Natural Gas Pipeline and Storage Infrastructure Projections Through 2030

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1 Executive Summary

Sufficient midstream natural gas assets, such as gathering systems, processing plants, transmission pipelines, storage fields, and liquefied natural gas (LNG) import terminals, are crucial for an efficient natural gas market. Insufficient natural gas infrastructure can lead to price volatility, reduced economic growth, and reduced delivery of natural gas to consumers who value it most. Since the last INGAA Foundation natural gas infrastructure study in 2004, an increased reliance on new and unconventional natural gas supplies, continued growth in natural gas consumption in the power generation sector, and an increased focus on carbon policy all point toward significant opportunities for the industry. The objective of this report is to provide a long-term planning document that can form a basis upon which the INGAA Foundation and industry can engage policy makers and stakeholders on the issues that are important for maintaining a healthy industry.

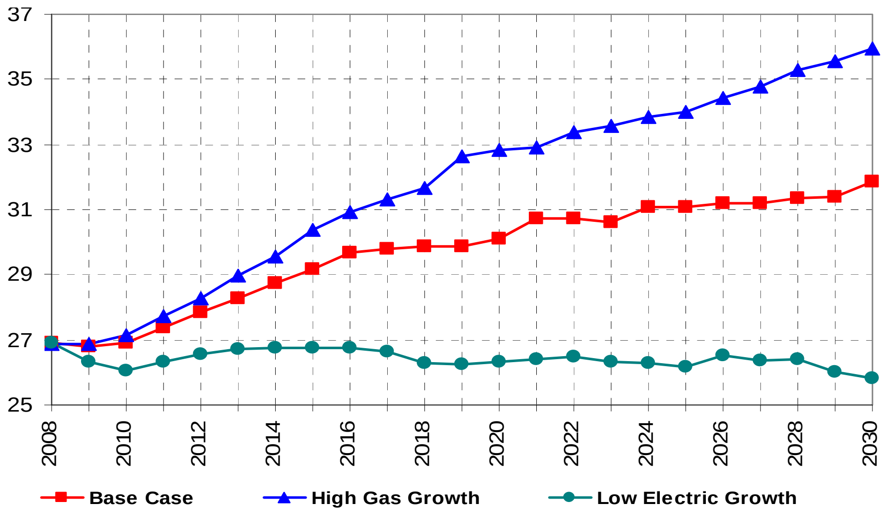
All three cases examined in this report result in the need for significant and continuous capital expenditures on natural gas infrastructure.

To forecast future natural gas infrastructure requirements, three different projections of the United States and Canadian natural gas market have been created; a Base Case, that represents an expected or most likely view of the future; a High Gas Growth Case in which markets and policies lead to greater growth in natural gas consumption; and a Low Electric Growth Case in which electricity sales growth is relatively lower in the future. The Base Case reflects an expected outcome for U.S. and Canadian natural gas markets by, in most cases, continuing recent market trends. The High Gas Growth Case tests the upper range of possible infrastructure needs by assuming reasonable policies and market results that increase natural gas consumption. The High Gas Growth Case also includes more optimistic, yet plausible, assumptions related to additional natural gas supplies. The Low Electric Growth Case assumes very strong and successful conservation measures for electricity sales. This case projects relatively lower gas consumption, because electricity sales are a key determinant of future natural gas consumption. All three cases result in the need for significant and continuous capital expenditures on natural gas infrastructure.

The three cases project very different levels of natural gas use. In the Base and High Gas Growth cases, gas use in the U.S. and Canada is projected to grow from 26.8 trillion cubic feet (Tcf) in 2008 to between 31.8 to 36.0 Tcf by 2030 (Figure 1) This equates to an increase of 18 to 34 percent or an annual growth rate of between 0.8 to 1.3 percent. In the Low Electric Growth Case, gas consumption that is relatively stable for most of the forecast declines to a level in 2030 that is about 4 percent below the 2008 level. However, significant infrastructure is still needed to move new supplies into the interstate pipeline transmission network.

About three-fourths of total market growth is projected to occur in the power sector in the Base and High Gas Growth cases. Electric load growth, penetration of renewable power technologies, penetration of clean coal with carbon capture, and expansion of nuclear generation are areas of uncertainty in the modeled cases. Greenhouse gas regulation will significantly influence these variables.

Figure 1
U.S. and Canada Natural Gas Consumption from 2008 Through 2030 (Tcf)



> *Insufficient natural gas infrastructure can lead to price volatility, reduced economic growth, and reduced delivery of natural gas supply to consumers who value it most.*

The INGAA Foundation cases also project very different levels of gas supply over time. U.S. and Canadian natural gas supply is diverse, with natural gas originating from many different sources and areas. Natural gas supply from multiple sources must grow to meet future consumption needs and to offset production declines from conventional supply sources. The cases project that U.S. and Canadian production from conventional formations and basins is projected to decline in terms of both the absolute production level and market share. Annual volumes from conventional formations are projected to decline from 19.0 Tcf in 2008 to a range of 10.0 to 13.5 Tcf by 2030 (Figure 2).

Conversely, unconventional[1] and frontier[2] natural gas production significantly increase in all three cases, even in the Low Electric Growth Case that projects a flat to declining gas market. Unconventional and frontier natural gas supplies grow from 8.0 Tcf in 2008 to between 16.1 and 22.4 in 2030. U.S. and Canadian LNG imports are projected to increase from a 2008 level of 350 billion cubic feet (Bcf) to between 1.6 to 1.8 Tcf per year by 2030 in the Base and High Gas Growth cases. LNG imports fluctuate near the 2008 level in the Low Electric Growth Case.

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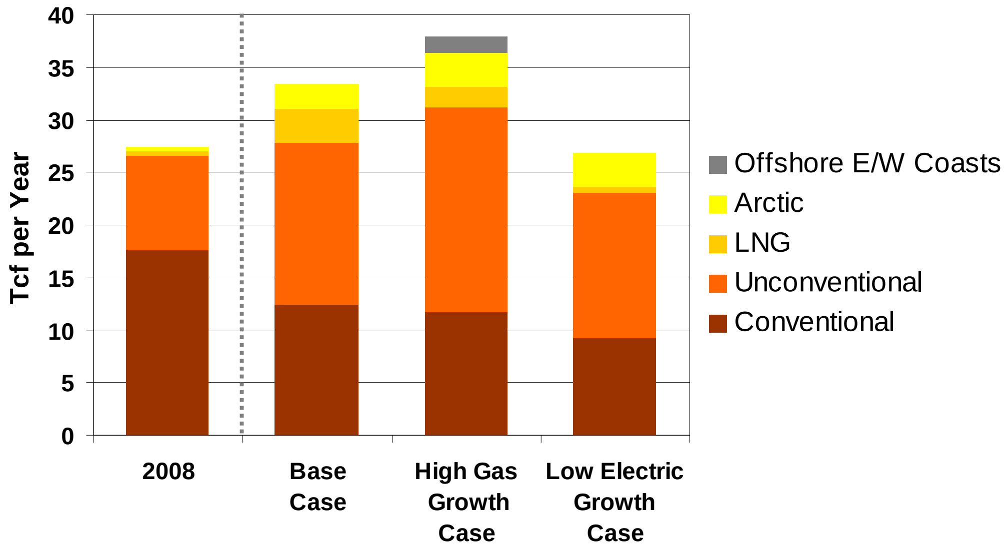
[1] Unconventional natural gas is produced from geologic formations that may require well stimulation or other technologies to produce. For more information, see the report ICF International prepared for the INGAA Foundation in 2008 entitled *Availability, Economics, and Production Potential of North American Unconventional Natural Gas Supplies*.

[2] Frontier supplies include Arctic natural gas production and production from remote or new offshore areas such as the deeper waters of the Gulf of Mexico and the offshore moratorium areas off of the East and West Coasts and the coasts of Florida.

Figure 2
Conventional, Unconventional, and Frontier Natural Gas Supplies, 2030 Versus 2008 Level



> *The U.S. and Canada will need 28,900 to 61,900 miles of additional natural gas pipeline and 371 to 598 Bcf of additional storage capacity.*

Future pipeline infrastructure will be most influenced by the shift of production from mature basins to relatively new production areas. As a result, even the Low Electric Growth Case exhibits a significant need for additional pipeline capacity. Natural gas consumption growth has an important, although relatively smaller, influence on natural gas infrastructure development. Incremental pipeline infrastructure will be needed to serve growth in power generation, because spare seasonal pipeline capacity will not be available.

To accommodate the changes in natural gas supply and demand, the U.S. and Canada will need 28,900 to 61,900 miles of additional natural gas pipeline by 2030. This will require an investment of $108 to $163 billion in pipeline assets[3]. Annual expenditures for pipeline infrastructure are expected to average between $5.0 and $7.5 billion per year, greater than the average annual expenditure over the past decade.

Changes in gas supply and demand also require significant investment in gas storage. Between 2009 and 2030, the U.S. and Canada will need 371 to 598 Bcf of additional gas storage capacity[4]. Total expenditures on new storage capacity range from $2 to $5 billion. Much of the new storage capacity that is needed is high deliverability storage to meet the growth in gas demand for electricity generation.

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[3] Includes both new pipeline and compression.

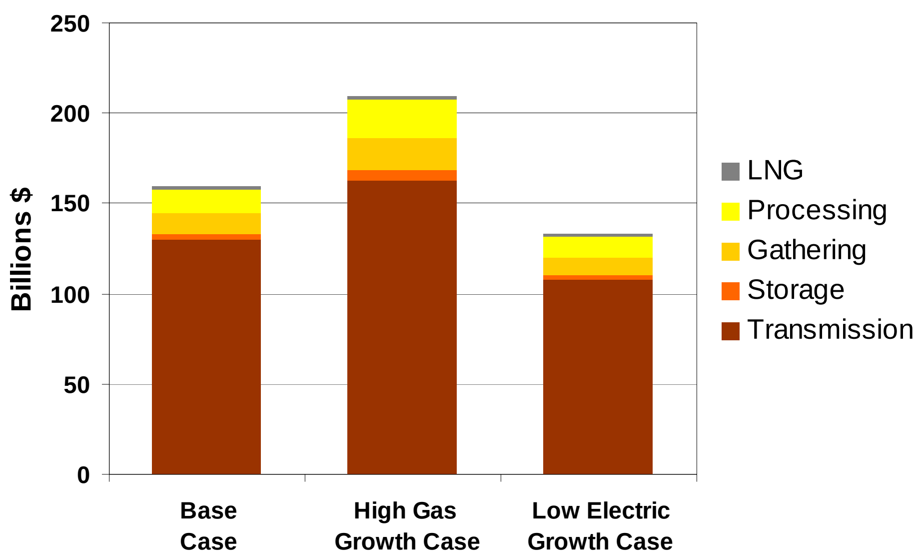
[4] Working gas capacity only – does not include base gas capacity.

From 2009 to 2030, a total of $133 to $210 billion must be spent on all types of midstream natural gas infrastructure, equating to a range between $6.0 and $10.0 billion per year (Figure 3). Approximately 80 percent of the necessary midstream infrastructure expenditures will be for natural gas transmission pipelines. New processing investments will account for 8 to 10 percent of the investment in midstream assets. Storage and liquefied natural gas (LNG) infrastructure, while important for efficient market operations, are projected to account for relatively small portions (2 to 3%) of the total future investment[5].

From 2009 to 2030, $133 to $210 billion (or about $6 to 10 billion per year) must be spent on all midstream natural gas infrastructure to satisfy market requirements.

Expansion of natural gas infrastructure is not guaranteed. Many issues loom, particularly uncertainties regarding direction of energy and environmental policies, and whether those policies will promote or discourage natural gas use.

Figure 3
Total Expenditures for Natural Gas Pipeline, Storage, and Gathering Infrastructure, 2009 – 2030 (Billion $)



[5] Current LNG import capacity is underutilized and can readily accommodate projected growth. Although storage working gas capacity increases by between 10 and 13 percent over 2008 levels in the projection, the cost of developing the incremental storage capacity is less, relative to pipeline investments.

2 Introduction

The INGAA Foundation has made a concerted effort to contribute to the knowledge base of the public policy dialogue concerning the natural gas pipeline industry through its periodic infrastructure studies undertaken in 1999, 2001, and 2004. These studies have provided a solid foundation for policy makers and industry participants to have a constructive dialogue about the issues that affect industry and markets. The natural gas industry has used the previous studies to highlight the importance of new pipeline and storage infrastructure in achieving the economic and environmental benefits of a growing natural gas market.

Sufficient midstream natural gas assets, such as gathering systems, processing plants, transmission pipelines, storage fields, and LNG import terminals, are crucial for an efficient natural gas market. In the U.S. and Canada, there are roughly 38,000 miles of gathering pipeline, 85 Bcf per day of natural gas processing capacity, 350,000 miles of transmission pipeline, 4.5 Tcf of natural gas storage capacity[6], and 12 Bcf per day of LNG import capacity.[7] These assets must be maintained and enhanced if the natural gas market is to continue to function and grow efficiently.

Since the last INGAA Foundation natural gas infrastructure study in 2004, an increased reliance on new and unconventional natural gas supplies, continued growth in natural gas consumption in the power generation sector, and an increased focus on carbon policy all point toward significant opportunities for the industry. The objective of this report is to provide a long-term planning document that can form a basis upon which the INGAA Foundation and industry can engage policy makers and stakeholders on the issues that are important for the natural gas industry to contribute to a cleaner environment and a healthy North American economy.

This 2009 report estimates future natural gas infrastructure requirements, discusses the factors that affect those requirements, and presents and analyzes the important issues that will determine whether or not that infrastructure can be placed in service on a timely basis. More specifically, the report:

- Discusses natural gas market drivers such as economic growth, oil prices, weather, and natural gas supply developments.
- Presents three detailed supply/demand outlooks for the U.S. and Canadian natural gas markets that provide a basis for the infrastructure analyses.
    - A Base Case that represents an expected view of the future.
    - A High Gas Growth Case in which specific policies lead to greater natural gas consumption relative to the Base Case.
    - A Low Electric Growth Case in which electricity sales growth is well below the Base Case level of growth. This case projects relatively lower natural gas consumption because electricity sales are a key determinant of future natural gas consumption.

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[6] Estimated amount of working gas capacity.
[7] Sources: Energy Information Administration, U.S. Department of Transportation Pipeline and Hazardous Materials Safety Commission Administration (Office of Pipeline Safety), Federal Energy Regulatory Commission, and Statistics Canada.

- Presents historical trends in natural gas demand by sector and projects the expected levels of natural gas consumption regionally though 2030.
- Presents historical trends in natural gas supply by source and projects the expected levels of supply regionally though 2030.
    - Summarizes recent developments in unconventional natural gas resources.
    - Discusses the outlook for LNG imports into North America.
- Describes the contribution of natural gas storage in meeting seasonal and daily natural gas requirements.
- Estimates natural gas infrastructure needs and utilization for the three market outlooks and relates them to projected changes in regional natural gas markets. Midstream infrastructure projections include:
    - Natural gas transmission pipeline mileage.
    - Natural gas pipeline horsepower (HP) compressor capacity.
    - Underground natural gas storage capacity.
    - Natural gas gathering system mileage.
    - Natural gas processing plant capacity.
    - LNG import terminal construction requirements including both new capacity and expansions to existing capacity.
- Discusses the historical and projected cost trends for rights-of-way, materials, and labor.
- Projects midstream natural gas infrastructure capital expenditures for the three market outlooks.
- Discusses the importance of maintaining the integrity and operable capacity of existing natural gas infrastructure and the efforts required to do so.
- Discusses key issues for the natural gas market, including greenhouse gas (GHG) emissions, alternative fuel vehicles, carbon capture and storage (CCS) in the power sector, renewable energy, and energy conservation.
- Summarizes the current status of the Arctic natural gas projects.
- Presents information concerning the potential of synthetic natural gas (SNG) and gas hydrates and the role they could play in the U.S. and Canadian natural gas market.
- Describes the market and regulatory environment in which new infrastructure investments are made.

The assumptions for the Base Case, the High Gas Growth Case and the Low Electric Growth Case have been defined in consultation with the INGAA Foundation staff and an INGAA Foundation Steering Committee. ICF has used its proprietary Gas Market Model (GMM) to produce U.S. and Canadian natural gas market projections through 2030.[8] Historical and proposed pipeline capacity, mileage, horsepower, and cost data used to project trends for the analysis have been obtained from the United States Energy Information Administration (EIA) [9]

[8] The ICF model is summarized in Appendix B.
[9] The EIA pipeline project database is largely a compilation of data from Federal Energy Regulatory Commission (FERC) filings of interstate pipelines although other public sources are also used.

and the Oil and Gas Journal[10]. Regional reporting in this document is as per the regions shown in Figure 4.

Figure 4
Regional Reporting

Note: Regions based on EIA classifications. Alaska / Arctic includes: Alaska and the Canadian territories of Yukon, Nunavut, and Northwest Territories. The Canada region includes all provinces south of latitude 60 degrees north or east of Hudson Bay.

[10] *Oil and Gas Journal*'s annual survey of pipeline construction costs.

3 Key Drivers of Natural Gas Infrastructure – Supply and Demand

The U.S. and Canadian natural gas commodity markets are deregulated, competitive, fairly well integrated, and relatively liquid markets. In 2008, the U.S. and Canada together consumed 26.8 Tcf of natural gas, with the U.S. consuming 23.2 Tcf and Canada consuming 3.5 Tcf. Most natural gas consumed in the U.S. and Canada is produced domestically. LNG imports from overseas sources accounted for only 1 percent of total U.S. and Canadian natural gas supplies in 2008.

Natural gas is produced and consumed at many different locations throughout the U.S. and Canada. Still, natural gas production often is hundreds, or even thousands, of miles from consumers. The U.S. and Canadian natural gas pipeline and storage network is a necessary link in getting natural gas production to the consumer when it is needed. The current interstate and intrastate pipeline infrastructure affects how much natural gas can reach the market at any one time. The analysis and quantification of future natural gas infrastructure needs is the primary objective of this report.

Natural gas is physically and financially traded at many different locations[11]. Prices provide signals for regional natural gas consumption, supply development, and storage decisions. The natural gas market is well integrated, so differences in regional prices generally represent the opportunity cost of moving natural gas between the market centers. Regional differences in gas prices determine how existing natural gas pipeline and storage infrastructure are used, as well as where and how much future infrastructure is built. Changes in the location of natural gas supply and demand are an important determinant of future needs for pipeline and storage infrastructure.

Table 1 below shows a compilation of several natural gas forecasts as reported in EIA's 2009 Annual Energy Outlook (AEO). The INGAA Foundation Base Case projection that has been created for this report is also included in the table. The INGAA Foundation case results are discussed in more detail in the next section. In order to compare the Base Case to the other forecasts, only U.S. results are shown in Table 1, although both U.S. and Canadian natural gas market results are reported in the rest of this report.

[11] Currently, Platts Gas Daily provides daily price quotes for 88 of the most commonly traded pricing points.

Table 1
Comparison of U.S. Natural Gas Market Projections, 2008 – 2030 (Tcf per year)

	EIA 2008	Delta 2030 less 2008 (Tcf per year)							
		INGAA (U.S. Only) Base Case	EIA AEO 2009 Reference	IHSGI	EVA	DB	IER	SEER	Altos
U.S. Dry Gas Production	20.56	5.31	3.04	1.77	(2.07)	(1.86)	(6.80)	(0.12)	(2.86)
Net Pipline Imports	2.67	(2.71)	(2.85)	(2.16)	(0.18)	(0.84)	(0.70)	(2.35)	(2.66)
LNG Imports	0.30	1.40	0.55	2.75	6.38	3.26	5.38	3.12	10.70
Total U.S. Consumption	23.18	3.96	0.33	2.69	6.23	0.63	(1.77)	1.00	6.86
Residential	4.87	0.20	0.01	0.52	0.56	1.19	0.73	0.05	(0.24)
Commercial	3.12	(0.02)	0.39	0.11	0.05	(0.77)	(0.62)	0.54	0.57
Industrial	6.62	0.61	(0.28)	0.70	1.98	(1.53)	(3.20)	0.00	0.99
Power Generation	6.66	2.93	0.03	1.09	3.28	1.93	(2.30)	0.32	5.54
Other	1.91	0.23	0.17	0.28	0.36	(0.18)	3.61	0.08	na

Source: EIA AEO Comparison of Natural Gas Projections
Note: INGAA forecast produced by ICF International (January 2009) - Excludes Canadian volumes in this table for comparison.
EIA AEO - Energy Information Administration Annual Energy Outlook 2009 - Updated Reference Case (April 2009)
IHSGI - IHS Global Insight Inc. (September 2008)
EVA - Energy Ventures Analysis, Inc. (January 2009)
DB - Deutche Bank (September 2008)
IER - Institute of Energy Economics and the Rational Use of Energy - Stuttgart (November 2008)
SEER - Strategic Energy and Economic Research, Inc. (April 2008)
Altos - Altos World Trade Model - (October 2008)

A growing natural gas market generally requires additional natural gas infrastructure. Even in a flat or declining market, however, additional natural gas pipeline and storage assets will be necessary if there are shifts in the location of supply and demand. Among the different forecasts shown in Table 1, the average increase in annual gas consumption between 2008 and 2030 is 2.4 Tcf. With almost 4 Tcf of increase, the INGAA Foundation's Base Case shows an increase in annual consumption that is above this average, but below the high value of almost 6.9 Tcf of annual increase projected by Altos. The greatest uncertainty for consumption occurs in the power sector, where ICF's increase in annual consumption of almost 3 Tcf is above the average increase of 1.4 Tcf in the scenarios compared by EIA, but slightly below EVA's projection and well below Altos' projection.

There are considerable differences in gas supply projected by the INGAA Foundation Base Case versus supply projected in the other cases in Table 1. By far, the INGAA Foundation Base Case exhibits the greatest increase in U.S. gas production over time. In fact, five of the other scenarios project declining gas production in the U.S. This certainly is contrary to the trend during the past few years when U.S. gas production has been growing, mostly due to increases in production from unconventional gas supplies, including substantial growth in gas production from shales. Trends for future production in the INGAA Foundation Base Case tend to be in line with recent history, reflecting continued growth in shale gas production, most notably, increasing production from the Barnett, Fayetteville, Woodford, Haynesville, and Marcellus shales. Like the other projections, the INGAA Foundation Base Case projects increasing LNG imports over time; still, the growth of LNG imports is below the growth rates projected in all but one of the other cases.

This section examines the key drivers of supply and demand and the assumptions for the INGAA Foundation Base Case. These assumptions drive the amount of natural gas infrastructure needed over time. Results for the INGAA Foundation High Gas Growth Case and the Low Electric Growth Case are discussed in Section 4 where relevant. To put the INGAA Foundation's assumptions in context, the INGAA Foundation Base Case is compared to the EIA's AEO 2009 revised forecast where possible. (Most, but not all, of the AEO forecast assumptions are publicly available.)

3.1 Key Drivers of Natural Gas Supply

The INGAA Foundation Base Case projects a robust increase in domestic natural gas production. As shown in Table 1 above, U.S. natural gas production is projected to be over 5 Tcf, or 25 percent higher in 2030 compared to the 2008 level. Growth in U.S. gas production from 2008 to 2030 in the AEO Reference Case is also significant, but somewhat less than projected growth in the INGAA Foundation's Base Case. A key supply assumption in both cases is that an Alaska natural gas pipeline is built sometime after 2019. The Alaskan North Slope gas is made available to the U.S. Lower-48 through imports via Canada.

Total annual gas production in Canada declines in the INGAA Foundation Base Case from 6.4 Tcf in 2008 to 5.2 Tcf in 2030. Net production growth occurs only in the U.S. While the amount of Canadian production in the AEO Reference Case is not publicly available, similar projected declines of net pipeline imports suggest a similar Canadian production decline as exhibited in the INGAA Foundation Base Case.

The INGAA Foundation Base Case projects substantial development of unconventional gas supplies in the Lower-48. The amount of development is determined by the market price of natural gas and the amount and quality of the remaining natural gas resource base.

3.1.1 Natural Gas Resource Base

The primary determinant of natural gas production over time is the amount of economically recoverable natural gas resource in the ground[12]. Total cumulative historical gas production for the U.S. and Canada has been about 1,200 Tcf. The U.S. and Canada have about 2,600 Tcf of remaining gas resource that can be recovered with existing exploration and production (E&P) technology (Figure 5). This equates to nearly 90 years of production at current consumption levels. Current reserves are approximately 260 Tcf, yielding about 10 years of production at current production levels.

Shale resources account for 800 Tcf, or about 30 percent, of the remaining resource in the U.S. and Canada. Gas production from shale and other unconventional formations is projected to be one of the largest growth areas for future production. Resource estimates from EIA are not readily available in the EIA AEO documentation.

[12] Natural gas "resource" is an estimate of the total amount of natural gas that could be produced using current technology. Natural gas "reserves" must be proven by well control.

Figure 5
U.S. and Canadian Technically Recoverable
Natural Gas Resource Base (Tcf)[13]

	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resources	Shale Assessment*
Alaska	8.2	294.4	302.6	0.0
West Coast Onshore	3.1	26.5	29.6	0.3
Great Basin	1.0	3.7	4.7	0.0
Rockies	59.5	235.0	294.5	15.7
West Texas	21.4	133.3	154.7	92.2
Gulf Coast Onshore	44.6	257.1	301.6	90.0
Mid-continent	28.3	234.2	262.5	168.2
Eastern Interior	19.7	331.6	351.2	262.4
Gulf of Mexico	17.7	299.7	317.4	0.0
U.S. Atlantic Offshore	0.0	39.0	39.0	0.0
U.S. Pacific Offshore	0.9	24.0	24.0	0.0
WCSB	56.9	316.0	372.9	166.2
Arctic Canada	0.0	71.0	71.0	0.0
Eastern Canada Onshore	0.5	12.8	13.3	7.0
Eastern Canada Offshore	0.5	83.0	83.5	0.0
Western British Columbia	0.0	10.9	10.9	0.0
US	204.4	1,878.4	2,082.8	628.8
Canada	57.9	493.6	551.5	173.2
North America	262.3	2,372.0	2,634.3	802.0

*Portion of total resource

The resource base will decline as natural gas is produced and consumed. Advances in E&P technology can be expected to increase the amount of resource that can be recovered using current technology. Conversely, legal and environmental restrictions reduce the amount of available resource. For example, about 180 Tcf or 6.8 percent of the resource in Figure 5 is currently off-limits to development (Table 2).

Table 2
Inaccessible Natural Gas Resource
Due to Legal and Environmental Restrictions (Tcf)

Region	***Amount of Inaccessible Resource***
Eastern Gulf of Mexico	28.4
Rocky Mountains	88.9
U.S. Atlantic Offshore	39
U.S. Pacific Offshore	24
Total	180.3

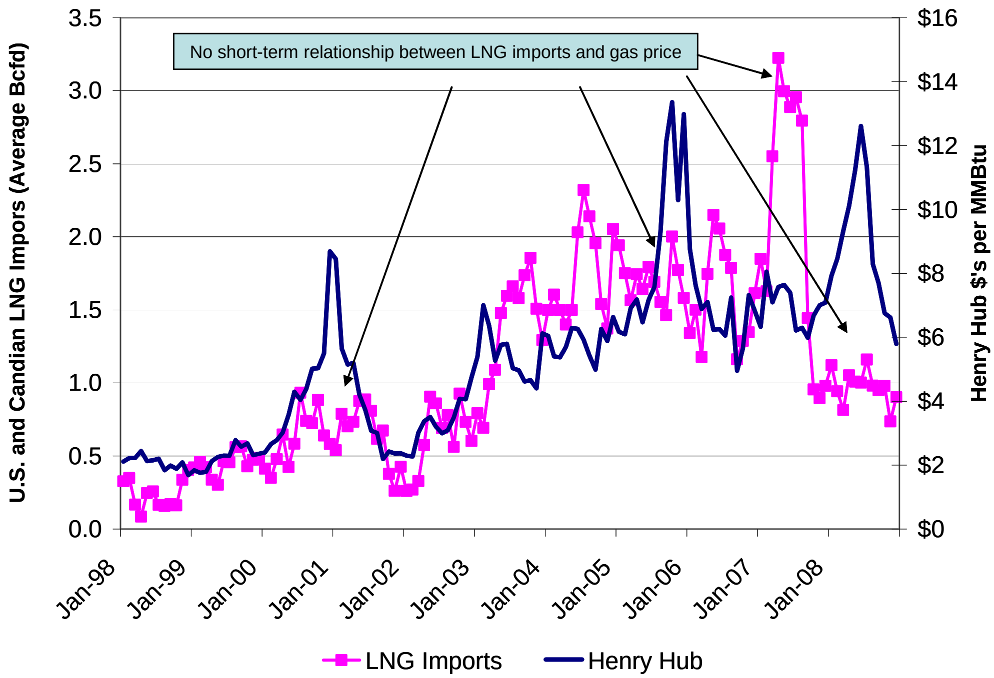
[13] For more detailed assessments, see the ICF International 2008 study for the INGAA Foundation entitled, *Availability, Economics, and Production Potential of North American Unconventional Natural Gas Supplies*. www.ingaa.org

3.1.2 Availability of Liquefied Natural Gas (LNG) Imports

Worldwide gas supply and demand influences the availability of LNG imports to the U.S. and Canada. Demand for gas is projected to grow in Europe and Asia, and countries in these regions will compete with the U.S. and Canada for LNG supplies. International LNG trade was over 8 Tcf in 2008, compared to 3 Tcf in 1993.[14] The INGAA Foundation Base Case projects continuing growth in the world's trade of LNG and a corresponding increase in LNG imports to North America. From 2008 to 2030, U.S. annual LNG imports are projected to increase by between 1.4 and 1.7 Tcf[15]. The AEO increase is smaller at only 0.55 Tcf, but is premised on the assumption of a smaller natural gas market. Canadian LNG imports, which were nonexistent in 2008, have been projected to rise to 100 Bcf in 2030.

LNG imports in 2008, which averaged just less than 1 Bcf per day, are significantly less than total LNG import capacity of 12 Bcf per day. LNG terminal import capacity does not appear to be a limiting factor for the foreseeable future. LNG imports accounted for just over 1 percent of natural gas supply for the U.S. and Canada in 2008. U.S. and Canadian LNG imports steadily grew between 1998 and 2004, but were flat or declining after 2005 (Figure 6).

Figure 6
Monthly LNG Imports and Henry Hub Price,
1998 – 2008 (Average Bcf per day and $ per MMBtu)



[14] *The LNG Industry 2008,* International Group of Liquefied Natural Gas Importers.

[15] Earlier this decade, many natural gas industry analysts had expected that LNG imports to the U.S. would grow much more significantly over time. In fact, in its own 2004 study regarding natural gas infrastructure requirements, The INGAA Foundation had projected that annual LNG imports would rise to above 6 Tcf in 2020, well above levels currently projected in the Base Case included in this study.

As shown in Figure 6, the trend for LNG imports has been increasing during the past 10 years. Generally, the U.S. has been attracting more LNG in the summer than in the winter. Also, there appears to be no clear relationship between the level of imports and gas prices in the U.S. At times, as in mid-to-late 2005 and during the first half of 2008, U.S. gas prices were relatively high, yet LNG imports were not appreciably higher than when gas prices were much lower. Conversely, gas prices in 2007 were not appreciably higher than in 2006, yet LNG imports rose dramatically during that summer. It is clear from this historical data that U.S. gas prices alone have not been a strong determinant of the level of LNG imports.

In the future, the INGAA Foundation scenarios show that the level of LNG imports will continue to be only loosely linked to U.S. natural gas prices, if at all. Although an increase in global supply associated with global liquefaction development is expected, increases in global gas use, particularly in Asian economies, are also expected. Consequently, much of the incremental LNG supply that is developed during the next 20 years is likely to be absorbed by consumers elsewhere throughout the world. A trend that is expected to continue as global LNG supplies grow is that the U.S. will continue to import substantially greater volumes of LNG in the summer as opposed to the winter. This is because the North American natural gas markets will continue to have substantially greater amounts of gas storage capability – capacity that is able to absorb the LNG – than markets elsewhere. North American markets are likely to remain swing markets for world LNG supplies as long as North American natural gas prices continue to trade below oil prices on a Btu basis.

3.2 Key Drivers of Natural Gas Demand

Natural gas market projections are highly dependent on several key assumptions. Assumptions regarding economic growth, carbon policy, prices of alternative fuels, and weather will impact any forecast of natural gas use. Table 3 below compares the most relevant demand assumptions from the INGAA Foundation Base Case to the assumptions from AEO 2009 forecast.

Table 3
Comparison of Key Demand Assumptions in the INGAA Foundation Base Case[16] versus the EIA 2009 Annual Energy Outlook Reference Case[17]

		INGAA Base Case	EIA AEO 2009 Reference
GDP Growth	Short-term	2009 and 2010	2009 and 2010
		-0.30%	-0.30%
	Long-term	2011 to 2030	2011 to 2030
		2.75%	2.73%
Electricity Sales	Average Annual	2008 to 2030	2008 to 2030
	Growth Rate	1.36%	0.98%
	Incremental tWhs	1,280	890
CO_2 Allowance Prices	Year	2008$ / ton	2008$ / ton
	2015	$15	$15
	2030	$40	
Power Generation	EIA 2008	Incremental Generation	
	Generation	2008 to 2030 (Billion kWh)	
Natural Gas	758	402	218
Coal	1,981	314	330
Nuclear	799	212	91
Hydro	262	21	35
Renewables	98	386	432
Oil	41	7	9
Total	3,939	1,341	1,115
Oil Prices		Average Refiner's Acquisition Cost	
	Year	$2008 / Barrel	$2008 / Barrel
	2009	$52	$43
	2010	$71	$55
	2020	$71	$123
	2030	$71	$138
Weather		Last 30 years	Last 10 years
		1978 - 2007	1998-2007

[16] Includes assumptions from a separately completed power modeling effort.

[17] EIA does not explicitly model carbon policy, but assumes that the cost of capital for coal plants is 3 percentage points higher and states that this is consistent with a $15 per ton carbon allowance price.

3.2.1 Economic Growth

In the short term, weather is the major cause of fluctuations in natural gas consumption, dwarfing the impacts of all other controlling factors. Economic growth, which is positively correlated with projected natural gas demand, is the most significant determinant of natural gas consumption in the long term. Greater economic growth equates to increased natural gas use. U.S. gross domestic product (GDP) growth has averaged approximately 3 percent per year since 1970. However, it has averaged only 2 percent from 2000 through the fourth quarter of 2008 (Figure 7).

The INGAA Foundation Base Case assumes that the U.S. economy remains in a recession from mid-2008 until 2010, which delays natural gas market growth for a few years. The U.S. economy is assumed to continue to experience negative growth through the fourth quarter of 2009, totaling six quarters of negative growth. The U.S. economy is assumed to grow by 2 percent in the first quarter of 2010 and, after a small bounce of 4 percent growth in the second quarter, economic growth remains at 2.75 percent per year in the third quarter of 2010 and thereafter. On average, the AEO 2009 forecast assumes similar GDP growth in both the short and long term, although the quarter-to-quarter or year-to-year patterns may differ.

In the INGAA Foundation Base Case, Canada experiences a similar pattern of negative GDP growth in 2008 and 2009. Starting in the third quarter of 2010, Canadian GDP growth is 2.3 percent per year until the end of the forecast.

The ultimate depth and length of the 2008 to 2009 recession is unknown. Potential impacts of the recession are discussed in Section 6.2.

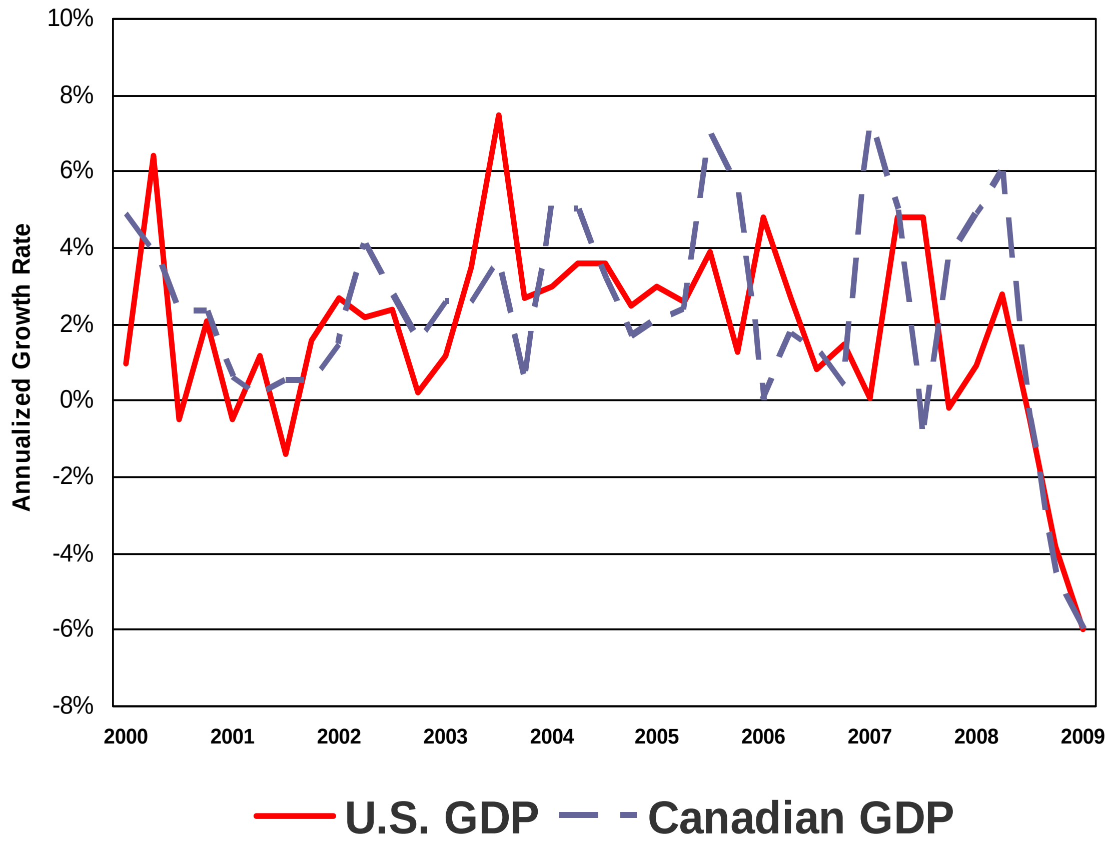
In recent years, about one third of the U.S. and Canadian economic growth can be attributed to population growth. Demographic trends tend to drive natural gas consumption in the residential and commercial sectors. Higher population levels translate into an increase in natural gas heated homes. The number of natural gas heated homes has been increasing slightly faster than population growth as natural gas continues to be the preferred fuel for newly constructed units. Natural gas also continues to gain market share as natural gas distribution systems are expanded and service is offered to neighborhoods that did not have gas service before. The growth in natural gas households is partially offset by efficiency improvements (e.g., more efficient furnaces and water heaters, better insulation and windows).

Increases in income also affect residential natural gas demand. A wealthier population can afford larger homes, which translates into increased natural gas use. In the commercial sector, population growth translates into growth in commercial floor space, which also translates into increased natural gas use. The vast majority of the natural gas consumed in the residential and commercial sectors is natural gas purchased from utilities, often referred to as local distribution companies (LDCs). Local utilities purchase significant amounts of natural gas pipeline and storage capacity.

Natural gas use in the industrial sector is highly influenced by economic conditions. The economy influences the demand for the industrial sector's output, and therefore, the demand for natural gas. Industries where the cost of natural gas is a high percent of value added are significantly impacted by the price of natural gas. For example, petrochemical production, and most notably ammonia production, is much more sensitive to natural gas price than stone, clay, and glass manufacturing, where the cost of natural gas is a rather low percent of value added.

Over the long-term, industrial production and the efficiency of new equipment will drive industrial natural gas use. Industrial activity in energy intensive activities has slowed over the past decade and activity in high-tech (generally not energy intensive) manufacturing (e.g., computer chip manufacturing) has accelerated as the U.S. has moved towards a "high-tech" economy. Such shifts in the economy and gains in efficiency have reduced the growth of natural gas use in the industrial sector.

Figure 7
Historical U.S. and Canadian GDP Growth Rates
(Annualized Percent per Quarter)



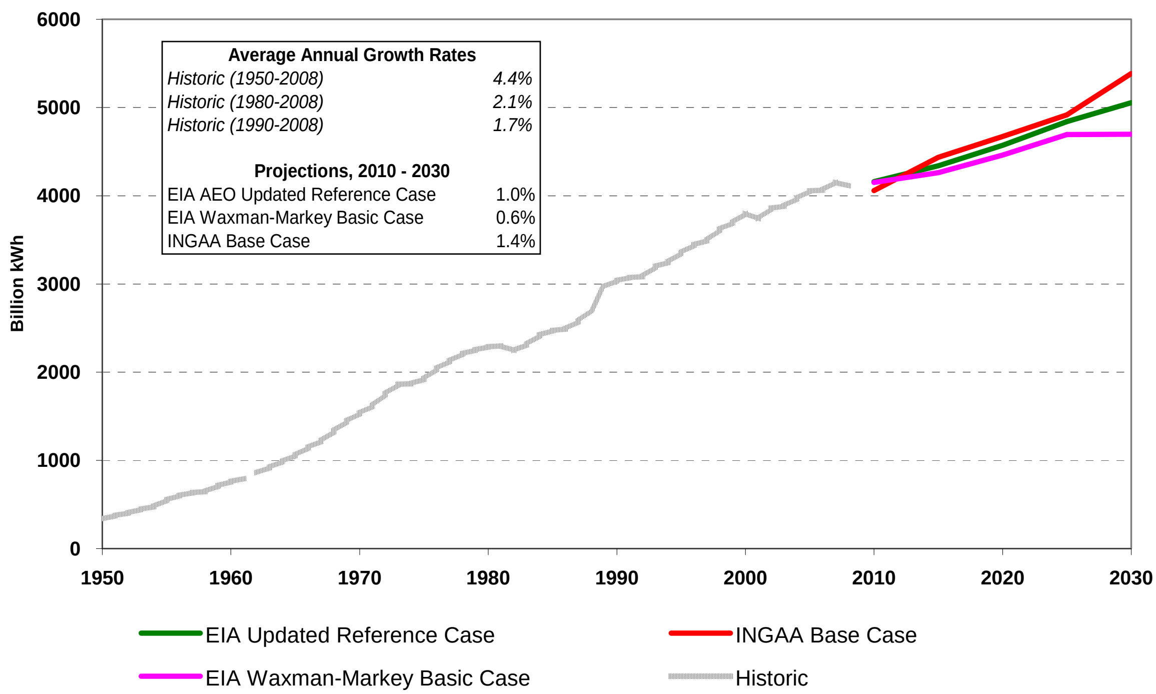
3.2.2 Electricity Sales

The amount of natural gas consumed in the power generation sector is dependent, in part, on total electricity sales. Electricity sales increase as the U.S. economy grows. The income elasticity of electricity sales, or the percentage growth of electricity sales per percentage growth in GDP, has been declining for decades. In prior decades, the income elasticity for electricity sales far exceeded unity, meaning electricity sales were growing at a faster rate than GDP on a percentage basis. The income elasticity of electricity sales has been about 0.7 during the past decade. The INGAA Foundation cases assume that the income elasticity will decline to about 0.6 by 2030. Implicitly, the projection assumes that the economy continues to improve the efficiency of end-use electricity applications, while also continuing to expand the number and scope of electric applications.

The relationship between the growth in GDP and the growth in electricity sales is a significant difference between the INGAA Foundation Base Case and the AEO 2009 forecast. Although the GDP growth assumptions are nearly identical, the INGAA Foundation Base Case projects that the growth in electricity sales is 45 percent larger by 2030. The AEO income elasticity for electricity sales will be between 0.3 and 0.4 by 2030, well below historical values.

Electric generation growth in the INGAA Foundation Base Case averages 1.4 percent per year from 2010 to 2030 (Figure 8), a growth rate below recent historical growth. The INGAA Foundation Base Case assumes continued efficiency improvements in electric appliances and equipment that reduces growth in electricity use. In comparison, electric generation growth in the AEO 2009 forecast only averages 1.0 percent per year from 2010 to 2030, which implies even greater improvement in efficiencies. Another recently released study from EIA assumes that electricity growth may only average 0.6% per year through 2030[18].

Figure 8
Comparison of Electric Generation Forecasts for the INGAA Foundation Base Case and the EIA 2009 Annual Energy Outlook Reference Case
(Billion kWhs)



The Low Electricity Growth Case (discussed at great length in the next section) projects the impact of reduced electricity sales growth on natural gas consumption. The assumed electricity sales growth in this scenario is consistent with the growth rate assumed in the EIA Waxman-

[18] Energy Information Administration, Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009, Report #: SR-OIAF/2009-05, August 4, 2009.

Markey Basic Case as shown in the figure above. The case reduces both the need for gas-fired power generation and growth in the North American natural gas market, and shows reduced need for natural gas infrastructure.

3.2.3 Carbon Policy and the Incremental Source of Electric Generation

Assumptions about future carbon policy and the cost of CO_2 allowances have an impact on gas market projections, especially in the power generation sector. The cost of CO_2 allowances influences the economics of fossil fuel generation since different fossil fuels emit different amounts of CO_2 per kilowatt-hour (kWh) generated. Among the fossil fuels, it is generally perceived that a higher cost of CO_2 allowances will favor natural gas over coal and oil generation. CO_2 allowances also make non-fossil generation options, such as nuclear or renewable generation units, relatively more economic.

The INGAA Foundation Base Case assumes a Federal cap-and-trade system to limit CO_2 emissions begins in 2015. The resulting CO_2 allowances prices under this system are assumed to be $15 per ton in 2015, rising to $40 per ton by 2030 (in 2008 dollars). The AEO does not explicitly assume CO_2 allowance costs but adds 3 percent to the cost of capital for coal plants and states that this is consistent with a $15 per ton cost for allowances. EIA's recently completed analysis for Waxman-Markey (referenced above) solves for CO_2 allowance prices that are well above $15 per ton.

The cost of CO_2 allowances impacts future electric generation. About 30 percent of the incremental generation in the INGAA Foundation Base Case comes from gas-fired units, while the AEO projects that only 13 percent will come from natural gas. Incremental coal generation, while lower in the AEO, represents a larger share of the total incremental growth through 2030. Incremental coal generation accounts for 36 percent of the growth in total generation in the AEO and only 23 percent of the total generation in the INGAA Foundation Base Case.

Assumptions about the amount of renewable generation directly impact the amount of generation from all fossil fuels, including natural gas. The INGAA Foundation Base Case assumes that current state renewable portfolio standards are met, but does not explicitly assume a national renewable energy standard (RES)[19]. State renewable portfolio standards are the major driver of renewable capacity additions, effectively setting a minimum level for future renewable generation. The AEO has similar levels of incremental renewable generation.

3.2.4 Oil Prices

Oil products can be a direct substitute for natural gas. Large industrial and power generation customers with dual-fuel capability can respond to natural gas price changes by switching to other fuel sources. The dual-fuel segment of the U.S. natural gas market is approximately 3 to 4 percent of total natural gas consumption. The extent of fuel switching is determined largely by the relationship between the natural gas price and the alternative fuel price (generally distillate

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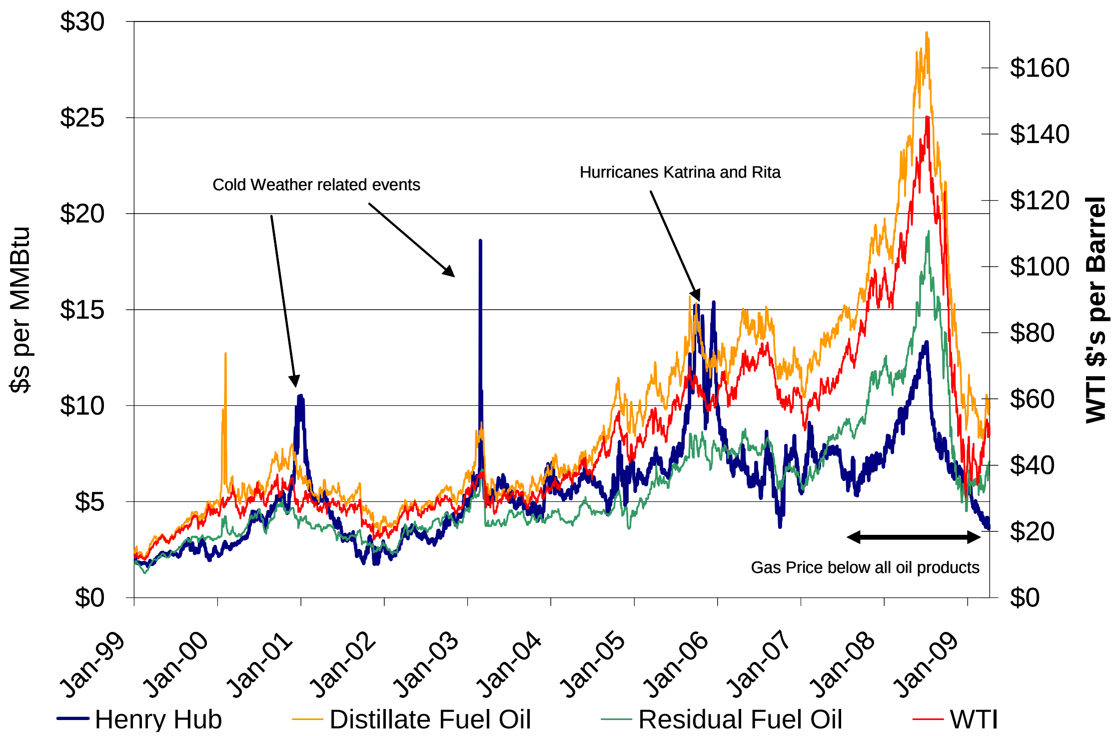
[19] At the time of this report, H.R. 2454 includes a national RES. While this analysis does not explicitly include or investigate the impacts of a national RES, the climate policy assumed in this work would likely have impacts on the levels of renewables generation similar to those that would occur with the national RES that would be enacted under H.R. 2454.

or residual fuel oil). Still, such fuel switching can occur only when the alternative fuel is available and the facility has the necessary air emission permits to burn the alternative fuel.

The INGAA Foundation Base Case assumes oil prices of approximately $71 per barrel (in 2008 dollars) after 2010. The AEO 2009 Reference Case projects that oil prices will escalate continuously to $138 per barrel by 2030. This implies that the AEO 2009 Reference Case envisions a generally higher resource cost environment.

Natural gas demand is much more price elastic when natural gas and oil product prices are about equal on a Btu basis. This had been the case for much of the last decade up until early 2007. Since then, however, all oil product prices have been several dollars per MMBtu above natural gas prices (Figure 9). During this period of relatively high oil prices, oil price variability has had less impact on natural gas demand because very little optional fuel switching has been occurring. Oil product prices will influence natural gas demand more significantly in the future if and when natural gas and residual fuel oil prices are closer to parity.

Figure 9
WTI, Residual, and Distillate Oil Versus
Henry Hub Natural Gas Prices ($ per MMBtu)



Both the INGAA Foundation Base Case and the AEO 2009 Reference Case assume a significant premium of oil product prices over natural gas prices in the future. This disconnect between oil and natural gas prices will restrict fuel switching to a relatively small portion of the market. Therefore, oil prices are projected to continue to have an insignificant impact on the natural gas market going forward.

3.2.5 Weather

Weather is the key driver of natural gas consumption in the short term. All sectors are impacted by weather to some degree. Colder weather can significantly increase residential and commercial sector natural gas consumption, since natural gas is the predominant fuel for space heating. Hotter weather impacts the amount of air conditioning used, and therefore, the demand for gas-fired power generation. Even the industrial sector has some space heating and cooling components to its consumption.

Most long term natural gas forecasts assume normal or average weather, although the time period from which the average has been calculated differs across forecasts. The INGAA Foundation Base Case assumes 30-year average weather based on the period ending with 2007, while the AEO forecast assumes a 10-year historical average. Recent weather has been warmer in the winter and hotter in the summer when compared with the 30-year average. Using a 10-year average weather assumption generally reduces space heating in the winter and increases power generation for air conditioning in the summer.

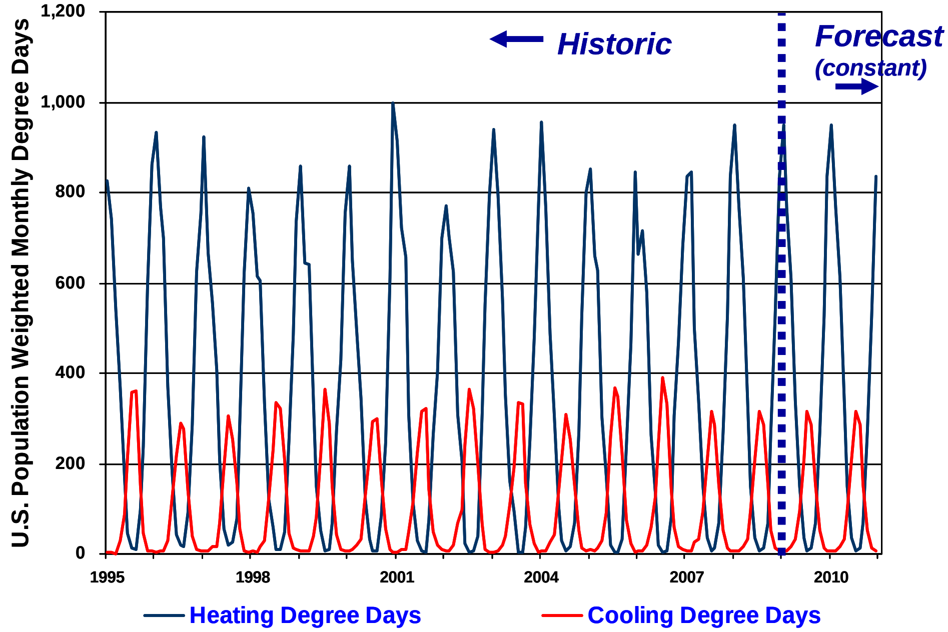
Heating and cooling needs for energy markets, including the natural gas market, are most often expressed in heating and cooling degree days (HDDs and CDDs)[20]. Relative to the INGAA Foundation Base Case, the AEO 10-year average assumption is 5 percent warmer in the winter and 7 percent warmer in the summer, based on U.S. population-weighted heating and cooling degree days.

Total monthly U.S. population-weighted HDDs can vary from over 1,000 in the winter to near 0 in the summer (Figure 10). Total U.S. population-weighted CDDs can range from a total of nearly 400 in July to 0 in the winter. Total HDDs have a greater impact on the U.S. and Canadian natural gas market relative to total CDDs, but this varies by location.

Versus the 2009 AEO Reference Case, the INGAA Foundation's cases project slightly greater gas consumption as a result of the different assumptions for weather. This is due to the relatively colder winters assumed in the INGAA Foundation's cases, consistent with 30-year averages that have a more prevalent impact on gas consumption. On average, natural gas consumption in INGAA Foundation's cases is greater than AEO's Reference Case by about 200 Bcf each year, or by less than 1 percent.

[20] A HDD is approximately equal to 65 less the average daily temperature. A CDD is approximately equal to the average daily temperature less 65.

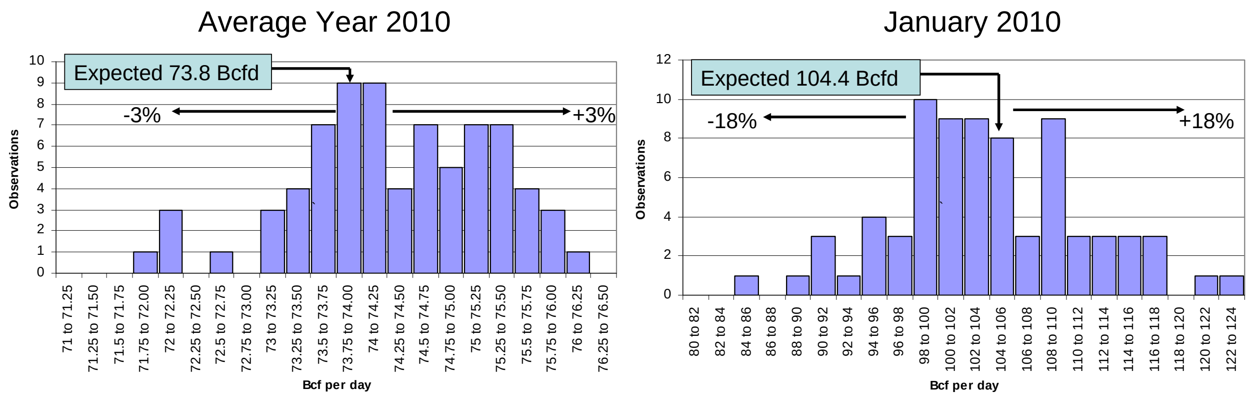
Figure 10
Historical and Projected Heating and Cooling Degree Days,
Expressed as U.S. Population-Weighted Values



Weather has a greater impact on natural gas consumption the shorter the time scale. Over longer periods of time, the effects of warmer- and colder-than-normal weather tend to cancel each other out, and consumption trends to an average consistent with normal weather, all other factors being equal. In addition, any prolonged period of warmer- or colder-than-normal weather also will affect natural gas prices. Price-induced increases or decreases in consumption counteract the impacts of weather on consumption.

In the INGAA Foundation Base Case, weather can shift yearly U.S. and Canadian natural gas consumption up or down by a significant amount. For example, as shown in Figure 11, weather can shift 2010 gas use by plus or minus 4.5 Bcf per day on average, or by 3 percent in each direction. In January, natural gas consumption can vary by plus or minus 20 Bcf per day on average, or by 18 percent in each direction.

Figure 11
Projected Variation of 2010 U.S. and Canadian
Natural Gas Consumption Due to Weather[21] (Average Bcf per day)



3.2.6 Other Factors Impacting Natural Gas Demand

Many additional factors affect natural gas demand, such as the available technology of natural gas consuming equipment, government policies, such as energy efficiency regulations, or subsidies (e.g., demand side management), and the price of electricity. Technological advancement in the efficiency of natural gas consuming equipment has the potential either to increase or reduce natural gas demand. If new equipment is mainly replacing older, less efficient units, then advancements in technology will reduce natural gas demand. However, if efficient natural gas consuming equipment replaces equipment that uses other fuels, then natural gas demand may increase.

Government policies may encourage natural gas use by favoring natural gas equipment, by increasing the cost of alternative fuels or sources of energy, and by reducing the cost of natural gas relative to other fuels. Conversely, government requirements for efficiency upgrades or tax credits or other inducements for things such as home insulation may reduce natural gas demand.

[21] Weather variation based on actual heating and cooling degree days by Census region for the years 1933 to 2006.

4 Natural Gas Market Projections through 2030

In order to forecast future natural gas infrastructure requirements, three different projections of the U.S. and Canadian natural gas market have been created: (1) a Base Case that represents an expected view of the future, (2) a High Gas Growth Case in which markets and policies lead to greater growth in natural gas consumption, and (3) a Low Electric Growth Case in which future electricity sales grow at a relatively slower rate. All cases studied here result in a need for significant and continuous capital expenditures on natural gas infrastructure.

4.1 Case Assumptions

All cases studied here result in a need for significant and continuous capital expenditures on natural gas infrastructure.

The scenarios discussed here have been produced by using ICF's Gas Market Model (GMM), a widely used model for the North American natural gas market.[22] Each scenario makes explicit assumptions about the future. The Base Case reflects an expected outcome for U.S. and Canadian natural gas markets by considering, and, in most cases, continuing recent market trends. For example, the case projects that, after the economy rebounds, gas-fired power generation will continue to grow consistent with observed growth during the past 10 years.

The High Gas Growth Case tests the upper range of possible infrastructure needs by assuming plausible policies and market results that lead to greater demand for natural gas than in the Base Case. This case uses the Base Case as a starting point, and modifies key variables to reflect the impact of potential changes in policies thought to be consistent with the direction signaled by the Obama administration.

The Low Electric Growth Case attempts to quantify the impacts for natural gas infrastructure if electricity sales and other gas conservation measures meet the assumptions set forth in the EIA Waxman-Markey Basic Case. The assumptions of this case create an environment of relatively constant to declining gas consumption. This case illustrates the need for future natural gas infrastructure even with a relatively weak market.

4.1.1 Common Assumptions for the Base Case, High Gas Growth Case, and Low Electric Growth Case

All cases assume that the U.S. economy remains in a deep recession from mid-2008 until 2010, which delays natural gas market growth for a few years. Actual U.S. and Canadian GDP through the fourth quarter of 2008 is an input into the GMM. In the last quarter of 2008 and the first quarter of 2009, the U.S. economy contracts at an annual rate of 4 percent. While the rate of contraction moderates, the U.S. economy continues to experience negative growth through the fourth quarter of 2009, totaling six quarters of negative growth. U.S. economic growth is

[22] The ICF model is summarized in Appendix B.

positive 2 percent in the first quarter of 2010 and, after a small bounce to 4 percent annualized growth in the second quarter, annualized economic growth remains at 2.75 percent in the third quarter of 2010 and thereafter. Canada experiences a similar pattern of negative GDP growth in 2008 and 2009. Starting in the third quarter of 2010, annualized Canadian GDP growth is 2.3 percent through the end of the forecast.

West Texas Intermediate (WTI) crude oil prices dip to average $50 per barrel in 2009 as the world recession continues to put downward price pressure on commodity prices. Both cases assume a price rebound at the end of the recession. Crude oil averages $70 per barrel (2008 dollars) from 2010 on. WTI crude prices reach $130 per barrel in nominal dollars by 2030, close to the recent 2008 high of over $140 per barrel.

Demographic trends for both the U.S. and Canada are consistent with trends observed during the past 20 years. Population levels in both countries increase at about 1 percent per year. Therefore, the number of gas heating customers in both the residential and commercial sectors increases as it has in the past. Weather is assumed to follow normal (30-year average) temperatures. There are no assumed significant hurricane disruptions to natural gas supply.

Natural gas E&P activity remains below recent activity levels throughout 2009 due to the recession, but rebounds in 2010[23]. A substantial North American natural gas resource base totaling nearly 2,400 Tcf of proven reserves and undiscovered resource is available to supply U.S. and Canadian natural gas markets for almost 100 years at current production levels. Unconventional natural gas comprises over 50 percent of remaining natural gas resource, with shale gas alone accounting for about 25 percent of this remaining resource. Current U.S. and Canadian proven natural gas reserves at the end of 2008 are approximately 260 Tcf. Additional reserves are developed to meet future production.

4.1.2 Contrasting Assumptions Among the Three Cases

The Base Case, High Gas Growth Case, and Low Electric Growth Case make different assumptions about government policy and technological (Table 4) that create different market outlooks for natural gas, and consequently, different natural gas infrastructure requirements. Although the Base Case assumes that various environmental policies are adopted as expected, the High Gas Growth Case assumes that stronger “green” policies are enacted. While some assumptions in the High Gas Growth Case reduce natural gas use, the overall effect of the policies assumed in the High Gas Growth Case is an increase in natural gas use over the Base Case levels due to natural gas being considered an environmentally friendly fuel compared to other fossil fuels. Certain reasonable technological assumptions in the High Gas Growth Case, both on the consumption and the supply side, also contribute to a larger natural gas market. In general, assumptions related to the power generation sector have the greatest impact on case outcomes. The Low Electric Growth Case assumes that strong conservation policy measures for electricity and natural gas consumption are successful. Relative to the Base Case, all contrasting assumptions in the Low Electric Case reduce gas consumption relative to the Base Case. Supply technology assumptions in the Low Electric Growth Case are the same as in the Base Case.

[23] Rig activity is actually an output of the ICF Gas Market Model, not an assumption. Future activity depends on natural gas prices and the remaining gas resource base. EURs (estimated ultimate recovery) and decline rates for wells are consistent with currently observed values, but change to reflect the quality of the remaining gas resource developed in the future.

Table 4
The INGAA Foundation Base Case, High Gas Growth Case, and Low Electric Growth Case Assumptions

Assumption	Base Case	High Gas Growth	Low Electric Growth
Electric Load Growth	1.4% growth per year, a little below 1.7% growth per year observed during the past 20 years.	Same as Base Case.	0.6% growth per year consistent with EIA 2009 Waxman-Markey Basic Case.
Climate policy	Gradual decline in emissions targets and/or safety valve limiting allowance prices. Liberal offset policy.	Steeper reduction in emission targets with no or higher safety valve prices. Offsets are more limited.	Same as Base Case.
Carbon capture and sequestration	Widely available, and incentives are provided.	CCS constrained before 2030.	Same as Base Case.
Nuclear power	About 25 GW of new capacity by 2030.	Very few new nuclear units built before 2030.	About 35 GW of new capacity by 2030.
Energy conservation (both within and in addition to climate policy)	Moderate goals are set and achieved.	Conservation goals are achieved to a greater extent, and demand growth is lower.	Conservation and demand-side management assumptions consistent with EIA AEO 2009.
Renewables	Effects of RPS and declining costs lead to large growth in renewables.	Renewables growth is more aggressive relative to the Base Case, reducing the need for gas-fired generation.	Renewables growth is less than in Base Case, consistent with lower growth in electric market, but still adequate to satisfy State RPS's.
Compressed Natural Gas (CNG) Vehicles	No national policy focus on using natural gas in vehicles.	Oil substitution policy akin to "Pickens Plan" is instituted.	Same as Base Case.
Plug-in Electric Hybrids	Modest market penetration before 2030.	Greater penetration of plug-in hybrids increases electricity demand and demand for gas-fired generation.	No penetration before 2030.
Upstream technologies	Growth in non-conventional natural gas is very substantial.	Technological advances accelerate growth of unconventional gas production.	Same as Base Case.
Drilling Moratoria	Despite Congress' action in 2008 to let bans expire, most restrictions are re-introduced in 2009.	More areas are made accessible.	Same as Base Case.
Arctic Natural Gas	Pipeline projects develop slowly. Mackenzie in 5 years. Alaska in 10 years.	Projects are accelerated and are in service at an earlier date.	Pipeline projects develop slowly. Mackenzie slips to 2020 and Alaska to 2025.

In all three cases, a U.S. federal carbon policy is assumed to be enacted, taking effect in 2015. All cases assume a multi-sector cap and trade program, based on enabling legislation with long-term emission goals similar to recent proposals by President Obama, Congress, and the power industry. The cap and trade program covers electric power, fuel production, industrial sources, and transportation. Allowance prices rise from $15 per ton in 2015 to over $40 per ton by 2030 in the Base Case. Allowance prices in the High Gas Growth Case are higher, but not substantially more than in the Base Case.[24]

Between 1998 and 2008, over 260 gigawatts (GWs) of new gas-fired generation capacity was built in the U.S. and Canada. Most of the constructed plants operate exclusively on natural gas. Of the new plants, only a small percentage have the capability to switch to oil, and most are restricted to a limited number of hours of switching per year. Power plant developers have chosen to build gas-fired plants for a variety of reasons. The initial capital cost for construction is lower for gas-fired plants than for most other types of capacity. The construction time is also shorter and the plants are easier to permit than most other plant types, hence they can be built more quickly. Sulfur dioxide and particulate emissions are far lower for gas-fired plants than for coal or oil plants. Natural gas is a relatively abundant and mostly domestic fuel. In both the Base Case and High Gas Growth cases, gas-fired generation capacity is projected to grow (Table 5). The future generation portfolio mix differs among the cases, in response to differences in future electricity generation needs as well as contrasting policy and technology assumptions.

Table 5
U.S. and Canadian[25] Power Generation Capacity, 2008 – 2030 (GWs)

		Base Case		High Gas Growth Case		Low Electric Growth Case	
Generation Type	2008	2020	2030	2020	2030	2020	2030
Natural Gas	435	487	556	523	630	433	433
Coal	303	307	334	276	276	307	334
Nuclear	101	108	126	104	111	120	161
Hydro	78	78	78	78	78	78	78
Renewables / Hydro / Other	57	108	168	135	258	104	156
Total U.S.	974	1,088	1,262	1,116	1,353	1,042	1,162
Canadian Natural Gas	23	41	50	43	53	38	45

In the Base Case and Low Electric Growth Case, carbon goals are met through gradual reductions in emissions targets. A relatively liberal offset policy has also been assumed, consistent with the Waxman-Markey bill passed by the U.S. House of Representatives on June 26, 2009.

In the High Gas Growth Case, reductions in emissions targets are steeper relative to the Base Case with either no safety valve or higher safety valve prices. The offset policy assumed in the High Gas Growth Case is also more limited. As a result, older coal-fired power plants are retired at a faster rate in the High Gas Growth Case. Net available coal capacity is about 10 percent lower by 2020, dropping down to 276 GW versus 307 GW in the Base Case. In the High Gas Growth Case, additions and reductions in gas-fired generation capacity are used to

[24] Comprehensive modeling of potential carbon allowance prices was not done in the alternate cases. However, some cursory modeling efforts for the High Gas Growth Case have suggested that allowance prices would be only slightly higher than the allowance prices in the Base Case.
[25] The full power market for Canada is not modeled in GMM. However, gas consumption and implied GWs of gas-fired capacity can be calculated.

offset the increases and decreases in other forms of generation capacity – coal, nuclear, and renewable – in order to meet expected electric load requirements during the forecast.

The High Gas Growth Case assumes that technological advances are not fast enough to implement carbon capture and sequestration (CCS) for coal-fired power plants widely on a commercial scale before 2030, even though such plants may be politically desired. As a result, coal capacity after 2020 remains at the 2020 level. By 2030 in the Base Case and Low Electric Growth Case, approximately 40 GWs of CCS coal plants are built, resulting in a net increase in capacity of 27 GWs from 2020 to 2030.

Of the expected 25 GW of additional nuclear capacity developed in the Base Case, 4 GWs represent capacity upgrades at existing facilities – otherwise referred to as "capacity creep" – and 21 GWs are the result of new units developed at existing sites. The High Gas Growth Case assumes that there are fewer new nuclear units built, resulting in only 10 GWs of incremental nuclear capacity (including capacity upgrades) through 2030. The Low Electric Growth Case assumes an additional 10 GWs of nuclear capacity is built relative to the Base Case. The incremental nuclear capacity is assumed to be built after 2018.

Renewable generation capacity, including wind, solar, geothermal, and biomass, triples in the Base Case from 57 GWs in 2008 to 168 GWs in 2030. This growth is mostly driven by individual state Renewable Portfolio Standards (RPS) requirements. The largest increase is expected to be wind generation. On average, renewable generation assets are projected to operate at a 30 to 40 percent load factor.

The Low Electric Growth Case has lower renewable generation because the lower electricity sales assumption reduces the amount of renewable generation needed to satisfy percentage based renewable portfolio standards. In the High Gas Growth Case, a relatively greater amount of renewable capacity is built due to increased incentives and a stricter carbon policy. Renewable capacity increases by a factor of five by 2030. Hydroelectric generation capacity is assumed to remain at current levels in all cases.

A significant increase in the use of plug-in hybrid electric vehicles (PHEVs) is assumed in the High Gas Growth Case. By 2030, 25 percent of passenger vehicles are assumed to be PHEV. These vehicles will operate almost exclusively on electricity, equating to 425 billion vehicle miles on electricity per year. Assuming 0.4 kWh per mile, electricity demand increases by about 200 terawatt-hours (TWh) per year by 2030, or by about 4 percent over the Base Case level. The High Gas Growth Case also assumes more intense demand side management (DSM) programs in the electricity market. Thus, total growth in electricity sales is similar between the Base Case and the High Gas Growth Case. Electric load growth averages about 1.4 percent per year after the economic rebound, somewhat below the 1.7 percent average observed over the past 20 years.

The High Gas Growth Case assumes increases in the use of natural gas as a transportation fuel, predominately in the long-haul trucking industry with a more limited increase in the passenger fleet. Annual gas consumption in vehicles rises to over 800 Bcf by 2030, versus a Base Case Level of only 20 Bcf. In both the Base Case and Low Electric Growth Case, natural gas continues to be consumed by only a portion of fleet vehicles over time.

The High Gas Growth Case also includes more optimistic, yet plausible, assumptions related to natural gas supply growth. Technological advancement in natural gas extraction from unconventional shale formations increases at a greater pace relative to the Base Case. As a result, approximately 4.5 Tcf per year[26] of additional shale production is available by 2030. Government policies also contribute to increase natural gas supply. Drilling moratoriums are assumed to be lifted off of the East and West coasts, as well as off of the coast of Florida in the Gulf of Mexico. Production within the moratorium areas begins within the next decade and reaches 2 Tcf per year by 2030. Government policy includes greater incentives to build Arctic Projects from Mackenzie Delta and Alaska. Both projects are moved up by 1 and 2 years, respectively, in the High Gas Growth Case.

The Low Electric Growth Case makes natural gas supply assumptions that are identical to those in the Base Case, Natural gas production is developed at a slower pace relative to the Base Case due to reduced natural gas consumption and lower natural gas prices. As a consequence of the smaller natural gas market, Arctic projects are delayed by a few years relative to the Base Case.

The High Gas Growth Case represents an environment with both higher gas demand growth and additional policies to provide the larger market with increased gas supply. The resultant case is a reasonable high case for U.S. and Canadian natural gas use. The Low Electric Growth Case reduces the need for future gas consumption. The result is a low case for U.S. and Canadian natural gas use.

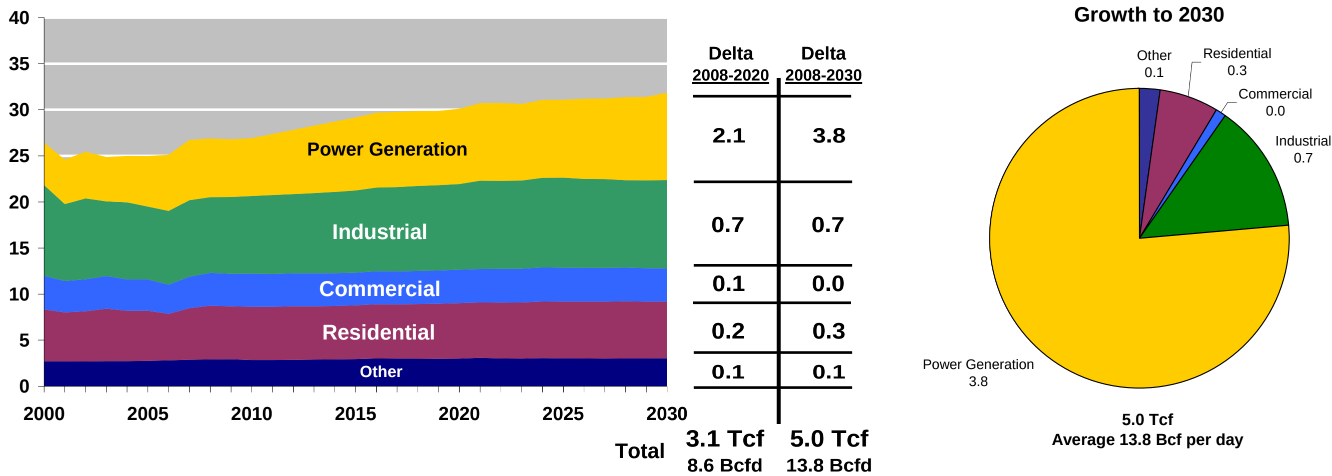
4.2 Natural Gas Demand

Natural gas consumption in the U.S. and Canada was 26.9 Tcf, or an average of 74 Bcf per day in 2008. By 2030, natural gas consumption in the Base Case increases by 18 percent to 31.8 Tcf, an increase of 4.9 Tcf over the 2008 level (Figure 12). This implies that the natural gas market in the Base Case grows on average by 0.8 percent per year. To accommodate this growth, an average of 13.8 Bcf per day of additional natural gas supply must be developed. The power generation sector accounts for approximately 70 percent of this total growth in natural gas consumption, with annual growth in the sector exceeding 2 percent per year. Other natural gas consuming sectors – residential, commercial, and industrial – grow much more slowly at a combined rate of only 0.3 percent per year. This growth will occur only if the natural gas industry is allowed to construct the infrastructure required to supply a growing market.

The modest growth in residential and commercial natural gas consumption occurs as a direct result of continued growth in population that leads to increasing housing stock and commercial floor space, but is balanced by efficiency gains. The growth in industrial natural gas use is also fairly modest as energy-intensive industrial activities (i.e., petrochemicals production, iron and steel manufacturing, paper production, etc.) grow relatively slowly. A larger proportion of growth in the economy is projected to come from less energy intensive activities, such as services.

[26] Volume at a similar gas price.

Figure 12
U.S. and Canadian Natural Gas Consumption by Sector, Base Case (Tcf)



Future increases in natural gas consumption in the power generation sector are a result of the addition of new natural gas-fired capacity (see Table 5 above) and increased utilization of existing units. The current utilization rate of all natural gas and oil units, including older oil/gas steam units and peaking units, is 17 percent. In the Base Case, total utilization rises to 22 percent by 2030. U.S. gas-fired generation capacity increases by roughly one-fourth during the projection from 435 to 556 GWs. Canadian gas-fired power generation capacity doubles during the projection from 23 to 50 GWs.

As anticipated, natural gas use in the High Gas Growth Case grows by substantially more than in the Base Case. In 2030, total natural gas use is up by an additional 12 percent, or by 4 Tcf over the Base Case level (Figure 13 and Table 6). By 2030, annual U.S. and Canadian natural gas use rises to 36 Tcf. In the High Gas Growth Case, U.S. consumption alone rises to 31 Tcf in 2030. Between 2008 and 2030, U.S. and Canadian natural gas consumption grows by 9.1 Tcf, or by an average of 25.1 Bcf per day. The market grows at around 1.3 percent per year. Consumption within the power generation sector alone grows by over 3 percent per year.

In the High Gas Growth Case, gas consumption in the power sector rises to at least two times the 2008 level. The primary driver behind the incremental growth is the reduced penetration of coal and nuclear capacity assumed in the case. An assumed increase in renewable generation is not enough to offset reduced generation from coal and nuclear capacity. Thus, gas-fired capacity, as the most practical alternative, fills the void.

Natural gas use in the Low Electric Growth Case falls slightly over time, with some year-to-year variation. By 2030, annual U.S. and Canadian natural gas use declines by 4 percent or by 1.1 Tcf relative to the 2008 level.

Figure 13
U.S. and Canadian Natural Gas Consumption by Sector,
High Gas Growth Case and Low Electric Growth Case (Tcf)

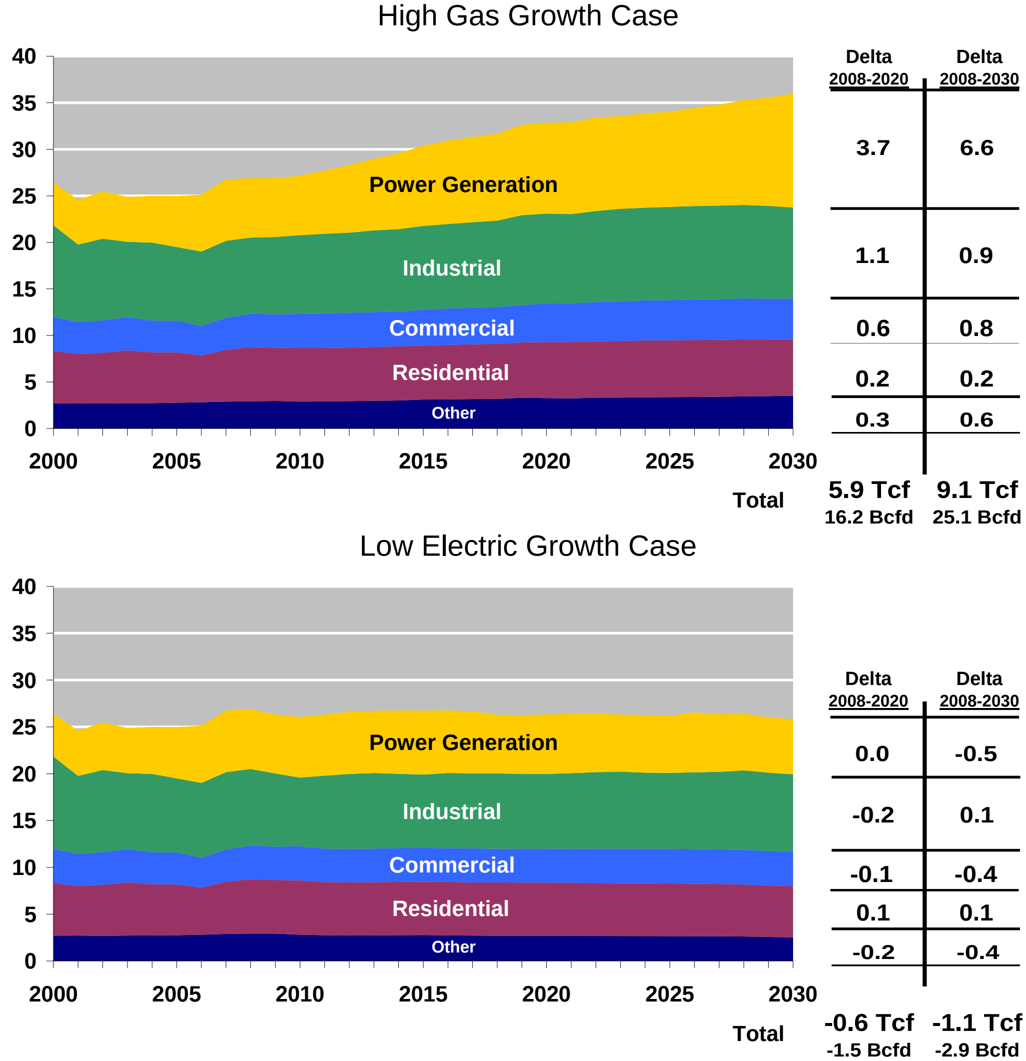


Table 6
Change in U.S. and Canadian Natural Gas Consumption by Sector
2008 to 2030 (Tcf)

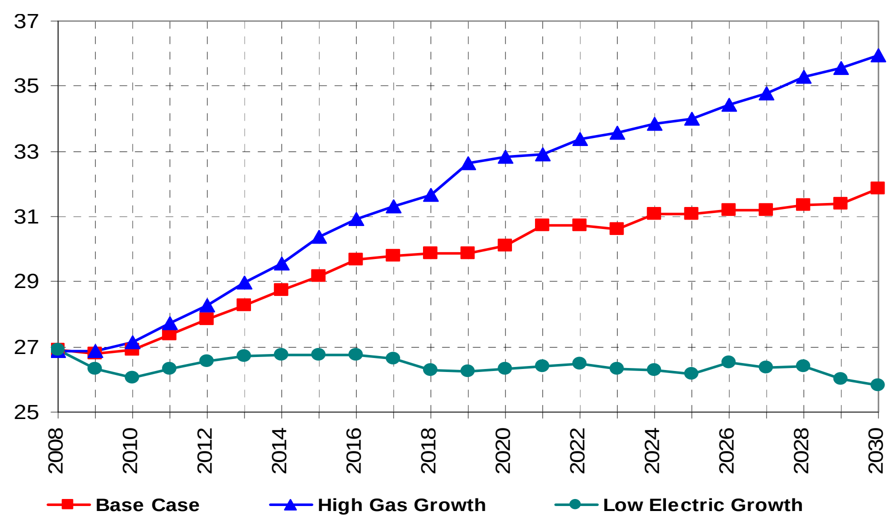
	2008	*Base Case*	*High Gas Growth Case*	*Low Electric Growth Case*
Residential	5.8	0.3	0.2	(0.4)
Commercial	3.6	0.0	0.8	0.1
Industrial	8.2	0.7	0.9	0.1
Power Generation	6.4	3.8	6.6	(0.5)
Other	2.9	0.1	0.6	(0.4)
	26.9	5.0	9.1	(1.1)

Gas consumption declines most in the power sector in the Low Electric Growth Case. As opposed to the robust growth that occurs in the other two cases, an assumed reduction of growth in electricity use leads to declines in gas-fired generation. Additional reliance on nuclear generation further reduces the need for gas generation. Over 70 percent of the natural gas consumption differences between the Low Electric Growth Case and the other two cases occur in the power sector.

Commercial natural gas consumption is higher in the High Gas Growth Case mainly due to the increased penetration of CNG vehicles. In that case, CNG vehicles account for about 15 percent of the total market increase of natural gas consumption over Base Case levels. The remainder of the commercial sector is flat.

Compared to the Base Case, residential growth is lower in the High Gas Growth Case due to increased efficiency assumptions. Residential growth is even lower in the Low Electric Growth Case due to even greater efficiency assumptions. The slight increase in industrial consumption in the High Gas Growth Case is price driven.[27] A year-to-year comparison of total natural gas consumption for all three cases is shown below (Figure 14).

Figure 14
Total Natural Gas Consumption
Base Case, High Gas Growth Case, and Low Electric Growth Case Comparison (Tcf)



4.2.1 Regional Natural Gas Demand

In both the Base Case and the High Gas Growth Case, natural gas demand is projected to grow throughout the U.S. and Canada. As consumption grows in all regions, additional infrastructure will be needed to serve this additional demand (Table 7). Still, because the power generation sector is the fastest growing segment of the natural gas market, and power generation peaks with cooling load in the summer, warmer parts of North America grow most, particularly those areas where population is growing most rapidly. The Southeast and Southwest regions account

[27] Natural gas prices are slightly lower in the High Gas Growth Case. See Section 4.4.

for approximately half of the consumption growth in the Base Case. Incremental Canadian natural gas consumption accounts for about one-fifth of the increment, even though the Canadian market today accounts for less than 15 percent of the total market. The higher growth rate of natural gas consumption in Canada is due to increased natural gas consumption for the development of the oil sands in Western Canada as well as the replacement of coal-fired generation in Ontario mandated by the provincial government.

Table 7
Change in U.S. and Canadian Natural Gas Consumption by Region
2008 to 2030 (Tcf)

	2008	*Base Case*	*High Gas Growth Case*	*Low Electric Growth Case*
Southeast	3.0	1.3	3.0	(0.3)
Southwest	6.2	1.2	1.6	0.0
Midwest	4.1	0.5	1.3	(0.1)
Western	3.3	0.5	0.3	(0.4)
Central	2.2	0.3	0.5	(0.2)
Northeast	4.2	0.2	1.4	(0.5)
Offshore	0.1	0.0	0.0	(0.0)
Arctic	0.5	0.2	0.1	0.1
Canada	3.4	0.9	0.9	0.3
	26.9	5.0	9.1	(1.1)

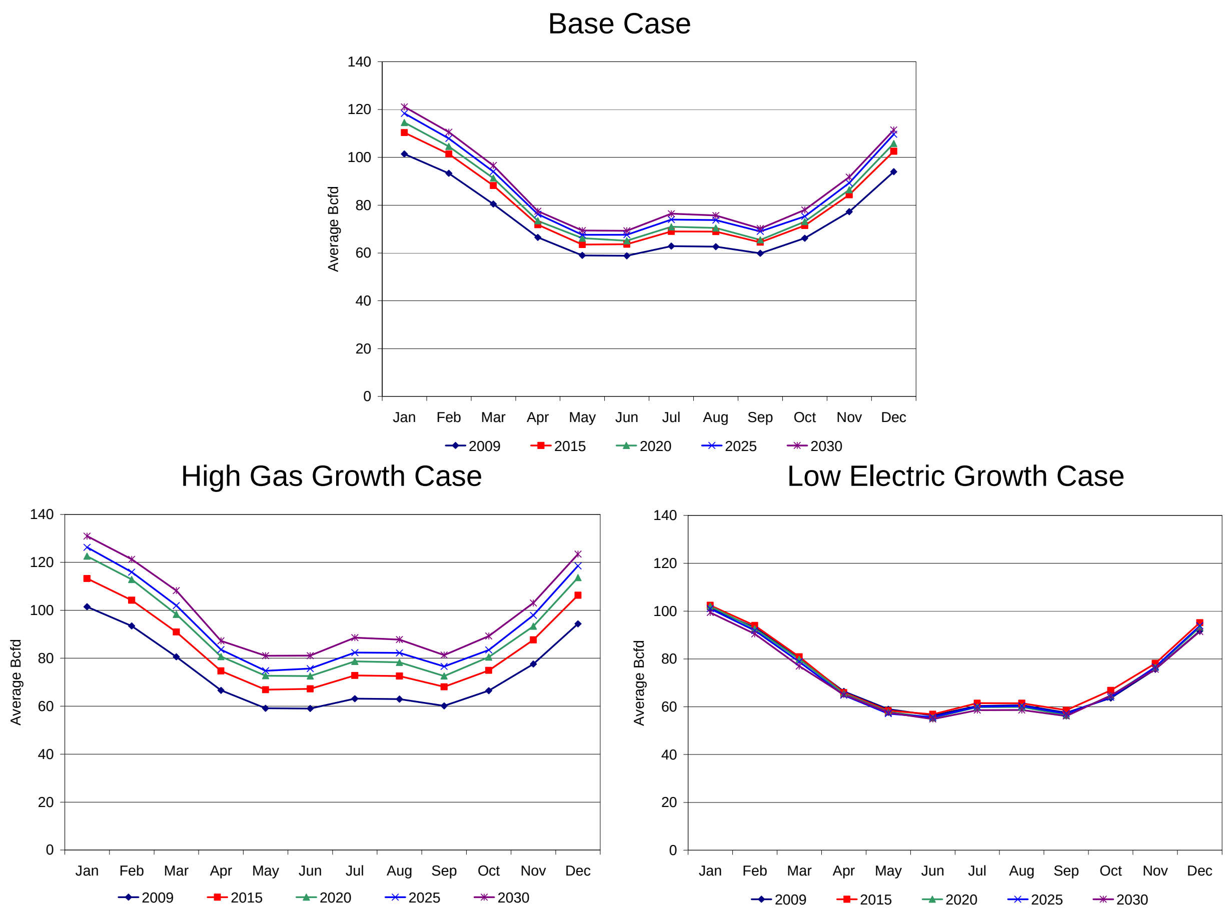
Regional natural gas consumption differences between the Base and High Gas Growth Cases are due primarily to changes in power sector natural gas consumption. The higher natural gas consumption for vehicle use and increased efficiency gains within the residential and commercial sectors in the High Gas Growth Case are spread over all regions. The change in the power plant mix varies among regions. Regions such as the Northeast and Southeast are assumed to have less nuclear capacity, because fewer new nuclear units are added in the High Gas Growth Case. Regions that have a high degree of coal generation such as the Midwest have greater coal retirements and natural gas capacity replacements in the High Gas Growth Case. Regions with little assumed change in generation capacity, such as the Western, Arctic, Canada, and the Central regions, exhibit modest changes in natural gas consumption between the two cases. Power sector natural gas consumption growth is the dominant driver of future natural gas market growth in all regions.

In contrast to the other two cases, the Low Electric Growth Case projects natural gas consumption that declines or is flat in most areas throughout North America. Only in Canada, where gas is used for development of oil sands is there a definite increase. Increasing gas consumption in the Arctic region is due to pipeline fuel related to the Arctic pipeline projects. In most regions, gas consumption declines as gas-fired power generation is replaced by renewable and nuclear generation. Increased conservation in the residential sector also reduces the need for gas consumption, particularly in cold-weather regions.

4.2.2 Seasonal Trends in Gas Consumption

Despite the increase in natural gas use for power generation, the U.S. and Canadian natural gas markets are, and will continue to be, winter peaking (Figure 15). The seasonality of space heating dominates all but the Southern parts of the U.S. Currently, with normal weather, U.S. and Canada demand in a peak winter month is over 60 percent above demand in a peak summer month. The Base Case shows that U.S. and Canada summer demand is anticipated to increase relative to winter demand. Even so, demand during a peak winter month remains 58 percent above demand in a peak summer month through 2030 in the case.

Figure 15
Monthly Natural Gas Consumption,
Base Case, High Gas Growth Case, and Low Electric Growth Case (Average Bcf per day)



Natural gas consumption grows fastest throughout the year in the High Gas Growth Case, and growth is greatest in the summer months. Still, the market remains a winter peaking market. Peak winter month consumption in 2030 is still 47 percent greater than peak summer month consumption in the High Gas Growth Case. The U.S. and Canadian natural gas markets will remain winter peaking markets for the foreseeable future under all reasonable forecast scenarios. The shoulder months during the spring and fall are anticipated to remain the lowest natural gas consumption months throughout the course of a year.

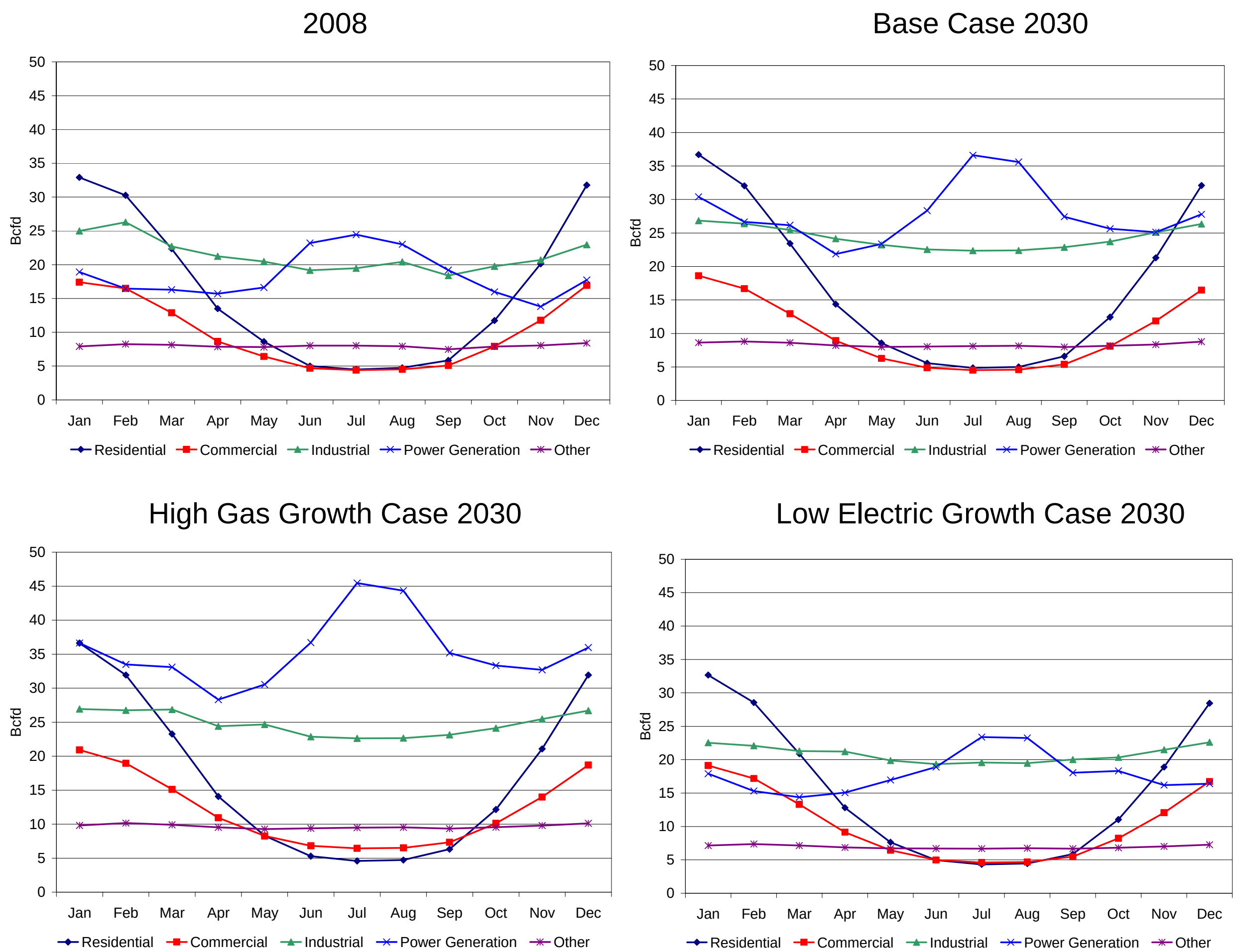
Seasonal patterns in the Low Electric Growth Case remain relatively constant from 2009 to 2030. Conservation measures impact both summer and winter gas consumption relatively equally.

It should be noted that much of the pipeline infrastructure is used during the summer to inject natural gas into storage. Since spare seasonal pipeline capacity will not be available, incremental pipeline infrastructure will be needed to serve an increasing summer power generation market.

Figure 16 presents the monthly pattern of combined U.S. and Canadian natural gas demand by sector for 2008 and the anticipated pattern in 2030 for the three cases. Most segments of the natural gas market are winter peaking. In 2008, the residential market is seven times larger in the winter than in the summer, while the commercial sector's winter demand is nearly four times larger. Industrial demand exhibits only slight variances between the winter and summer, but still shows a modest winter peak. Only the power generation sector is counter cyclical, peaking during the summer. Still, the variance between seasons is not nearly as large as it is in the sectors dominated by space heating, and therefore, the U.S. and Canadian market as a whole exhibits a winter peak. It should be noted that much of the pipeline infrastructure is used during the summer to inject natural gas into storage. Since spare seasonal pipeline capacity will not be available, incremental pipeline infrastructure will be needed to serve an increasing summer power generation market.

The 2030 seasonal patterns in each case are similar to each other, albeit the market is much larger in both the Base Case and High Gas Growth Case. The ratio of winter to summer consumption increases slightly in the residential and commercial sectors since peak consumption grows slightly faster than average consumption. By 2030, the ratio of peak summer to winter natural gas consumption in the power sector declines from about 1.4 in 2008 to 1.3 and 1.25 in 2030 for the Base Case and High Gas Growth Case, respectively. This is due to gas-fired generation being used more extensively for baseload generation in the future, especially in the High Gas Growth Case. The 2030 seasonal pattern in the Low Electric Growth Case is similar to the 2008 pattern. Differences are mostly attributed to actual 2008 weather versus the assumed normal weather for 2030.

Figure 16
Monthly Natural Gas Consumption by Sector,
Base Case, High Gas Growth Case, and Low Electric Growth Case, 2008 and 2030
(Average Bcf per day)



4.3 Natural Gas Supply

North American natural gas supply is diverse, with natural gas originating from many different sources and areas. Historically, North American natural gas markets have been self-reliant, and most of the natural gas supply for the markets has come from the U.S. Gulf Coast and the Western Canadian Sedimentary Basin. Recently, traditional formations in both areas have shown signs of resource depletion, and the focus of natural gas producers has shifted to unconventional formations, deeper sediments and other areas. There has been an increasing focus on LNG imports as well. Natural gas suppliers are increasingly looking to new frontiers for future supplies. Given the maturity of the North American natural gas resource, this new focus is likely to continue well into the future.

4.3.1 U.S. and Canadian Natural Gas Resource Development and Production

As discussed in Section 3.1.1 above, a significant and widespread resource of nearly 2,400 Tcf remains to be developed in the U.S. and Canada. It is highly unlikely, though, that this total natural gas resource will be fully developed, as not all of the resource is cost-effective to develop. The supply analysis supporting this work indicates that approximately 600 Tcf of natural gas can be developed economically using current technology with Henry Hub gas prices at $5.00 per MMBtu. Additional resource can be developed at higher prices or as E&P technology advances.

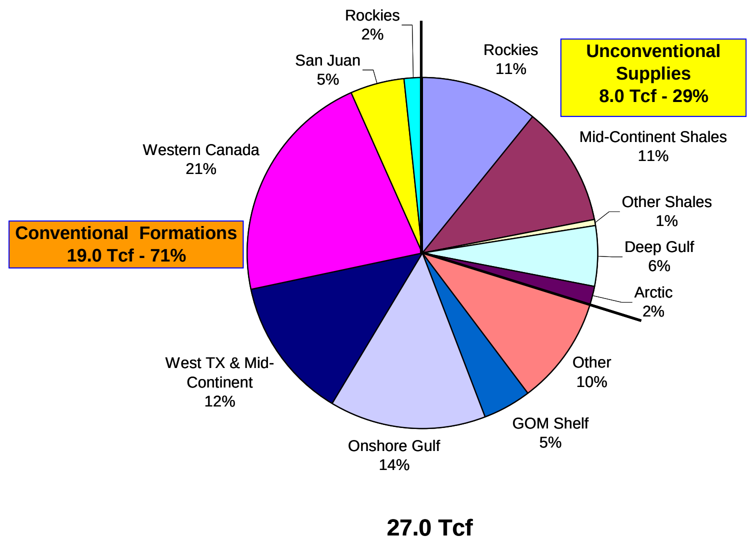
In order to maintain sufficient levels of natural gas supply to satisfy market needs, natural gas development must continue at a relatively high rate. Table 8 shows historical and projected natural gas well completions for the U.S. and Canada for all three cases. The table shows that gas well completions will remain near or above recent completion levels well into the future. Annual completions in the Base Case and High Gas Growth case rise above 50,000, well above recent averages of approximately 38,000 per year. Even the Low Electric Growth Case projects annual gas well completions near 35,000, close to recent averages.

Table 8
Natural Gas Well Completions Through 2030 for the Base Case, High Gas Growth Case, and Low Electric Growth Case

	Average Annual Gas Well Completions		
	2002 to 2006	2007 to 2015	2016 to 2030
Base Case	38,474	41,966	50,250
High Gas Growth Case	38,474	42,833	52,508
Low Electric Growth Case	38,474	34,771	35,013

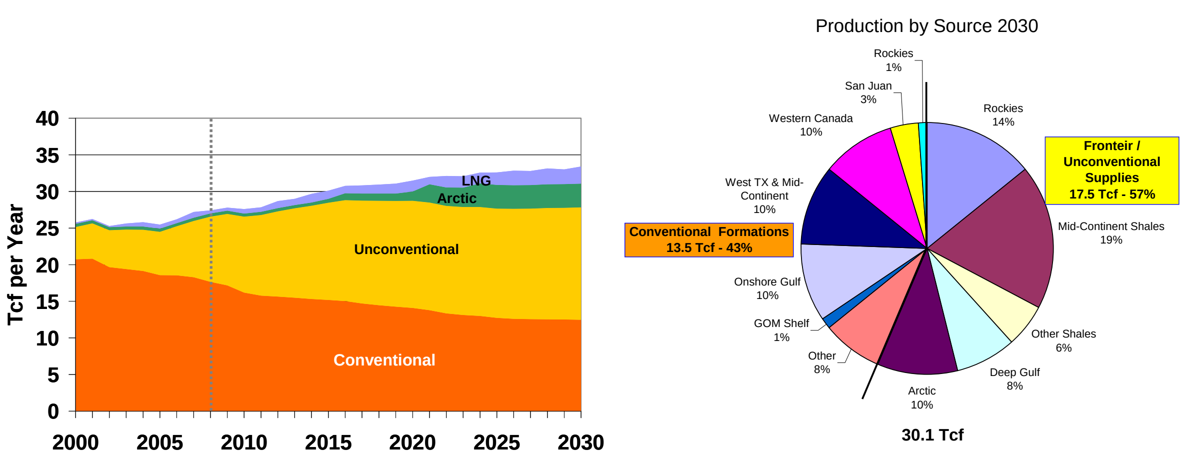
Natural gas supplies from multiple sources must grow to meet future demand. Traditional producing formations in Western Canada, West Texas, Oklahoma, South Texas, South Louisiana, the Offshore Shelf in the Gulf of Mexico and the San Juan Basin currently produce 19 Tcf per year, accounting for 71 percent of all U.S. and Canadian natural gas production (Figure 17). The remaining 8 Tcf of annual production comes from unconventional and frontier sources in the Rockies, the deeper waters of the Gulf of Mexico and recently developed shale formations mainly in the Mid-continent. Many industry analysts believe that recent production declines from the traditional basins will continue, and growth in production will increasingly come from unconventional and more remote frontier sources of supply.

Figure 17
2008 Production by Area



While production from conventional formations is projected to remain an important part of the total supply portfolio, conventional production is likely to decline in terms of absolute production volumes and market share. In the Base Case, annual volumes from traditional basins are projected to decline by well over 5 Tcf, and these areas will account for only 43 percent of total U.S. and Canadian gas production by 2030 (Figure 18). The declines in production from traditional supply sources are due mainly to the lack of quality drilling prospects in mature basins. Natural gas producers must work harder to develop additional deliverability as decline rates increase and reserves-per-well fall below past levels.

Figure 18
Base Case
Conventional and Unconventional Production, 2000 – 2030 (Tcf)



Hence, much future gas supply is likely to come from unconventional and frontier gas supplies. Natural gas from shales is the fastest growing source of natural gas in the U.S. and Canada. By 2030, the Base Case projects that shales in the Mid-continent, most notably the Barnett, Haynesville, Woodford, and Fayetteville, will account for nearly one-fifth of total domestic production. Other shales in the East (the Marcellus) and British Columbia (the Horn River and Montney) could add another 6 percent of gas supply. In the Base Case, annual shale gas supply rises to 7.5 Tcf by 2030, more than doubling recent production estimated at 3.3 Tcf in 2008.

The importance of the recent and projected success of shale gas development should not be understated. Less than 10 years ago, most industry analysts projected that the majority of incremental natural gas supply needed to meet growing demand would come from the deeper waters of the Gulf of Mexico. In reality, however, production from the area has failed to grow by enough to counteract declines in production from the shallower waters in the Gulf of Mexico. Shortly after, analysts projected that LNG would be the largest single source of new supply. Depending on the scenario, LNG imports are projected to increase (see next section), but not as significantly as in earlier forecasts (see Footnote 15 above). Now, the majority of industry analysts believe that shale and other unconventional natural gas formations will satisfy market needs in the U.S. and Canada. Unlike Gulf of Mexico production and LNG imports, shale gas production continues to surpass earlier expectations.

In addition to shale gas, frontier basins in the Arctic, such as Alaska and the Mackenzie Delta, and underdeveloped domestic areas such as the Northern Rockies may be needed to serve U.S. and Canadian demand. In the High Gas Growth Case, total unconventional (shale) and frontier natural gas supplies are projected to reach 22.4 Tcf by 2030, which will account for nearly two-thirds of U.S. and Canadian gas production. LNG imports may also play a key role. Of course, new pipeline infrastructure will be required to transport natural gas from new supply areas.

The projected shift of natural gas supply, even in a weak natural gas market, will require new natural gas infrastructure.

The High Gas Growth Case includes several government policy and technological assumptions that enable more gas production to be developed. It is assumed that drilling moratoria off of the west coast of Florida and the East and West Coasts of the U.S. are not reinstated, yielding a total annual increase in offshore production of 2 Tcf by 2030 (Figure 19). Additionally, the High Gas Growth Case assumes that technologies enabling extraction of natural gas from shales and other unconventional formations advance more rapidly than assumed in the Base Case. Consequently, annual shale production is 1.5 Tcf above the Base Case level, rising to 9 Tcf by 2030. Also, annual production from unconventional formations in the Rockies is 1 Tcf greater. While total Arctic supplies are the same as in the Base Case, it is assumed that Arctic gas is developed a few years earlier. The increased level of natural gas supply development in the High Gas Growth Case necessitates development of additional natural gas infrastructure.

Even though natural gas consumption is down over time in the Low Electric Growth Case, there is still a very strong need to develop unconventional and frontier gas supplies to counterbalance declining production from areas that have been historically relied upon. Total U.S. and Canada natural gas production declines from 27 Tcf in 2008 to 26.3 Tcf in 2030, but unconventional and frontier gas production more than doubles from 8 Tcf to over 16 Tcf over the same time period (Figure 20). The projected shift of natural gas supply, even in a weak natural gas market, will require new natural gas infrastructure.

Figure 19
High Gas Growth Case
Conventional and Unconventional Supply, 2000 – 2030 (Tcf)

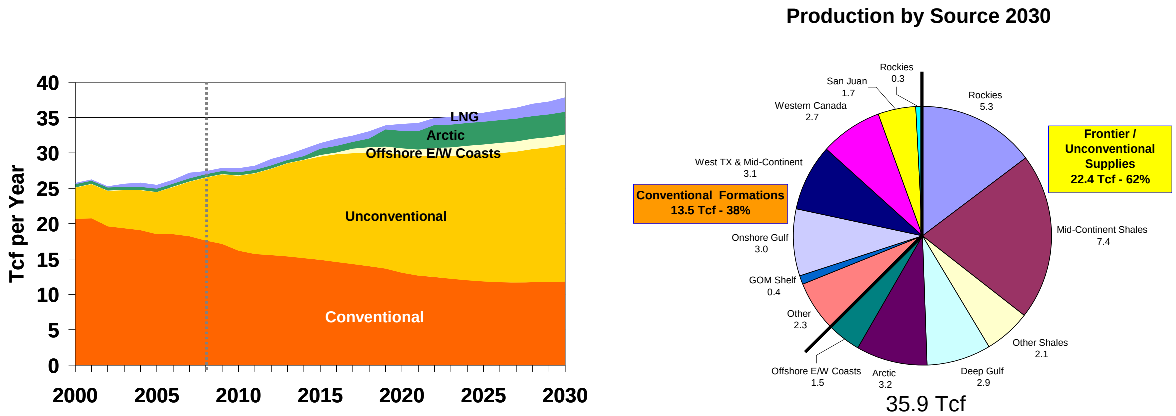
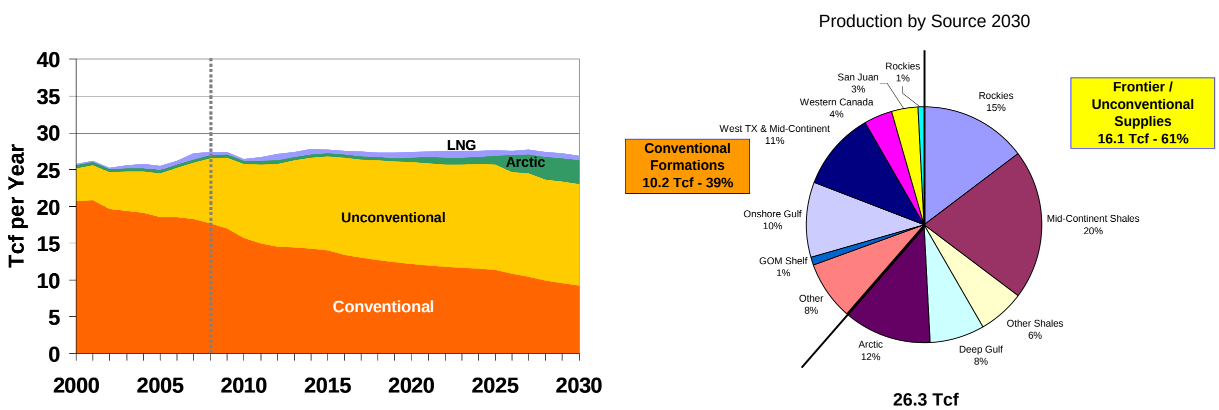


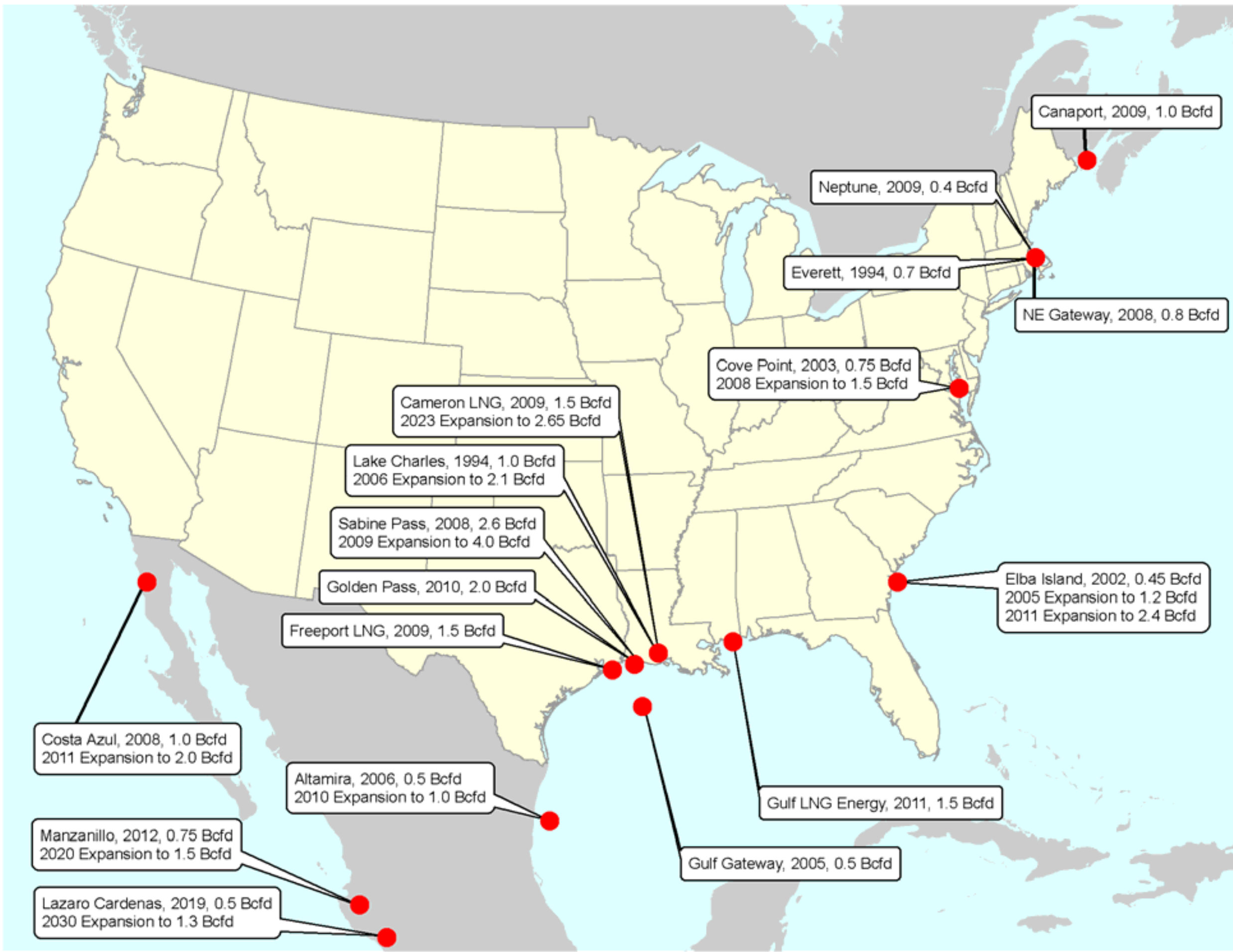
Figure 20
Low Electric Growth Case
Conventional and Unconventional Supply, 2000 – 2030 (Tcf)



4.3.2 LNG Imports

In addition to the need for natural gas production from unconventional and frontier basins, both the Base Case and High Gas Growth Case projections rely on significant increases in LNG imports to meet the demand requirements of the U.S. and Canadian natural gas markets. Current LNG import capacity of over 12 Bcf per day consists of eight operating LNG import terminals in the U.S.[28], plus three additional buoy docking systems[29] where the regasification occurs onboard the LNG tanker itself (Figure 21). Both the Canaport LNG import terminal in New Brunswick and the Cameron terminal in Louisiana commenced operations in 2009. An expansion of Sabine Pass in Louisiana, which commenced operations in 2008, also was completed in 2009. Golden Pass in Texas is expected to commence operations in 2010. These new and expanded terminals will add a combined 6.2 Bcf per day of import capacity.

Figure 21
LNG Regasification Facilities in the Cases



A large portion of projected LNG import capacity has already been constructed. Since current LNG import terminals are operating at a load factor of around 10 percent, imports easily can increase simply by utilizing existing infrastructure. Only one additional terminal in the Gulf of Mexico is projected to be completed before 2030. It is projected that additional new and planned capacity additions at existing sites increase total U.S. and Canadian LNG import capacity by 3.5 Bcf per day to about 20 Bcf per day. LNG capacity assumptions are the same in all cases.

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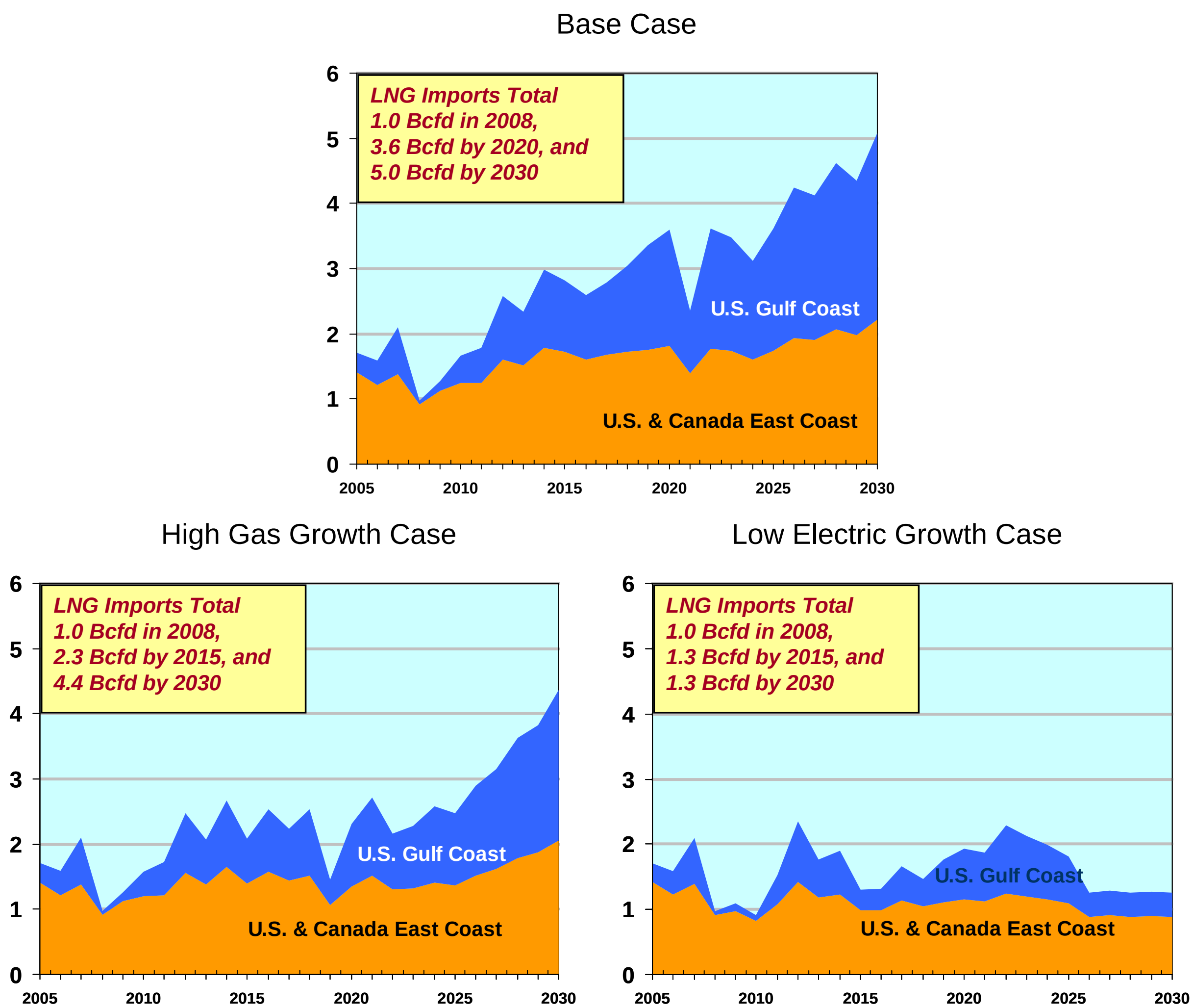
[28] Everett, MA; Cameron, LA; Canaport, NB; Cove Point, MD; Elba Island, GA; Lake Charles, LA; Freeport, TX; and Sabine Pass, LA.

[29] Northeast Gateway and Neptune 2 systems offshore near Boston, MA and Gulf Gateway in the Gulf of Mexico.

U.S. LNG imports for 2008 totaled about 350 Bcf, averaging about 1.0 Bcf per day. The Base Case projects that U.S. and Canadian LNG imports increase to an average of 3.6 Bcf per day by 2020 and continue to trend upward to 5.0 Bcf per day, or to 1.7 Tcf in 2030 (Figure 22). Given a total import capacity of 20 Bcf per day, average load factors for all terminals rise to about 25 percent in that case.

Figure 22
LNG Imports, 2000 – 2030 (Bcf per day)



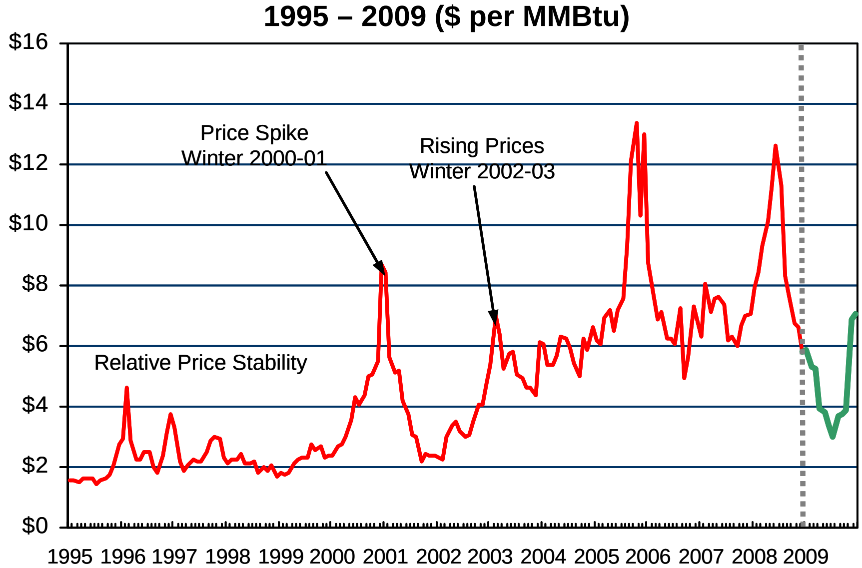
The High Gas Growth Case has lower LNG imports than the Base Case even though it has the same assumed LNG import capacity. Although there is a need for greater natural gas supply in the High Gas Growth Case, incremental shale and offshore production entirely satisfy increased gas consumption. LNG deliveries must compete with domestic production. Thus, if available, domestic supply will displace LNG imports. In the High Gas Growth Case, LNG imports are projected to grow to an average of 4.5 Bcf per day by 2030, or to 1.6 Tcf per year, which is slightly less than in the Base Case.

LNG imports in the Low Electric Growth Case remain near current levels, fluctuating between 1 and 2 Bcf per day. North American natural gas prices are not sufficiently high enough to attract additional LNG in this case. Most of the LNG imported into North America is under firm contract, but some incremental LNG imports occur in the summer when there is no other outlet in world markets.

4.4 Natural Gas Price and Basis

The U.S. and Canadian natural gas markets have undergone a fundamental shift that began around the year 2000. Between 2000 and 2007, natural gas prices at most trading locations throughout the U.S. and Canada averaged in excess of $5 per MMBtu (Figure 23)[30]. Price volatility has increased significantly compared to volatility observed during the1990s, when prices were fairly constant between $2.00 and $3.00 per MMBtu.

Figure 23
Monthly Henry Hub Natural Gas Prices, 1995 – 2009 ($ per MMBtu)



The supply and demand balance for natural gas in this new era is much tighter than during the 1990s. By around 2000, the significant surplus in natural gas well productive capacity had been eliminated by overall market growth. The result has been significantly higher natural gas prices and greater price volatility. Even though 2009 prices are relatively low at under $4 per MMBtu, natural gas prices are not projected to stay at this level for very long as natural gas supply and demand are expected to tighten with a recovering economy.

In the Base Case, nominal values for the Henry Hub natural gas price are projected to increase from a recent historical average of near $6 per MMBtu to an average of about $10 per MMBtu in the later years of the projection (Table 9)[31]. Projected natural gas prices trend at a level that is sufficient to encourage continued natural gas supply development, but not so high as to

[30] Henry Hub price is shown here. The Henry Hub price is a widely recognized benchmark for U.S. gas prices. It is also the physical location for the NYMEX futures price.

[31] The table shows average gas prices over periods of time. Yearly gas prices are shown in Appendix C.

discourage continued market growth. Since the U.S. and Canadian natural gas markets are highly integrated, all price points in the U.S. and Canada will be at about the same levels as the prices shown in Table 9.

Future natural gas prices in the High Gas Growth Case average about $1 per MMBtu below the Base Case level. Although the High Gas Growth Case projects increased natural gas use, additional supply from unconventional formations and the incremental offshore gas development more than offset upward price pressures created by the increased level of gas use in the case.

Future natural gas prices in the Low Electric Growth Case average almost $4 per MMBtu below the Base Case level in nominal terms. Since the case has similar supply assumptions to those in the Base Case, the lower gas prices are a result of the reduced level of gas use over time.

Table 9
Henry Hub Natural Gas Prices and Oil Product Prices Through 2030
(2008 $ and Nominal $ per MMBtu)

	Prices in 2008 $/MMBtu			*Prices in Nominal $/MMBtu*		
	2002 to 2006	2007 to 2015	2016 to 2030	2002 to 2006	2007 to 2015	2016 to 2030
Henry Hub Natural Gas						
Base Case	$6.60	$6.47	$6.96	$6.04	$6.81	$9.85
High Gas Growth	$6.60	$6.18	$6.02	$6.04	$6.49	$8.54
Low Electric Growth	$6.60	$5.53	$4.45	$6.04	$5.79	$6.14
Petroleum Products						
West Texas Intermidiate	$8.07	$13.18	$13.09	$7.40	$13.86	$18.43
Distillate Fuel Oil	$9.25	$15.43	$15.32	$8.49	$16.23	$21.57
Residual Fuel Oil	$5.75	$9.85	$9.78	$5.27	$13.86	$13.77

In all cases, natural gas prices are projected at a level that is significantly below assumed oil prices. Even residual fuel oil, the main substitute for natural gas, remains at a several dollar per MMBtu premium throughout the forecast. Significant oil-to-gas substitution is not likely to occur at these price levels. In fact, all industrial and power consumers that have the option to use natural gas instead of oil will do so because of the cost advantage. Gas-to-oil switching may still occur at some power plants, but mostly to assure electric system reliability. Also, on peak natural gas consumption days, gas-to-oil switching may be necessary in areas where natural gas pipelines become constrained, such as in New York City.

Adjusted for inflation, Henry Hub natural gas prices remain fairly steady after 2009 for both the Base Case and the High Gas Growth Case. After the economy recovers, natural gas prices rebound back into the $6 to $7 per MMBtu range in real terms, consistent with the recent historical average.[32] Real gas prices in the Low Electric Growth Case are projected to average $4.50 to $5.50 per MMBtu, somewhat below recent historical averages due to the declining gas use over time.

The term basis refers to natural gas price differentials between regions. Pipeline rates and tolls do not determine basis. Instead, basis is determined by the opportunity costs to move natural gas between locations. When there is significant excess pipeline capacity between markets, such as between Henry Hub and Chicago, basis differentials can be quite low (Table 10),

[32] At completion of this report, Henry Hub was trading at under $3 per MMBtu.

approaching variable costs. The largest component of variable cost is pipeline compression fuel[33]. Due to the U.S. pipeline rate structures, the commodity portion of firm rates is typically only a few cents per MMBtu even for long haul transport.

Natural gas price basis is the most direct indicator of the need for new pipeline infrastructure.

Conversely, in a market where there is a deficiency of pipeline capacity, such as out of the Northern Rocky Mountain region, basis is the market signal that represents the true opportunity cost between regions, or the potential value that additional new capacity could capture if built into the market. Even price cap restrictions on transportation in the primary and secondary capacity markets do not prevent the basis from rising to levels that exceed tariff maximums. Natural gas price basis is the most direct indicator of the need for new pipeline infrastructure.

Table 10
Selected Regional Basis in the Base Case Through 2030
(2008 $ and Nominal $ per MMBtu)

	Basis in 2008 $/MMBtu			***Basis in Nominal $/MMBtu***		
	2002 to 2006	2007 to 2015	2016 to 2030	2002 to 2006	2007 to 2015	2016 to 2030
Henry Hub to NYC	0.97	0.94	0.78	0.88	0.98	1.10
Henry Hub to Dominion North Point	0.84	0.52	0.45	0.76	0.54	0.63
Henry Hub to Dominion South Point	0.43	0.40	0.36	0.39	0.41	0.51
Henry Hub to Chicago	-0.10	0.08	-0.02	-0.09	0.09	-0.03
Henry Hub to Dawn	0.14	0.46	0.54	0.13	0.49	0.76
Henry Hub to South Florida	0.52	0.58	0.60	0.47	0.61	0.85
AECO to Chicago	0.97	0.70	0.66	0.88	0.73	0.93
Opal vs Henry Hub	1.34	1.47	0.66	1.22	1.49	0.94
Opal to Dominion North Point	2.18	1.98	1.11	1.98	2.03	1.57
Opal to Dominion South Point	1.77	1.86	1.02	1.61	1.90	1.44
Opal to Southern California	0.72	1.11	0.47	0.65	1.12	0.68
Southern California vs Henry Hub	0.62	0.36	0.19	0.57	0.37	0.26
Midcontintent vs Henry Hub	0.58	0.49	0.29	0.54	0.50	0.41
East Texas vs Henry Hub	0.29	0.15	0.09	0.27	0.16	0.13
San Juan Basin vs Henry Hub	1.19	0.72	0.46	1.08	0.74	0.65

Incremental supply and pipeline capacity will tend to reduce basis between regions. In the Base Case, price basis from Henry Hub to Northeast points declines due to new supply availability via the Rockies Express Pipeline. Additionally, increased LNG imports directly to the U.S. Northeast and Eastern Canada and increased gas production in the Northeast from the Marcellus shale also exert influence that causes a lower Henry Hub to Northeast price basis. The Henry Hub to Chicago basis fluctuates around parity, similar to recent history. Basis is projected to be lower immediately after new natural gas supplies come online either from the Rockies or Canada (the Arctic projects) into the Chicago area. Price basis from Henry Hub to Dawn, Ontario is expected to increase as pipelines through Michigan initially fill with Rockies gas and then fill with Arctic supplies beginning in 2020.

Price basis out of the Northern Rockies, represented by the Opal index, is projected to remain relatively high. Actual basis will be highly dependent on how well the timing of incremental

[33] There is no CO_2 charge assumed for pipeline fuel in this analysis.

pipeline capacity out of the region matches the timing of increased production. Delays in additional pipeline capacity can increase the basis significantly. Basis from Texas and the Mid-continent to Henry Hub is expected to decline from recent levels. Significant pipeline capacity has recently been built, or will soon be completed in 2009. The new pipeline projects will reduce or eliminate regional pipeline bottlenecks. The basis from the Alberta Energy Company interconnect with the Nava System (AECO) to Chicago remains relatively stable even though throughput out of Western Canada is expected to decline from current levels. National Energy Board regulations applicable to the TransCanada Pipeline system require a minimum price for interruptible transportation, which helps maintain a price basis across the system.

The projected basis patterns in the High Gas Growth Case are generally similar to those in the Base Case (Table 11). Generally, price differentials between regions are slightly higher in the High Gas Growth Case. Pipeline infrastructure is used more intensively due to increased natural gas production and consumption. Conversely, projected basis values in the Low Electric Growth Case are lower relative to the Base Case (Table 12). Pipeline infrastructure is used less intensively due to lower natural gas consumption. In addition, lower natural gas prices reduce fuel costs, reducing the variable costs of gas transmission.

Table 11
Selected Regional Basis in the High Gas Growth Case Through 2030
(2008 $ and Nominal $ per MMBtu)

	Basis in 2008 $/MMBtu			***Basis in Nominal $/MMBtu***		
	2002 to 2006	2007 to 2015	2016 to 2030	2002 to 2006	2007 to 2015	2016 to 2030
Henry Hub to NYC	0.97	0.94	0.95	0.88	0.98	1.35
Henry Hub to Dominion North Point	0.84	0.51	0.37	0.76	0.54	0.52
Henry Hub to Dominion South Point	0.43	0.39	0.27	0.39	0.41	0.38
Henry Hub to Chicago	-0.10	0.05	-0.16	-0.09	0.06	-0.23
Henry Hub to Dawn	0.14	0.45	0.66	0.13	0.48	0.95
Henry Hub to South Florida	0.52	0.55	0.38	0.47	0.57	0.54
AECO to Chicago	0.97	0.74	0.44	0.88	0.77	0.61
Opal vs Henry Hub	1.34	1.66	0.73	1.22	1.69	1.02
Opal to Dominion North Point	2.18	2.17	1.10	1.98	2.22	1.54
Opal to Dominion South Point	1.77	2.04	1.01	1.61	2.10	1.41
Opal to Southern California	0.72	1.24	0.27	0.65	1.25	0.38
Southern California vs Henry Hub	0.62	0.42	0.46	0.57	0.43	0.64
Midcontintent vs Henry Hub	0.58	0.54	0.44	0.54	0.55	0.62
East Texas vs Henry Hub	0.29	0.15	0.08	0.27	0.15	0.11
San Juan Basin vs Henry Hub	1.19	0.78	0.73	1.08	0.81	1.02

Table 12
Selected Regional Basis in the Low Electric Growth Case Through 2030
(2008 $ and Nominal $ per MMBtu)

	Basis in 2008 $/MMBtu			***Basis in Nominal $/MMBtu***		
	2002 to 2006	2007 to 2015	2016 to 2030	2002 to 2006	2007 to 2015	2016 to 2030
Henry Hub to NYC	0.97	0.82	0.50	0.88	0.85	0.68
Henry Hub to Dominion North Point	0.84	0.44	0.27	0.76	0.46	0.37
Henry Hub to Dominion South Point	0.43	0.33	0.23	0.39	0.35	0.31
Henry Hub to Chicago	-0.10	0.07	0.14	-0.09	0.08	0.19
Henry Hub to Dawn	0.14	0.40	0.50	0.13	0.43	0.68
Henry Hub to South Florida	0.52	0.57	0.38	0.47	0.60	0.52
AECO to Chicago	0.97	0.62	0.28	0.88	0.64	0.40
Opal vs Henry Hub	1.34	1.28	0.56	1.22	1.31	0.78
Opal to Dominion North Point	2.18	1.72	0.83	1.98	1.76	1.15
Opal to Dominion South Point	1.77	1.62	0.78	1.61	1.65	1.09
Opal to Southern California	0.72	0.91	0.36	0.65	0.93	0.50
Southern California vs Henry Hub	0.62	0.37	0.20	0.57	0.38	0.28
Midcontintent vs Henry Hub	0.58	0.49	0.20	0.54	0.50	0.27
East Texas vs Henry Hub	0.29	0.14	0.05	0.27	0.14	0.07
San Juan Basin vs Henry Hub	1.19	0.69	0.36	1.08	0.71	0.50

5 Projected Infrastructure

> *Insufficient natural gas infrastructure can lead to price volatility, reduced economic growth, and reduced delivery of natural gas supply to consumers who value it most.*

Insufficient natural gas infrastructure can lead to price volatility, reduced economic growth, and reduced delivery of natural gas supply to consumers who value it most. If U.S. and Canadian natural gas markets grow as projected in either the Base Case or High Gas Growth Case, significant amounts of new pipeline and storage infrastructure will be needed for U.S. and Canadian natural gas markets to function efficiently. Even if the future U.S. and Canada natural gas market resembles conditions in the Low Electric Growth Case, regional shifts in natural gas supply and flow will create the need for a significant amount of new natural gas infrastructure beyond what is needed solely to meet market growth.

5.1 Projected Infrastructure Costs

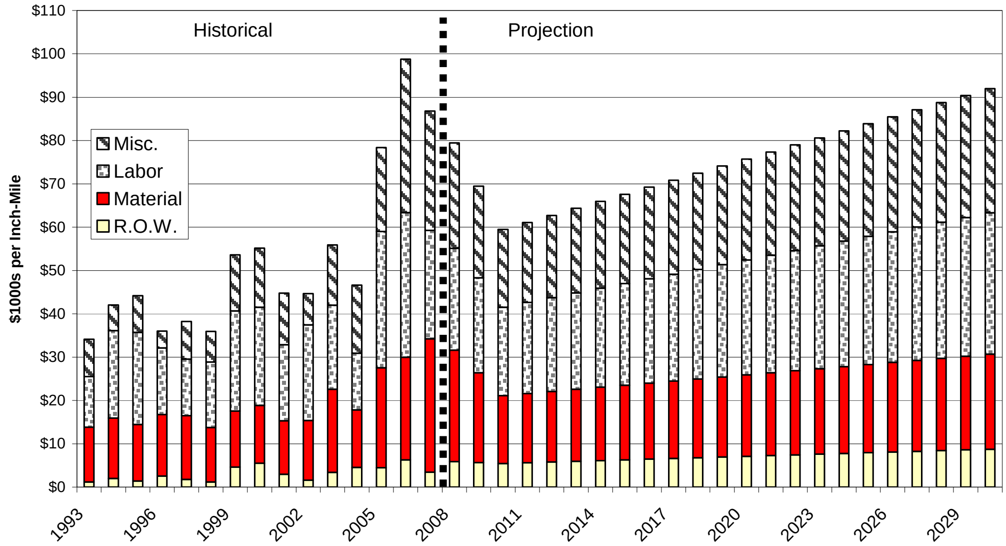
The cost of building natural gas pipeline[34] infrastructure varied between $30,000 and $100,000 per inch-mile[35] from 1993 to 2007 (Figure 24). Through 2004, increases in pipeline construction costs were generally modest. After 2004, however, costs began to escalate dramatically, nearly doubling previous levels by 2006. This was due, in part, to high world commodity prices, especially the price of steel. Costs have declined recently and the several year cost run-up is expected to only be temporary. Since all three cases have similar GDP assumptions, input costs are assumed to be the same in all cases. Construction costs are projected to decline through 2010. After 2010, costs resume a general upward pattern consistent with the pre-2004 cost trends, which are slightly less than the assumed future inflation rate of 2.5 percent per year.

The cost of pipeline construction is divided roughly equally between materials, labor, and miscellaneous. In 2007, materials costs accounted for over 35 percent of total costs, but have since declined. The miscellaneous category includes engineering, surveying, administration, and environmental costs. Costs for right-of-way account for 8 to 9 percent of total construction costs. This component has recently increased at a slightly faster rate than the other components. It is projected that the labor and right-of-way components will grow slightly faster than the other components, as skilled labor remains a premium commodity and pipeline permitting and siting continue to increase in complexity. The cost of materials is projected to increase at a rate slightly less than inflation and account for about 25 percent of total pipeline construction costs by 2030.

[34] Pipeline only, excluding compression.

[35] To provide clarity, a 24-inch diameter pipeline at a cost of $100,000 per inch-mile would cost $2,400,000 per mile.

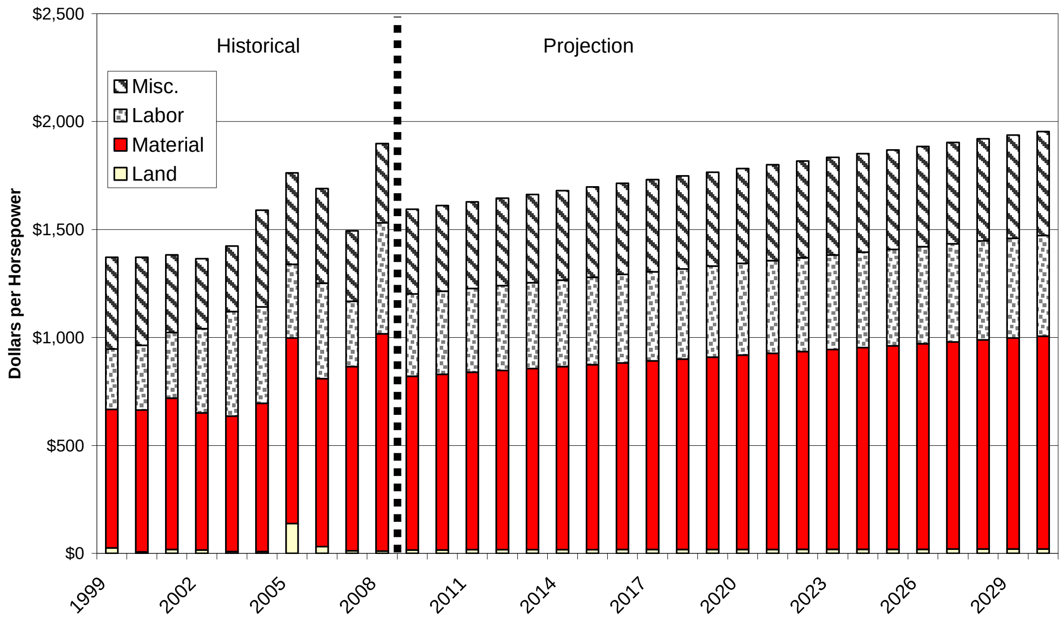
Figure 24
Natural Gas Pipeline Costs ($1000 per inch-mile)



Average of large-diameter gas pipelines 30 to 36 inches FERC data compiled by Oil & Gas Journal
2010 to 2030 projections by cost component is based on trends from 1993 to 2004.
Micellaneus includes includes surveys, engineering, supervision, interest, administration, overheads, contingencies, allowances for funds used during construction (AFUDC) and FERC fees.

Between 1999 and 2007, the cost of building pipeline compression ranged from $1,400 to $1,800 per horsepower (Figure 25). Compression costs have not been as volatile as pipeline costs. Similar to pipeline costs, compression costs are expected to trend upward at a rate near inflation, consistent with recent historical trends. Materials costs, which account for one-half of the cost of adding horsepower, represent the single largest component of the total cost of adding horsepower, because they include the manufactured compressor itself. Labor costs and the miscellaneous component, which includes engineering and environmental compliance, account for roughly one-fourth each. Land costs in connection with adding compression are insignificant. Unlike pipelines that can extend for many miles and cross the property of multiple landowners, the cost of land in connection with adding compression is limited to the immediate area surrounding the compressor station.

Figure 25
Natural Gas Compression Costs ($ per Horsepower)



Historical costs compiled by Oil & Gas Journal
2010 to 2030 projections by cost component is based on trends from 1999 to 2004.
Miscellaneous includes surveys, engineering, supervision, interest, administration, overheads, contingencies, allowances for funds used during construction (AFUDC) and FERC fees.

Both pipeline and compression construction costs vary by region (Table 13). Regional costs vary by up to 50 percent between the highest to the lowest cost regions. Costs in more densely populated regions tend to be more expensive than in less populated regions due to the increased costs of permitting, safety, and environmental compliance. The region with the highest construction costs is the Northeast U.S., while Canada and the Southwest U.S. are among the lowest costs areas.

Table 13
Regional Pipeline and Compressor Construction Cost Comparison

Region	Pipeline	Compression
Canada	0.86	1.00
Central	0.92	0.98
Midwest	1.00	1.13
Northeast	1.29	1.20
Offshore	0.86	na
Southeast	1.17	0.97
Southwest	0.86	0.95
Western	1.02	1.05
Grand Total	1.00	1.00

Based on U.S. and Canadian Pipeline Projects, 1999 – 2008.
An index of 1 equals the U.S. and Canadian average.

5.2 Projected Infrastructure Requirements and Expenditures

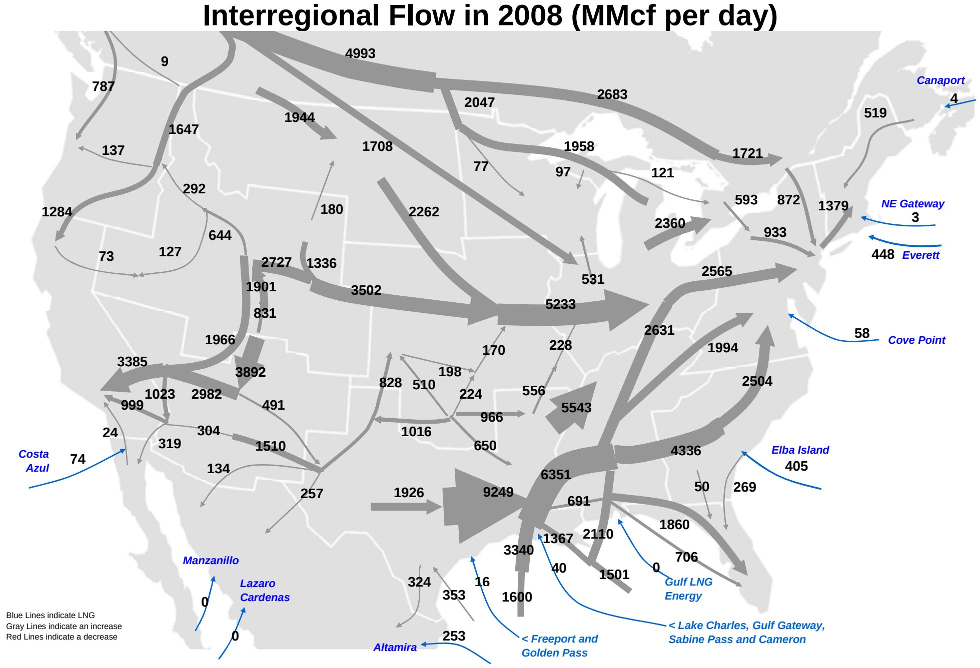
The significant growth in unconventional and frontier natural gas supplies in all three cases is the main driver of future natural gas infrastructure needs. Natural gas supplies from new sources replace supplies from mature producing areas. Therefore, most of the growth in transmission occurs along corridors that deliver new unconventional and frontier supplies to markets. Although natural gas consumption grows significantly in both the Base Case and the High Gas Growth Case, it is not the primary driver of future natural gas infrastructure needs.

The significant growth in unconventional and frontier natural gas supplies in all three cases is the main driver of future natural gas infrastructure needs.

5.2.1 Projected Changes in Interregional Flow

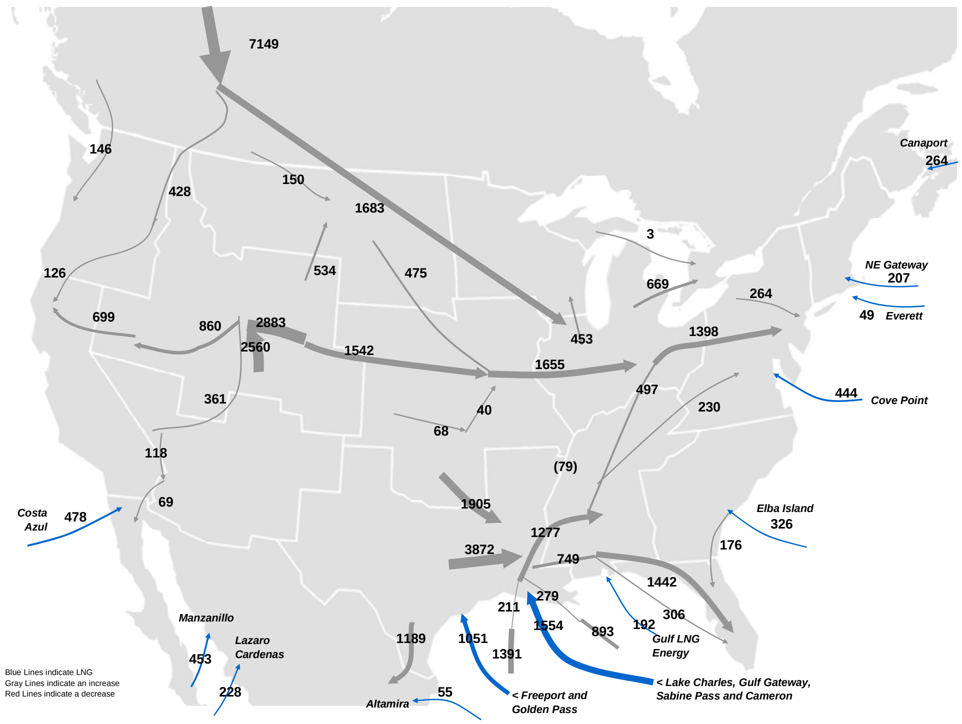
The U.S. and Canadian natural gas market is heavily reliant on three main supply areas: (1) the Gulf Coast including the Mid-Continent, (2) Western Canada, and (3) the Rockies. Interregional natural gas flow patterns for 2008 indicate large movements of natural gas out of these regions to major consuming regions in the Midwest and along the East Coast, and, to a lesser extent, the West Coast and Florida (Figure 26). While LNG also enters the North American market at specific locations along the East and Gulf Coasts, volumes are much smaller relative to interregional pipeline flows. LNG imports entering the East Coast can be “pinpointed” directly into consumption markets, and therefore, require little pipeline capacity to enable the natural gas to make its way to where it is needed. LNG importers that deliver supply along the Gulf Coast need to contract with long-haul pipelines to reach many large consumption markets.

Figure 26
Interregional Flow in 2008 (MMcf per day)



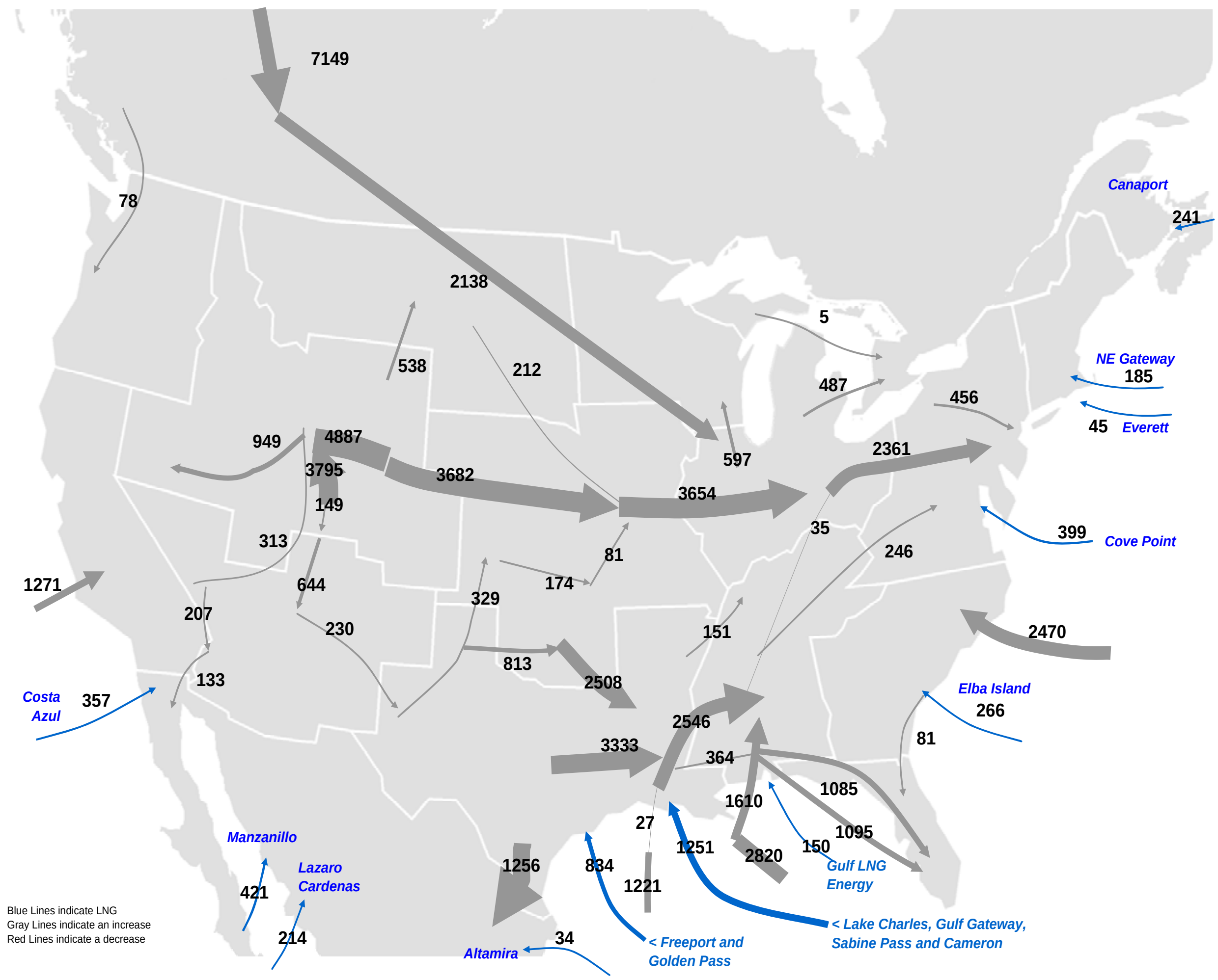
By 2030, interregional flows will increase predominately due to growing unconventional production in the Mid-continent and the Northern Rockies, from LNG imports, and from the Arctic projects if and when they are constructed (Figure 27). In the Base Case, the pipeline corridors with the most significant volume increases include the Rockies Express corridor from Wyoming to the U.S. Northeast, the Mid-continent and East Texas to Northern Louisiana corridor, the Western Canada to Chicago corridor, and along the Gulf Coast into Florida. All but one of these volume shifts is a "supply push" increase. The exception is Florida, where the increased flow is driven by a "demand pull". Most of the increases in LNG imports occur along the Gulf Coast. Interregional flows from the Gulf Coast to the Northeast increase only modestly. Large flows into the Gulf Coast from the Mid-continent and from LNG are offset in part by declining conventional production and increased regional consumption.

Figure 27
Increases in Interregional Flow,
Base Case, 2008 – 2030 (MMcf per day)



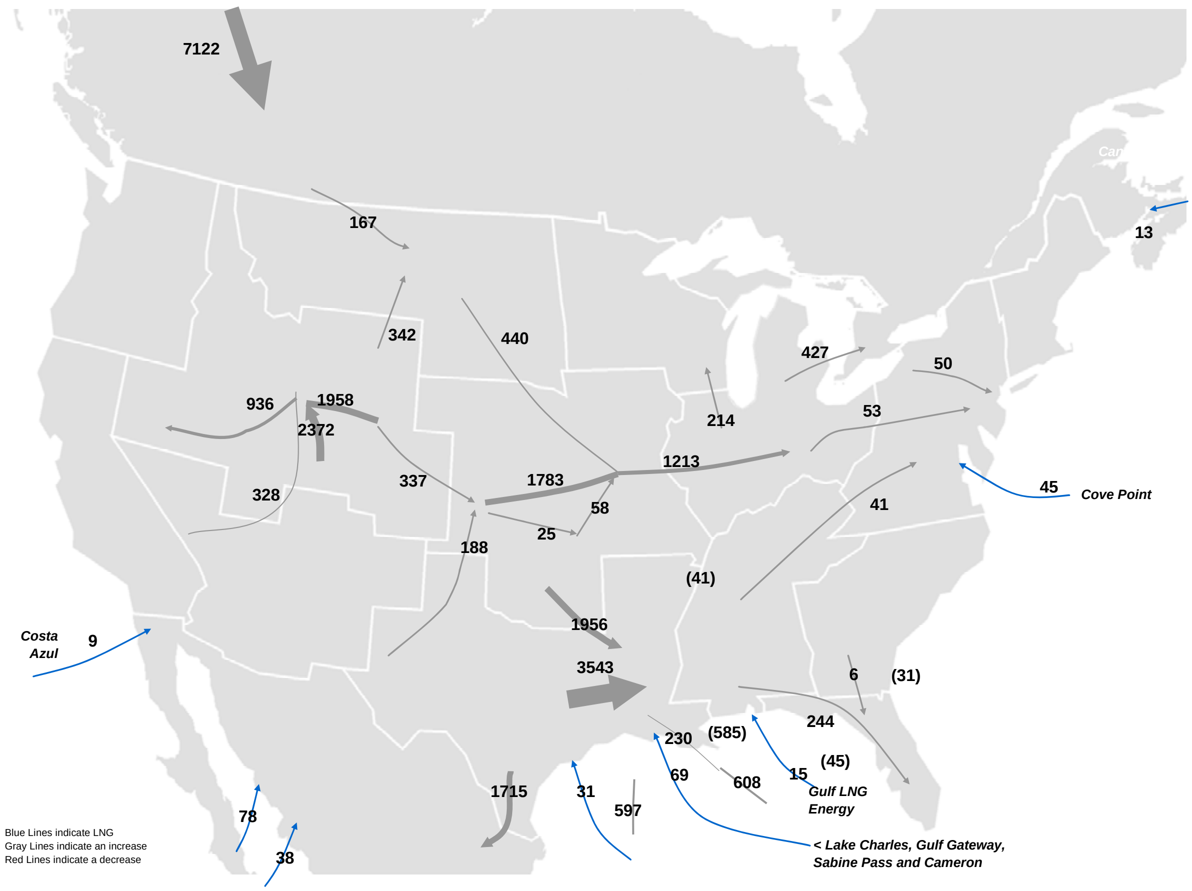
Interregional flows in the High Gas Growth Case are larger relative to the Base Case flows, due to increased domestic supply development and increased natural gas consumption (Figure 28). The High Gas Growth Case includes increased flow out of Western Canada due to increased shale development in British Columbia, out of the Mid-continent due to increased shale development in East Texas, Northwest Louisiana, Oklahoma, and Arkansas, and out of the Northern Rockies due to unconventional gas production growth. Since the case assumes that the offshore drilling moratoria are lifted, new drilling off of the west coast of Florida and the U.S. East and West Coasts yields significant increases in flows originating from offshore areas. LNG imports increase in the High Gas Growth Case but to a lesser extent relative to the Base Case, because incremental domestic production reduces the need for imported LNG.

Figure 28
Increases in Interregional Flow,
High Gas Growth Case, 2008 – 2030 (MMcf per day)



Several pipeline corridors in the Low Electric Growth Case show significant increases in interregional flow from 2008 to 2030 (Figure 29). As in the Base Case, flow increases out of the Mid-continent due to gas development from shales and out of the Northern Rockies due to growth in unconventional gas production. However, unlike the Base Case, there is no incremental flow above the 2008 level out of Western Canada. Even with over 7 Bcf per day of additional natural gas supply from Arctic pipeline projects, reduced production in Alberta and British Columbia, coupled with the same increased gas consumption for oil sands development assumed in the Base Case reduces natural gas pipeline exports below current levels.

Figure 29
Increases in Interregional Flow,
Low Electric Growth Case, 2008 – 2030 (MMcf per day)



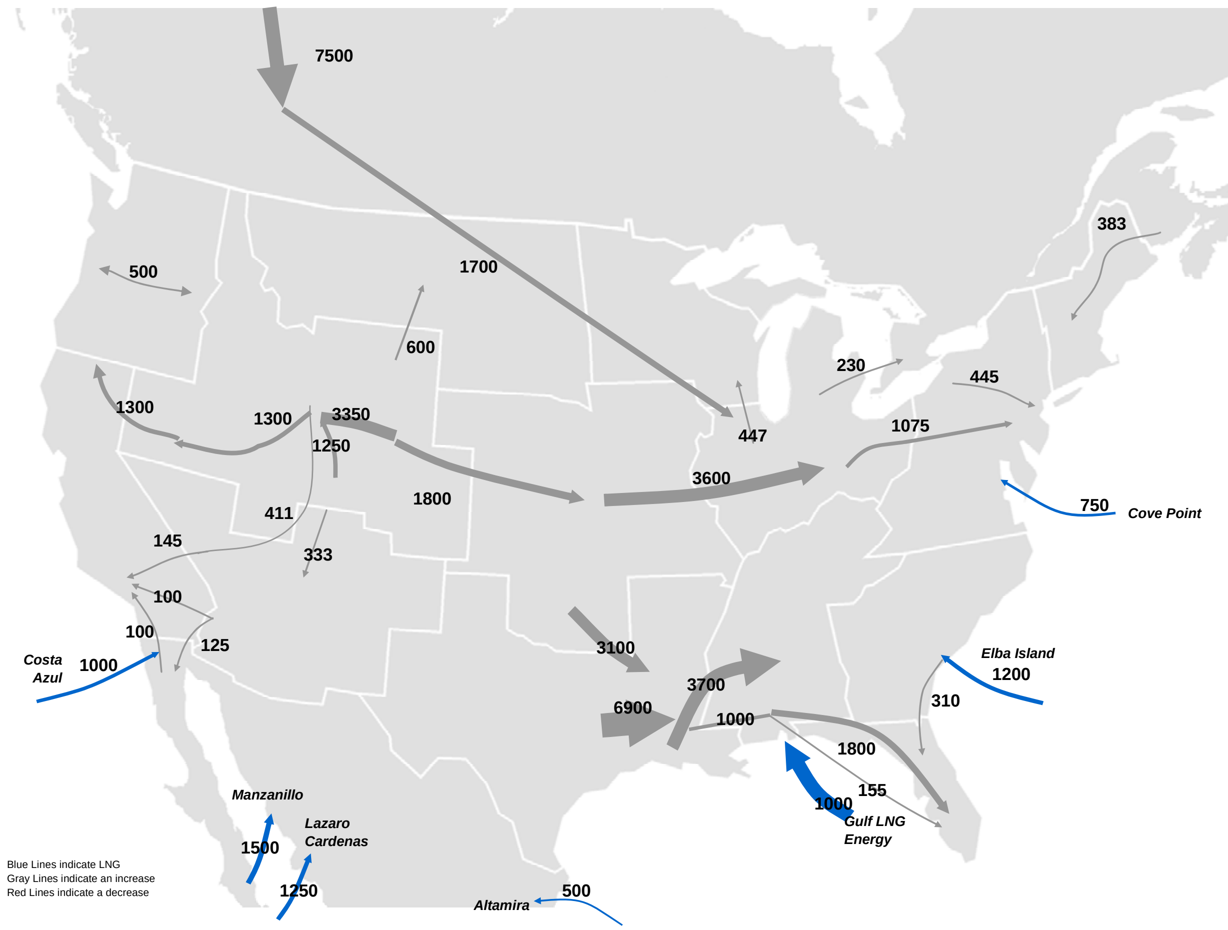
5.2.2 Projected Changes in Interregional Pipeline Capacity

In all three cases, interregional pipeline infrastructure development projected from 2010 through 2014 is based on announced pipeline projects, factoring in ICF's assessments of each project's viability. Longer-term pipeline capacity in each case has been assumed to be built within a year or so after basis differentials justify construction.

In the Base Case, about 25 Bcf per day of incremental pipeline capacity, a 20 percent increase over current capacity, will be required to transport new natural gas supplies to growing markets.

New pipeline capacity must be built to accommodate increases in interregional flow in all three cases. In the Base Case, about 25 Bcf per day of incremental pipeline capacity, yielding a total of 155 Bcf per day of interregional pipeline capacity, will be required to transport new natural gas supplies to growing markets (Figure 30). This is about a 20 percent increase in interregional transport capability, currently estimated at 130 Bcf per day.

Figure 30
Projected Increase in U.S. and Canadian Interregional Pipeline Capacity, Base Case, 2008 to 2030 (MMcf per Day)

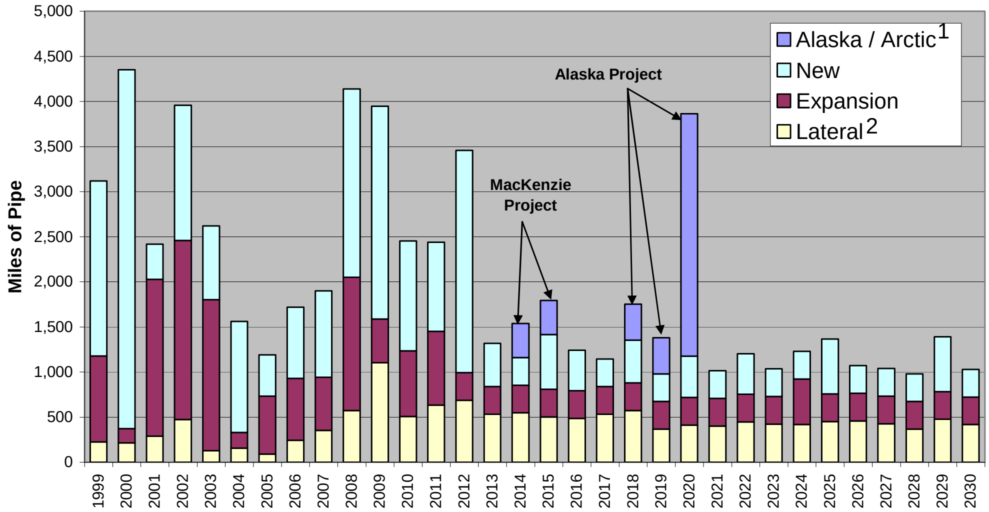


Pipeline capacity will be needed out of the Rockies, out of the Mid-continent, and into Florida. In addition, as long-haul pipeline capacity out of Western Canada fills up after the start up of the Alaska and Mackenzie pipeline projects, new capacity is projected to be built into the U.S. Lower-48.[36]

[36] Much of the incremental gas supplies from Alaska and Mackenzie Delta could make their way to downstream markets using existing pipeline capacity out of Alberta. However, with the addition of these new supplies, the existing pipelines become very full and basis out of Western Canada to downstream markets increases, justifying the expansion of existing pipelines or construction of a new pipeline. In the Base Case, capacity was added on the Alliance Pipeline corridor, but capacity could be added on any of the existing corridors or on a new path out of Western Canada.

Much of the projected pipeline capacity is related to specific projects that are expected to be in service before 2012. These projects include pipeline capacity to connect Mid-continent gas production from shales, to connect LNG import terminals along the Gulf and East Coasts, to increase export capacity out of the Rockies, and to increase import capacity into Florida. In addition, the 1.8 Bcf per day Rockies Express East pipeline from Missouri to Ohio will be completed. These projects, as well as others, will require roughly 3,000 miles per year of new pipeline between 2009 and 2012 (Figure 31).

Figure 31
Projected U.S. and Canadian Pipeline Additions in the Base Case (Miles)



[1] Includes pipeline mileage of downstream expansions on existing corridors in the U.S. and Canada in addition to the pipeline associated with the arctic Canada and Alaska frontier projects.

[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

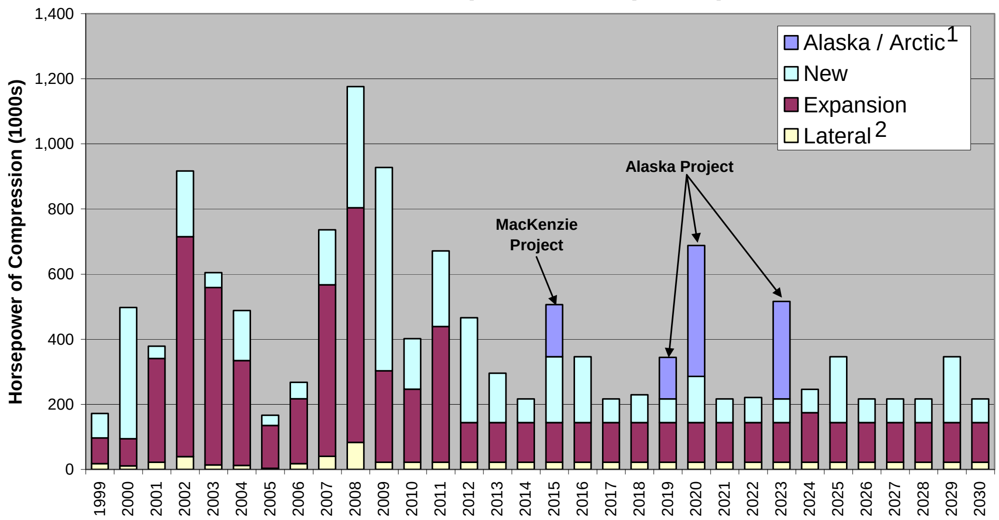
The pace of long-haul interregional pipeline capacity construction is projected to slow after 2012. Much of the recently constructed and currently planned pipeline capacity is related to major shifts from traditional to unconventional basins. As mentioned above, a significant amount of pipeline capacity has been, or will soon be built to move natural gas out of the Mid-continent and the Northern Rockies, both to the east and the west. After 2012, most of the incremental long-haul interregional pipeline capacity developed will be related to Arctic projects. A relatively small amount of additional pipeline capacity is expected to be built out of the Rockies. Some incremental capacity will be needed into Florida.

Beyond 2012, excluding years with Arctic projects, between 1,000 and 1,500 miles of new transmission pipeline will be needed in order to serve U.S. and Canadian natural gas consumption needs through 2030.

Beyond 2012, excluding years with Arctic projects, between 1,000 and 1,500 miles of new transmission pipeline will be needed in order to serve U.S. and Canadian natural gas consumption needs through 2030. About one-half of this will be for transmission laterals that connect production, storage, power plants, and isolated demand areas. The remaining half will be split between new greenfield projects and expansions of existing pipelines.

U.S. and Canadian incremental compression is expected to follow a similar construction pattern (Figure 32). In the Base Case, there is a relatively large increase in horsepower from 2009 to 2012 and more modest annual increases thereafter, with the exception of years that include Arctic projects. From 2009 to 2012, annual incremental compression averages over 600,000 HP per year. From 2013 to 2030, the average is lower at 250,000 HP per year. The Arctic projects consisting of the Mackenzie Valley Pipeline, the Alaska Pipeline, and a subsequent compression expansion of the Alaska project, along with a 1.5 Bcf per day pipeline from Alberta to Chicago, require a total of 1,000,0000 HP of compression. In the Base Case, this Arctic project compression is added in four different years, depending on assumed project timing (2015, 2019, 2020, and 2023).

Figure 32
Projected U.S. and Canadian Compression Additions in the Base Case (1000 Horsepower)



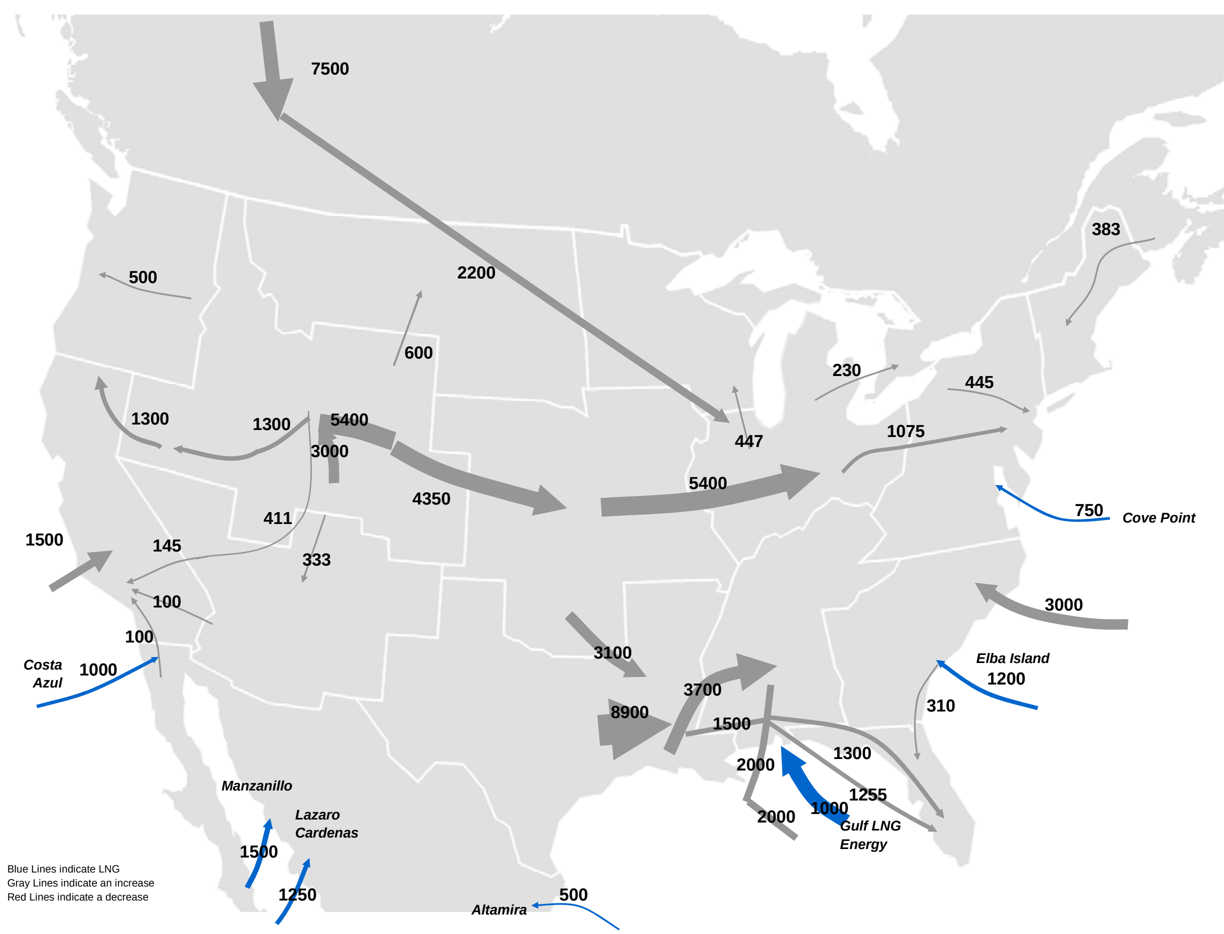
[1] Includes compression horsepower of downstream expansions on existing corridors in the U.S. and Canada in addition to the compression horsepower of arctic Canada and Alaska frontier projects.

[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

Since incremental natural gas consumption from 2009 to 2030 in the High Gas Growth Case is 85 percent greater than in the Base Case, more interregional pipeline capacity is required. By 2030, approximately 37 Bcf per day of additional interregional transport is needed in order to serve the demand projected in the High Gas Growth Case (Figure 33), or about 50 percent more than in the Base Case. In both cases, a portion of the market growth is served by utilizing existing infrastructure at higher capacity factors.

In the High Gas Growth Case, most of the pipeline capacity necessary to transport production from newly opened offshore areas to the onshore is developed between 2013 and 2017. Compared to the Base Case, additional capacity is needed out the Rockies and Mid-continent and into Florida. Even though British Columbia shale production increases by 1.5 Bcf per day over the Base Case, only 250 million cubic feet (MMcf) per day of additional pipeline capacity is needed out of Western Canada. For the most part, British Columbia shale production replaces declines in conventional production in Alberta. Consequently, much of the existing infrastructure downstream of Alberta can accommodate the new production from the shales.

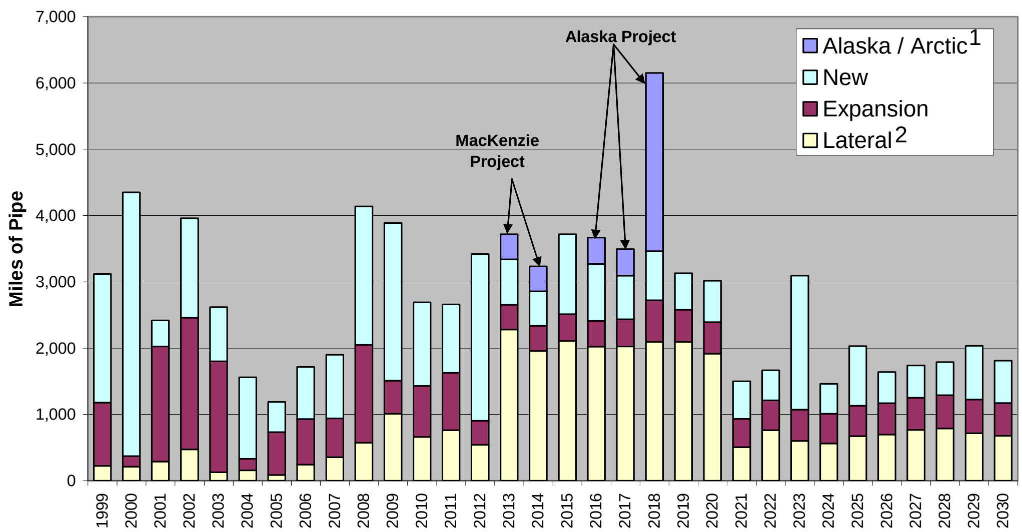
Figure 33
Projected Increase in U.S. and Canadian Interregional Pipeline Capacity, High Gas Growth Case, 2008 – 2030 (MMcf per Day)



Market growth is more consistent in the High Gas Growth Case after 2013 relative to the Base Case (Figure 34). From 2013 to 2030, approximately 2,400 pipeline miles will be needed in the U.S. and Canada to serve markets that grow to nearly 36 Tcf, reflecting a natural gas consumption growth that is more than double the Base Case growth. A large portion of the increase is represented by pipeline laterals. Between 2013 and 2020, a substantial amount of the incremental pipeline mileage projected in the High Gas Growth Case will be associated with expansion of the interstate transmission system to accommodate natural gas vehicles that consume well over 2 Bcf per day of natural gas by 2020.

Post-2020, additional large volume long-haul pipeline capacity will be needed (similar to the current Rockies Express project) in order to transport Rocky Mountain natural gas supplies to Midwest and Eastern markets. Similar to the Base Case, Arctic projects account for 4,000 to 5,000 miles of new pipeline capacity in the High Gas Growth Case.

Figure 34
Projected U.S. and Canadian Pipeline Additions in the High Gas Growth Case (Miles)

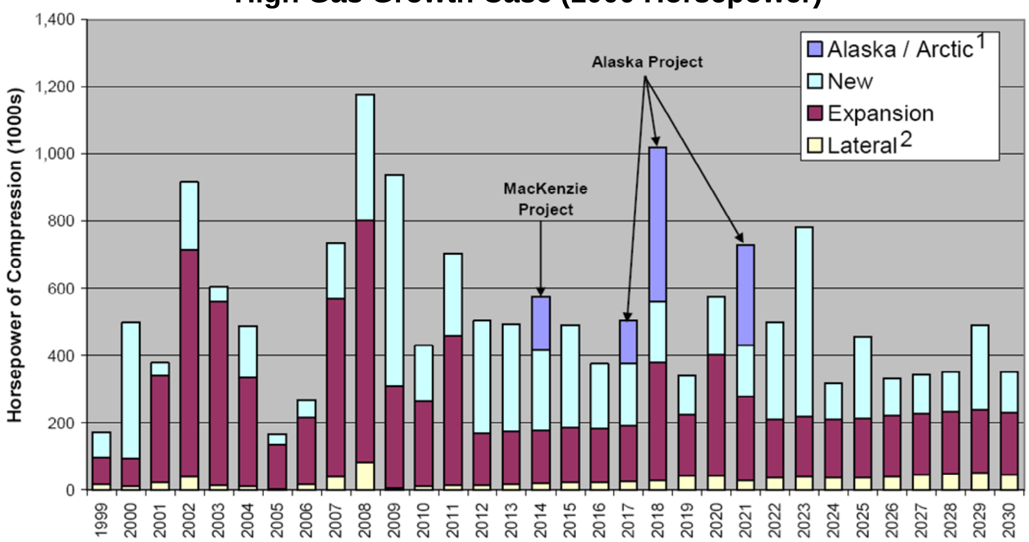


[1] Includes pipeline miles of downstream expansions on existing corridors in the U.S. and Canada in addition to the milage associated with the arctic Canada and Alaska frontier projects.

[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

Prior to 2012, U.S. and Canadian incremental compression in the High Gas Growth Case is similar to the Base Case, averaging 600,000 HP per year (Figure 35). Most of this additional horsepower is attributed to currently planned projects. Annual horsepower additions decline after 2012, but to a lesser degree than in the Base Case. In the High Gas Growth Case, horsepower added per year averages 450,000 HP, excluding the Arctic projects. When compared with the Base Case, even though pipeline miles added are more than double in the High Gas Growth Case, compression additions are only 80 percent greater. A large portion of the pipelines added in the High Gas Growth Case are laterals that do not require additional compression. Arctic project compression is added earlier in the High Gas Growth Case (in 2014, 2017, 2018, and 2022).

Figure 35
Projected U.S. and Canadian Compression Additions in the High Gas Growth Case (1000 Horsepower)

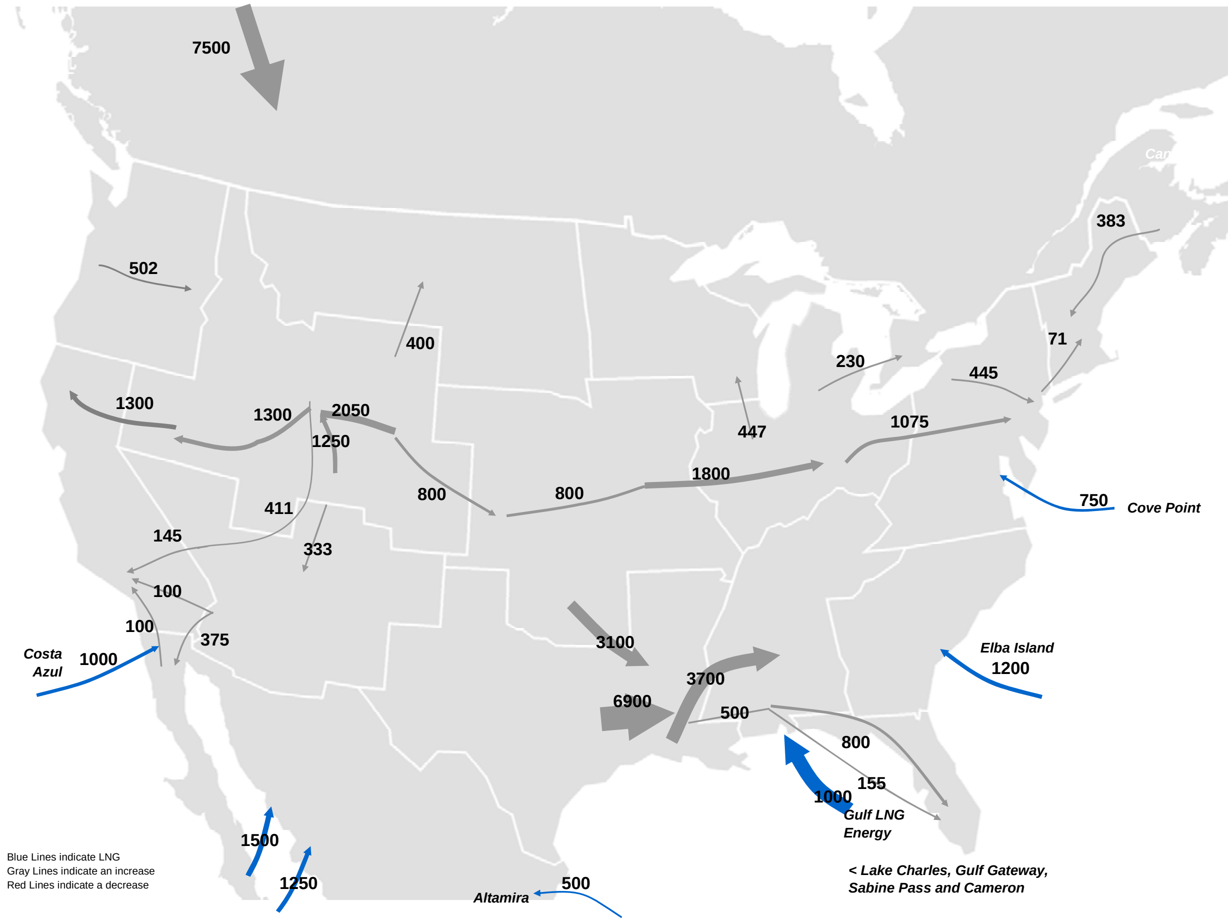


[1] Includes pipeline miles of downstream expansions on existing corridors in the U.S. and Canada in addition to the mileage associated with the arctic Canada and Alaska frontier projects.
[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

In the Low Electric Growth Case, about 21 Bcf per day of incremental pipeline capacity, a 16 percent increase over current capacity, will be required in order to transport new natural gas supplies to mostly existing markets.

Since gas consumption declines from 2009 to 2030 in the Low Electric Growth Case, less interregional pipeline capacity is needed relative to the other two cases. However, since a large amount of the interregional pipeline capacity is attributed to planned projects completed before 2013, total incremental interregional pipeline capacity by 2030 is only modestly lower than in the Base Case (Figure 36). Most planned projects make delivery of growing gas supplies from unconventional and frontier areas possible. In the Low Electric Growth Case, about 21 Bcf per day of incremental pipeline capacity, yielding a total of 151 Bcf per day of interregional pipeline capacity, will be required in order to transport new natural gas supplies to mostly existing markets. This is about a 16 percent increase in interregional transport capability.

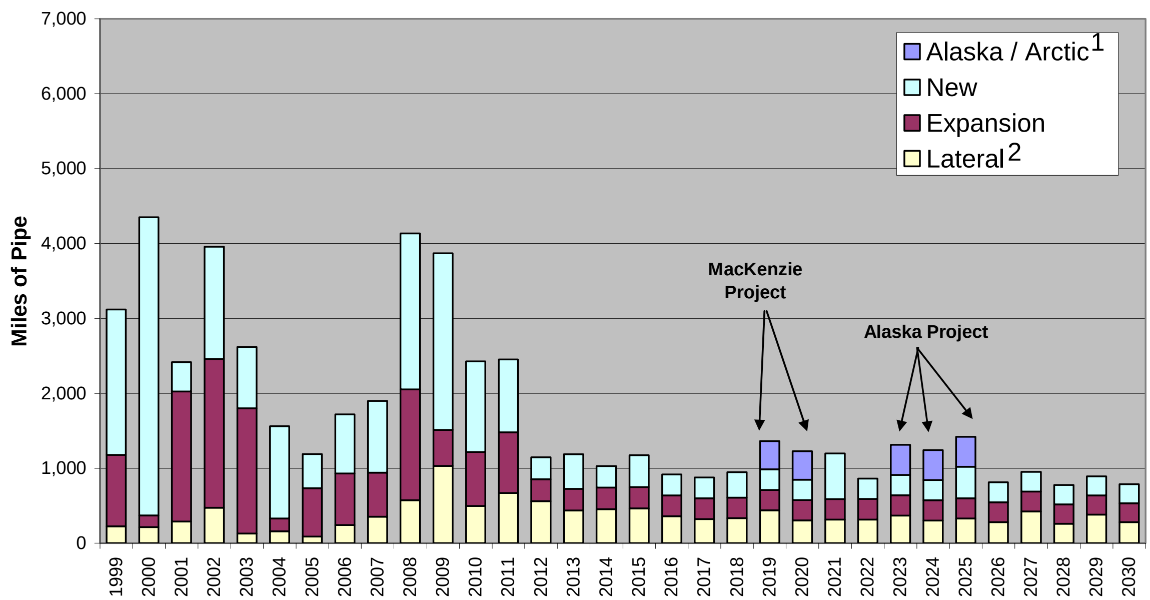
Figure 36
Projected Increase in U.S. and Canadian Interregional Pipeline Capacity, Low Electric Growth Case, 2008 – 2030 (MMcf per Day)



Incremental pipeline capacity will be needed out of the Rockies and Mid-continent and into Florida in the Low Electric Growth Case. Unlike in the Base Case, another major pipeline from the Rockies to Eastern markets, the current Rockies Express Pipeline corridor, is not needed. Even though there is growth in British Columbia shale production, declines in other producing areas throughout Western Canada make it possible for the Arctic pipeline projects to entirely rely on existing downstream pipeline capacity.

In the Low Electric Growth Case, the pipeline mileage constructed from 2009 to 2011 is similar to the amount of mileage constructed in the Base Case at approximately 2,900 miles per year, mostly from planned projects (Figure 37). Most of the pipeline infrastructure needed to access new unconventional production has planned in-service dates that occur within the next few years. Therefore, projected pipeline miles drop in 2012 and later after the projects are completed and as the size of the North American natural gas market declines over time. Short distance laterals and expansions will be needed even in this low electric growth environment to accommodate shifts in natural gas production and consumption. The Arctic pipeline projects are the only significant large scale pipeline projects included in the latter half of the projection. From 2012 to 2030, average miles of pipeline constructed per year in the Low Electric Growth Case averages about 1,000 miles per year, versus an average of about 1,500 miles per year in the Base Case.

Figure 37
Projected U.S. and Canadian Pipeline Additions in the Low Electric Growth Case (Miles)

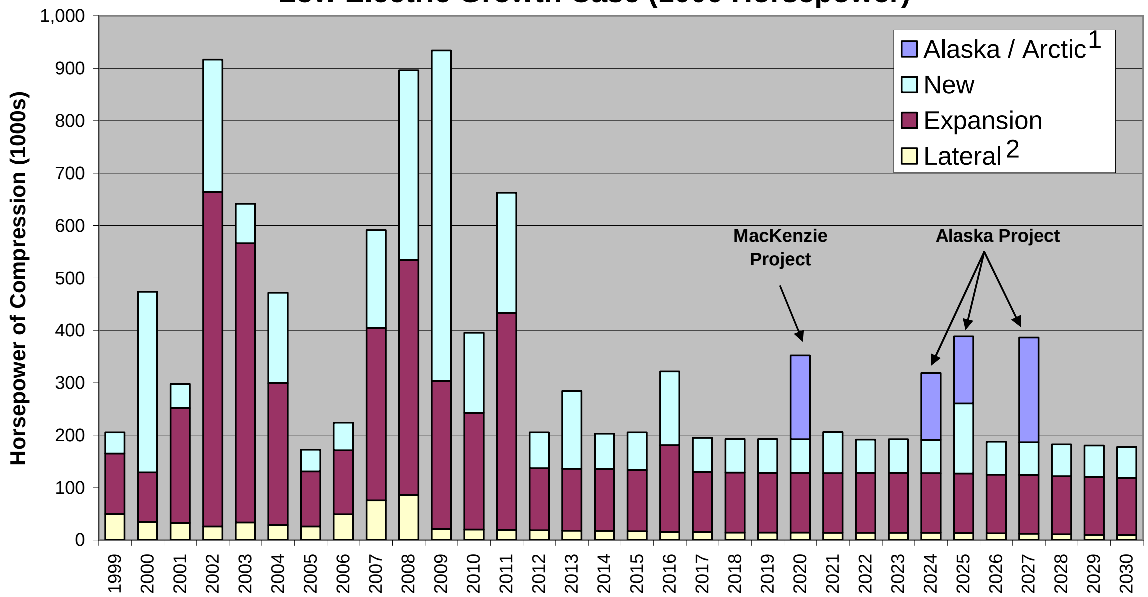


[1] Arctic Canada and Alaska frontier projects use existing pipeline capacity downstream of Alberta Canada.

[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

Prior to 2012, U.S. and Canadian compression added in the Low Electric Growth Case is similar to the amount added in the Base Case, averaging 600,000 HP per year (Figure 38). Most of this additional horsepower is built as part of currently planned projects. Annual horsepower additions decline after 2012, and the decline is more pronounced than it is in the Base Case. In the Low Electric Growth Case, compression horsepower added per year averages a little over 200,000 HP, excluding compression needed for the Arctic projects. Arctic project compression is added in later years in the Low Electric Growth Case based on the assumptions in the case (in 2019, 2024, 2025, and 2027).

Figure 38
Projected U.S. and Canadian Compression Additions in the Low Electric Growth Case (1000 Horsepower)



[1] Arctic Canada and Alaska frontier projects use existing compression capacity downstream of Alberta Canada.

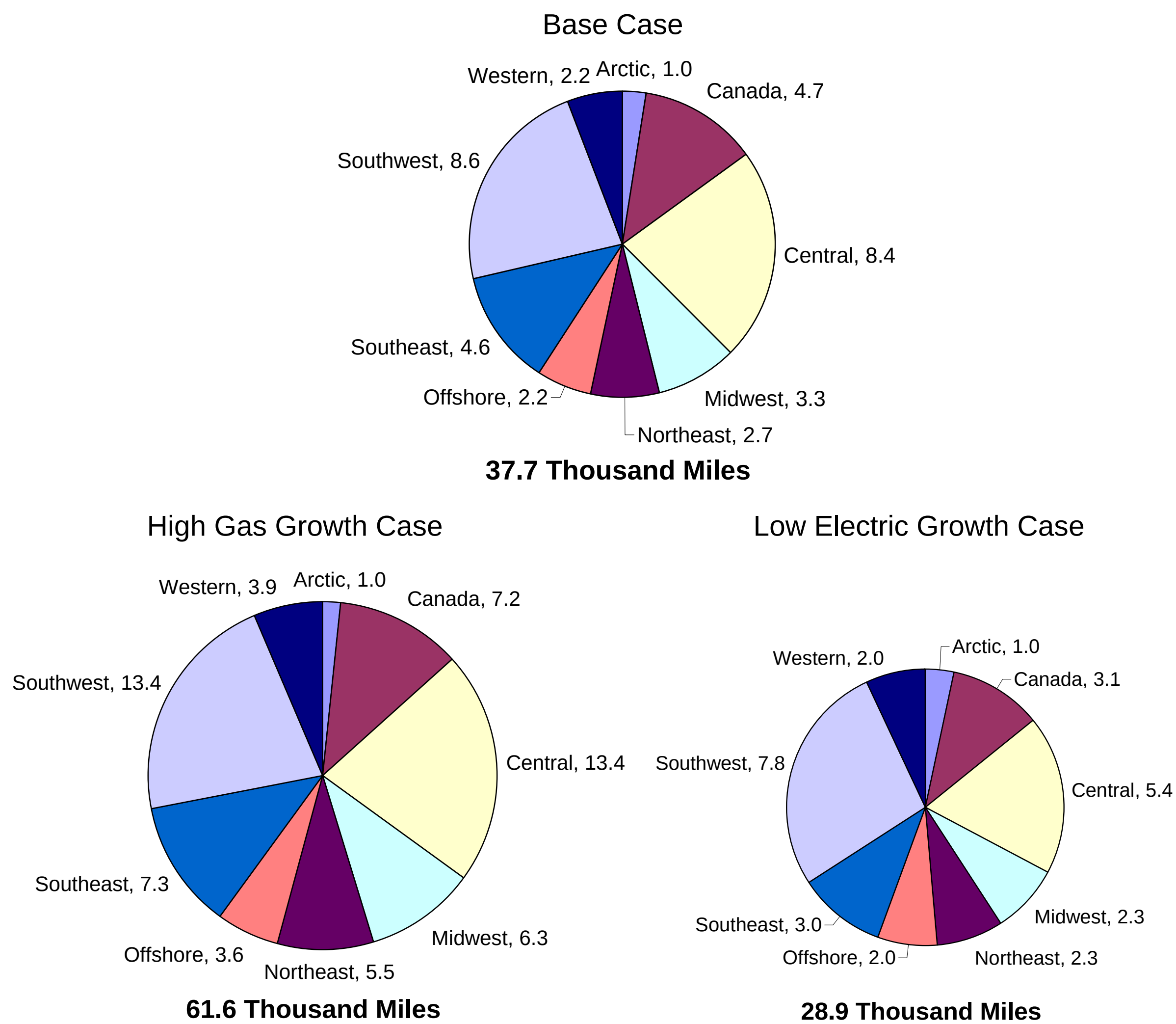
[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

5.2.3 Projected Natural Gas Transmission Infrastructure Requirements

In total, the U.S. and Canada will need about 28,900 to 61,600 miles of new natural gas pipeline through 2030. New infrastructure will be needed for new demand growth and/or shifts in demand, as well as to bring newly developed supplies to market.

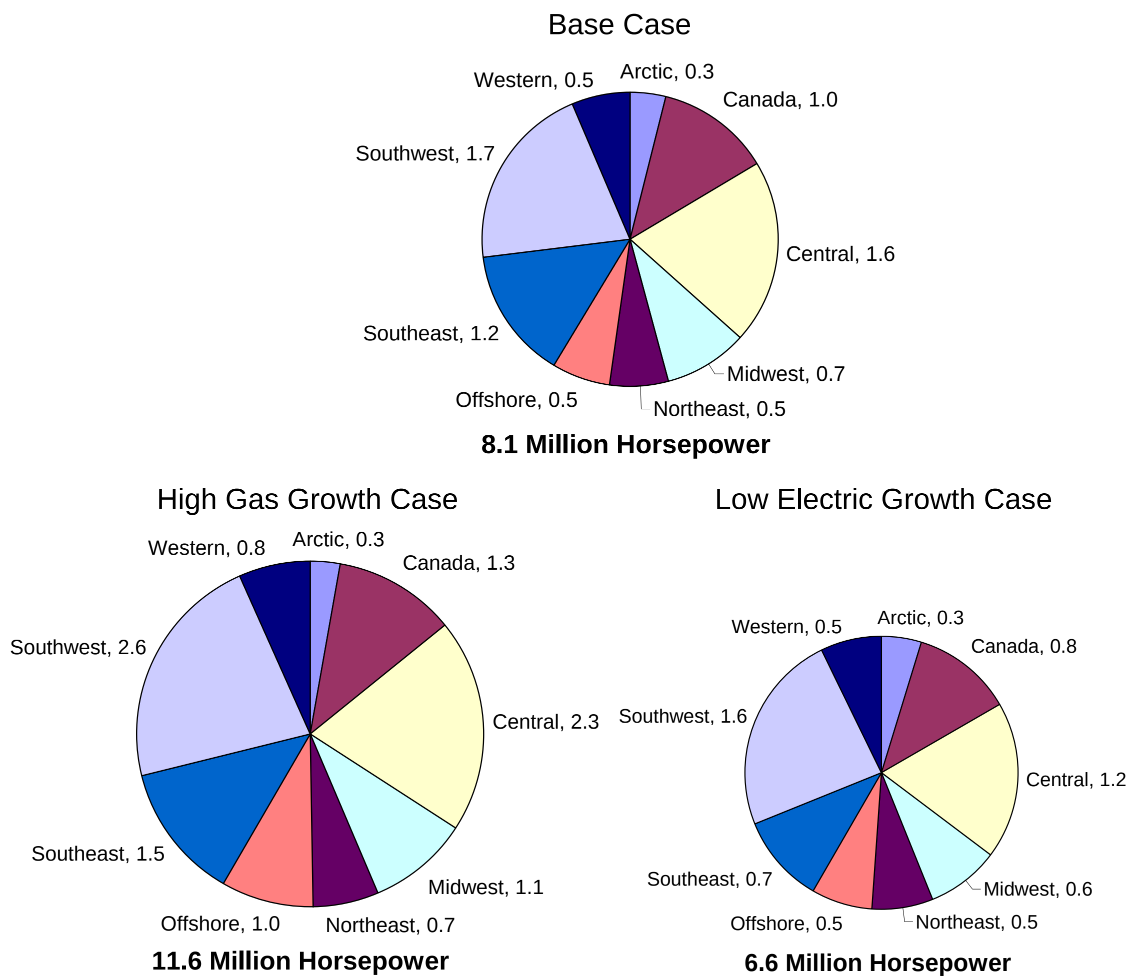
In total, the U.S. and Canada will need 28,900 to 61,600 miles of additional natural gas pipeline through 2030 (Figure 39). New infrastructure is needed throughout the U.S. and Canada and not just to move natural gas across long distances between regions. All regions will need natural gas infrastructure to serve growing demand and/or shifts in demand. Even regions with mature producing basins will continuously need some additional development. Since shifts in supply from traditional to unconventional sources have been, and are projected to continue to be the key driver of pipeline construction, regions with growing unconventional production will experience a higher proportion of infrastructure development. Thus, the Southwest and Central regions account for approximately 45 percent of projected incremental pipeline mileage added in all three cases. The same two regions account for only 23 percent of projected consumption growth in the Base Case and High Gas Growth Case. The Western and Northeast regions that are predominately consuming regions, account for only 13 to 15 percent of projected incremental pipeline construction through 2030, even though they account for a larger portion of consumption growth in the Base Case and High Gas Growth Case.

Figure 39
Regional Pipeline Mileage Additions, 2009 – 2030 (1000 Miles)



Compression added by region is also expected to be greater in regions with higher growth in unconventional natural gas production (Figure 40). In all three cases, the Southwest and Central regions together account for over 40 percent of compression added 2030.

Figure 40
Regional Compression Additions, 2009 – 2030 (Million Horsepower)

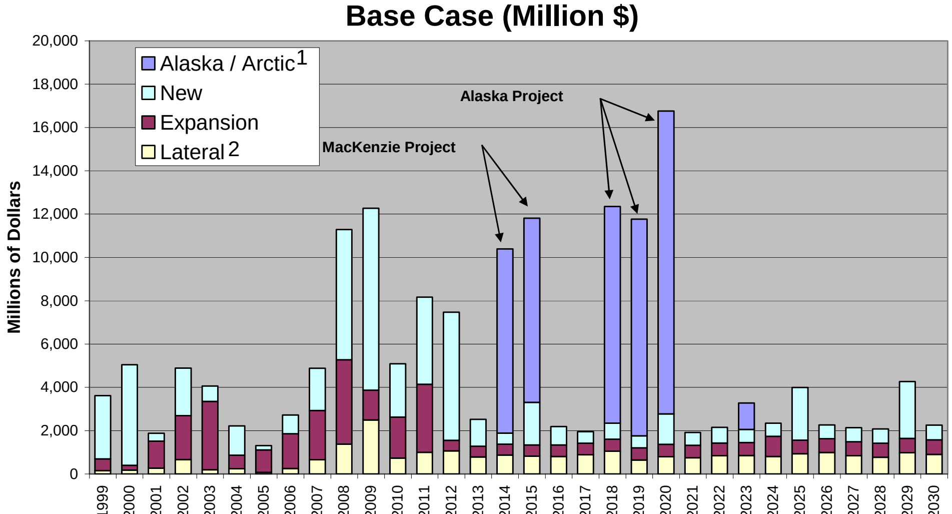


5.2.4 Projected Natural Gas Transmission Expenditures

Between $108 and $160 billion will be needed for new pipeline infrastructure development from 2009 to 2030. Even if Arctic pipeline projects are excluded, projected capital expenditure will range from $3 to $5 billion per year.

For the U.S. and Canadian natural gas industries to accommodate a significant shift in the main supply sources of natural gas as well as a potential annual consumption growth of 5 to 9 Tcf by 2030, significant pipeline infrastructure investment will be required. The Base Case and High Gas Growth Case project that $130 to $160 billion will be needed for new pipeline infrastructure development from 2009 to 2030. Even in the Low Electric Growth Case, which has much lower natural gas consumption, $108 billion is required in pipeline investments mainly to accommodate major shifts in the location of natural gas supply. Average annual expenditures for pipeline and compression infrastructure average approximately $5.9, $7.5, and $5.1 billion per year for the Base Case, High Gas Growth Case, and Low Electric Growth Case, respectively. In all three cases, projected expenditures exceed the $4.1 billion per year average from 1999 to 2008 (Figure 41 , Figure 42, and Figure 43). Expenditures are greater even though the amount of incremental pipeline mileage needed is lower, due to the cost of the Arctic projects and general construction cost escalation.

Figure 41
Projected U.S. and Canadian Capital Expenditures for Pipelines in the Base Case (Million $)

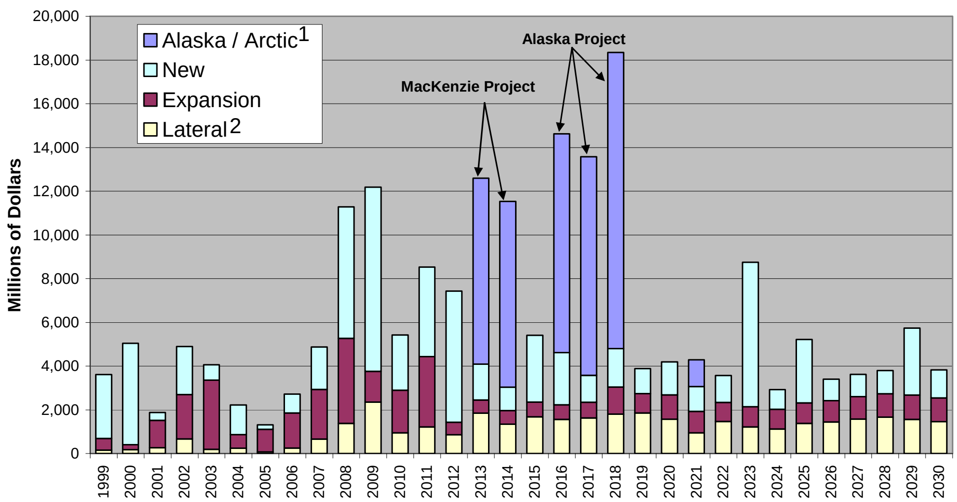


[1] Includes cost of downstream expansions on existing corridors in the U.S. and Canada in addition to the cost of arctic Canada and Alaska frontier projects.
[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

Arctic pipeline projects and the associated pipeline capacity necessary to bring Arctic natural gas to the U.S. Lower-48 account for 30 to 45 percent of the total expenditures from 2009 to

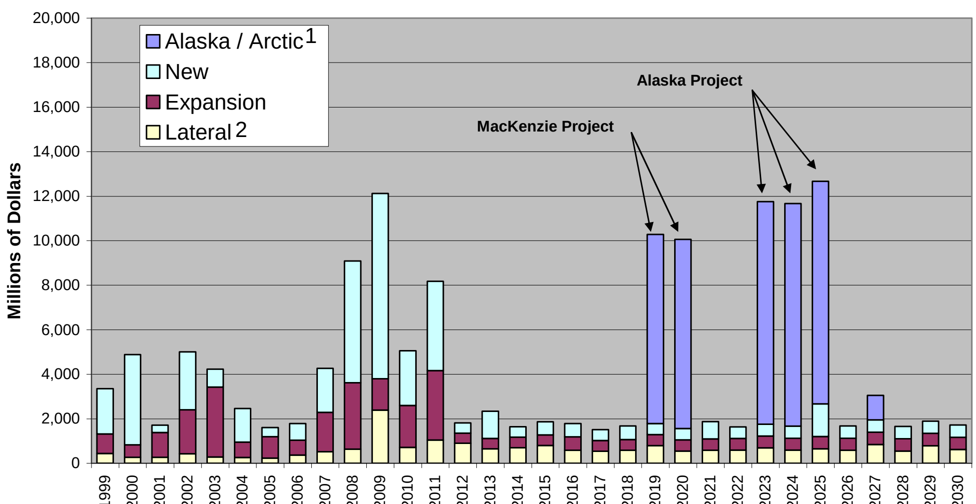
2030. If these expenditures are excluded, projected capital investment would average between $3.5 and $5.0 billion per year for the Base Case and High Gas Growth Case, respectively, consistent with recent averages. The Low Electric Growth Case would average $2.9 billion per year, in the low end of the range of yearly expenditures from 1999 to 2008.

Figure 42
Projected U.S. and Canadian Capital Expenditures for Pipelines in the High Gas Growth Case (Million $)



[1] Includes cost of downstream expansions on existing corridors in the U.S. and Canada in addition to the cost of arctic Canada and Alaska frontier projects.
[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

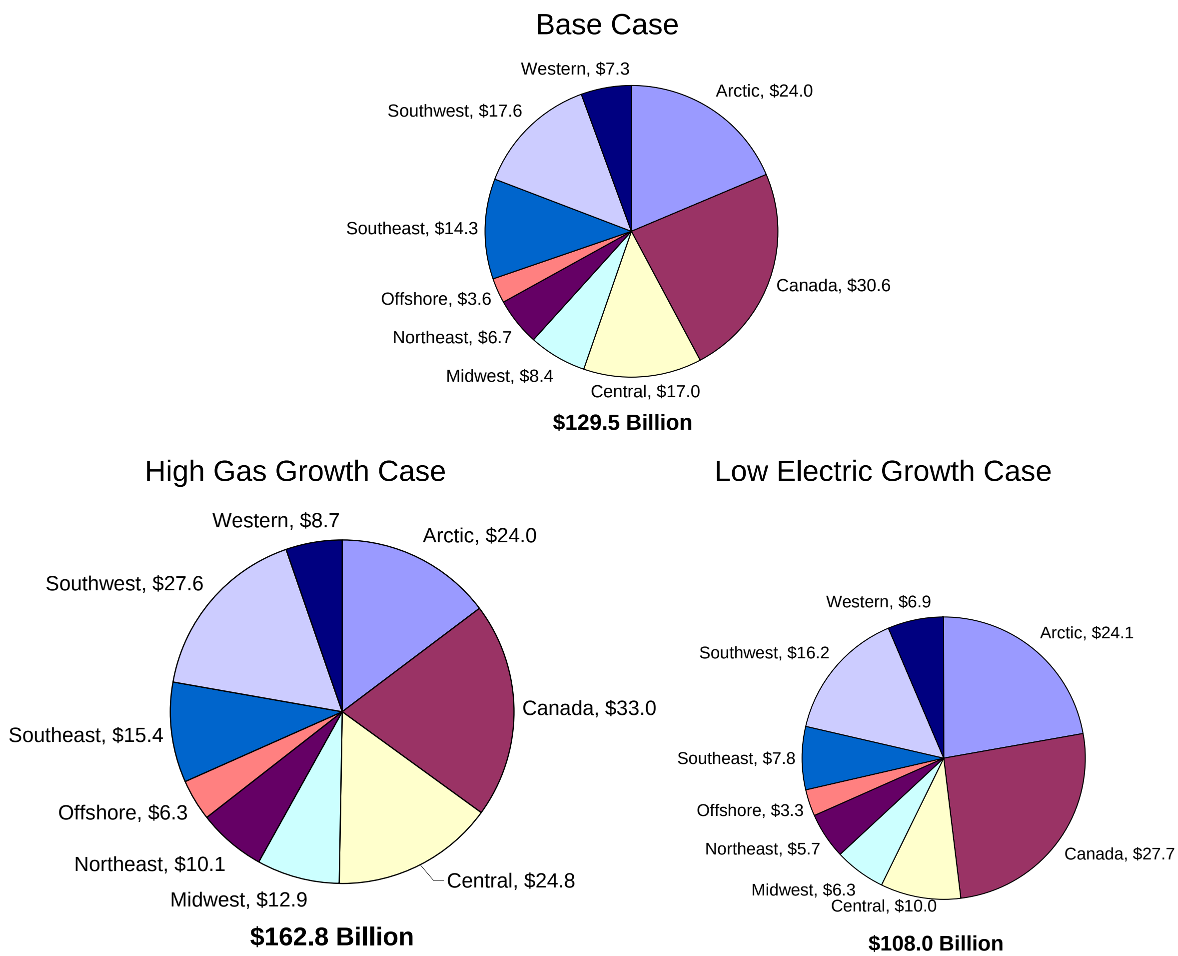
Figure 43
Projected U.S. and Canadian Capital Expenditures for Pipelines in the Low Electric Growth Case (Million $)



[1] Arctic Canada and Alaska frontier projects use existing pipeline capacity downstream of Alberta Canada.
[2] Lateral is defined as a spur off the main transmission line, normally used to connect production, storage, power plants, LNG terminals or isolated demand centers.

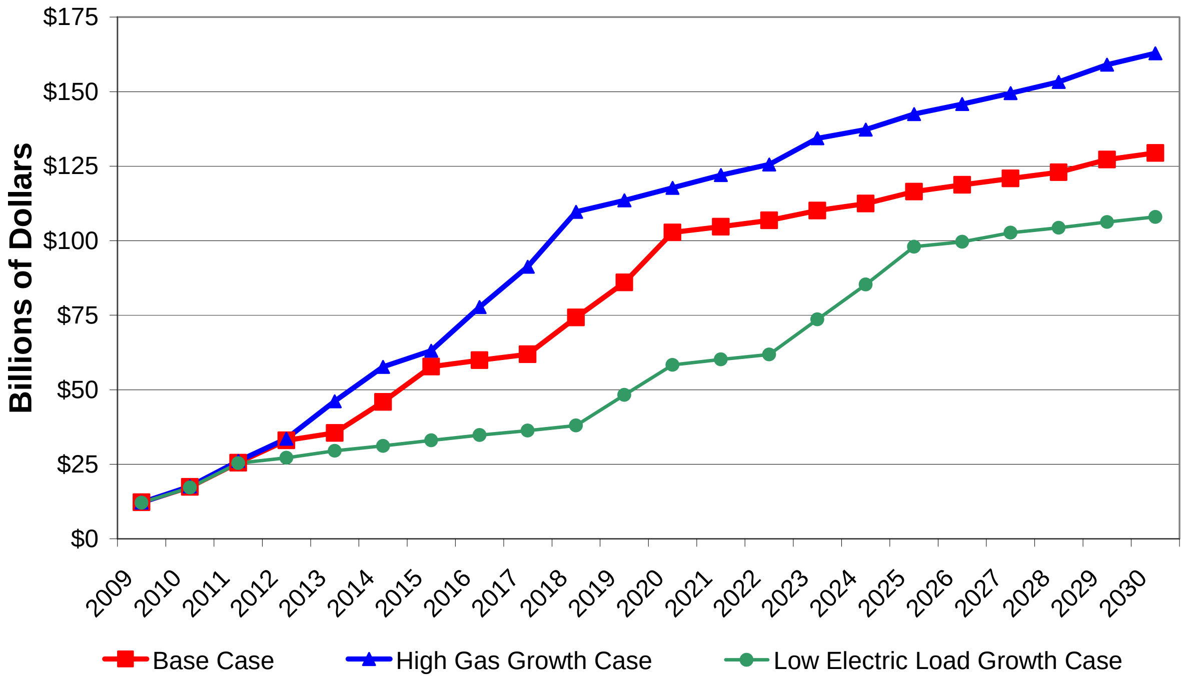
The location of natural gas supply development is projected to be the key driver for regional pipeline expenditures (Figure 44). The largest expenditures are projected for regions with growing unconventional supplies – the Central and the Southwest – and regions directly impacted by the Alaska and Mackenzie Valley pipeline projects (the Arctic and Canada regions). In all three cases, approximately two-thirds of all future pipeline expenditures are for projects in these four regions.

Figure 44
Cumulative Pipeline Expenditures by Region, 2009 – 2030 (Million $)



In all cases, cumulative transmission pipeline expenditures are similar through 2012, but they diverge thereafter (Figure 45). Considering the time required for pipeline planning, permitting, and construction, it will take a few years before policy shifts such as those assumed in the High Gas Growth Case and the Low Electric Growth Case affect natural gas infrastructure investment. Pre-2012 pipeline infrastructure projects are already in advanced planning or already under construction, so they are not likely to be affected much by policy changes.

Figure 45
Cumulative Pipeline Expenditures, 2009 – 2030
(Billion $)



5.2.5 Pipeline Integrity and Maintenance of Existing Infrastructure

The Pipeline Safety Improvement Act (PSIA) of 2002 required the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation to promulgate rules implementing Integrity Management Programs (IMP) for U.S. natural gas transmission pipelines. The gas pipeline integrity management programs benefit public safety by supplementing existing safety requirements with risk-based management principles that focus on safety risks in highly populated or frequented areas, referred to as high consequence areas (HCAs). The IMPs require each pipeline company to test a certain amount of its HCA pipeline each year. The PSIA specifically required that at least 50 percent of all HCA pipelines be tested by 2007. HCAs are required to be fully tested by 2012. In the future, pipelines must be retested every seven years.

When the PSIA was enacted, it was uncertain how the IMP would affect the need for investment in pipeline replacement. It now appears that the U.S. natural gas pipeline system is robust and that mandatory replacements of pipeline due to IMP inspections are infrequent.

In 2008, the INGAA Foundation studied[37] 10 member companies representing over 120,000 miles of pipeline to analyze how the IMPs have affected its members during the first few years of the program. Over the four-year period studied, over 28,500 miles of pipe were inspected. Approximately 3,100 miles were located in HCAs, accounting for about 54 percent of all HCA miles across the 10 companies' systems. As a result of the inspections, only 24 total miles of pipeline were replaced during the four-year period. Of the pipeline replaced, only two miles were in HCAs, representing less than 0.1 percent of the total HCA miles inspected. Nearly half of the damage discovered in HCAs was due to third party damage, mainly from excavation equipment.

Direct replacement of natural gas pipelines, entailing replacement of natural gas pipelines along the same route at the same capacity, is relatively rare. From 1997 to 2008, less than 100 miles of pipeline per year was replaced out of the 300,000 miles of pipeline on the U.S. natural gas transmission system. Pipelines are more often indirectly replaced as a consequence of expansions and/or abandonment. Expansions can include replacement of pipeline segments with larger or higher maximum allowable operating pressure (MAOP) pipes that yield greater capacities. Whole pipeline segments can be abandoned if a new pipeline or pipeline segment can replicate the previous services. An example is the Columbia Transmission pipeline in southern New York. It was "replaced" when the Millennium Pipeline was built. Columbia Transmission now ships natural gas on Millennium to serve markets that it formerly served directly. Replacement investments for all cases are included in the new and expansion investment numbers discussed above.

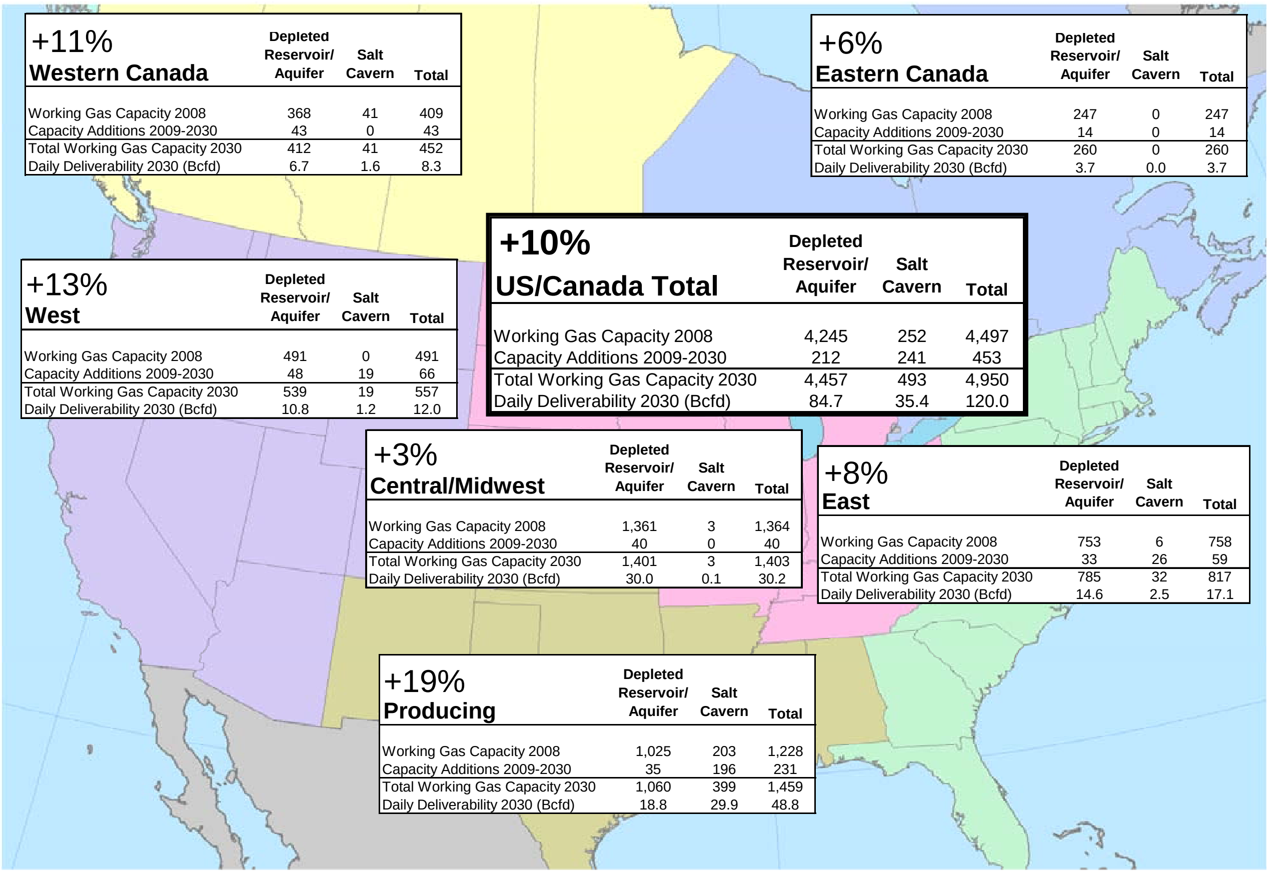
5.2.6 Natural Gas Storage

From 2009 to 2030, the Base Case adds a total of about 450 Bcf of working gas capacity in the U.S. and Canada. About 340 Bcf of this capacity are announced projects expected to be constructed by 2015.

Growing natural gas markets require additional natural gas storage capacity. Current U.S. and Canadian working gas storage capacity totals approximately 4,500 Bcf. Just over 250 Bcf, or 5.5 percent, of the current capacity is high deliverability salt cavern storage. The remainder is comprised of depleted reservoirs and aquifers. Through 2015, incremental working gas storage capacity projections for all three cases include viable announced storage projects. Beyond 2015, additional capacity is added in response to market growth. From 2009 to 2030, the Base Case adds a total of about 450 Bcf of working gas capacity in the U.S. and Canada (Figure 46), representing a 10 percent increase over current levels. Approximately 340 Bcf of this capacity represents announced projects expected to be constructed by 2015, while the remaining 115 Bcf are unnamed future projects based on market need.

[37] "The Impact of the Integrity Management Program on Gas Transmission Pipeline, Summary of Results 2004-2007"; Process Performance Improvement Consultants, LLC; July 2008.

Figure 46
Base Case Working Gas Capacity (Bcf)



+11% Western Canada

	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	368	41	409
Capacity Additions 2009-2030	43	0	43
Total Working Gas Capacity 2030	412	41	452
Daily Deliverability 2030 (Bcfd)	6.7	1.6	8.3

+6% Eastern Canada

	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	247	0	247
Capacity Additions 2009-2030	14	0	14
Total Working Gas Capacity 2030	260	0	260
Daily Deliverability 2030 (Bcfd)	3.7	0.0	3.7

+10% US/Canada Total

	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	4,245	252	4,497
Capacity Additions 2009-2030	212	241	453
Total Working Gas Capacity 2030	4,457	493	4,950
Daily Deliverability 2030 (Bcfd)	84.7	35.4	120.0

+13% West

	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	491	0	491
Capacity Additions 2009-2030	48	19	66
Total Working Gas Capacity 2030	539	19	557
Daily Deliverability 2030 (Bcfd)	10.8	1.2	12.0

+3% Central/Midwest

	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	1,361	3	1,364
Capacity Additions 2009-2030	40	0	40
Total Working Gas Capacity 2030	1,401	3	1,403
Daily Deliverability 2030 (Bcfd)	30.0	0.1	30.2

+8% East

	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	753	6	758
Capacity Additions 2009-2030	33	26	59
Total Working Gas Capacity 2030	785	32	817
Daily Deliverability 2030 (Bcfd)	14.6	2.5	17.1

+19% Producing

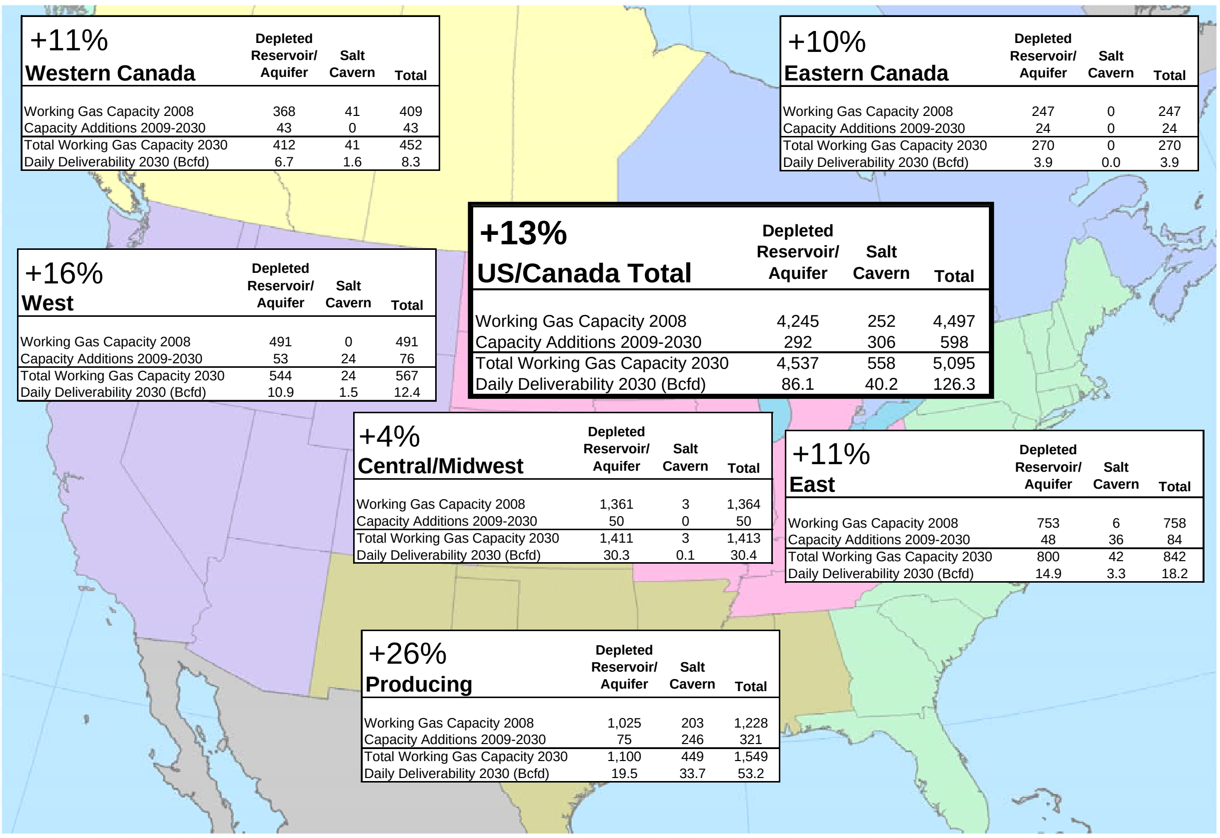
	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	1,025	203	1,228
Capacity Additions 2009-2030	35	196	231
Total Working Gas Capacity 2030	1,060	399	1,459
Daily Deliverability 2030 (Bcfd)	18.8	29.9	48.8

More than half of the new storage capacity developed through 2030 is projected to be high deliverability salt cavern storage, which essentially doubles the current capacity of such storage. In comparison, depleted reservoir and aquifer capacity increases by only 5 percent from 2008 to 2030. Natural gas storage capacity in the producing region along the Gulf Coast increases the most on both a percentage and absolute basis. That is because the geology of the region better supports salt cavern development than other regions.

More than half of the storage capacity additions developed through 2030 are projected to be high deliverability salt cavern storage, essentially doubling the current capacity of such storage.

The projection for incremental storage capacity in the High Gas Growth Case is greater due to higher market growth. By 2030, total U.S. and Canadian natural gas storage capacity is projected to increase by about 600 Bcf, or by about 13 percent over current levels (Figure 47). Similar to the Base Case, the largest storage capacity additions are in the producing region, due to the availability of sites for salt cavern development.

Figure 47
High Gas Growth Case Working Gas Capacity (Bcf)



+11% Western Canada	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	368	41	409
Capacity Additions 2009-2030	43	0	43
Total Working Gas Capacity 2030	412	41	452
Daily Deliverability 2030 (Bcfd)	6.7	1.6	8.3

+10% Eastern Canada	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	247	0	247
Capacity Additions 2009-2030	24	0	24
Total Working Gas Capacity 2030	270	0	270
Daily Deliverability 2030 (Bcfd)	3.9	0.0	3.9

+13% US/Canada Total	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	4,245	252	4,497
Capacity Additions 2009-2030	292	306	598
Total Working Gas Capacity 2030	4,537	558	5,095
Daily Deliverability 2030 (Bcfd)	86.1	40.2	126.3

+16% West	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	491	0	491
Capacity Additions 2009-2030	53	24	76
Total Working Gas Capacity 2030	544	24	567
Daily Deliverability 2030 (Bcfd)	10.9	1.5	12.4

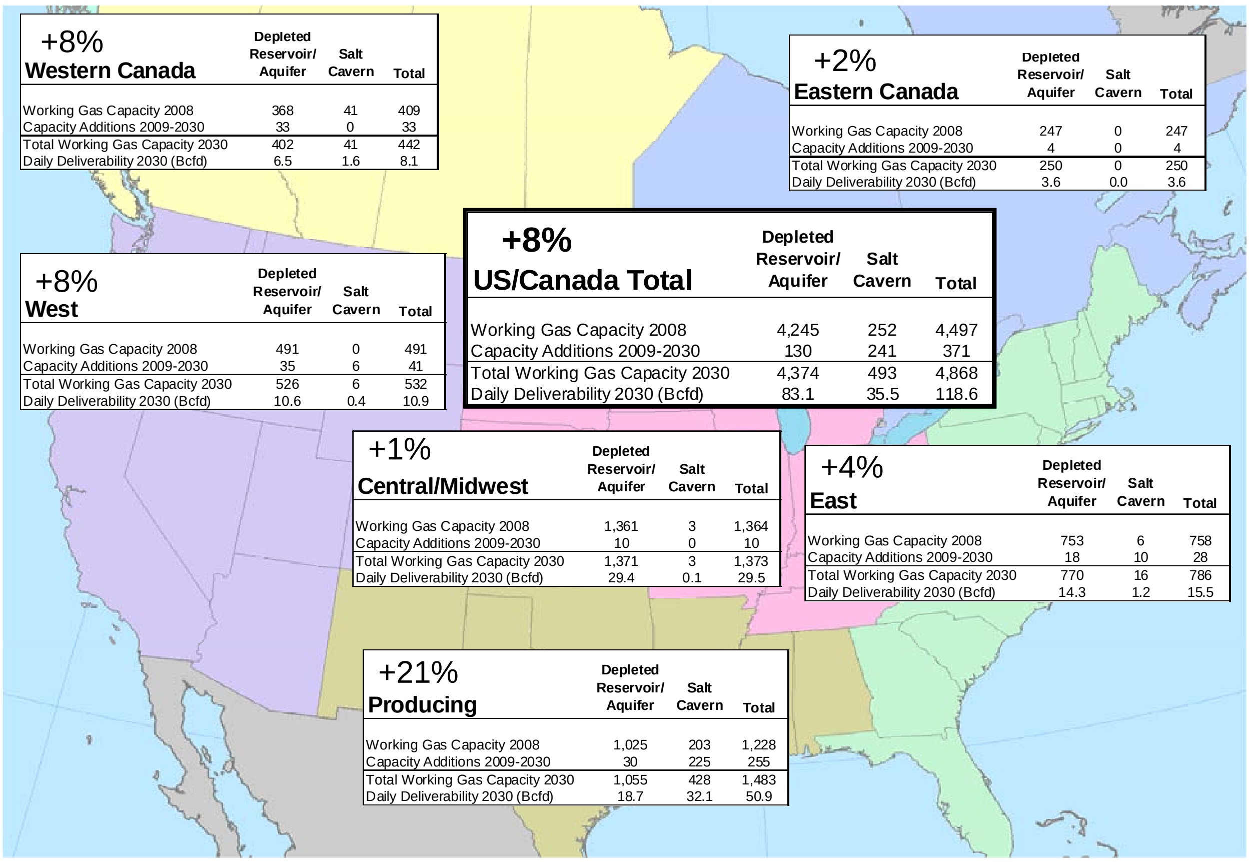
+4% Central/Midwest	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	1,361	3	1,364
Capacity Additions 2009-2030	50	0	50
Total Working Gas Capacity 2030	1,411	3	1,413
Daily Deliverability 2030 (Bcfd)	30.3	0.1	30.4

+11% East	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	753	6	758
Capacity Additions 2009-2030	48	36	84
Total Working Gas Capacity 2030	800	42	842
Daily Deliverability 2030 (Bcfd)	14.9	3.3	18.2

+26% Producing	Depleted Reservoir/ Aquifer	Salt Cavern	Total
Working Gas Capacity 2008	1,025	203	1,228
Capacity Additions 2009-2030	75	246	321
Total Working Gas Capacity 2030	1,100	449	1,549
Daily Deliverability 2030 (Bcfd)	19.5	33.7	53.2

The only natural gas storage projects assumed in the Low Electric Growth Case are those projects that are currently planned. The projection for incremental storage capacity in the Low Electric Growth Case is less due to decline in the gas market. By 2030, total U.S. and Canadian natural gas storage capacity is projected to increase by about 370 Bcf, or by about 8 percent over current levels (Figure 48). Similar to the other two cases, the greatest storage capacity additions are in producing areas, where numerous sites are readily available for salt cavern development.

Figure 48
Low Electric Growth Case Working Gas Capacity (Bcf)



In 2007, storage construction costs ranged from $6.7 to $13.6 million per Bcf of working gas capacity (Table 14) [38], depending upon the field type being developed. New aquifer storage is the most costly, while depleted reservoir storage is the least expensive type of storage. The cost of new storage capacity averaged between 25 and 35 percent greater than the cost of expanding existing fields.

Table 14
Storage Construction Cost Comparison

Region	Factor			
		Assumed Year 2007 Costs $Million's per Bcf Working Gas Capacity		
		Field Type	Expansion	New
Canada	0.88	Salt	$6.7	$8.4
Central	1.03	Depleted	$4.9	$6.6
Midwest	0.77	Aquifer	$10.9	$13.6
Northeast	1.83			
Southeast	1.10			
Southwest	1.18	Non-base gas costs escalated at 2% per year.		
Western	0.93	Base gas costs adjusted for projected gas prices.		
Grand Total	1.00			

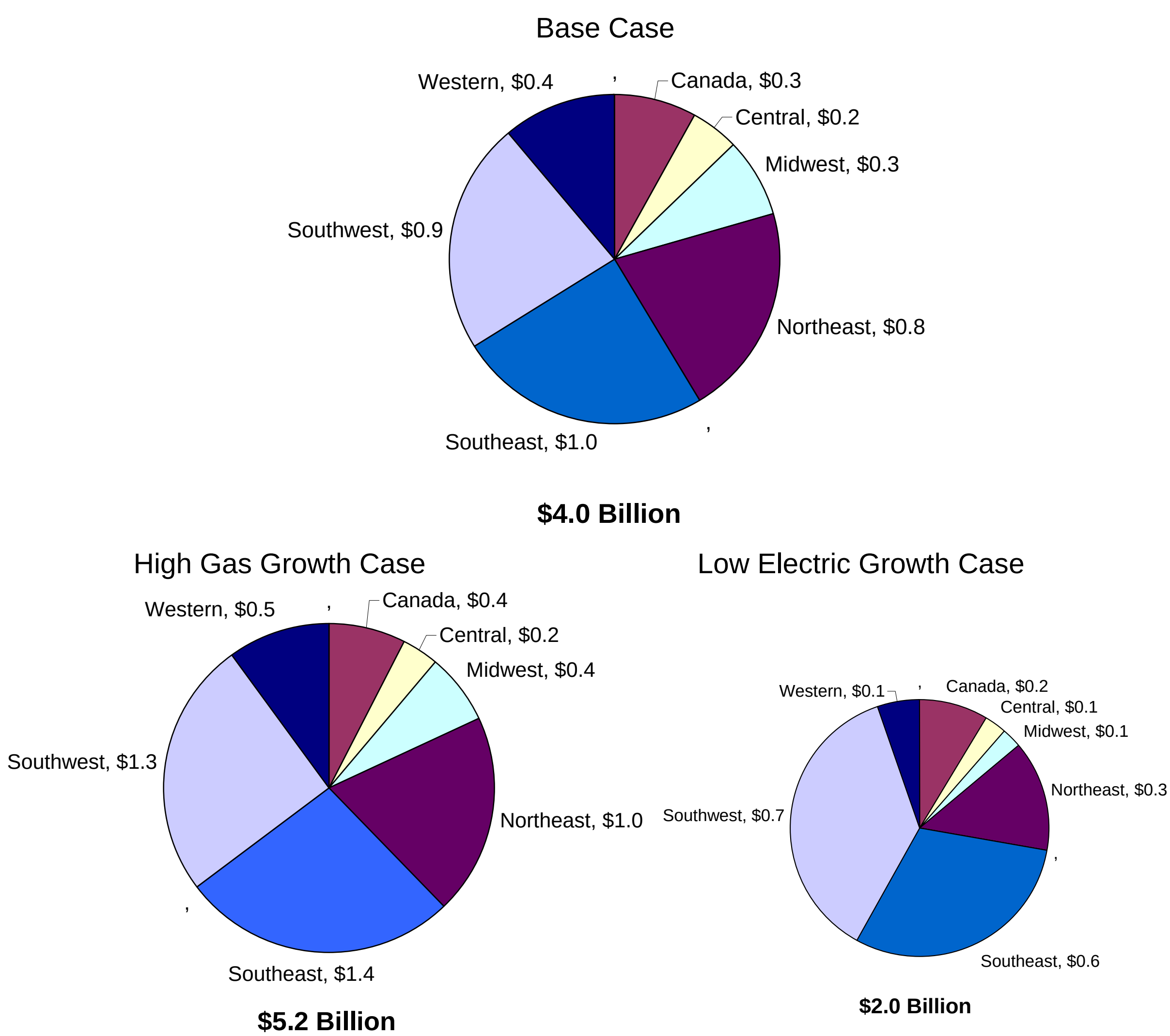
Regional natural gas storage development costs can vary by well over 100 percent between the least and most costly regions. New storage in the Northeast is the most expensive. Storage development is least costly in Canada and the Midwest.

Projected storage development costs have been separated into base gas and non-base gas portions. Costs also include compression at the storage field. Base gas costs have been based on projected average natural gas prices for the year preceding the in-service date of the new storage capacity. It is assumed that depleted reservoir and aquifer storage would need one Bcf of base gas for each one Bcf of new working gas capacity. For salt caverns, it is assumed that the working gas to base gas ratio is 2 to 1.

[38] Storage costs for 2007 are based on historical cost trends for actual storage projects from 1997 through 2007. Costs (other than the cost of base gas) have been escalated from the 2007 level at a constant rate of 2 percent.

Between 2009 and 2030, total expenditures for new storage capacity range from $2.0 to $5.2 billion (Figure 49). About half of all projected storage expenditures in every case are in the Southwest or Southeast, where the majority of salt cavern development is expected to occur. Storage capital expenditures are well below projected pipeline and compression expenditures.

Figure 49
Regional Storage Capital Expenditures, 2009 – 2030 (Million $)



5.2.7 Other Midstream Infrastructure: Gathering, Processing, and LNG

In addition to pipeline and storage infrastructure, investment in gathering pipelines and processing plants will be required. More LNG infrastructure may also be built, even though there is currently an excess of capacity.

5.2.7.1 Gathering Pipeline Infrastructure

As of 2008, there are over 450,000 producing natural gas wells in the U.S. Excluding individual natural gas well connections, nearly 20,000 miles of mainline gathering pipeline is necessary to connect domestic natural gas production to the U.S. transmission system (Table 15)[39]. Approximately two-thirds of this pipeline mileage is onshore and the remainder is offshore. On average, offshore gathering mainlines are larger in diameter relative to onshore gathering lines (16 inches versus 7 inches in diameter).

Table 15
U.S. Gathering Pipeline Mileage by Diameter, 2007

Pipeline Diameter	Offshore	Onshore	Total
4 inches or less	157	4,422	4,579
4 to 10 inches	1,020	5,690	6,711
11 to 20 inches	4,533	1,803	6,336
21 to 28 inches	822	296	1,118
Over 28 inches	563	207	770
Total	7,095	12,475	19,570
Average Diameter	16	7	

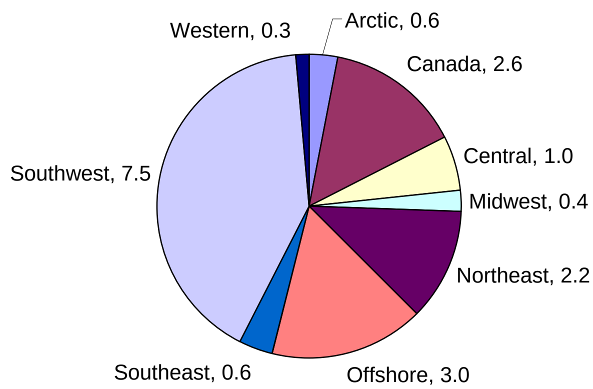
Source: U.S. Transportation Safety Administration

Future mainline gathering requirements will be driven by the need to connect new production to the transmission system. In order to obtain annual production rates of 27 to 35 Tcf by 2030, between 15,000 and 26,000 miles of new gathering mainlines will be needed from 2009 to 2030 (Figure 50). New gathering lines are needed even in mature basins to replace retired lines or to hook up new natural gas wells. Projected incremental gathering pipeline mileage by region is based on historical mileage of gathering pipeline as a function of projected drilling activity and natural gas well completions. The Southwest region is the center of significant shale gas production development, and is expected to be the region with the most new gathering pipeline miles. Relative to the onshore, more gathering pipeline is needed to connect offshore production, because the vast majority of supply must reach the onshore before it can be processed. Consequently, significant amounts of gathering pipeline are projected for the offshore even though it is not a high production growth area.

[39] Canadian production is roughly one-third of the level of the U.S. gas production. Based on the U.S. Department of Transportation data and assuming the ratio of gathering pipeline mileage to production is approximately the same in Canada, approximately 7,000 miles of new gathering pipeline will be needed in Canada.

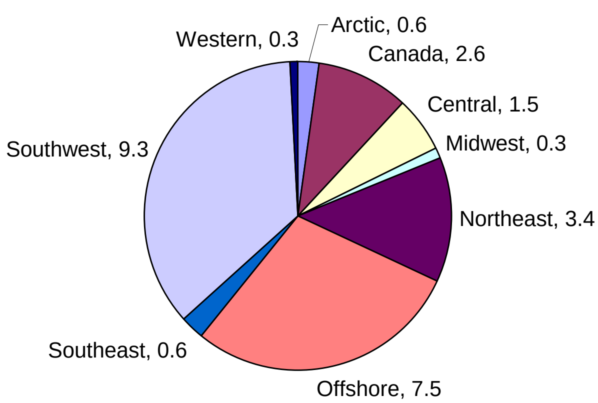
Figure 50
Cumulative Gathering Pipeline Mileage Additions, 2009 – 2030 (1000 Miles)

Base Case



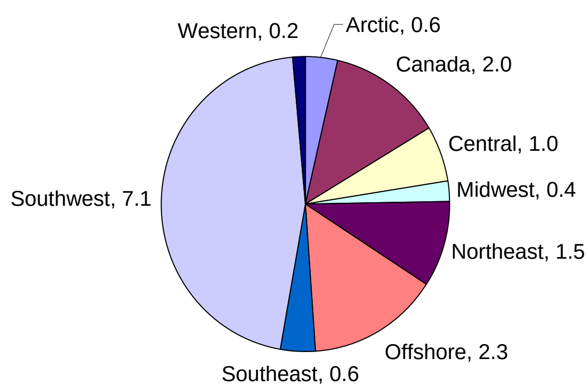
18.2 Thousand Miles

High Gas Growth Case



26.0 Thousand Miles

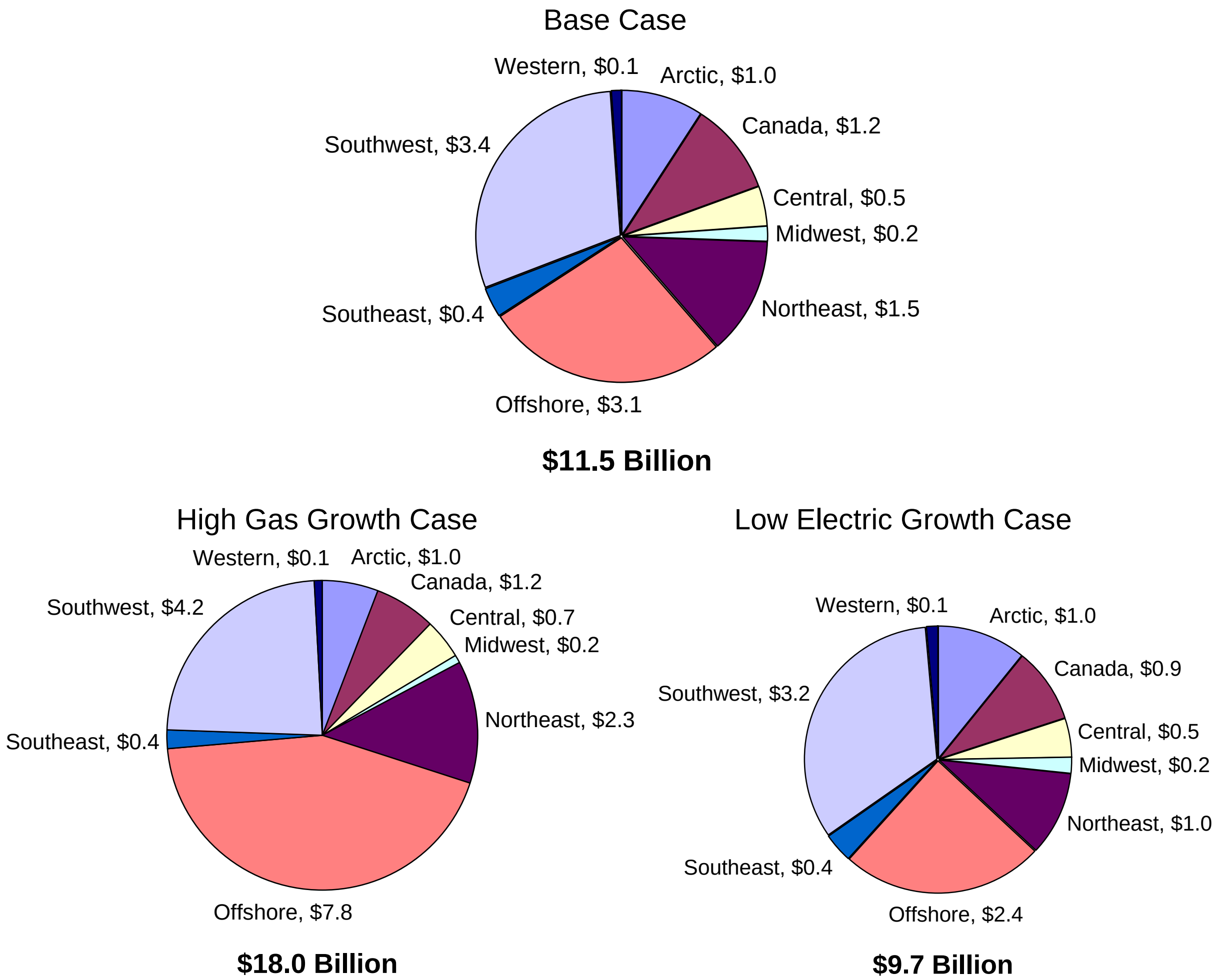
Low Electric Growth Case



15.5 Thousand Miles

From 2009 to 2030, expenditures on gathering mainlines are projected to range from $9 to $18 billion, equating to $500 million to $1 billion per year (Figure 51). Offshore gathering infrastructure accounts for 25 percent of total expenditures. If significant offshore acreage is opened to drilling, as in the High Gas Growth Case, expenditures for offshore gathering could more than double relative to the Base Case. Offshore gathering infrastructure accounts for over 40 percent of total expenditures on gathering in the High Gas Growth Case.

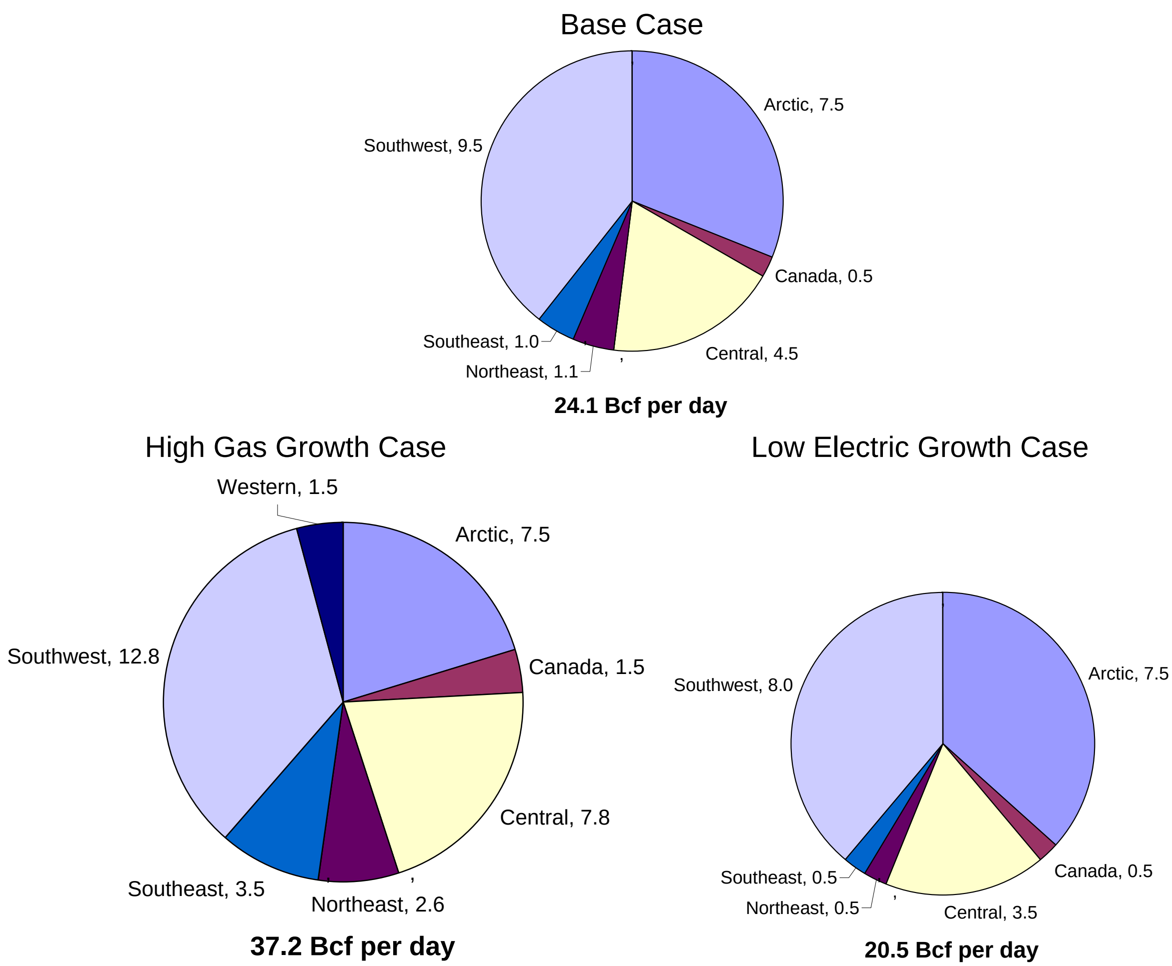
Figure 51
Cumulative Natural Gas Gathering Pipeline Expenditures, 2009 – 2030 (Billion $)



5.2.7.2 Natural Gas Processing

From 2008 to 2030, net U.S. and Canadian natural gas production is projected to increase by 11 to 24 Bcf per day in the Base Case and High Gas Growth Case, and remain relatively stable in the Low Electric Growth Case. Even without an increase in production, the U.S. and Canada will require additional natural gas processing capacity, because production will shift from conventional to unconventional basins over time. It is estimated that a minimum of 20 Bcf per day of additional natural gas processing capacity will be needed just to accommodate the shifts in the location of natural gas production in the Low Electric Growth Case (Figure 52). In the Base Case and the High Gas Growth Case, 24 to 37 Bcf per day of additional gas processing capacity will be needed, more than the net incremental production would suggest.

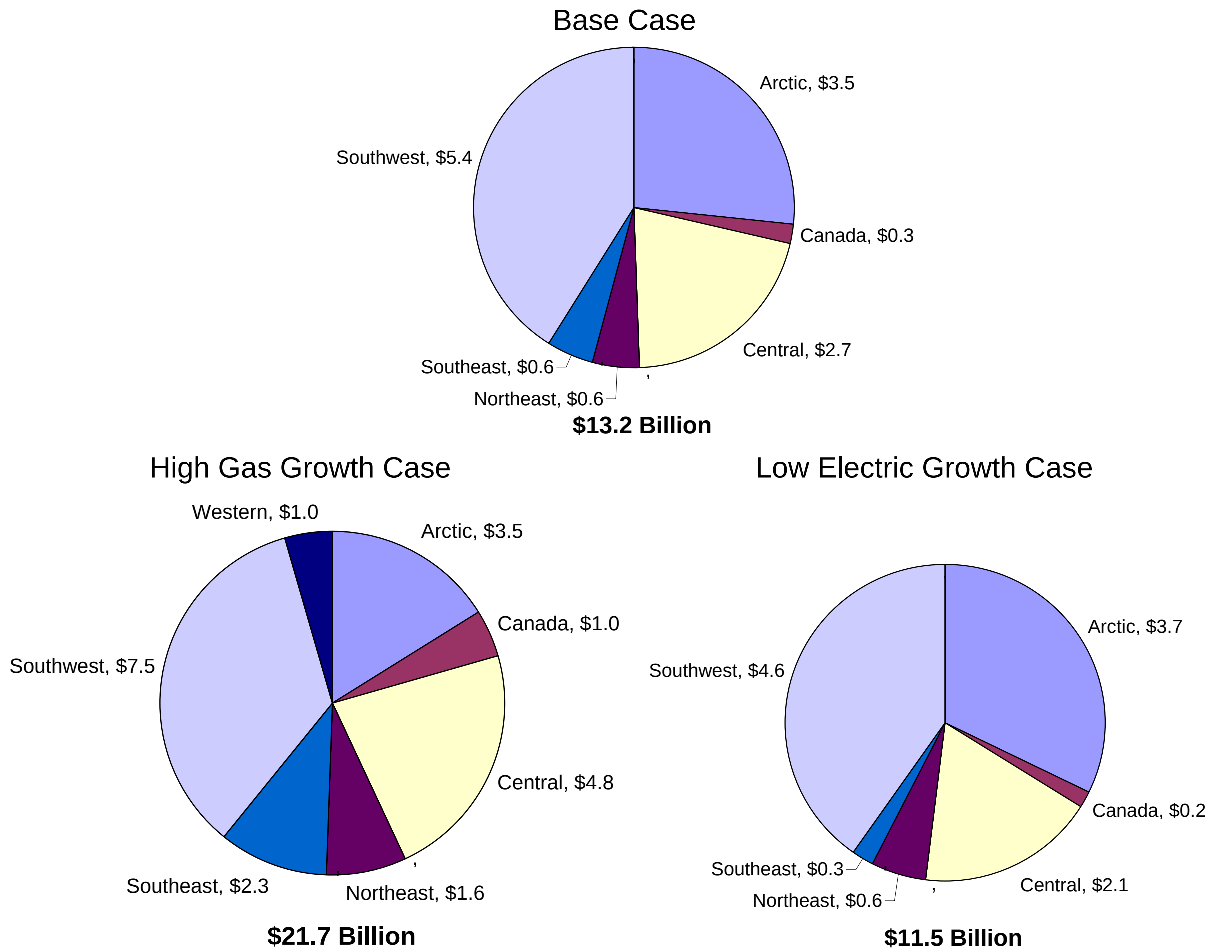
Figure 52
Cumulative Processing Plant Additions, 2009 – 2030 (Bcf per day)



The majority of new natural gas processing will be built in regions with new unconventional and frontier production. If the Arctic projects move ahead as assumed in both cases, at least 7 Bcf per day of processing facilities will be needed to support them alone. An additional 0.5 Bcf per day will be needed for potential satellite field development along the Mackenzie Valley Pipeline route in the Northwest Territories. Increases in most other regions are due predominately to shale gas development. New processing capacity developed in the Central region will help process the growing production from tight sand formations in the Northern Rockies. In the High Gas Growth Case, production from offshore areas where the drilling moratorium has been lifted would increase the need for additional processing capacity in the nearby onshore Western and Southeast regions.

Between 2009 and 2030, it is projected that the U.S. and Canada will have to invest between $11 and $22 billion in new natural gas processing infrastructure for growing production and to accommodate the expected shifts in the location of natural gas supplies (Figure 53). Over half of the expenditures are projected to be in the Southwest and Central regions. Arctic processing investments include $2.6 billion for a new plant in Alaska, with the remainder being in Northern Canada for production entering the Mackenzie Valley Pipeline.

Figure 53
Cumulative Processing Plant Expenditures, 2009 – 2030 (Billion $)



5.2.7.3 LNG Infrastructure

As discussed in Section 4.3.2 above, in 2008 U.S. LNG regasification capacity operated at relatively low load factors near 10 percent. Significant investment in LNG regasification terminals is not projected to be necessary in the U.S. and Canada for the foreseeable future. North American LNG imports can easily increase through increased utilization of existing terminals.

Despite this, some modest increases in LNG import capacity may occur in the future. All cases assume one additional terminal, the Gulf LNG Energy terminal in Pascagoula, Mississippi, is developed in North America with a regasification capacity of 1.5 Bcf per day in 2011. A planned 1.2 Bcf per day expansion at Elba Island and an expansion of 0.8 Bcf per day at the Cameron LNG terminal in Louisiana in 2023 also are assumed in the cases. The total investment needed to expand LNG import capacity by the 3.5 Bcf per day across these three terminals is projected to be about $1.8 billion.

5.2.8 Summary

From 2009 to 2030, $130 to $210 billion will need to be spent on midstream natural gas infrastructure; about 80 percent of these expenditures will be for natural gas transmission pipelines.

From 2009 to 2030, approximately $130 to $210 billion will need to be spent on midstream natural gas infrastructure in order to meet projected market requirements (Table 16), equating to between $6 and $10 billion per year. Approximately 80 percent of necessary midstream infrastructure expenditures will be for natural gas transmission pipelines. Expenditures on new processing facilities will account for about 8 to 10 percent of the total investment on new midstream assets. Storage and LNG infrastructure, while important for efficient market operations, are projected to account for a relatively small portion of the total future investment needs. Current LNG terminal import capacity is underutilized and can accommodate projected growth. Although storage working gas capacity increases by between 8 and 13 percent over 2008 levels, the cost of storage development is lower, relative to transmission investments.

The largest projected midstream infrastructure expenditures are expected to occur in the regions with the greatest projected growth in gas production. Shifts in natural gas supply sources are projected to be the main driver of midstream investments and not natural gas consumption growth. Canadian and Arctic expenditures are projected to represent 30 to 40 percent of future U.S. and Canadian expenditures. Most of the expenditures in these areas are related to the Alaska and Mackenzie Valley Pipeline Projects. If the roughly $50 billion required to construct the Arctic pipelines is not spent, then the portion of total investment that occurs in these regions will be significantly lower.

Table 16
Total Projected Pipeline, Storage, and Gathering Infrastructure Expenditures, 2009 – 2030 (Billion $)

Base Case

Region	Transmission	Storage	Gathering	Processing	LNG	Total	Percent
Canada	$30.6	$0.3	$1.2	$0.3	-	$32.4	20%
Arctic	$24.0	-	$1.0	$3.5	-	$28.6	18%
Southwest	$17.6	$0.9	$3.4	$5.4	$0.4	$27.7	17%
Central	$17.0	-	$0.5	$2.7	-	$20.2	13%
Southeast	$14.3	$1.0	$0.4	$0.6	$1.4	$17.6	11%
Northeast	$6.7	$0.8	$1.5	$0.6	-	$9.7	6%
Midwest	$8.4	$0.3	$0.2	-	-	$8.9	6%
Western	$7.3	$0.4	$0.1	-	-	$7.8	5%
Offshore	$3.6	-	$3.1	-	-	$6.7	4%
Total	**$129.5**	**$3.4**	**$11.5**	**$13.2**	**$1.8**	**$159.3**	**100%**
Percentage	**81%**	**2%**	**7%**	**8%**	**1%**	**100%**	

High Gas Growth Case

Region	Transmission	Storage	Gathering	Processing	LNG	Total	Percent
Canada	$33.0	$0.4	$1.2	$1.0	-	$35.5	17%
Arctic	$24.0	-	$1.0	$3.5	-	$28.5	14%
Southwest	$27.6	$1.3	$4.2	$7.5	$0.4	$41.1	20%
Central	$24.8	$0.2	$0.7	$4.8	-	$30.5	15%
Southeast	$15.4	$1.4	$0.4	$2.3	$1.4	$20.8	10%
Northeast	$10.1	$1.0	$2.3	$1.6	-	$15.1	7%
Midwest	$12.9	$0.4	$0.2	-	-	$13.4	6%
Western	$8.7	$0.5	$0.1	$1.0	-	$10.4	5%
Offshore	$6.3	-	$7.8	-	-	$14.1	7%
Total	**$162.8**	**$5.2**	**$18.0**	**$21.7**	**$1.8**	**$209.5**	**100%**
Percentage	**78%**	**2%**	**9%**	**10%**	**1%**	**100%**	

Low Electric Growth Case

Region	Transmission	Storage	Gathering	Processing	LNG	Total	Percent
Canada	$27.7	$0.2	$0.9	$0.2	-	$29.0	22%
Arctic	$24.1	-	$1.0	$3.7	-	$28.8	22%
Southwest	$16.2	$0.7	$3.2	$4.6	$0.4	$25.1	19%
Central	$10.0	$0.1	$0.5	$2.1	-	$12.7	10%
Southeast	$7.8	$0.6	$0.4	$0.3	$1.4	$10.4	8%
Northeast	$5.7	$0.3	$1.0	$0.6	-	$7.6	6%
Midwest	$6.3	$0.1	$0.2	-	-	$6.6	5%
Western	$6.9	$0.1	$0.1	-	-	$7.2	5%
Offshore	$3.3	-	$2.4	-	-	$5.7	4%
Total	**$108.0**	**$2.0**	**$9.7**	**$11.5**	**$1.8**	**$132.9**	**100%**
Percentage	**81%**	**1%**	**7%**	**9%**	**1%**	**100%**	

6 Policies and Issues Affecting the Future of the Natural Gas Market

Government policies and future market and technological changes will affect the magnitude and timing of future natural gas infrastructure developments. Additionally, there may be unforeseen developments that significantly affect the demand for natural gas and the demand for midstream natural gas infrastructure. A notable example is the rapid growth in domestic shale gas production. Very few industry analysts fully anticipated the extent of the growth in this important domestic source of natural gas. Similar events undoubtedly will occur in the future. It is important that the regulatory and policy framework that influences the construction of natural gas infrastructure allows industry to respond to events in a timely fashion. This section discusses some, but not all, of the issues currently on the horizon that may affect the future of the natural gas market.

6.1 Regulatory Environment for Approving Infrastructure Construction

The siting and permitting process for pipeline, storage, and other midstream natural gas infrastructure can be both time consuming and expensive. The Federal Energy Regulatory Commission (FERC) is responsible for the review and authorization of interstate natural gas transmission facilities in the United States. This authority derives from the Natural Gas Act (NGA), a New Deal statute that recognized the interstate nature of natural gas service and the need for a national approach to building a pipeline network. Other federal statutes that affect the construction of interstate natural gas pipelines include the Clean Air Act, Clean Water Act, the Endangered Species Act, the Coastal Zone Management Act, the Fish and Wildlife Coordination Act, the Historic Preservation Act, the Rivers and Harbors Act, the Mineral Leasing Act, the Federal Land Policy Management Act, and the Wild and Scenic Rivers Act.[40]

In addition to being subject to federal regulation, additional state and local agency approvals may be necessary before pipeline construction can begin. Each agency has its own forms, processes, and data requirements. In the future, as a result of the authority given to FERC under Energy Policy Act of 2005, this process may be streamlined in order to facilitate expeditious development of pipeline capacity, or it may become even more time consuming and difficult to construct natural gas pipelines.

Pipeline projects, by their nature, can be disruptive during construction, even though significant progress has been made to minimize both the temporary effects of construction and permanent environmental effects along the pipeline right-of-way. Routes must be selected to avoid both environmentally sensitive areas and urban areas. Assembly line methods of construction have been developed to shorten how long construction crews must be on site, and restoration methods also have been improved.

[40] Intrastate pipelines, pipelines within a single state may not be subject to FERC jurisdiction but may be subject to these other federal statutes.

Still, regardless of the market benefits of a pipeline or storage project, a variety of groups likely will oppose pipeline projects. Urban development has encroached on many existing pipeline right-of-ways thereby making some expansions parallel to existing pipelines difficult to implement. Projects often are opposed by multiple stakeholders, including landowners, environmentalists, and others with competing interests.

There are a number of means by which opponents may delay or derail natural gas pipeline projects. For example, despite the fact that interstate pipelines are under federal jurisdiction, natural gas pipelines proposed in coastal areas must request consistency determinations from individual states pursuant to plans that the states have adopted under the federal Coastal Zone Management Act. These and other permitting procedures administered by the states pursuant to delegated federal authority effectively permit individual states to frustrate the construction of energy infrastructure that FERC has determined to be in the public convenience and necessity.

Delays in natural gas pipeline infrastructure construction can result in significant costs on consumers. Delayed pipeline construction will reduce the available supply of natural gas to the market. Consequently, natural gas prices will be relatively higher and U.S. industrial competitiveness in world markets will suffer due to the increased costs. There may be job losses in natural gas consuming industries. There may also be direct job losses in the pipeline construction business. The competitiveness of natural gas versus other fuels may be reduced due to natural gas prices that are higher than otherwise would be the case.

6.2 Impacts of a Longer or Shorter Recession

Both the Base Case and the High Gas Growth Case assume that the U.S. and Canada are out of the current recession by the beginning of 2010. A shorter recession would have little impact on the projected amounts of midstream infrastructure developed. If economic growth resumes a few months earlier, the results would be only slightly different. All other factors being held equal, natural gas consumption and prices would rise more quickly due to the increased economic activity. Still, the change would most likely be unnoticeable. Current pipeline and storage projects most likely would not be impacted much, and future infrastructure projects beyond 2012 may be put in place six months to a year earlier.

If the recession were slightly longer, the impacts would be the reverse. Natural gas consumption and prices would tend to be lower than projected. A severely prolonged recession could, however, be problematic. Unconventional production has a relatively high decline rate. Drilling programs need to be continued in order to maintain production. Natural gas infrastructure will still need to be built to accommodate the locational shift in natural gas supply sources even if total U.S. and Canadian natural gas consumption is level or even declining.

A severe recession could limit the capital available for upstream and midstream investments necessary for the natural gas value chain to respond efficiently to demand. The credit quality of pipeline shippers might be impaired, creating another potential hurdle to proceeding with future pipeline projects.

6.3 Arctic Pipeline Projects

Natural gas fields in Northern Alaska and in the Mackenzie Delta in Northern Canada were discovered in the late 1960s and early 1970s. The Alaska fields have 35 Tcf of known reserves while the Mackenzie region has about 6 Tcf. Plans to build a natural gas pipeline to the lower half of Canada and the U.S. Lower-48 have been contemplated for decades. The construction of both projects is assumed in the INGAA Foundation Base Case and the High Gas Growth Case.

Still, the timing of these projects and whether they will be built at all before 2030 is uncertain. Growing domestic shale supplies in the U.S. and Southern Canada potentially reduce the need for Arctic natural gas supplies.

6.3.1 The Mackenzie Valley Pipeline

The Mackenzie Valley Pipeline consists of a consortium of four oil companies (Imperial, ConocoPhillips, Shell, and ExxonMobil) plus the Aboriginal Pipeline Group (APG) to which the oil companies have agreed to sell one-third interest in the project. The project would consist of 746 miles (1,220 km) of 30" pipeline from the Mackenzie Delta in the Canadian Northwest Territories to Northwest Alberta.

Many issues are holding up the project. There are questions about whether the project is economic. There is a serious concern about whether there is enough natural gas resource to keep the pipeline continuously supplied for a 30-year project life and what the cost of doing so would be. Additionally, some wonder if the production that would be transported by the project can compete on a cost basis with other domestic production and/or LNG. Uncertainty about the ultimate cost of the pipeline itself further complicates making a decision to proceed with the project.

Press reports on the project have suggested that the producers and the Canadian government are in discussions regarding a fiscal arrangement to help support the project. Support could potentially be in the form of Government contributions to infrastructure and pre-development costs. Discussions between the project proponents and the Canadian government to discuss this and other means of fiscal and economic support for the project are currently ongoing. In January 2009 the Canadian government offered financial aid for infrastructure, such as roads, airstrips, docks, and some pre-construction expenses. Another problem concerns the APG. The APG does not have funds to pay for its one-third share of the project, and it is uncertain where, or even if, it can access such funds.

There also have been regulatory delays. The Canadian federal and provincial Joint Review Panel's environmental and social impact report was scheduled to be released in 2008 and now is scheduled for late 2009. In addition, wildlife and environmental groups' concerns for polar bears, grizzly bears, and woodland caribou have slowed down the permitting process.

6.3.2 The Alaska Pipeline Projects

Competing projects propose to transport natural gas in the North Slope of Alaska to markets in Canada and the lower-48 states. There also is a competing proposal to transport natural gas to southern Alaska and export it via a LNG terminal. All three cases in this study assume North Slope gas is transported to market via a pipeline from Alaska to Alberta.

There currently are two competing pipeline-only projects that would transport Alaska natural gas to Alberta, Canada: one is sponsored by the Denali joint venture of BP and ConocoPhillips and the other by TransCanada Pipeline and ExxonMobil. Generally, both propose a 2,000 mile 48" diameter pipe that would run from Prudhoe Bay to the Alberta border, including 700 to 750 miles of pipeline within Alaska.

In July 2007, the Alaska Gasline Inducement Act (AGIA) was passed offering $500 million in state aid for a qualifying project to build a pipeline from the Alaska North Slope to the U.S. Lower-48. Five companies submitted applications pursuant to AGIA, and only TransCanada's met all the State's requirements. None of the major North Slope producers submitted applications. The Denali project, which did not submit an AGIA application, is preparing to spend $600 million of its own money in initial engineering work.

Both projects are currently in the FERC's NEPA pre-filing process and are working towards open seasons that will be held in 2010. Both projects are currently completing environmental studies and finalizing the scope and capital cost estimates for the projects which are all required for the open season. The results of the open season will provide an indication of which of the two projects, if any, the Alaska North Slope producers are prepared to support.

The choice of a pipeline project is complicated by the pipeline-to-LNG project proposal. The All-Alaska Pipeline is a proposal by former Secretary of the Interior and former Alaska Governor Wally Hickel to construct an 800 mile pipeline from Prudhoe Bay to Valdez, Alaska. It is backed by the Alaskan Gasline Port Authority (AGPA), a consortium formed by the North Slope Borough, Fairbanks North Star Borough, and the City of Valdez. Although this project currently does not have the same momentum as the pipeline-only projects, the availability of this option creates further uncertainty.

The potential Alaska pipeline projects face economic uncertainty different from that faced by the Mackenzie Valley Pipeline Project. Unlike the Mackenzie project, there is relative certainty that there are sufficient reserves available to support the pipeline. Opening of the Arctic National Wildlife Refuge (ANWR) does not appear necessary given the natural gas resources available outside ANWR. What is uncertain is whether the natural gas can be brought to the U.S. Lower-48 at a cost that is competitive with other domestic, Canadian import, and LNG supply alternatives.

If the build-up of Alaska Pipeline capacity is more gradual than assumed in either the Base Case or the High Gas Growth Case, the existing pipeline capacity downstream of Alberta (i.e. TransCanada Mainline, Northern Border, Alliance, Spectra Westcoast, and Gas Transmission Northwest) collectively may have sufficient spare capacity to accommodate the Alaskan volumes such that the construction of new pipeline along the Alberta-to-Chicago corridor would not be required. Making use of existing infrastructure could result in lower tolls for both Alaskan shippers and the existing shippers that transport gas from Western Canada to other North American markets downstream.

6.4 Competition from Other Transmission Networks

The natural gas pipeline grid is unlikely to be the only transmission grid expanded in the future. New electric transmission lines and possibly CO_2 pipelines used for carbon capture and sequestration are possible. All transmission networks will have to compete for rights-of-way, especially in highly populated areas.

Doubling the use of renewable generation is unlikely without expanding the electricity transmission grid. Wind and solar resources are more abundant in the West and Great Plains. The nation will need significant transmission grid investments in order to transport renewable electrons to where most Americans live. Current White House energy plans have called for at least 3,000 miles of new transmission lines.[41] Some of the wind farms and solar plants built in the future may be sited near growing natural gas production, especially in states such as Texas. Electric transmission lines from these areas may compete for the same infrastructure rights-of-way as natural gas pipelines.

If built, CO_2 pipelines also may compete for rights-of-way. A recent INGAA Foundation study[42] focused on the pipeline infrastructure requirements for carbon capture and sequestration (CCS) in connection with compliance with potential mandatory greenhouse gas emissions reductions. The study forecasts that between 15,000 and 66,000 miles of pipeline will be needed in the U.S. by 2030, depending on how much CO_2 must be sequestered, and the extent to which enhanced oil recovery (EOR) is involved.

Fortunately, a majority of the natural gas pipelines in the INGAA Foundation's cases will be in production areas that are sparsely populated.[43] Therefore, right-of-way competition with other transmission networks will be less problematic. Still, there may be problems for new market area pipelines, such as the additional pipeline capacity projected in Florida.

CO_2 pipelines also may compete with natural gas pipelines for labor and materials. According to some studies, cumulative CO_2 pipeline costs through 2030, including pumps and compressors, could range from $25 to $100 billion. If investment in CO_2 pipelines is near the high end of this range, it would equate to over 50 percent of the projected investment in midstream natural gas infrastructure. This incremental demand for construction resources could increase the cost of building natural gas pipelines. Still, annual combined natural gas and CO_2 pipeline expenditures would be less than 2008 levels, except for years when Arctic projects are built. Given recent history, such annual pipeline construction levels are sustainable.

6.5 Backup to Renewable Generation

Due to the variability inherent in some forms of renewable power generation, it is likely that some form of backup generation capacity will be needed in order to ensure the reliability of the electric power system. The need for this type of backup generation will increase as more states implement renewable portfolio standards (RPS). A possible federal clean energy standard would add to this demand. Natural gas-fired generation is a likely candidate to cover this backup generation need since it is one of the cleanest and most economic options available. Natural gas turbines easily can be operated as spinning reserves that can adjust to renewable generation variability in real time and provide a stable level of electricity output. In fact, it is common today for some wind and solar plants to use combined-cycle gas turbines as backup generation. Other generating technologies, such as coal-fired power plants, do not have the ability to respond in this near instantaneous fashion.

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[41] President Barack Obama - Saturday Radio Address, January 24, 2009.

[42] "Developing a Pipeline Infrastructure for CO2 Capture and Storage: Issues and Challenges"; ICF International; 2009.

[43] There are exceptions such as the Barnett shale production in and near Dallas / Fort Worth, Texas.

Gas-fired generation could be operated such that it is countercyclical to renewable generation. To ensure the reliability of both electricity and natural gas networks, sufficient natural gas pipeline and storage infrastructure must be available to cover peak day (and peak hour) consumption assuming little or no generation is available from highly variable generation sources, such as wind and solar. Wind and solar generation capacity may increase the need for natural gas pipeline and storage capacity even though the assets may be used at relatively low load factors. Natural gas operational flexibility would need to increase to meet greater variations in gas-fired power generation as it follows both changes in electricity demand and renewable generation output.

Renewable generation from sources such as biomass and geothermal is not as susceptible to interruption due to weather conditions. Such base load renewable generation will lessen the need for natural gas consumption in the power sector. To the extent that such generation or other forms of non-variable generation are built, it will lessen the need for natural gas pipeline and storage infrastructure.

Other backup options for renewable energy generation will lessen the need to develop additional natural gas infrastructure. There is ongoing research into non-hydrocarbon, zero emission backup options. These options involve storing energy at times of high renewable generation and withdrawing the energy during times of low generation. If available, this would allow for a relatively steady generation output to the electricity grid. Contemplated energy storage devices include: utility scale flywheels that convert electricity to and from kinetic energy, compressed air storage in salt caverns in which released compressed air could run turbines[44], super capacitor batteries, and hydrogen fuel cells. None of these options is currently economic, making natural gas the best for providing backup for intermittent renewables.

6.6 Alternative Fuel Vehicles

Approximately one-third of the delivered energy in the U.S. and Canada, over 30 quadrillion Btu in 2008, is used in the transportation sector. Over 97 percent of the transportation sector is powered by liquid hydrocarbon fuels such as gasoline and diesel fuel. How the transportation sector evolves could greatly impact natural gas consumption. The sector may move in the direction of greater use of either plug-in hybrid vehicles (PHEVs) or natural gas vehicles (NGVs). The INGAA Foundation High Gas Growth Case assumes a greater use of both of these technologies in the future, while the Base Case does not assume any significant penetration of either of these types of vehicles over time.

Because PHEVs are becoming more economic due to growing research in the field, the overall market share of PHEVs may increase at the expense of traditional gasoline-powered vehicles. These vehicles typically offer improved fuel economy compared to gasoline-powered cars.

While there are several issues facing PHEVs, the electric power industry has significant incentive to cooperate in surmounting these barriers. First, the pricing structures utilized by many power companies are not designed with PHEVs in mind. Although many owners would tend to charge their vehicle overnight during the off-peak hours of electricity usage, it is not very common for a power company to offer off-peak pricing. Thus, the additional utilization required

[44] This technique is used in a limited capacity at two plants, one in Alabama and another in Germany.

to charge a PHEV could significantly impact an owner's monthly electricity bill, and may even go so far as to push them into a higher rate schedule. The other issue with PHEVs regards infrastructure. PHEV owners who only have access to public or mass parking areas might have difficulty finding a place to plug in. Adding plug-in stations to all parking areas would require significant wiring as well as extensive underground work. Most importantly, the upfront capital cost of the vehicle, which can be $8,000 to $10,000[45] above the cost of a conventional vehicle, may not be economically justified without government incentives.

Natural gas vehicles (NGVs) are another potential source of competition to gasoline-powered vehicles. Although they are not readily used in the consumer market today, NGVs are used in many cities for public transportation buses. Still, NGVs face significant infrastructure issues. In order to make NGVs marketable to individual consumers, a network of natural gas fueling stations throughout the country would need to be constructed.[46] The investment and time required to build a network that approaches the scope of the current gasoline distribution system could be prohibitively large. Another issue with NGVs concerns the natural gas storage tank within each vehicle. These tanks are significantly larger than those in gasoline-powered vehicles, and thus cut into the space available for storage, seating, etc. However, given the current and projected prices, natural gas will have a significant cost advantage over petroleum-based fuels. As a result, interest in using natural gas for fleet vehicles and long-haul trucking is likely to continue to grow.

6.7 The Role of Natural Gas in Reducing GHG Emissions

There is significant political support for the U.S. and Canadian economies to move towards renewable and clean sources of energy. Still, hydrocarbons likely will need to be used for decades while the economy transitions to these new technologies and the necessary infrastructure is developed. Natural gas can be an important strategic fuel as the economy makes this transition. It is the cleanest burning fossil fuel, and there is growing acceptance that it is domestically abundant.

It is technologically possible to increase natural gas use for both electric generation and transportation, which now are dominated by coal and oil, respectively. Compared to coal-fired power plants, the current major source of electricity in the U.S., natural gas-fired plants emit virtually no mercury, 99 percent less sulfur dioxide, 80 percent less nitrogen oxide, and about half the amount of CO_2, the chief greenhouse gas. While technologies to capture CO_2 and burn coal cleanly eventually may be deployed on a widespread basis, a market based cap-and-trade system for controlling CO_2 could motivate consumption of natural gas relative to coal, particularly in its early years. Eventually, utilities may develop clean coal burning technologies to capture CO_2. As a transportation fuel, natural gas powered vehicles emit less CO_2 than gasoline powered vehicles.

As an alternative to natural gas, wind and solar power generation produce zero harmful emissions. Still, the wind and the sun provide varying levels of reliability in different parts of the country. So, as reliance on wind and solar increases, there needs to be a certain amount of technology available to provide a backup, either in the form of supplemental power generation or load management. While a zero emission technology, such as energy storage technology,

[45] "Cost-Benefit Analysis of Plug-In Hybrid Electric Vehicle Technology"; A. Simpson; 2006.

[46] This infrastructure is assumed in the High Gas Growth Case.

may be available in the future, gas-fired generation is the most likely backup in the immediate future.

There are numerous risks and uncertainties with carbon policy. It is unclear exactly what direction the U.S. and Canadian governments will take in regards to energy and carbon policies. Natural gas is not necessarily an easy win in the power sector. Some policy makers have a bias against all hydrocarbons, including natural gas.

6.8 Other Potential Sources of Natural Gas – Synthetic Fuels and Hydrates

For the foreseeable future, shale gas appears to be a dominant source of supply for U.S. and Canada. As technology advances, however, other "unconventional" natural gas supply sources may become economically producible. Two such potential sources are synthetic natural gas from coal (SNG) and natural gas hydrates. Both U.S. and Canadian coal and hydrate resources are vast, with the ability to supply natural gas for multiple decades or even centuries. If these two sources can be tapped economically, the domestic natural gas market can maintain or even grow well into the next century. Thus, the transition away from a hydrocarbon economy will be for environmental reasons, and not necessarily due to a lack of additional natural gas supply sources.

6.8.1 Synthetic Natural Gas

From 2001 to 2007, synthetic natural gas (SNG) accounted for only 0.27 percent of total marketed natural gas production in the U.S.[47] There is no significant production of SNG in Canada. SNG production has not fluctuated with natural gas price, which indicates that other barriers have prevented SNG technology from being adopted.

SNG production can occur in two ways. One is from underground coal gasification (UCG), which converts coal that could not be otherwise mined into a gaseous product under a high temperature and pressure. Wells drilled into a coal seam enable the injection of air or oxygen to combust coal in-situ and produce coal gas. The coal gas is then extracted through the same wells used to inject the air or oxygen. While UCG could increase the amount of recoverable coal reserves in the US, it faces several challenges before it can become a reliable source of natural gas in the country.

The first is the need for a revived interest in the research and development of UCG production, which dissipated after the 1989 decline in natural gas prices. Issues to be explored and developed include: costs and economics, monitoring and management of underground gasification processes, coupling of carbon capture and sequestration (CCS) technology with UCG in a carbon-constrained world, siting and permitting of UCG operations, improved simulation of cavity formation and flow and transport of natural gas. These are just a few of the obstacles that must be overcome to make UCG available on a commercial scale.[48]

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[47] EIA's database on US supplemental supplies of natural gas.

[48] National Coal Council. Chapter 6: Underground Coal Gasification. "The Urgency of Sustainable Coal." May 2008. pp. 163-165.

Gasification of coal also can occur at synfuel plants. Currently, there is only one synfuel plant[49] in the U.S. that produces pipeline quality natural gas. This plant was built in 1984.[50] Natural gas produced in such a process must undergo additional treatment to meet natural gas pipeline specifications. Inert products must be removed from SNG to increase its heating value. Other impurities, some introduced in the gasification process, also must also be removed. The combined cost of coal gasification and post-gasification processing make SNG uncompetitive with conventionally-produced natural gas.

Although capture and sequestration of CO_2 is part of the SNG production process, it actually produces 2.5 to 3.5 times as many CO_2 emissions as natural gas produced via conventional methods due to the use of high temperatures to break the coal into carbon monoxide and water molecules. For this reason, CCS must be a consideration for lifecycle CO_2 emissions from any syngas-production or coal-gasification power plants in order to be comparable to the emissions from conventionally produced natural gas or a coal-fueled power plant. Therefore, uncertainties in CO2 emissions regulation will hinder the development of SNG.

An estimate of the cost of constructing a syngas production plant is difficult to obtain. First, there is only one in existence in the U.S., built over 20 years ago. The costs of syngas production will vary by geography, capacity, construction climate, and coal type. An MIT study[51] estimated the cost of syngas per MMBtu, with and without CCS technology, to be $7.66 and $6.85 per MMBtu, respectively. These results indicate that SNG production would only be economical if natural gas prices were at least $8.00 per MMBtu, in 2008 dollar terms, at the point of production. Until production costs decline, syngas is an alternative to natural gas only under a relatively high price environment.

6.8.2 Natural Gas Hydrates

A natural gas hydrate, or methane hydrate, is a cage-like lattice of ice inside which methane molecules are trapped. Methane is the chief constituent of natural gas. Methane hydrate deposits can be several hundred meters thick and have been found throughout the world in two types of settings: (1) beneath the ocean floor at water depths equal to or greater than 500 meters; (2) under the Arctic permafrost. World assessments for natural gas hydrates are in the area of 700,000 Tcf, with an estimated 300,000 Tcf below U.S. land or waters. The U.S. resource estimate is equal to 12,000 years of current U.S. natural gas consumption.

There is no current estimate of potential technical or economic recovery, and there is no current commercial production of hydrates worldwide. There is no significant private sector research in developing gas hydrates since hydrates are not expected to be economically viable within the next decade. Still, there are research programs currently funded by the governments of U.S., Japan, Canada, and India aimed at developing the technologies needed to achieve economic production. Japan has set a goal of achieving commercial production from gas hydrates by 2017.

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[49] The Great Plains Synfuels Plant - Dakota Gasification Company in Beulah, North Dakota.

[50] A delayed response to the gas shortages in the 1970s.

[51] MIT. “The Future of Coal.” 2007. pp. 153-158. http://web.mit.edu/coal/The_Future_of_Coal.pdf.

Other research has focused on the possible effect of methane hydrates on climate change. Methane is a very powerful greenhouse gas. The risk of a major methane release during the production process is unknown. Research continues on how the release of methane hydrates may have affected climate change in the past and how it could potentially affect the climate in the future. Given the current economic climate, the availability of more traditional sources of natural gas and the expected advancement of methane hydrates technology, it appears that commercial methane hydrates production is still many years away. While hydrates could be an important source of natural gas in the distant future, there is already a vast amount of domestic gas resource that can meet the needs of a growing North American gas market for many years to come.

7 Conclusions

The 2009 analysis of midstream natural gas infrastructure requirements sponsored by the INGAA Foundation can be summarized as follows:

- In the INGAA Base Case projection, the U.S. and Canadian natural gas markets grow significantly over the next 20 years. Annual natural gas consumption is projected to grow from about 26.8 Tcf in 2008 to 31.8 by 2030. This equates to total market growth of 18 percent, or an annual growth rate of 0.8 percent.

- Interregional transmission pipeline capacity between major areas throughout the U.S. and Canada is currently approximately 130 Bcf per day. By 2030, the need for interregional natural gas transport is likely to increase by between 21 and 37 Bcf per day, driving development of additional pipeline and storage capacity. Interregional natural gas transport capacity will be needed even without a growing North American natural gas market due to shifts in the location of natural gas production. The need for laterals within regions to access new production and to deliver natural gas to new customers, such as new gas-fired power plants, will also drive pipeline investment decisions.

- From 2009 to 2030, new midstream natural gas infrastructure has been projected to include:

    - 28,900 to 61,600 miles of new gas transmission pipeline.

    - 6.6 to 11.6 million HP of new gas transmission pipeline compression.

    - 371 to 598 Bcf of new working gas storage capacity.

    - 15,000 to 26,000 miles of new gathering pipeline.

    - 20 to 38 Bcf per day of new natural gas processing capacity.

    - 3.5 Bcf per day of new LNG import terminal capacity.

- Cumulative capital expenditures for new midstream natural gas infrastructure will range from $133 to $210 billion from 2009 through 2030.

- Future pipeline infrastructure will be driven predominately by a shift in production from mature basins to areas of unconventional or frontier natural gas production. Regions with unconventional production growth and those affected by Arctic projects are projected to have the greatest infrastructure investment. Natural gas consumption growth has an important, but relatively smaller influence on future natural gas pipeline infrastructure investments.

- INGAA's two alternative cases bracket reasonable ranges of future gas consumption.

- U.S. and Canadian natural gas consumption could reach as high as 36.0 Tcf per year by 2030, a growth rate of 1.3 percent per year, if policies assumed in the INGAA High Gas Growth Case are adopted.
- If very strong conservation and energy efficiency measures are adopted as assumed in INGAA's Low Electric Growth Case, by 2030 U.S. and Canadian natural gas consumption could decline by 4 percent to 25.8 Tcf per year.

- If the U.S. and Canadian natural gas market increases, about three-fourths of the market growth will occur in the power sector. Electric load growth, penetration of renewable generation technologies, penetration of clean coal with carbon capture, and expansion of nuclear generation are areas of uncertainty. The growth rate of natural gas consumption in the electric generation sector is the predominant determinant of the growth rate of the entire natural gas market.

- The U.S. and Canadian natural gas resource base is robust and E&P technology advancements have contributed significantly to the development of unconventional natural gas supplies. Most of the incremental natural gas supplies for the U.S. and Canada will come from domestic production of unconventional formations such as shale and tight sands. Increased LNG imports and Arctic supplies will also contribute, assuming necessary pipeline projects are built.

- Many issues loom, particularly uncertainties regarding the direction of energy and environmental policies and whether those policies will promote or discourage natural gas use.

    - Policies and legislation that create additional procedural hurdles or allow local issues and sentiment to derail needed energy infrastructure projects would have negative impacts on consumers.

    - Public relations effort to promote natural gas widely as an environmentally friendly fuel may affect public policy decisions by creating greater public support for the product.

Appendix A: Glossary of Terms

AEO	Annual Energy Outlook
AECO	Alberta Energy Company interconnect with Nova System
AGIA	Alaska Gas Inducement Act
AGPA	Alaska Gasline Port Authority
ANWR	Arctic National Wildlife Refuge
APG	Aboriginal Pipeline Group
bbl	Barrel
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
CCS	Coal Capture and Sequestration
CDD	Cooling Degree Day
CNG	Compressed Natural Gas
DSM	Demand Side Management
EIA	United State Energy Information Administration
E&P	Exploration and Production
EEA	Energy and Environmental Analysis Inc.
EOR	Enhanced Oil Recovery
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GMM	ICF's Gas Market Model
GW	Gigawatt
GWh	Gigawatt-hours
HDD	Heating Degree Day
HP	Horse Power
ICF	ICF International
INGAA	The Interstate Natural Gas Association of America
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
kWh	Kilowatt hour
Mcf	Thousand cubic feet
MMbtu	Million British thermal units
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
NGA	Natural Gas Act of 1938
NGV	Natural Gas Vehicle
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
PHEV	Plug-in Hybrid Electric Vehicle
PV	Photovoltaic
R/C	Residential/Commercial

RACC	Refiner Acquisition Cost of Crude
RPS	Renewable Portfolio Standard
SNG	Synthetic Natural Gas
Tcf	Trillion cubic feet
TWh	Terawatt hour
UCG	Underground Coal Gasification
U.S.	United States of America
WTI	West Texas Intermediate

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. (EEA), 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:

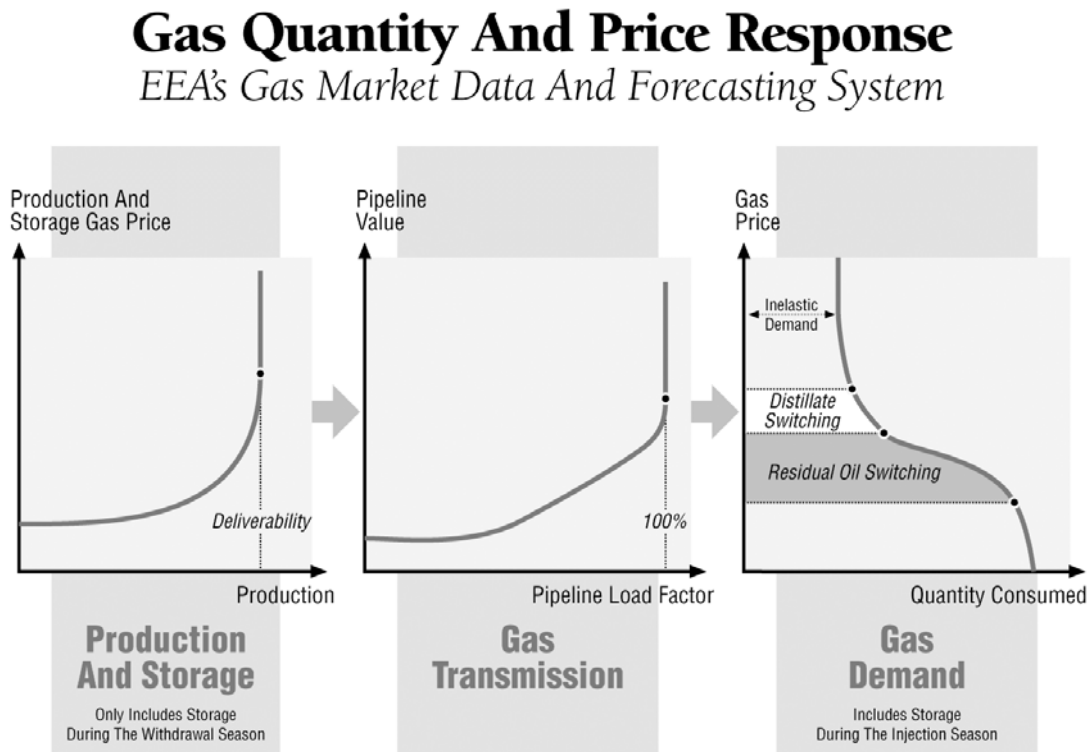
- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

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 INGAA, who 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 (Figure 54). 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 demand 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.

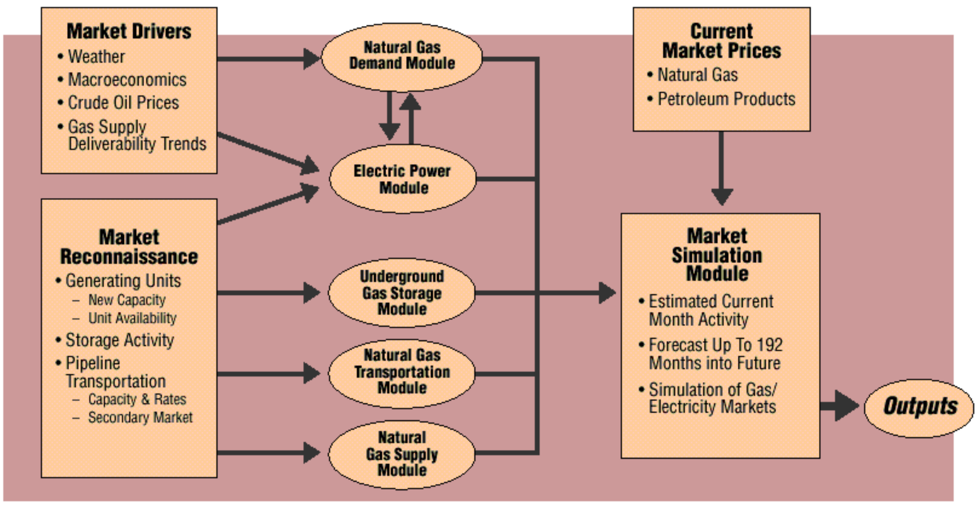
Figure 54
Supply/Demand Curves



Source: ICF International

There are nine different components of EEA's model, as shown in Figure 55. 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.

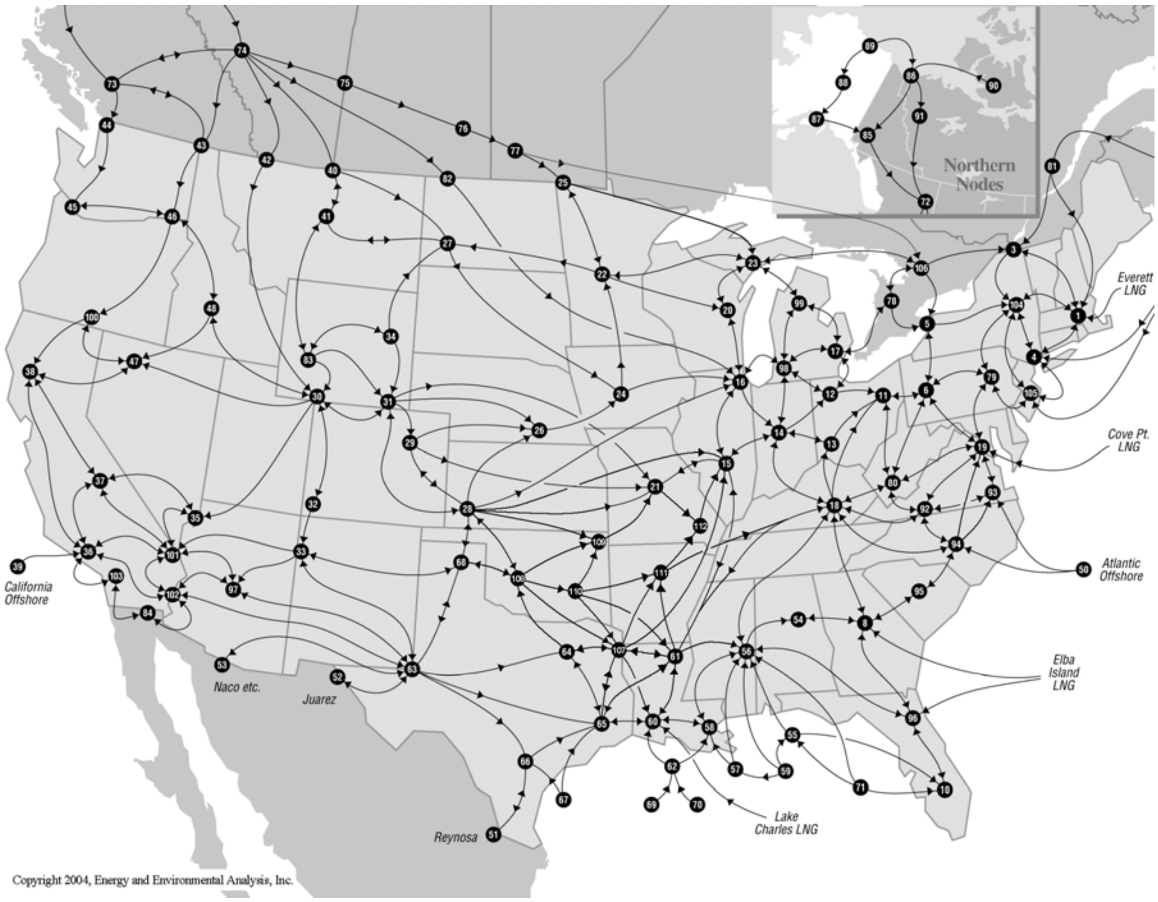
Figure 55
GMM Structure



Source: ICF International

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 Figure 56. 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 (HSM) 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.

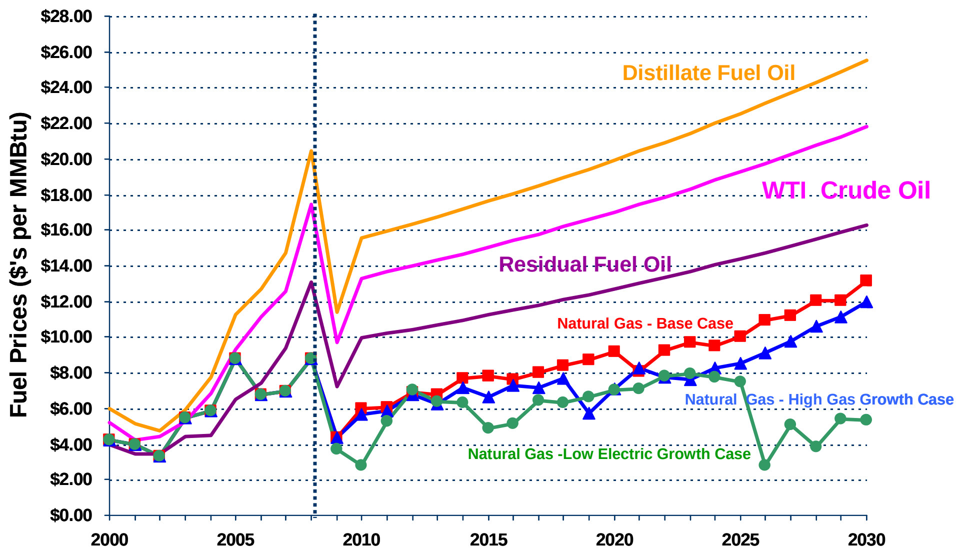
Figure 56
GMM Transmission Network



Source: ICF International

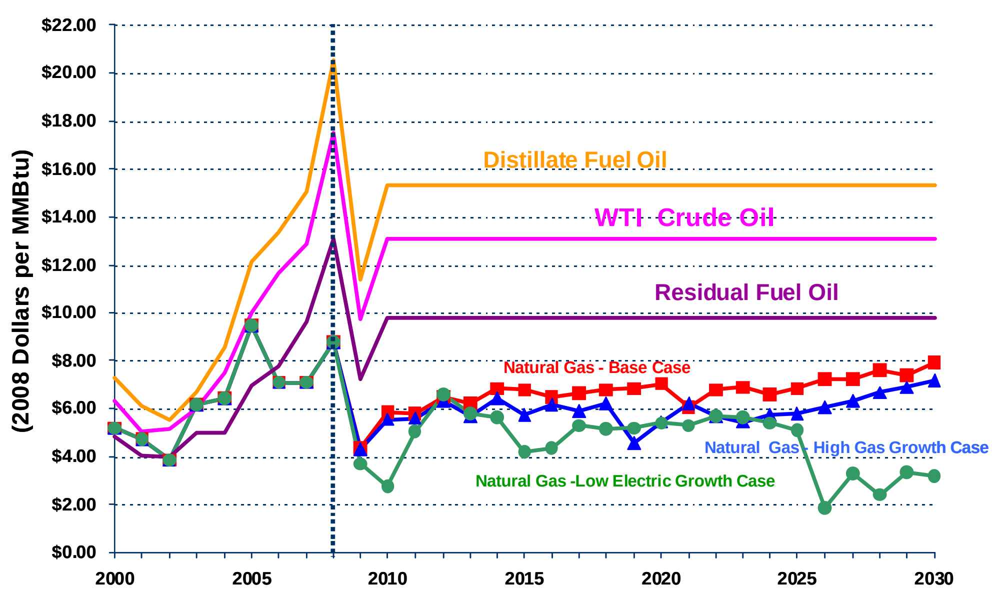
Appendix C: Projected Natural Gas Prices

Figure 57
Natural Gas Prices (Nominal $ per MMBtu)



Sources: Historical data from Platts Gas Daily

Figure 58
Natural Gas Prices (2008 $ per MMBtu)



Sources: Historical data from Platts Gas Daily and EIA