent history. Indeed, gas prices are expected to remain moderate over the 2010 to 2030 period. By the end of the forecast period, ICF believes that over 80 percent of the gas going to New York City will be shale gas from nearby areas.

For the LDCs that serve New York City, ConEd and NGrid, the peak day demand is the critical design challenge, which they meet through a combination of supply contracts on pipelines, short-term peak-shaving facilities that can store gas for use during peak periods, interrupting interruptible customers, and purchase of capacity released by other shippers. Without taking into account conversions from heavy oil to natural gas , both LDCs expect growth in their peak-day sendout requirements of about 1.1 percent per year, as well as growth in total deliveries of less than one percent per year.

Conversions to natural gas as a result of the City's phase-out of heavy oil use are expected to increase peak-day sendout and delivery growth rates for the LDCs, exacerbating existing upstream and local supply and delivery constraints, and require both increased pipeline capacity and expansion of the LDCs' distribution systems. While we expect that conversions will take place over the next decade, which may moderate their short-term impact on gas supply system needs, locally and upstream, the length of the implementation term does not change the overall conclusion regarding the effects of conversions from heavy oil to natural gas and the associated system needs.

ICF estimates that the conversion of all No. 4 and No. 6 oil boilers to natural gas would increase average daily sendout by about 0.16 Bcfd and peak day firm sendout by about 0.56 Bcfd. The former represents a 16 percent incremental increase, and the latter constitutes a 30 percent incremental increase over the forecasts described above. The conversions would constitute a 58 percent increase in peak day load for ConEd and a six percent increase in peak day load for NGrid. Lesser conversion levels would result in smaller, but still significant, increases in the LDCs' peak day requirements.

6.2 Analysis of Life Cycle Emissions for Oil and Natural Gas

Life-cycle emissions of GHGs from fossil fuels are an important environmental consideration due to the global impacts of GHGs. With one exception, recent studies of the LCA of fossil fuels have shown that GHG emissions from shale gas are on the order of 11 percent higher than for conventional gas and that the GHG emissions from gas-fired electricity production range from 36 percent to 47 percent lower than coal-fired electricity production. As to the exception it is important to note that the different results from the Howarth study were largely based on input assumptions rather than new empirical analysis or new data.

The information from the other recent LCA studies can be applied to develop an LCA comparison of natural gas and fuel oil used in boilers in New York City. This analysis estimates total lifecycle emissions of 91.5 kg CO_2e/MMBtu for boilers in New York City using natural gas,[48] as compared to lifecycle emissions of 112.9 kg CO_2e/MMBtu for heat from ULS No. 2 fuel oil and 113.9 kg CO_2e/MMBtu for No. 6 fuel oil. In other words, natural gas has life-cycle GHG emissions roughly 20 percent lower than fuel oil per unit of energy delivered to customers. It also shows that the boiler losses due to efficiency are much larger than the effect of upstream emissions for oil-fired boilers and roughly comparable for gas-fired boilers. Biofuel has lifecycle GHG emissions of 25.2 CO_2e/MMBtu, making it an environmentally beneficial addition to conventional heating oil. Heating oil with a 20% biofuel admixture has lifecycle GHG emissions nearly as low as natural gas.

The estimation of GHG emissions from shale gas production continues to be studied and refined. The collection of better data on these emissions will allow for better characterization of the emissions. There are also proposed federal and state regulations that would require reductions to these emissions starting in 2012. Those regulations, if adopted, will result in life-cycle emissions for shale gas that are lower than those calculated here.

In sum, this study concludes that converting No. 6 fuel oil boilers in New York City to cleaner fuels, including natural gas, will create significant GHG reductions.

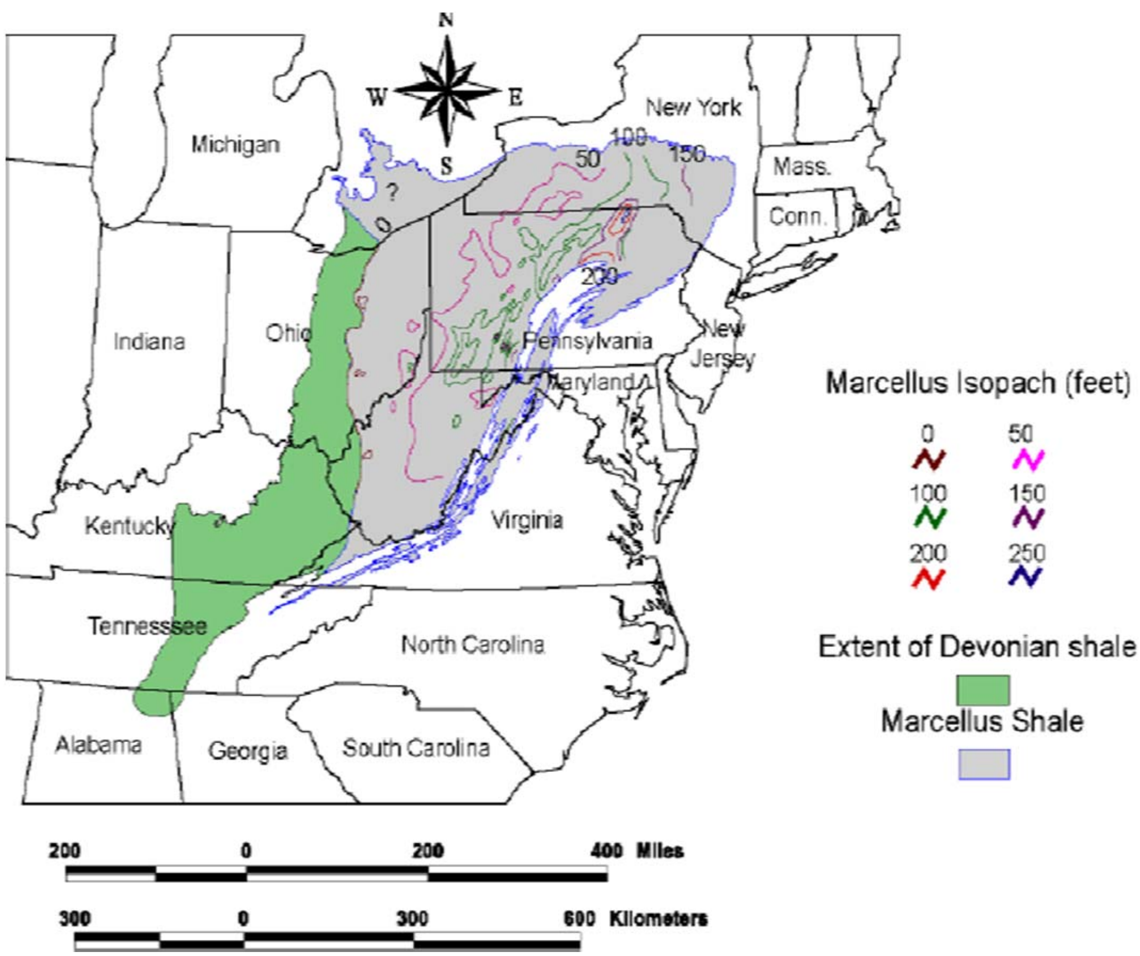
[48] Including boiler loses.

7. Appendix A: Marcellus Shale Development

Marcellus Shale is a Middle Devonian-age black, low density, carbonaceous shale with a slightly radioactive signature that makes it very easy to pick out on a geophysical well log. It is found nearly a mile below the surface of West Virginia, Ohio, Pennsylvania, New York, and small portions of Maryland, Virginia, Kentucky, and Tennessee. The thickest parts of the formation are in north central Pennsylvania (Exhibit 7-1).

Until recently, Marcellus Shale was not seen as a major target for development. In 2002, the United States Geological Survey assessed the resource at nearly 2 Tcf, a significant amount of gas, but considering the geographic extent of Marcellus Shale, not much gas on a per acre basis. Exploration company Range Resources – Appalachia LLC (Range Resources) is given the credit for starting the Marcellus Shale development in Pennsylvania, as it drilled wells into the shale formation as early as 2003. Range Resources experimented with hydraulic fracturing methods that had worked in the Barnett Shale in Texas. Marcellus Shale production began in 2005 and by the end of 2007 nearly 400 wells had been permitted in Pennsylvania.

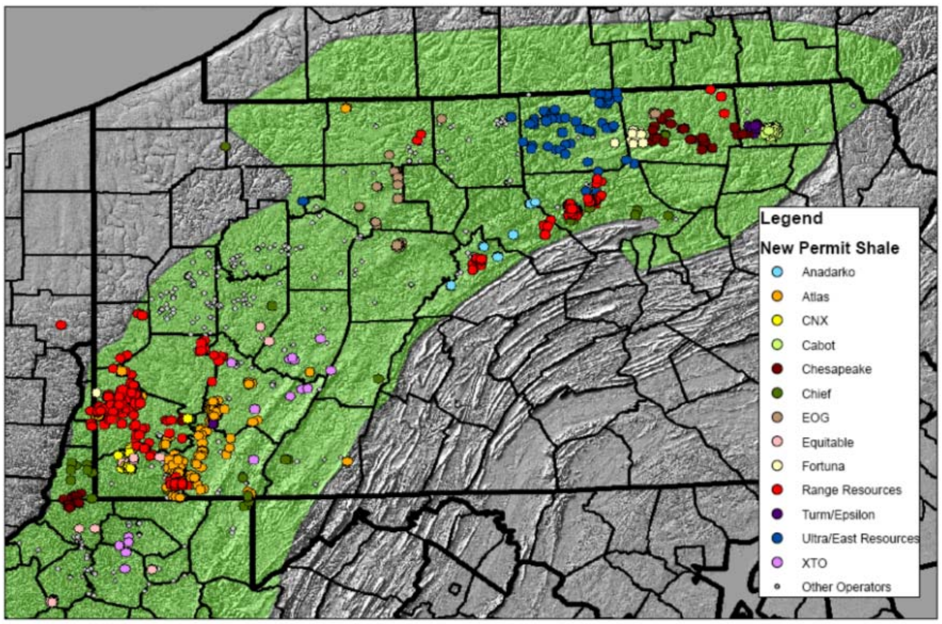
Exhibit 7-1: Thickness Map of Marcellus Shale



Source: USGS.

In early 2008, a study by two professors, Terry Englender and Gary Lash, produced much higher estimates than previously reported, calculating the Marcellus Shale gas resources at 500 Tcf, of which 10 percent or 50 Tcf might be recoverable[49]. After this study was released, Range Resources found that it had competition for Marcellus Shale acreage, as at least twelve other producers have shown interest in the Pennsylvania portions of the Marcellus Shale (Exhibit 7-2). Nearly 500 Marcellus Shale wells were permitted in Pennsylvania in 2008, and another 2,000 wells were permitted in 2009. Roughly 40 percent of the issued permits had been drilled through 2009.

Exhibit 7-2: Marcellus Shale Drilling Permits



Source: Range Resources

The Marcellus Shale formation is located close to market areas in the Northeast and is situated right in the middle of existing pipeline corridors. (See Exhibit 3-5 in the main report.) Five major long haul interstate pipelines cross through the formation. All of these pipelines have access to premium price markets along the East Coast, and can relatively easily expand takeaway capacity to accommodate growing Marcellus Shale gas production.

[49] Englender, Terry and Lash, Gary. "Marcellus Shale Play's Vast Potential Creating Stir in Appalachia." The American Oil and Gas Reporter. May 2008. http://www.marcellus.psu.edu/resources/PDFs/EngelderLash08OGRept.pdf . .

8. Appendix B: ICF's Gas Market Model

ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed by Energy and Environmental Analysis, Inc., now a wholly owned business unit within ICF International, in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. For example, much of the initial work with the model in 1996-97 focused on assessing the impact of the Alliance pipeline completed in 2000. The questions answered in the initial studies include:

- What is the price impact of gas deliveries on Alliance at Chicago?
- What is the price impact of increased takeaway pipeline capacity in Alberta?
- Does the gas market support Alliance? If not, when will it support Alliance?
- Will supply be adequate to fill Alliance? If not, when will supply be adequate?
- What is the marginal value of gas transmission on Alliance?
- What is the impact of Alliance on other transmission and storage assets?
- How does Alliance affect gas supply (both Canadian and U.S. supply)?
- What pipe is required downstream of Alliance to take away "excess" gas?

Subsequently, GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

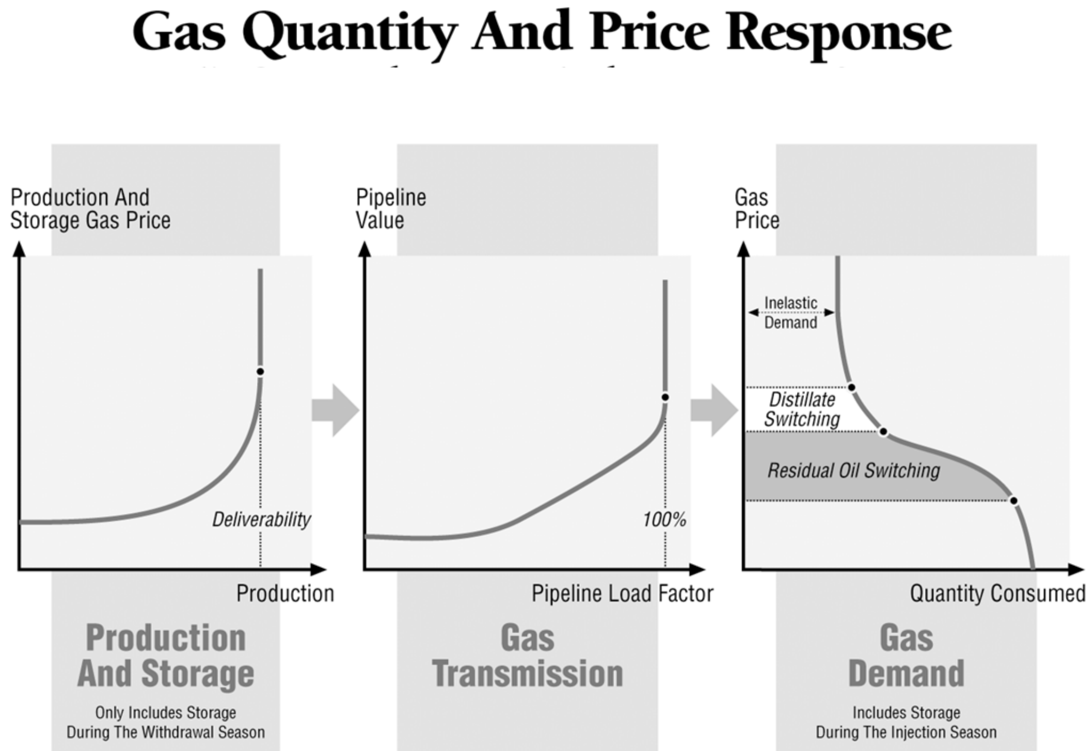
- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including the Interstate Natural Gas Association of America, which relied on the model for the 30 Tcf market analysis completed in 1998 and again in 2004. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003.

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Exhibit 8-1). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Exhibit 8-1: Natural Gas Supply and Demand Curves in the GMM

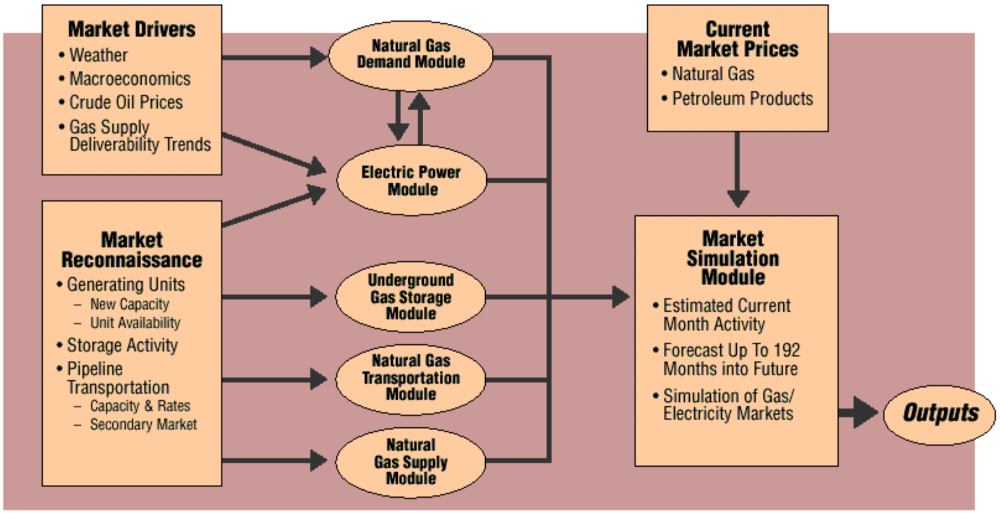


Source: ICF GMM®

There are nine different components of ICF's model, as shown in Exhibit 8-2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

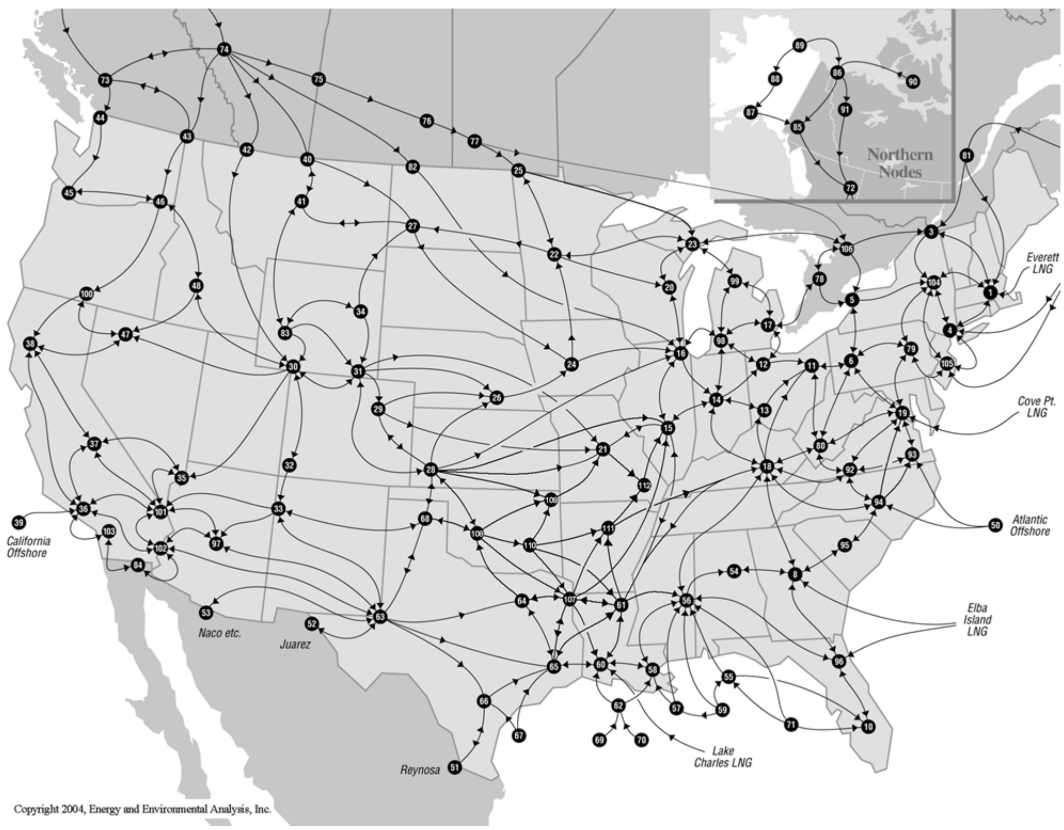
The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Exhibit 8-3. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The Hydrocarbon Supply Model may be integrated with the GMM to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (*i.e.*, gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (*i.e.*, end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

Exhibit 8-2: GMM Structure



Source: ICF GMM®.

Exhibit 8-3: GMM Transmission Network



Source: ICF GMM®.