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CANADIAN NATURAL GAS MARKET REVIEW

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CANADIAN NATURAL GAS MARKET REVIEW

Canadian Natural Gas Market Review

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Executive Summary

This study looks at the future of Canada's natural gas upstream industry, taking into consideration the history of the industry, changing market dynamics due to the advancements in horizontal drilling and hydraulic fracturing technology, the recent drop in oil and natural gas prices, and policy developments.

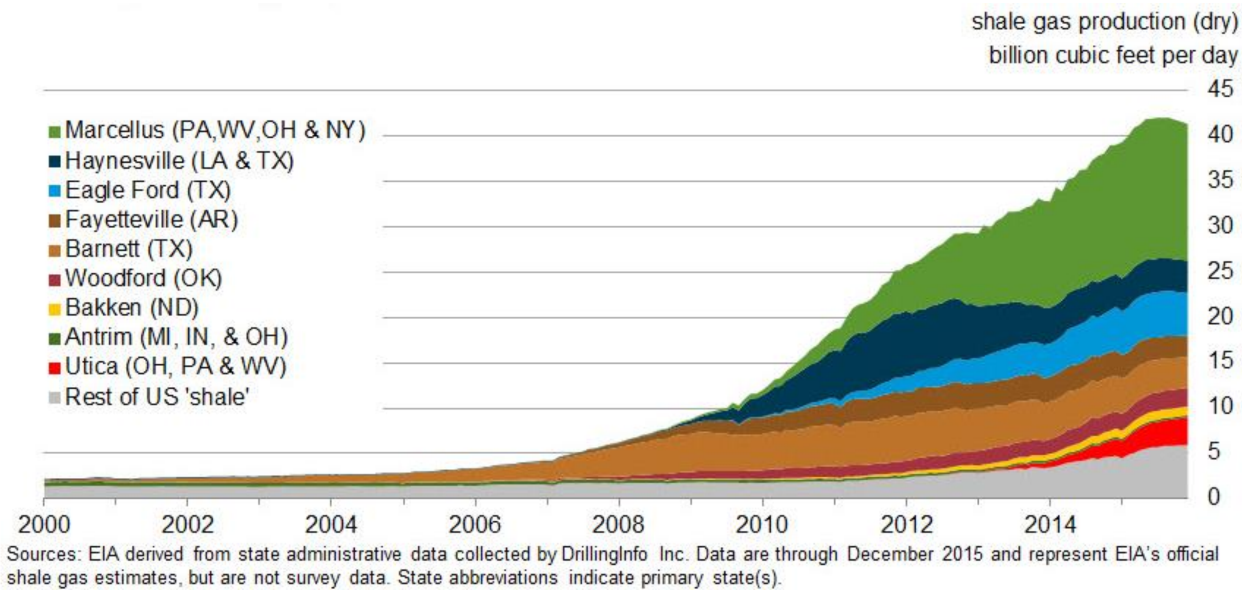
Canada was estimated to have 1,087 trillion cubic feet (Tcf) of marketable natural gas resources remaining as of the end of 2014.[1] Just under 80 percent of this is concentrated in the Western Canadian Sedimentary Basin (WCSB).[2] In 2014, Canada was the fifth largest producer of natural gas globally with a volume of 5,719 billion cubic feet (Bcf) over the year, with Alberta representing approximately three-quarters of the country's production.[3] This level of production in 2014 meant an average rate of 10.2 billion cubic feet per day (Bcfpd), down from a peak of 14.1 Bcfpd in 2006.[4]

Even with these high levels of production, transportation infrastructure and economics dictate that Canada also imports natural gas from the United States, particularly in eastern Canada. Canada's demand for natural gas has risen from 7.2 Bcfpd in 2003 to 8.9 Bcfpd in 2013. While historically Canada's exports to the United States vastly exceeded its imports from the United States, this gap is shrinking as advances in the US Marcellus Shale bring lower priced gas onto the market. The demand for Canadian gas is shrinking as Marcellus gas displaces it in the market, primarily in eastern Canada.

US production of natural gas has increased sharply in recent years due to the rapid growth in production out of the Marcellus Shale. This sharp increase can be attributed to improvements in drilling technology, making previously unattractive areas productive and profitable. As of September 2015, the Marcellus Shale represented 37 percent of the total US shale production,[5] as illustrated in Figure E.1.

[1] NEB, "Canada's Energy Future 2016". 2016
[2] Ibid.
[3] BP website, BP Statistical Review of World Energy June 2015, https://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf, pp. 22. (Accessed on February 14, 2016)
[4] Finance Alberta, Marketable Natural Gas Production in Alberta, http://www.finance.alberta.ca/aboutalberta/osi/aos/data/Marketable-Natural-Gas-Production-AB.pdf (Accessed on February 14, 2016)
[5] Market Realist website, Why the Marcellus Shale is important for US oil and gas, December 14, 2014, http://marketrealist.com/2014/12/marcellus-shale-important-us-oil-gas/ (Accessed on February 14, 2016)

Figure E.1: Dry Shale Gas Production



Source: EIA[6]

This sharp increase in shale gas production has impacted North American natural gas markets contributing to the decline in the price of natural gas, with other influencing factors including the 2014 drop in oil prices, the financial crisis and unseasonably warm weather. Lower oil and gas prices, over-supply, and increased competition in key markets will challenge the competitiveness of Canadian natural gas exports. The unprecedented growth in natural gas production, led by the US eastern shale basins of Marcellus and Utica shales, has changed the North American gas flows and has pushed Canadian gas exports out of the markets that traditionally-sourced western Canadian gas.

Looking ahead 20 years, the price of natural gas is expected to rebound, although not reach the levels seen in 2008. This influences Canadian natural gas production, as the relatively low prices dictate that many producing regions will no longer be economically attractive. Despite this, Canadian production is expected to increase after 2019 and remain stable. With the WCSB producing 98 percent of Canada's total natural gas, the Canadian Energy Research Institute (CERI) modeled WCSB production in order to determine supply costs for various plays. British Columbia's Montney formation will continue to see high levels of interest due to its favourable supply cost, while horizontal drilling in Alberta, particularly in the corridor to the east of the Rocky Mountains will continue to see growth. There is an observable relationship between the price of natural gas and the rig count, but as drilling technologies evolve, this is likely to decouple rig count from gas price. CERI expects Canadian natural gas production to reach 21,000 million cubic feet per day (Mmcfpd) by the end of this study period.

[6] US Energy Information Administration website, Energy in Brief, Shale in the United States, http://www.eia.gov/energy_in_brief/article/shale_in_the_united_states.cfm (Accessed on February 14, 2016)

Canadian natural gas demand is expected to rise over the study period due to expected growth in population, the Canadian economy, and the shift away from coal-fired power generation. Demand is expected to reach 15 Bcfpd.[7] Comparing this demand with production of 21 Bcfpd means Canada could remain as a net exporter of natural gas through the next 20 years.

Should Canadian LNG projects go ahead, CERI has estimated a total of 4 Bcfpd of gas demand. This demand is matched by an increase in production out of the Horn River and Liard Basins in British Columbia. The equivalency of demand and supply in this case do not impact Canada's overall supply/demand balance.

US production of natural gas is expected to continue to increase to 138 Bcfpd[8] throughout the duration of this study period, with growth of 72 percent from 2016 through 2037. Specifically, shale gas production is expected to increase by 117 percent; these gains are largely seen in the Marcellus and Utica shales. US demand for natural gas is expected to grow as well, albeit not as sharply as production. Demand is expected to reach just under 100 Bcfpd in 2037, from just under 80 Bcfpd in 2016.[9]

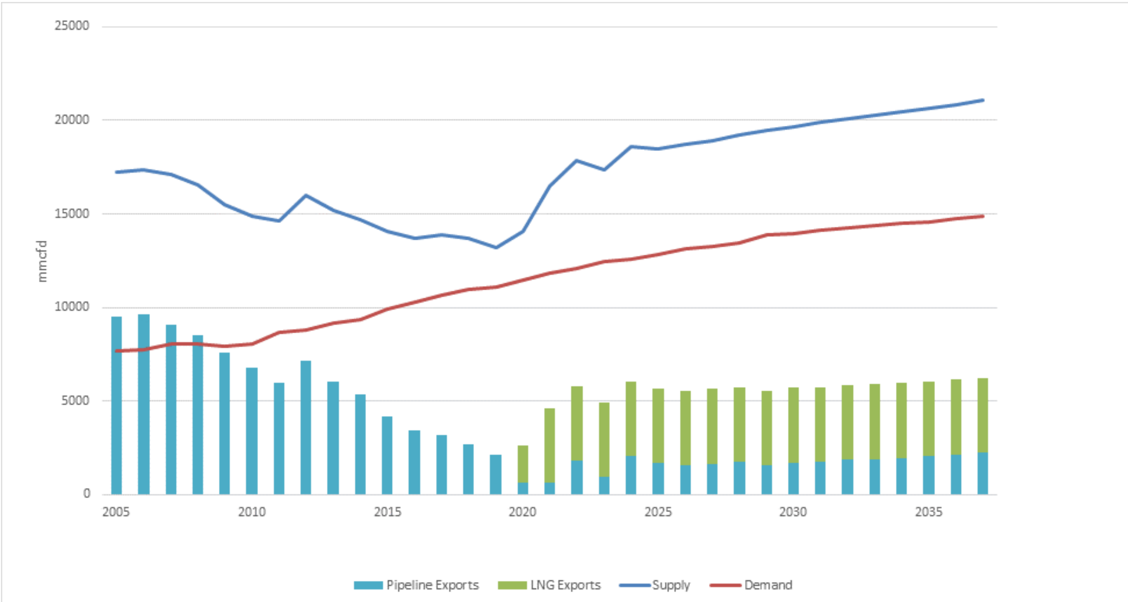
As illustrated in Figure E.2, Canada has the potential to continue as a net exporter of natural gas to the US through 2037. However, the flows of natural gas are dictated by existing pipelines, and regional balances see western Canada continuing to export gas to the US and to eastern Canada, and eastern Canada also receiving imports from the US.

[7] This value of natural gas demand is lower than the primary natural gas demand value discussed in Chapter3 because it does not include non-marketed natural gas used directly by those that produce it. Examples of this include flared gas, natural gas produced and consumed by in situ oil sands producers, and natural gas produced and consumed by offshore oil production.

[8] U.S. Energy Information Administration, Annual Energy Outlook 2015, April 14, 2015, http://www.eia.gov/forecasts/aeo/

[9] Ibid.

Figure E.2: Canadian Supply and Demand Outlook



Source: CERI, NEB

With the large increase in production, specifically from the low-cost Marcellus, the market for Western Canadian gas is not growing at the rate it once was. Expected pipeline additions to the US Midwest from Marcellus will further increase the regions which the Marcellus can supply.

The export volumes projected in Figure E.2 indicate the maximum estimated amount assuming BC LNG projects proceed.

Chapter 1: Introduction

Natural gas is an important fuel in North America. It has applications for various end-users, including residential, commercial, industrial, and power generation. Natural gas is also a valuable source of energy for space heating, electricity generation, for use in transportation, oil sands production, as well as used as a chemical feedstock in the manufacture of organic chemicals and plastics.

Advances in horizontal drilling, 3-D seismic technology and hydraulic fracturing (frac'ing or fracking) are opening up new shale gas resources in North America, previously determined as not feasible to produce. Among them are the Fayetteville Shale in northern Arkansas, the Haynesville Shale in eastern Texas and northern Louisiana, the Eagle Ford in Texas, the Barnett Shale in Texas, and the Marcellus Shale in Appalachia. Canadian shale gas growth has been focused on the Montney and Horn River basins of British Columbia.

Natural gas production in the US is at record levels, led by the Marcellus Shale and the Utica Shale, both located in the enormous Appalachian Basin. While this is positive for Pennsylvania, West Virginia, Ohio and other jurisdictions, natural gas producers in Canada, on the other hand, are facing pressure to compete with the lower-priced gas.

This unprecedented growth in production has impacted North American natural gas flows and has certainly impacted western Canadian gas producers being pushed out of the US Northeast and central Canada, markets once served by western Canadian gas.

This study examines the changing nature of natural gas flows and evaluates how the Canadian upstream industry is evolving as a result. Not only are natural gas flows dynamic, but so is the liquefied natural gas (LNG) landscape in North America. The US is on the verge of transitioning from a net importer to a net exporter, likely to occur in 2016-17. Another important question with regards to increasing northeastern US supply includes its impact on natural gas storage, particularly in eastern Canada.

However, before one investigates the future of Canadian natural gas, it is first prudent to review the current state of gas supply and demand in Canada and the United States, as well as the current prices (both wholesale and retail), price hubs and differentials in both jurisdictions. Chapter 2 provides a useful foundation of the current situation in Canada and the US.

Chapter 3 examines Canadian gas supply and demand outlook. This section is divided into four parts: Canadian supply, Canadian gas demand, pricing and storage, and climate change policies (provincial and federal). The Canadian supply section includes western Canadian, eastern Canadian, offshore, compressed natural gas and northern Canada. While the Canadian demand section includes power generation, oil sands, petrochemical, coal retirement policies, industrial/commercial, and substitution for oil and energy efficiency.

Chapter 4 examines US gas supply and demand outlook. This section is divided into two parts: US supply and US demand.

Chapter 5 reviews the outlook of potential exports and imports of natural gas and is divided into two parts: natural gas pipeline exports and imports, and LNG projects. It is, however, beyond the scope of this study to analyze and review individual projects, but rather the likelihood of change in LNG projects.

Chapter 6 provides concluding thoughts and answers key focus questions regarding the future of the Canadian upstream natural gas industry.

Appendix A discusses the production forecast and supply cost methodology while Appendix B describes the study areas used to estimate production and supply costs.

Chapter 2: Natural Gas Background

This chapter provides background for the analysis and is divided into three parts. The first discusses the current state of Canadian gas supply and demand while the second reviews the current state of gas supply and demand in the US. The third part reviews the current prices (both wholesale and retail), price hubs and price differentials.

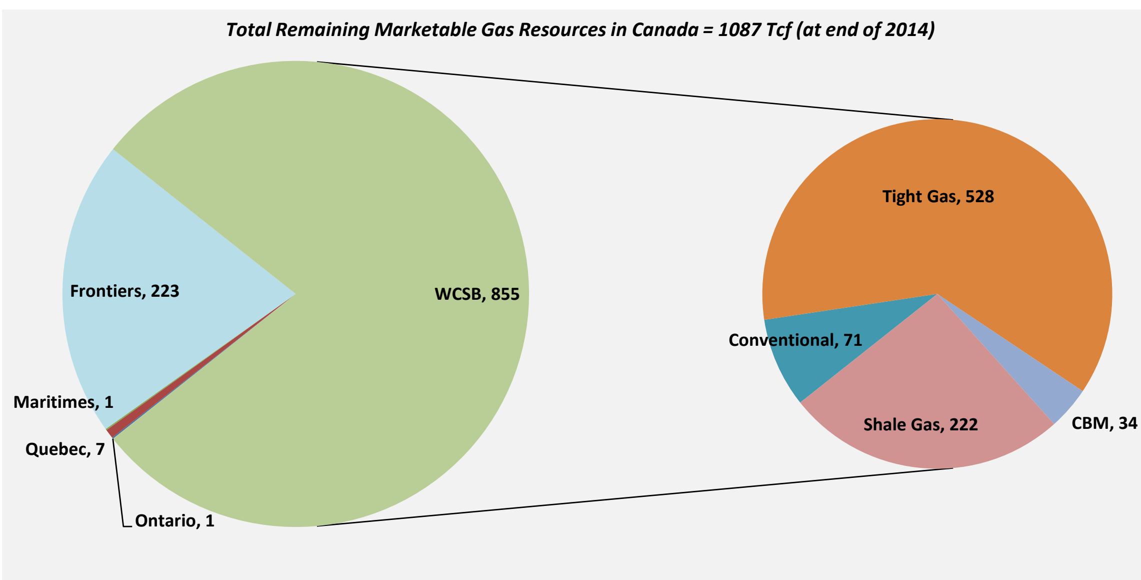
Current State of Canadian Natural Gas Supply and Demand

This section is divided into two parts: supply and demand. The former reviews Canadian domestic production and imports of natural gas into Canada. The latter is subsequently divided into two separate components: imports from the US (primarily via pipeline) and imports from liquefied natural gas (LNG) regasification. The demand section review is also divided into two separate components: domestic demand and exports to the US (primarily via pipeline).

Canadian Supply (Domestic Production, Imports from the US and LNG Regasification)

Figure 2.1 shows the National Energy Board's (NEB) estimate of remaining marketable natural gas resources in Canada as of December 2014. The bulk of Canada's remaining resources are concentrated in the Western Canada Sedimentary Basin (WCSB), a large area that extends from northern British Columbia eastward through Alberta, southern Saskatchewan and into Manitoba, and from the Yukon and Northwest Territories in the north to the US border in the south.

Figure 2.1: Natural Gas Resources Estimates (Tcf)



Source: NEB[1]

[1] NEB, "Canada's Energy Future 2016". 2016

The WCSB includes approximately 855 trillion cubic feet (Tcf) in conventional (including tight gas of 528 Tcf) resources, 222 Tcf in shale gas and 34 Tcf in coalbed methane (CBM). Frontier regions, including Nova Scotia and Newfoundland, Mackenzie-Beaufort, Arctic Islands and other frontiers, account for approximately 223 Tcf of remaining natural gas resources. Offshore Nova Scotia and Newfoundland account for 90 Tcf. Eastern Canada is the third ranked region in Canada with 8 Tcf; this number, however, may increase, particularly in Quebec with the Utica Shale and the Macasty Shale. The former is located between Montreal and Quebec City, along the St. Lawrence River, while the latter is primarily located on Anticosti Island, in the St. Lawrence Estuary. Recall, the remaining marketable gas resources estimates include technically and recoverable gas.[2] Resource estimates of natural gas "in place" includes resources not yet discovered or not technologically or economically recoverable under current conditions.[3]

Natural Resources Canada (NRCan) suggests that Canada has approximately 71 Tcf of proved reserves as of the end of 2012, and between 885 and 1,556 Tcf of technically recoverable resources (gas estimated to be recoverable as drilling and infrastructure expands),[4] of which between 357 and 436 Tcf are considered conventional and between 528 and 1,130 Tcf are unconventional resources.[5] The latter includes CBM, shale gas and tight gas. Canada's technically recoverable shale resources are the fifth largest in the world, behind China, Argentina, Algeria and the US.[6] Shale gas resources are found in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, and Newfoundland & Labrador.

Canadian Natural Gas Production

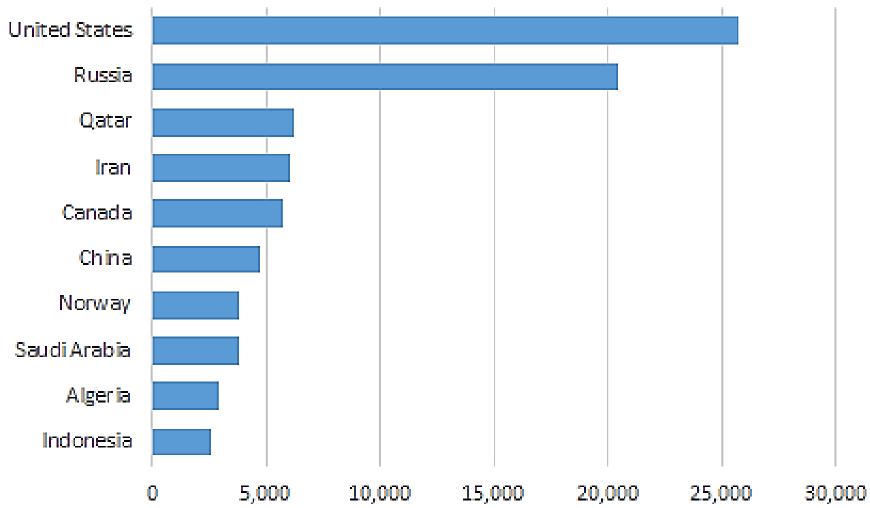
Canada is an important player in natural gas production and is one of the largest natural gas producers in the world. According to the 2015 BP statistical review, Canada is ranked fifth in the world in production at approximately 5,719 billion cubic feet (Bcf) (or 162 billion cubic meters, Bcm), producing 4.7 percent of world production.[7] This is behind only the US (21.4 percent), Russia (16.7 percent), Qatar (5.1 percent) and Iran (5.0 percent).[8] Global annual natural gas production is dominated by the US and Russia at 25,709 Bcf (728.3 Bcm) and 20,428 Bcf (578.7

[2] National Energy Board website, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, Marketable Resources, https://apps.neb-one.gc.ca/ftrppndc / (Accessed on April 26, 2016).
[3] Natural Resources Canada website, Geology of Shale and Tight Resources, Resource Potential, http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17675 (Accessed on April 26, 2016).
[4] Natural Resources Canada website, Energy Markets Fact Book 2014-2015, http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/files/pdf/2014/14-0173EnergyMarketFacts_e.pdf, pp. 39 (Accessed on February 14, 2016)
[5] ibid
[6] Natural Resources Canada website, Energy Markets Fact Book 2014-2015, http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/files/pdf/2014/14-0173EnergyMarketFacts_e.pdf, pp. 40 (Accessed on February 14, 2016)
[7] BP website, BP Statistical Review of World Energy June 2015, https://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf, pp. 22. (Accessed on February 14, 2016)
[8] ibid

Bcm), respectively.[9] Interestingly, production in the US increased 6.1 percent over 2013 while production in Russia decreased 4.3 percent.[10].

Figure 2.2 illustrates the world's top 10 natural gas producers by country in 2014.

Figure 2.2: Natural Gas Production by Country, 2014 (Bcf)



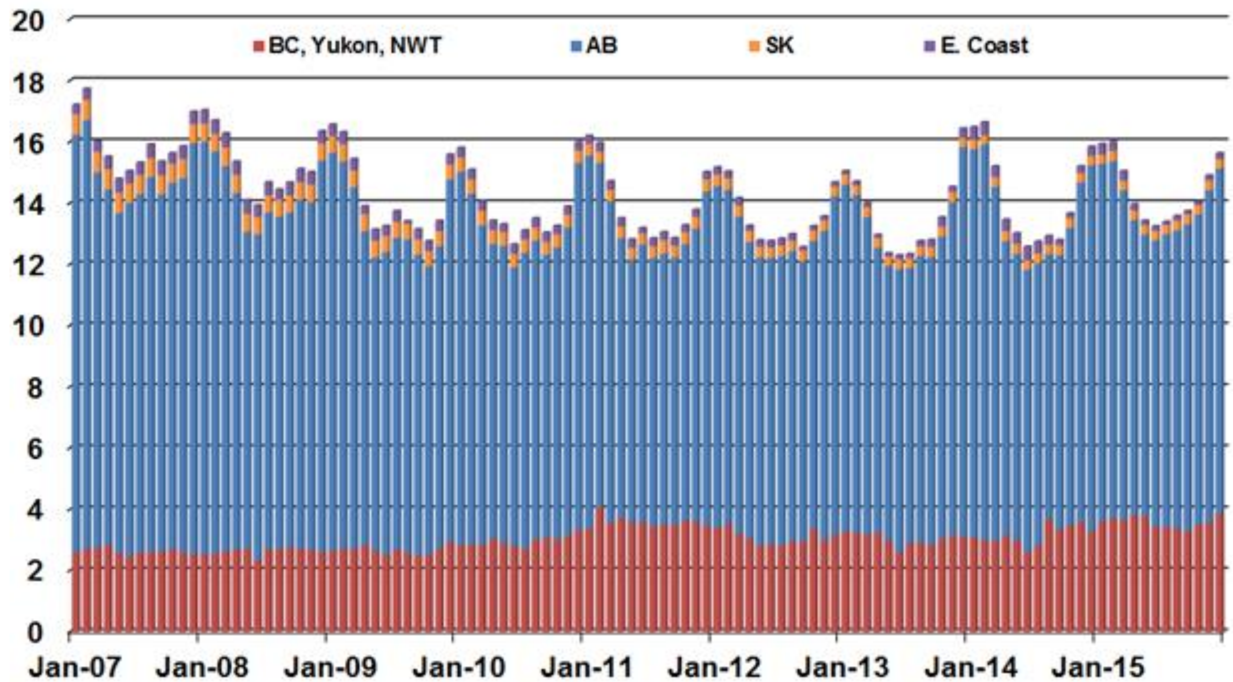
Source: BP,[11] CERI

Canadian production increased 3.8 percent year-over-year.[12] Most of Canada's natural gas came from sources located primarily in western Canada; the WCSB is the largest producing region in Canada.

Figure 2.3 shows monthly marketable production in Canada by province. The figure shows the cyclical nature of Canadian drilling rig activity. Due to weather-related factors, drilling plunges due to spring thaw and drilling crews move their equipment to avoid environmental damage. Canada's total annual average production in 2015 was 14.4 billion cubic feet per day (Bcfpd), up from 14.3 Bcfpd in 2014 and up from 13.7 Bcfpd in 2013.[13] It is, however, important to mention that production is down from an all-time high of 16.0 Bcfpd in 2007, as natural gas prices continued to decline and some higher-cost Canadian gas basins could not compete with some of the shale gas areas in the US.

[9] ibid
[10] ibid
[11] ibid
[12] ibid
[13] Statistics Canada, Table 131-0001 Supply and disposition of natural gas, http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=1310001&paSer=&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid= (Accessed on February 14, 2016)

Figure 2.3: Canadian Marketable Production by Province/Region, 2007-2015 (Bcfpd)



Source: Statistics Canada[14] and CERI[15]

The largest player in marketable gas production by province (in 2013) is Alberta, accounting for 74 percent, followed by British Columbia at 22 percent and Saskatchewan at 2 percent.[16] While the WCSB is traditionally the largest producer of natural gas, with Alberta leading the way, the dynamic in the WCSB is changing. British Columbia's wealth of emerging sources of shale and tight gas are changing the dynamics of Canadian supply, accounting for 35 percent of Canada's natural gas resources, of which 90 percent is found in the Montney Shale and the Horn River Basin.[17] The former is a tight gas play while the latter is a shale gas play.

Natural gas production in Alberta (including conventional marketable natural gas, coalbed methane and shale gas) decreased from 14.1 Bcfpd in 2006 to 10.2 Bcfpd in 2014.[18] Of that amount, conventional gas production decreased from 13.5 Bcfpd to 9.4 Bcfpd, with only 106

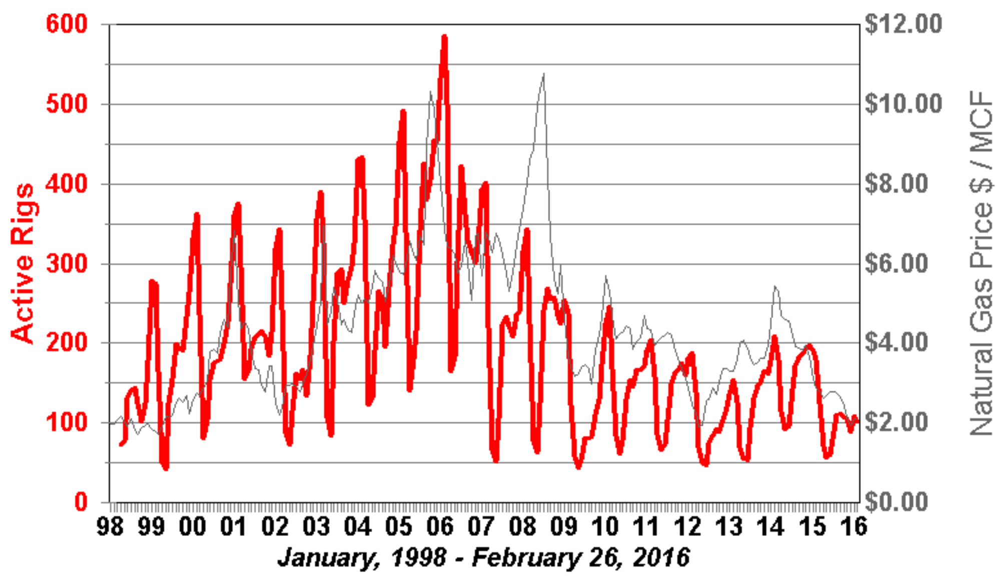
[14] Statistics Canada, Table 131-0001 Supply and disposition of natural gas, http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=1310001&paSer=&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid= (Accessed on February 14, 2016)
[15] Graphic is created by CERI for its monthly Natural Gas Commodity Report.
[16] Natural Resources Canada, Energy Markets Fact Book 2014-2015, Natural Gas: International Context, http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/files/pdf/2014/14-0173EnergyMarketFacts_e.pdf, pp. 42. (Accessed on February 14, 2016)
[17] Carlos Murillo, Alternate Markets and Uses for BC`s Abundant Natural Gas, BC Natural Gas Symposium, CERI, June 2015, pp. 6.
[18] Finance Alberta, Marketable Natural Gas Production in Alberta, http://www.finance.alberta.ca/aboutalberta/osi/aos/data/Marketable-Natural-Gas-Production-AB.pdf (Accessed on February 14, 2016)

million cubic feet per day (MMcfpd) from shale gas sources in the latter.[19] Production in British Columbia has increased from 2.72 Bcfpd in 2006 to 3.16 Bcfpd in 2014.[20]

Recent advances in technology have greatly increased the supply outlook for unconventional natural gas in Canada and the United States.[21] In addition to changing dynamics within the WCSB, changing economics and an unprecedented growth in US shale gas production are pushing the WCSB out of traditional markets by lower-cost US natural gas. While conventional gas production is decreasing, the importance of tight gas and shale gas in Canada and the US cannot be understated.

This is reflected in drilling activity in Canada. The number of wells drilled is down dramatically over the past several years. Figure 2.4 illustrates the Canadian rotary rig count drilling for natural gas between January 1998 and February 2016. The figure shows the cyclical nature of Canadian drilling rig activity. Due to weather-related factors, drilling plunges due to spring thaw and drilling crews move their equipment to avoid environmental damage. That being said, it is clear that the peak of winter drilling activity this past year is considerably lower than in past years, as is the trough of the cycle.

Figure 2.4: Canadian Rotary Rig Count – Drilling for Natural Gas



Source: Energy Economist[22]

[19] ibid

[20] Statistics Canada, Table 131-0001 Supply and disposition of natural gas, http://www5.statcan.gc.ca/cansim/a26?lang=eng&retrLang=eng&id=1310001&paSer=&pattern=&stByVal=1&p1=1&p2=-1&tabMode=dataTable&csid= (Accessed on February 14, 2016)

[21] Gowithnaturalgas.com website, Canada's Supply and Demand, http://www.gowithnaturalgas.ca/operating-with-natural-gas/fuel/natural-gas-as-an-energy-source/canadas-supply-and-demand/ (Accessed on February 14, 2016)

[22] Energy Economist website, Canadian Rotary Rig Count – Drilling for Natural Gas, http://www.energyeconomist.com/a6257783p/exploration/graphs/rigs/rotary/short/rigcang.gif (Accessed on February 14, 2016)

According to Baker Hughes, the total gas-directed rotary rig count in Canada is 92 as of the week of February 26, 2016, down from 97 rigs from the previous week. This is, however, 67 rigs lower than the same time last year, or a decrease of 42.1 percent, as shown in Table 2.1. Despite the increase in percentage share of gas-directed drilling in Canada (up from 48.2 percent as of February 27, 2015 to 52.6 percent as of February 26, 2016), total gas-directed drilling has decreased over the past year.

Table 2.1: Rig Count in Canada by Target and Trajectory

Canadian Rig Count				Change		% Change	
	02/26/2016	02/19/2016	02/27/2015	Weekly	Annual	Weekly	Annual
Total Canada	175	206	330	(31)	(155)	-15.0%	-47.0%
Oil-Directed	83	109	171	(26)	(88)	-23.9%	-51.5%
%	47.4%	52.9%	51.8%	-5.5%	-4.4%		
Gas-Directed	92	97	159	(5)	(67)	-5.2%	-42.1%
%	52.6%	47.1%	48.2%	5.5%	4.4%		
Directional	3	1	5				
Horizontal	89	95	153				
Vertical	0	1	1				

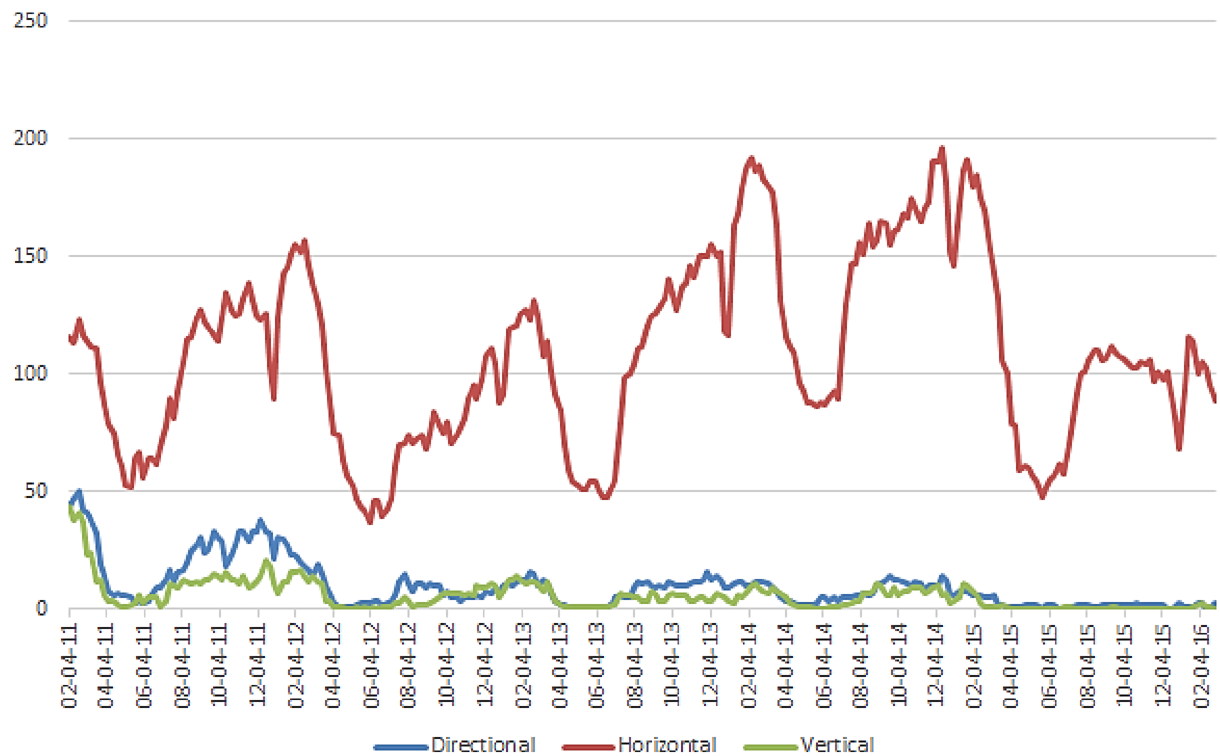
Source: WTRG Economics[23] & Baker Hughes[24]

Figure 2.5 illustrates the natural gas rig count by trajectory over the past 5 years, from February 4, 2011. There are two clear conclusions. First, natural gas-directed drilling is down over the illustrated time frame; the peak of winter drilling activity this past year is considerably lower than in past years. Second, horizontal drilling activity dominates drilling by trajectory, particularly after February 2015.

[23] WTRG Economics, North American Rotary Rig Counts, http://www.wtrg.com/rotaryrigs.html (Accessed on February 14, 2016)

[24] Baker Hughes, Rotary Rig Count, North America Rotary Rig Count Pivot Table, http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm?showpage=na (Accessed on February 14, 2016)

Figure 2.5: Canadian Rotary Rig Count by Trajectory – Natural Gas-Targeted

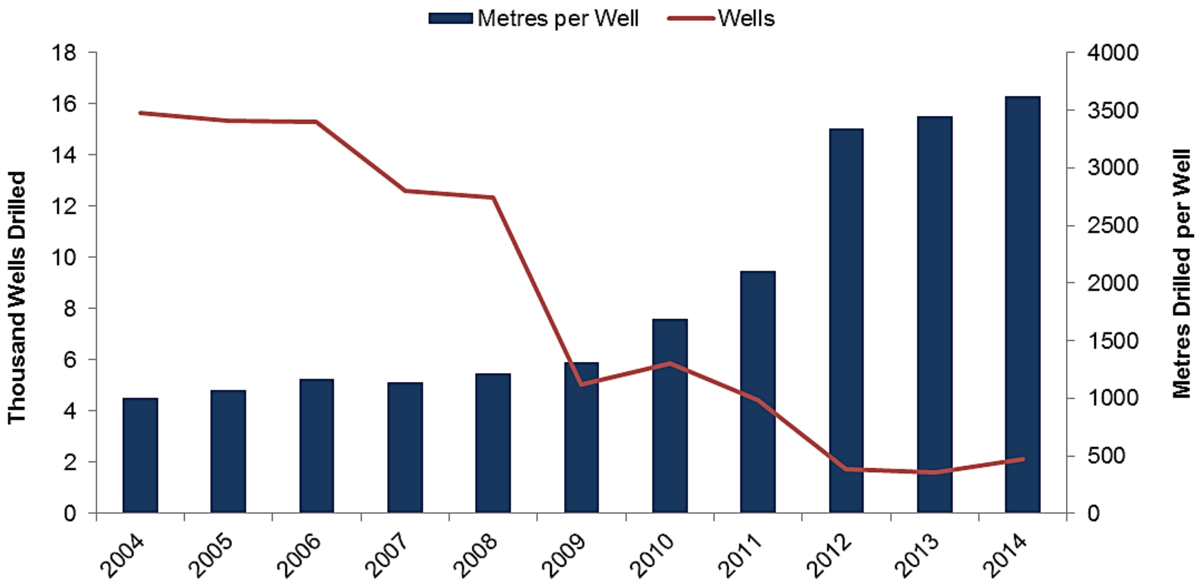


Source: Baker Hughes,[25] CERI

While wells drilled are down dramatically, metres drilled are up. This is illustrated in Figure 2.6, showing total drilling activity in terms of wells drilled and metres drilled between 2004 and 2014. Recent technological advances are leading to efficiency gains, leading to higher production per well.[26] This is due to the increasing length of horizontal wells and more effective fracking techniques; the average length drilled in 2014 was 3,623 metres.[27]

[25] Baker Hughes, Rotary Rig Count, North America Rotary Rig Count Pivot Table, http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm?showpage=na (Accessed on February 14, 2016)
[26] Natural Resources Canada website, North American Natural Gas Market: 2015-2016 Heating Season Outlook, Executive Summary, https://www.nrcan.gc.ca/energy/sources/natural-gas/17894, (Accessed on April 26, 2016)
[27] ibid

Figure 2.6: Drilling Activity in Canada, Wells Drilled and Metres Drilled



Source: NRCAN[28]

Canadian Natural Gas Imports

The second element to Canadian supply is imports from the US and LNG imports. Despite being one of the world's largest producers of natural gas and its vast natural gas resource base, Canada imports natural gas, largely in eastern Canada. Imports from the US come primarily via an extensive network of pipelines from various points of entry. Canada has one of the world's largest natural gas pipeline networks, with more than 450,000 kilometers of pipelines moving natural gas from producing areas to end users.[29] Imports of LNG, on the other hand, are delivered through the Canaport LNG regasification terminal at Saint John, New Brunswick. LNG is also trucked into Canada but only in small amounts.

While Canada exports more natural gas than it imports, the gap between the two is diminishing as a result of decreasing western Canadian exports to the US and eastern Canada. This is due to lower cost Marcellus gas being closer to markets in central Canada, the US Northeast and US Midwest, giving it cost advantages over western Canadian gas. While the rapid increase in production of the Marcellus is good news for gas producers and supporting industries in Pennsylvania and nearby states, the flood of lower cost Marcellus gas has had a profound effect

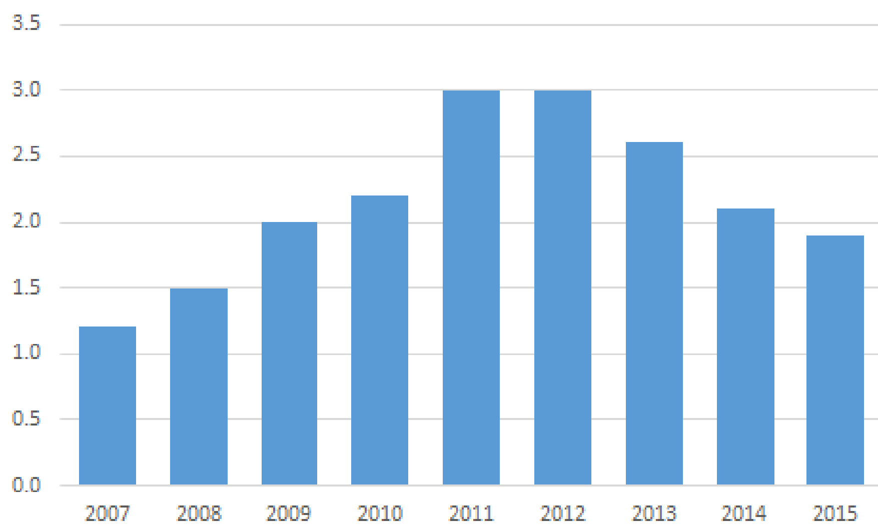
[28] ibid

[29] Canadian Gas Association, Gas Stats, Chart 16 Natural Gas Distribution, http://www.cga.ca/wp-content/uploads/2015/06/Chart-16-Natural-Gas-Distribution-System.pdf (Accessed on February 14, 2016)

on North American gas flows. Western Canadian gas is being displaced out of central Canada and the US Northeast.[30] Marcellus gas is also having an impact on offshore natural gas exploration.

While decreasing Canadian gas exports are discussed in the US supply section, the impact of US exports into Canada is clear. Total Canadian imports, including imports via pipeline and LNG, are illustrated in Figure 2.7. Canadian natural gas imports, predominantly into eastern Canada have been increasing since 2007, reaching as high as 3 Bcfpd in 2011-2012. Since then, however, the volume of natural gas imports decreased from 2.6 Bcfpd in 2013 to 1.9 Bcfpd in 2015.[31] This decrease reflects a decrease in Ontario pipeline imports[32] and is likely due to the declining volume of sales to the residential and commercial sectors. For example, between November 2014 and November 2015, natural gas sales in residential and commercial declined by 9.1 percent and 7.1 percent, respectively.[33] Nearly 97 percent of the natural gas imports into Canada were by pipeline, or 2.1 Bcfpd, while approximately 0.05 Bcfpd or 3 percent of total imports, were LNG.[34]

Figure 2.7: Canadian Natural Gas Import Volumes (Bcfpd)



Source: NEB,[35,36] CERI

[30] Platt's Gas Daily, Marcellus to displace Rockies, Canada gas: Bernstein, May 13, 2015, https://online.platts.com/PPS/P=m&e=1431562255713.2709137032677465172/GD_20150513.xml?artnum=c60d69e2f-ba44-469e-9feb-4b069e58d1ba_16 (Accessed on February 14, 2016)
[31] National Energy Board website, 2015 Natural Gas Exports and Imports Summary, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ntrlgssmmr/2015/smmry2015-eng.html (Accessed on March 31, 2016)
[32] Total includes imports via pipeline and LNG
[33] National Energy Board, The Daily, January 22, 2016, Natural gas transportation and distribution, November 2015, http://www.statcan.gc.ca/daily-quotidien/160122/dq160122d-eng.pdf.
[34] National Energy Board website, 2015 Natural Gas Exports and Imports Summary, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ntrlgssmmr/2015/smmry2015-eng.html (Accessed on March 31, 2016)
[35] ibid
[36] National Energy Board, ARCHIVED - 2012 Natural Gas Exports and Imports Summary, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/ntrlgssmmr/2012/smmry2012-eng.html (Accessed on February 14, 2016)

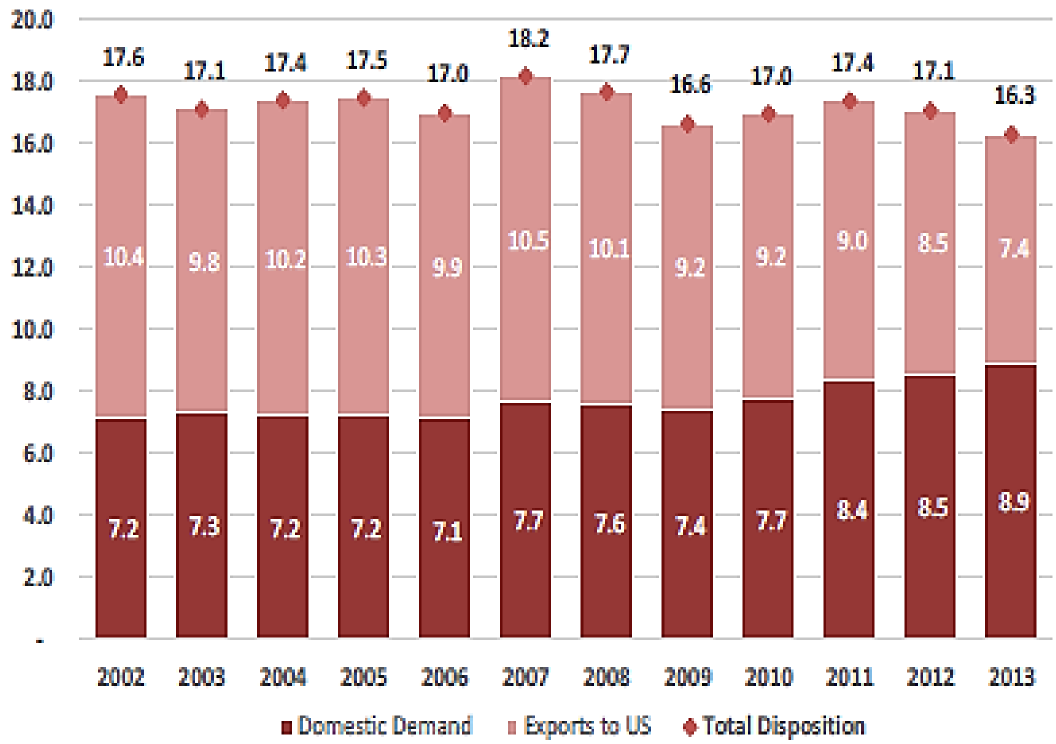
In 2014, nearly 100 percent of LNG imports came from Trinidad and Tobago, with only a small portion of LNG imported from the US by truck.[37] In 2015, 85 percent of LNG imports came from Trinidad and Tobago, with 15 percent from Spain.[38] The origin of LNG has changed dramatically; in 2011 Trinidad and Tobago made up 44 percent of LNG at Canaport LNG while the remaining 56 percent of LNG was imported from Qatar.[39] Thus far in 2015 (until October 2015), Canaport LNG imported 18.5 Bcf of LNG, down from 19.6 Bcf of LNG in 2014 and 36.3 Bcf of LNG in 2013.[40] The latter includes short-term and long-term cargos. While the amount of truck shipments is up dramatically over the past two years, the total amount is only a small fraction of the total LNG imported. LNG is trucked across two points of entry/exit in Canada (Port Huron, Michigan; Sarnia, Ontario; Coutts, Alberta; and Sweetgrass, Montana).

Canadian Natural Gas Disposition (Domestic Demand, Exports to the US)

Figure 2.8 illustrates Canadian demand and total disposition between 2002 and 2013, divided by domestic demand and exports to the US. As of 2013, domestic demand accounted for 8.9 Bcfpd, or 55 percent of Canada's disposition, while exports to the US accounted for 7.4 Bcfpd, or 45 percent. In 2002, exports to the US accounted for 59 percent while domestic demand accounted for 41 percent. Domestic demand grew rapidly, increasing from 7.2 Bcfpd in 2003 to 8.9 Bcfpd in 2013.

[37] National Energy Board website, Commodity Statistics, LNG – Shipment Details, https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx (Accessed on February 14, 2016)
[38] ibid
[39] National Energy Board website, ARCHIVED - 2012 Natural Gas Exports and Imports Summary, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/ntrlgssmmr/2012/smmry2012-eng.html (Accessed on February 14, 2016)
[40] National Energy Board website, Commodity Statistics, LNG – Shipment Details, https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx (Accessed on February 14, 2016)

Figure 2.8: Canadian Natural Gas Demand/Disposition (Bcfpd)



Source: CERI[41]

Canadian Domestic Demand

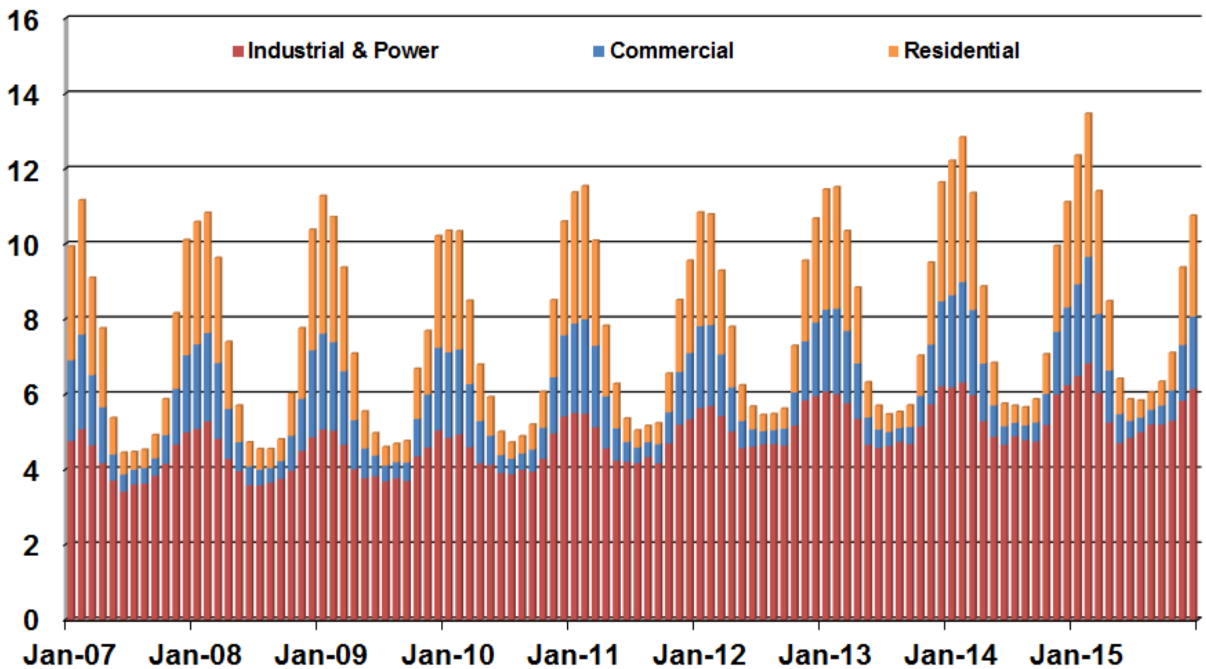
Domestic demand for natural gas can further be broken down into several sectors: residential, commercial, industrial and power generation. Figure 2.9 illustrates Canadian monthly natural gas consumption by sector (residential, commercial, industrial and power generation). The latter two are aggregated in the figure. While there were only 21,885 industrial natural gas customers in Canada in 2014,[42] industrial demand is the highest user at 49 percent. This is followed by residential at 20 percent, commercial at 15 percent and electricity generation at 13 percent.[43]

Natural gas demand in Canada is seasonal in nature. Demand peaks in the winter time, with summer volumes falling by about half. The reason for this is that Canadian residences and commercial enterprises are heated in large part by natural gas furnaces. In recent years, demand has also grown in the summer. This is due to the increasing popularity of air conditioning, which requires electricity provided increasingly by natural-gas fired electrical generation. The 2015 peaks and valleys are the highest in recent history, offering evidence that overall natural gas demand is growing, not only in winter but also in summer months. From a sectoral point of view,

[41] Carlos Murillo, Understanding natural gas markets, NGLs markets, and petrochemical feedstock availability in Canada, Alberta Petrochemical Development Opportunities Seminar, CERI, May 2015, pp. 9.
[42] Canadian Gas Association website, Gas Stats, Natural Gas Customers – Canada – 2014, http://www.cga.ca/wp-content/uploads/2015/05/Chart-17-Natural-Gas-Customers.pdf (Accessed on February 14, 2016)
[43] Natural Resources Canada website, North American Natural Gas Market: 2015-2016 Heating Season Outlook, Executive Summary, https://www.nrcan.gc.ca/energy/sources/natural-gas/17894 (Accessed on February 14, 2016)

seasonal variation is highest in the residential sector, as would be expected because of heating requirements. Seasonal variation is lowest in industrial and power because of applications in that sector that are required throughout the year.

Figure 2.9: Canadian Natural Gas Consumption by Sector (Bcfpd)



Source: Statistics Canada[44] & CERI[45]

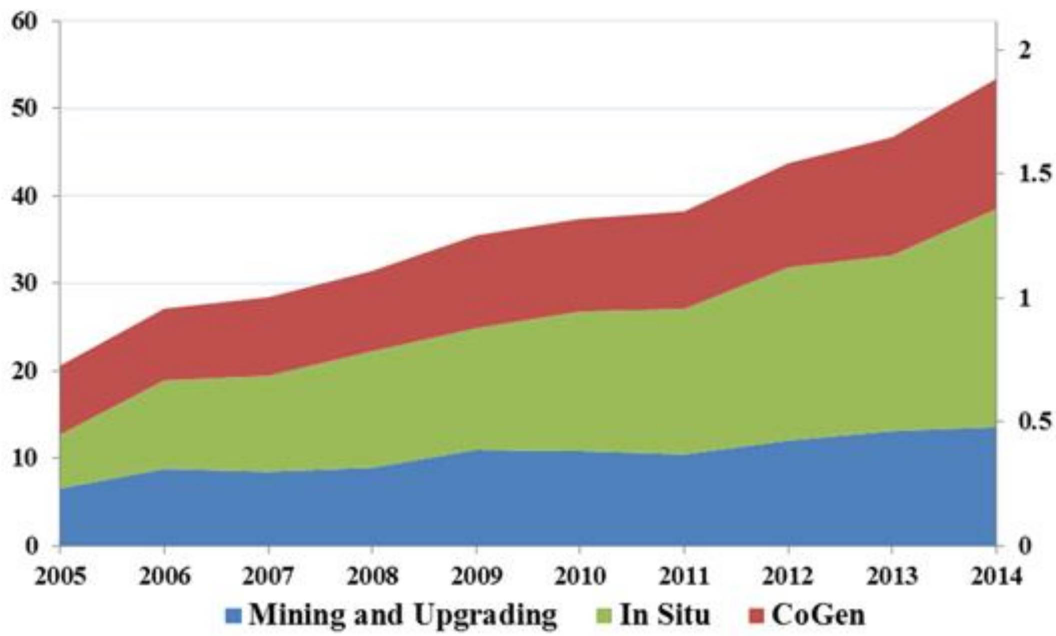
Residential and commercial sectors use natural gas as a source of space heating, water heating, clothes drying, and in cooking applications. With over six million homeowners utilizing natural gas to heat homes and water, natural gas is the single-largest form of energy used in Canadian homes,[46] accounting for 56 percent of space and water heating in Canada, followed by electricity (25 percent), wood (9 percent), heating oil (8 percent), and propane and coal (2 percent).[47] It is important to note that the commercial sector is a broad category, including offices, retail, warehousing, government and institutional buildings, utilities and communication industries.[48]

[44] Statistics Canada, Table 129-0002 Receipts and disposition of natural gas utilities, (http://www5.statcan.gc.ca/cansim/a05?lang=eng&id=1290002) & Table 129-0003 Sales of Natural Gas, (http://www5.statcan.gc.ca/cansim/pick-choisir?lang=eng&p2=33&id=1290003) (Accessed on February 14, 2016)
[45] Graphic is created by CERI for its monthly Natural Gas Commodity Report
[46] Canada's Natural Gas website, Supply and Demand, http://www.canadasnaturalgas.ca/supply-demand/#demand (Accessed on February 14, 2016)
[47] Canadian Gas Association, Gas Stats, Space & Water Heating – Canada, http://www.cga.ca/wp-content/uploads/2015/05/Chart-20-Residential-Heating-Types.pdf (Accessed on February 14, 2016)
[48] National Energy Board website, NEB - Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035, November 2013, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/index-eng.html#s4 (Accessed on February 14, 2016)

The industrial sector uses natural gas as a source of process heat, as a fuel for the generation of steam and as a feedstock in the production of petrochemicals and fertilizers. The industrial sector includes manufacturing, forestry, fisheries, agriculture, construction and mining.[49] The latter is a growing user and includes oil and gas or mining activities. The oil sands industry uses natural gas to generate electricity and steam. The latter utilizes steam in in situ oil production and for the production of hydrogen used to upgrade bitumen into synthetic crude oil.[50]

Figure 2.10 illustrates the average annual purchased natural gas requirements for oil sands operations, including mining and upgrading, in situ and cogeneration. Total natural gas purchases for oil sands operations in 2014 is 1.95 Bcfpd, or 55.2 $10^6 m^3/d$. This is up from 1.6 Bcfpd in 2013, or 46.7 $10^6 m^3/d$. The largest portion of natural gas requirements is in situ operations, accounting for over 45 percent of natural gas purchases, up from a 30 percent share in 2004.[51]

Figure 2.10: Average Annual Natural Gas Requirements for Oil Sands Operations $10^6 m^3/d$ (l) and Bcfpd (r)



Source: NEB[52]

The electric power generation sector uses natural gas to produce electricity. While the electricity mix varies among Canadian provinces and territories, natural gas-fired generation plays an important role, accounting for 15 percent of the capacity mix in 2012, second only to hydro at 57

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[49] ibid

[50] National Energy Board website, Canadian Energy Overview 2014 - Energy Briefing Note, July 2015, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/vrvw/2014/index-eng.html (Accessed on February 14, 2016)

[51] National Energy Board website, Canadian Energy Overview 2013 - Energy Briefing Note, June 2014, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/vrvw/2013/index-eng.html (Accessed on February 14, 2016)

[52] National Energy Board website, Canadian Energy Overview 2014 - Energy Briefing Note, July 2015, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/vrvw/2014/index-eng.html (Accessed on February 14, 2016)

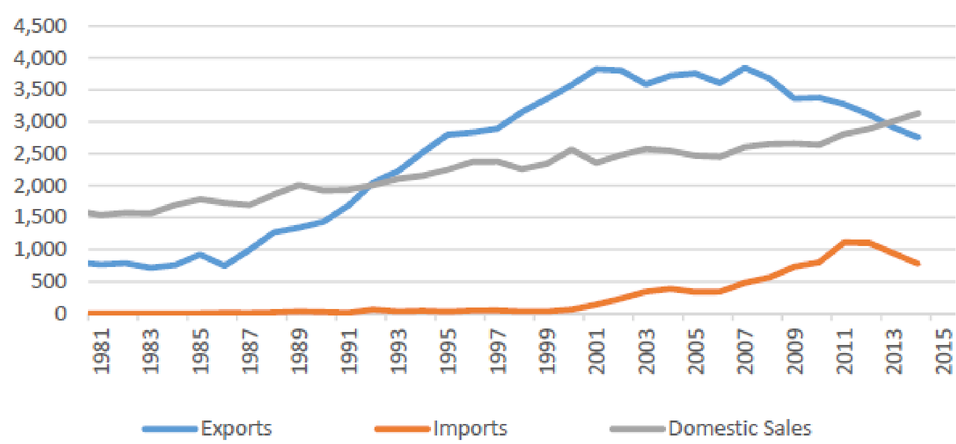
percent.[53] With the role of nuclear (10 percent) and coal (9 percent) likely to diminish, natural gas-fired generation is expected to increase to 22 percent by 2035.[54]

Canadian Natural Gas Exports

Surplus natural gas is exported to the United States through an integrated pipeline network – the second component to Canadian demand. Canada is ranked fourth globally, accounting for approximately 8 percent of the world's total exports, ranked behind Russia (20 percent), Qatar (11 percent) and Norway (10 percent).[55] In recent years, however, natural gas exports to the United States have declined.

Figure 2.11 illustrates natural gas exports and imports in Canada from 1981 to 2015. Exports increased from the mid-1980s to 2001 where it stayed relatively constant until 2007. Exports to the US coincide with the shale boom in the US, particularly with the rapid increase in natural gas production of unconventional sources, such as the Marcellus Shale. In 2014, natural gas exports to the US were 2,636 Bcf, down from 2,787 Bcf in 2013 and down from the five-year average of 3,096 Bcf.[56] Figure 2.10 also illustrates the increase of imports (and subsequent decrease since 2012) as well as the increase in the domestic sale of natural gas.

Figure 2.11: Exports and Imports of Natural Gas in Canada (Bcf)



Source: CGA[57]

[53] National Energy Board website, NEB - Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035, November 2013, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/index-eng.html#s8 (Accessed on February 14, 2016)
[54] ibid
[55] Natural Resources Canada, Energy Markets Fact Book 2014-2015, Natural Gas: International Context, http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/files/pdf/2014/14-0173EnergyMarketFacts_e.pdf, pp. 38. (Accessed on February 14, 2016)
[56] US Energy Information Administration website, Natural Gas, U.S. Natural Gas Imports & Exports 2014, January 29, 2016, https://www.eia.gov/naturalgas/importsexports/annual/(Accessed on February 14, 2016)
[57] Canadian Gas Association website, Gas Stats, Exports, Imports and Sales of Natural Gas in Canada, http://www.cga.ca/wp-content/uploads/2015/05/Chart-10-Exports-Imports-and-Sales.pdf (Accessed on February 14, 2016)

The largest exporting pipelines by points of exit (and the name of the operator in Canada-US): Huntingdon (Westcoast Energy-various pipelines[58]), Kingsgate (TransCanada Pipelines & Westcoast Energy-Gas Transmission Northwest), Monchy (Foothills Pipe Lines-Northern Border Pipeline), Elmore (Alliance Pipeline Canada and Alliance USA), Emerson (TransCanada Pipelines-Great Lakes Gas Transmission Company & Viking Gas Transmission) and Iroquois (TransCanada Pipelines-Iroquois Gas Transmission).[59] Huntingdon and Kingsgate are located on the British Columbia-Washington border while Monchy and Elmore are located on the Saskatchewan-North Dakota border. Emerson, on the other hand, is located on the Manitoba-Minnesota border while the Iroquois is located on the border between Ontario and New York.

Current State of US Natural Gas Supply and Demand

This section is divided into two parts: supply and demand. The former reviews US domestic production and imports of natural gas into the US. The latter is subsequently divided into two separate components: imports from Canada/Mexico to the US (primarily via pipeline) and imports from liquefied natural gas (LNG) regasification. The demand section is also divided into two separate components: domestic demand and exports from the US. Exports from the US are divided into two parts: exports from the US (primarily via pipeline) to Canada/Mexico and LNG exports. There is currently one liquefaction facility operating in the US, however, there are five currently under construction. The LNG exports section reviews LNG exports by vessel, by truck and LNG re-exports.

US Supply (Domestic Production, Imports from Canada/Mexico and LNG Regasification)

The US has approximately 308 Tcf of proved reserves as of the end of 2012 and 2,431 Tcf of technically recoverable resources (gas estimated to be recoverable as drilling and infrastructure expands).[60] Of that, 664 Tcf are considered shale gas and tight gas and 1,766 Tcf considered other.[61] In terms of proved reserves, the US, as of the end of 2013, is ranked fourth at 5 percent, behind Russia (24 percent), Iran (17 percent) and Qatar (13 percent). Canada is ranked nineteenth in the world in terms of proved reserves.[62]

[58] Pipelines include: Northwest Pipeline, Sumas Pipeline USA, Sumas International Pipeline, Sumas-Cascade Pipeline and Ferndale Pipeline

[59] US Department of Energy website, Fossil Energy, Table 1
Natural Gas Pipeline Points of Entry/Exit and Transporters,
http://www.fe.doe.gov/programs/gasregulation/analyses/qrsections/pdf/Table_1_POEE-Trasporters__Rev_8-27-12.pdf (Accessed on February 14, 2016)

[60] Natural Resources Canada website, Energy Market Facts,
http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/files/pdf/2014/14-0173EnergyMarketFacts_e.pdf (pp. 39) (Accessed on February 14, 2016)

[61] ibid

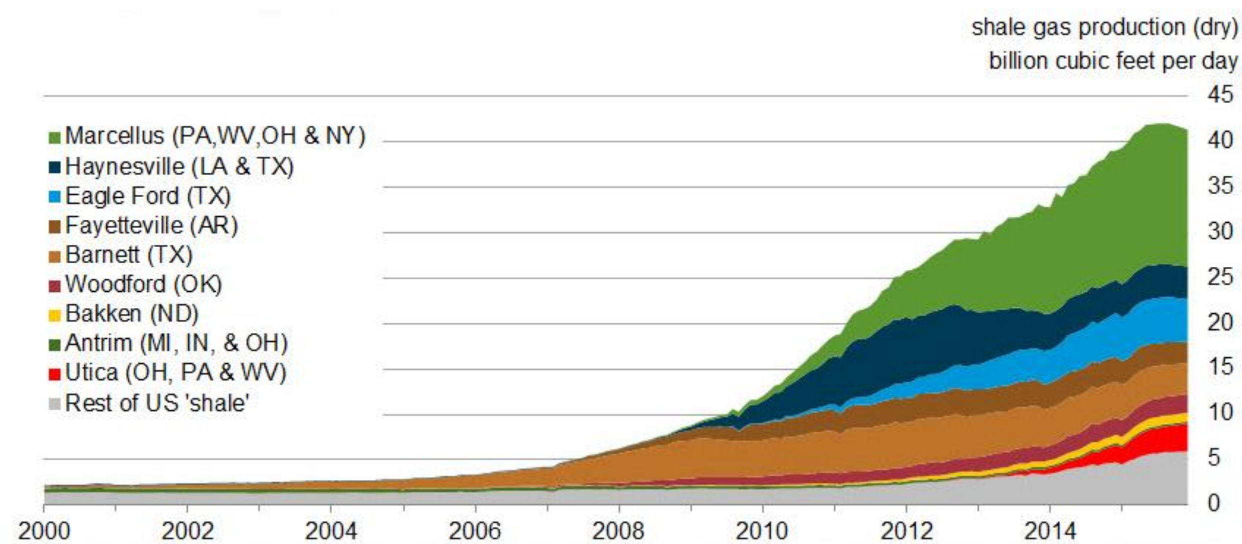
[62] ibid

Technically recoverable shale resources in the US are the fourth largest in the world at 8 percent, behind China (15 percent), Argentina (11 percent) and Algeria (10 percent).[63] As of December 31, 2015, the top 5 proved shale gas reserves in the US are Pennsylvania (56,210 Bcf), Texas (54,158 Bcf), West Virginia (28,311 Bcf), Oklahoma (16, 653 Bcf) and Louisiana (12,792 Bcf).[64] Other states with reserves over the 1,000 Bcf level include: Arkansas (11,695 Bcf), North Dakota (6,442 Bcf), Ohio (6,384 Bcf), Colorado (3,775 Bcf) and Michigan (1,432 Bcf).[65] Among the largest shale plays in the US are the Fayetteville Shale in northern Arkansas, the Haynesville Shale in eastern Texas and north Louisiana, the Eagle Ford in Texas, the Barnett Shale in Texas, and the Marcellus Shale and Utica Shale in Appalachia.

US Natural Gas Production

Figure 2.12 demonstrates the rapid growth in production of shale gas in the US and the dramatic rise of the Marcellus Shale. At the moment, the Marcellus Shale is the largest producing shale in North America by a wide margin.

Figure 2.12: US Shale Gas Production



Sources: EIA derived from state administrative data collected by DrillingInfo Inc. Data are through December 2015 and represent EIA's official shale gas estimates, but are not survey data. State abbreviations indicate primary state(s).

Source: EIA[66]

[63] Natural Resources Canada website, Energy Markets Facts, http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/files/pdf/2014/14-0173EnergyMarketFacts_e.pdf (pp. 40) (Accessed on February 14, 2016)

[64] US Energy Information Administration website, http://www.eia.gov/dnav/ng/ng_enr_shalegas_a_EPG0_R5301_Bcf_a.htm (Accessed on February 14, 2016)

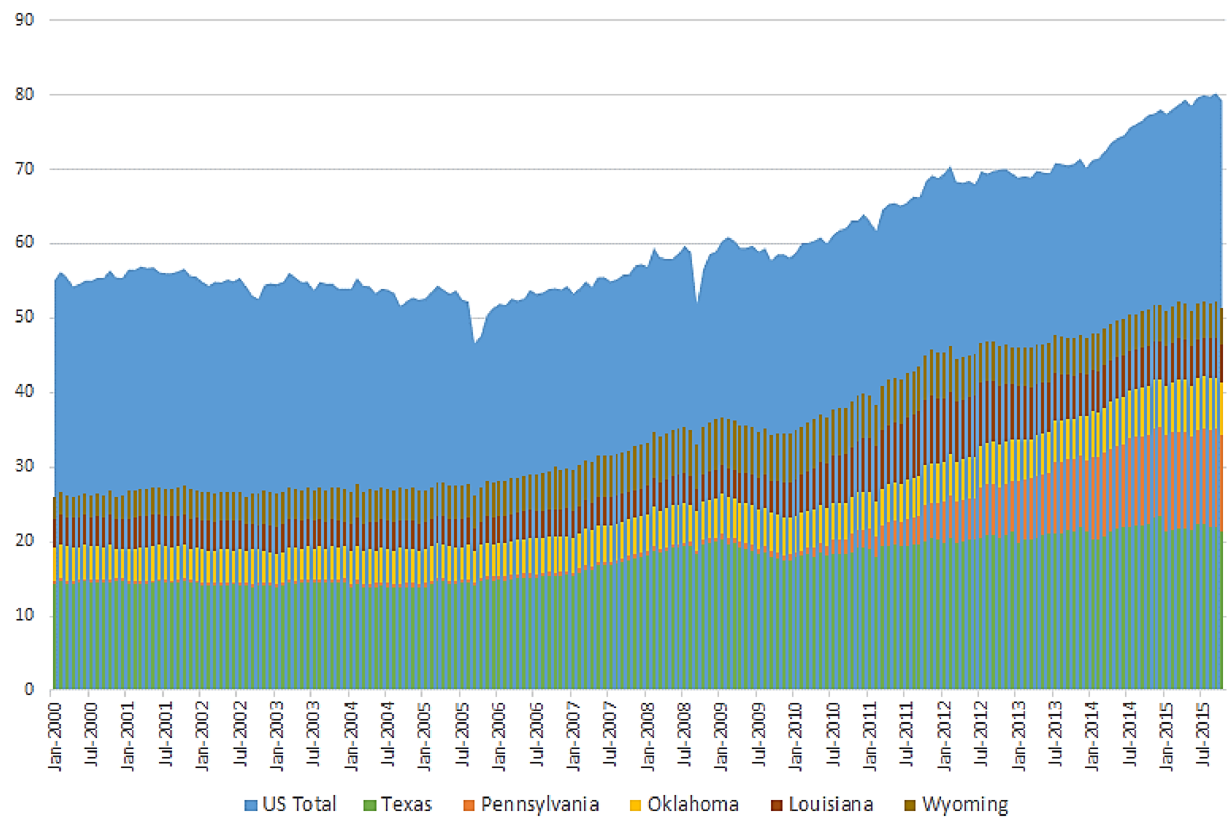
[65] ibid

[66] US Energy Information Administration website, Energy in Brief, Shale in the United States, http://www.eia.gov/energy_in_brief/article/shale_in_the_united_states.cfm (Accessed on February 14, 2016)

The US is an important player in natural gas production and is the largest natural gas producer in the world, producing 20 percent of world production. Only Russia is close, producing 19 percent of world production.[67]

Figure 2.13 shows total marketable production in the US and by the top producing states. In October 2015, US total production averaged 79 Bcfpd, down from a record high of 80 Bcfpd in September 2015. In 2014, the average total production was 74.9 Bcfpd, up from 70.0 Bcfpd in 2013; in 2015 (January-October) production is 79.1 Bcfpd.

Figure 2.13: US Marketable Production, Top 5 States (Bcfpd)



Source: EIA[68] & CERI[69]

[67] Natural Resources Canada website, Energy Markets Facts, http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/files/pdf/2014/14-0173EnergyMarketFacts_e.pdf (pp. 38) (Accessed on February 14, 2016)

[68] US Energy Information Administration website, Natural Gas, Natural Gas Gross Withdrawals and Production (Volumes in Million Cubic Feet converted to Bcfpd), Marketed Production, http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_m.htm (Accessed on February 14, 2016)

[69] Graphic is created by CERI for its monthly Natural Gas Commodity Report

According to the US Energy Information Administration (EIA),[70] leading the way in production in the US is Texas, producing 21.3 Bcfpd in October 2015 and averaging 21.8 Bcfpd in 2014. Pennsylvania is the second largest producing state in the US, reaping the rewards of shale gas and, more specifically the Marcellus Shale. The state is averaging 13.0 Bcfpd in October 2015 and averaged 11.5 Bcfpd in 2014.[71] Until 2010, Pennsylvania was a relatively small producer. Oklahoma is the third largest natural gas producer in the US and is a traditional natural gas producer. The state is averaging 6.9 Bcfpd in October 2015 and averaged 6.3 Bcfpd in 2014.[72] Louisiana is the fourth largest producing state, averaging 5.27 Bcfpd in October 2015 and averaged 5.4 Bcfpd in 2014.[73] Production in Louisiana peaked at 8.3 Bcfpd in 2011 and has been declining since. Rounding out the top 5 is Wyoming, averaging 4.8 Bcfpd in October 2015 and averaged 4.9 Bcfpd in 2014.[74]

While conventional gas production is decreasing, the importance of tight gas and shale gas in Canada and the US is increasing. In October 1995 the top 5 largest producing states were Texas (16.9 Bcfpd), Louisiana (13.0 Bcfpd), Oklahoma (5.0 Bcfpd), New Mexico (4.5 Bcfpd) and Kansas (1.9 Bcfpd).[75] While Texas, Louisiana and Oklahoma still remain the largest players, emerging sources of shale and tight gas are changing the dynamics of US supply.

Other states not previously mentioned that have increased their production include Ohio, North Dakota and West Virginia. Production in Ohio increased from 0.9 Bcfpd in January 2014 to 3.4 Bcfpd in October 2015, while production in North Dakota increased from 0.6 Bcfpd in January 2014 to 1.3 Bcfpd in October 2015 and production in West Virginia increased from 1.6 Bcfpd in January 2013 to 3.6 Bcfpd in October 2015.[76] West Virginia and Ohio are home to the Marcellus Shale and Utica Shale while the Bakken Shale is located in North Dakota.

It is, however, important to note that drilling activity is being impacted by the reduced price of oil and the decreasing price of natural gas. With decreases in the price of natural gas, gas-directed rigs in the US have decreased as well.

Table 2.2 shows the rig count in the United States, as well as oil- and gas-directed drilling activity.

[70] US Energy Information Administration website, Natural Gas, Natural Gas Gross Withdrawals and Production (Volumes in Million Cubic Feet converted to Bcfpd), Marketed Production, http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_m.htm (Accessed on February 14, 2016)
[71] ibid
[72] ibid
[73] ibid
[74] ibid
[75] ibid
[76] ibid

Table 2.2: Rig Count in the United States by Target and Trajectory

US Rig Count				Change		% Change	
	02/26/2016	02/19/2016	02/27/2015	Weekly	Annual	Weekly	Annual
Total U.S.	502	514	1,267	(12)	(765)	-2.3%	-60.4%
Oil-Directed	400	413	986	(13)	(586)	-3.1%	-59.4%
%	79.7%	80.4%	77.8%	0.0%	-5.5%		
Gas-Directed	102	101	280	1	(178)	1.0%	-63.6%
%	20.3%	19.6%	22.1%	0.7%	-1.8%		
Directional	17	16	44	1	-27	5.9%	-61.4%
Horizontal	81	84	210	-3	-129	-3.7%	-61.4%
Vertical	4	1	26	3	-22	75.0%	-84.6%

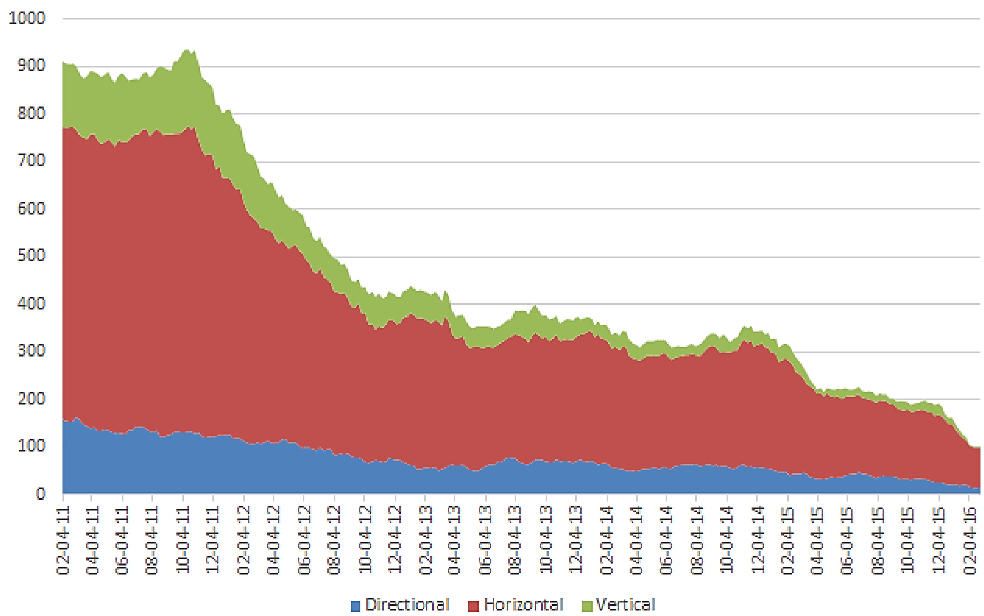
Source: WTRG Economics[77] & Baker Hughes[78]

As of February 26, 2016, natural gas rigs decreased to 102. Natural gas-directed rigs are down 63.6 percent from the same time last year, when rigs numbered 280, a decrease of 178 rigs. Since January 2011, natural gas rigs peaked at 936 as of the week of October 14, 2011 to a low of 101 as of the week of February 19, 2016. The percentage of gas-directed drilling decreased to 20.3 percent, from 22.1 percent a year ago. This is due to the dramatic fall in oil rig activity in the past year.

Figure 2.14 illustrates the US natural gas rotary rig count between January 2011 and present. Of the total rotary rig count in the US, horizontal drilling is the largest category by trajectory. As of the week of February 26, 2016, there are 81 active rigs that utilize horizontal drilling, down from 129 rigs at the same time last year – a decrease of 61.4 percent.[79] As of February 26, 2016, there are only 4 active vertical rigs and 17 directional rigs. Vertical drilling is down 22 rigs from the previous year – a decrease of 84.6 percent.[80] Directional drilling is down 27 rigs from the previous year; this a decrease of 61.4 percent from the previous year.[81]

[77] WTRG Economics, North American Rotary Rig Counts, http://www.wtrg.com/rotaryrigs.html EnergyEconomist.com, Weekly Rotary Rig Count, http://www.energyeconomist.com/a6257783p/exploration/rotaryrigweekly.html (Accessed on February 14, 2016)
[78] Baker Hughes, US Rig Count – Total Report, http://gis.bakerhughesdirect.com/Reports/StdRptTotals.aspx
[79] ibid
[80] ibid
[81] ibid

Figure 2.14: US Natural Gas Rig Count by Trajectory



Source: Baker Hughes,[82] CERI

US Natural Gas Imports

The second component to US supply is imports from Canada/Mexico and LNG. The former is primarily via pipelines from various points of entry while imports of LNG are primarily through the several LNG regasification terminals.

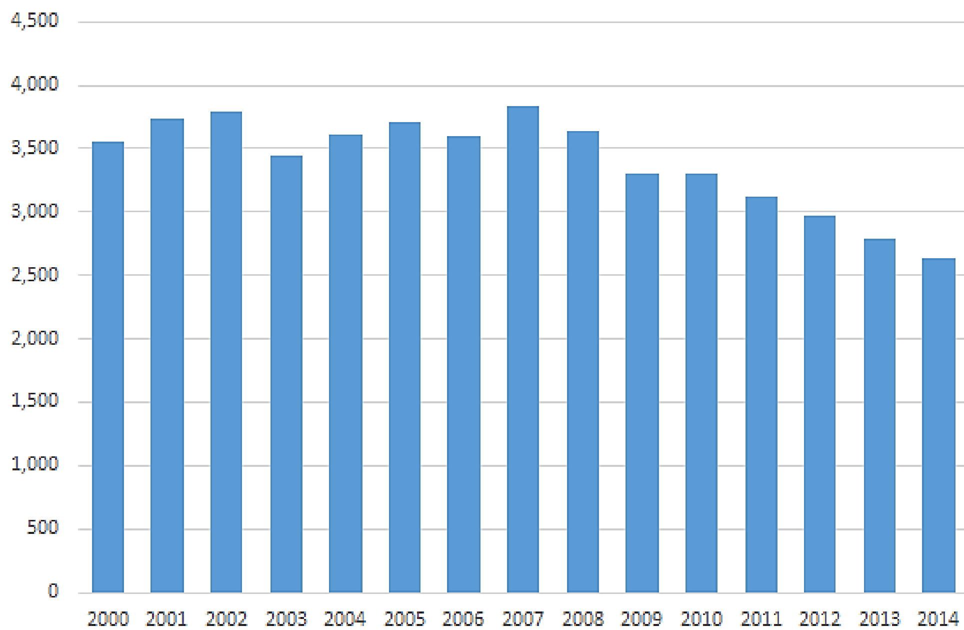
The first element is imports from Canada and Mexico. This section focuses on Canada, as US imports from Mexico are marginal, only 83 MMcf in October 2015.[83] Between January-October 2015, US gas imports from Mexico average 79.6 MMcf, down from 118.9 MMcf from 2014.[84] Natural gas imports from Canada in 2Q2015, on the other hand, are 98.9 percent of total imports.[85]

The US imported 2,636 Bcf of natural gas in 2014 from Canada, down from 2,787 Bcf in 2013 and down from the five-year average of 3,096 Bcf.[86] US imports peaked in 2007 at 3,837 Bcf and had

[82] Baker Hughes North America rotary Rig Count January 2000 to Current (Accessed on February 14, 2016)
[83] US Energy Information Administration website, Natural Gas, US Natural Gas Pipeline Imports from Mexico, http://www.eia.gov/dnav/ng/hist/n9102mx2M.htm (Accessed on February 14, 2016)
[84] ibid
[85] US Department of Energy, Office of Fossil Energy, Natural Gas Imports and Exports, Second Quarter Report 2015, http://energy.gov/sites/prod/files/2015/10/f27/2Q2015.pdf, pp. 1. (Accessed on February 14, 2016)
[86] US Energy Information Administration website, Natural Gas, US Natural Gas Imports & Exports 2014, May 11, 2015, https://www.eia.gov/naturalgas/importsexports/annual/ (Accessed on February 14, 2016)

been in decline since with a brief respite in 2010.[87] Figure 2.15 illustrates imports of Canadian natural gas into the US from 2000 to 2015.

Figure 2.15: US Imports of Canadian Natural Gas (Bcf)



Source: EIA,[88] CERI

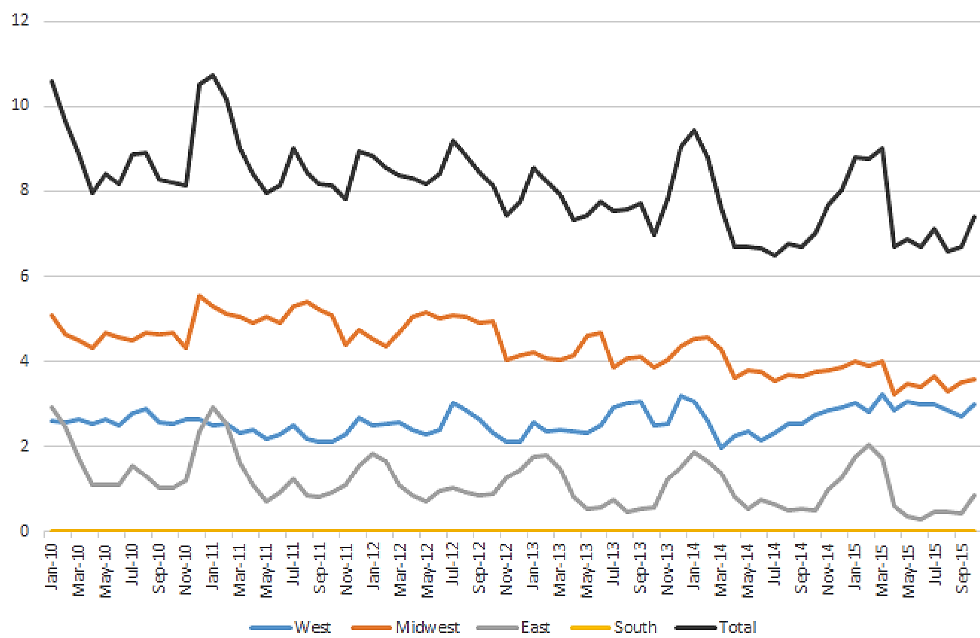
The decreases in imports from Canada are due in part to lower cost Marcellus gas closer to markets in the US Northeast and US Midwest, giving it cost advantages over western Canadian gas. The rapid increase in production of the Marcellus and Utica Shales is having a profound effect on North American gas flows, primarily in the US Northeast, Midwest and central Canadian markets. As previously discussed, western Canadian gas is being pushed out of the Midwest and the increasing amount of lower cost Marcellus gas is further displacing western Canadian gas out of central Canada and the US Northeast.[89]

Regional pipeline monthly export volumes are illustrated in Figure 2.16, showing Canadian pipeline exports to the West, Midwest, East and South regions of the US. Natural gas imports to the Midwest decreased from 4.2 Bcfpd (43.1 Bcm) in 2013 to 3.9 Bcfpd (40.3 Bcm) in 2014, a 7 percent decrease.[90] Natural gas imports into the West and East regions decreased by 5 percent.[91]

[87] US Energy Information Administration website, Natural Gas, US Natural Gas Pipeline Imports, Annual, http://www.eia.gov/dnav/ng/hist/n9102us2a.htm (Accessed on February 14, 2016)
[88] ibid
[89] Platt's website, Gas Daily, Marcellus to displace Rockies, Canada gas: Bernstein, May 13, 2015, https://online.platts.com/PPS/P=m&e=1431562255713.2709137032677465172/GD_20150513.xml?artnum=c60d69e2f-ba44-469e-9feb-4b069e58d1ba_16 (Accessed on February 14, 2016)
[90] National Energy Board website, 2014 Natural Gas Exports and Imports Summary, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ntrlgssmmr/2014/smmry2014-eng.html#fn4-rf (Accessed on February 14, 2016)
[91] ibid

Natural gas imports into the West decreased from 2.7 Bcfpd (27.4 Bcm) in 2013 to 2.5 Bcfpd (26.1 Bcm) in 2014.[92] Likewise, natural gas imports into the East decreased from 1.0 Bcfpd (10.3 Bcm) in 2013 to 0.96 Bcfpd (99.9 Bcm) in 2014.[93] There are no exports to the South region of the US.

Figure 2.16: Pipeline Import Volumes by Region (Bcfpd)



Source: NEB,[94] CERI

Of the total amount of imports (2,695 Bcf) into the US in 2014, the vast majority, or 2,636 Bcf, are via pipeline. A smaller component is imported via LNG regasification terminals. Compressed natural gas (CNG) is also imported into the US from Canada, but in very small quantities, approximately 0.3 Bcf in 2014.[95] It is not discussed in further detail due to its small volumes.

Currently, there are twelve liquefaction or regasification facilities in the US. Aside from the Kenai LNG Export Terminal, the remaining eleven terminals are import or regasification terminals. Nine of those terminals are under Federal Energy Regulatory Commission (FERC) jurisdiction, the organization responsible for the regulation of natural gas pipelines, storage and LNG, while the other two offshore facilities are under the jurisdiction of the United States Maritime Administration (MARAD) and the United States Coast Guard (USCG).

[92] ibid
[93] ibid
[94] National Energy Board website, 2014 Natural Gas Exports and Imports Summary, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ntrlgssmmr/2014/smmry2014-eng.html#fn4-rf (Accessed on February 14, 2016)
[95] US Energy Information Administration website, U.S. Natural Gas Imports & Exports 2014, May 11, 2015, http://www.eia.gov/naturalgas/importsexports/annual/#tabs-prices-2 (Accessed on February 14, 2016)

Table 2.3 illustrates the existing import and export LNG terminals in the US, their company name, location and capacity.

Table 2.3: Existing US LNG Import Terminals[96]

Location	Company Name	Capacity (Bcfpd)
Everett, MA	GDF SUEZ - DOMAC	1.035
Cove Point, MD	Dominion – Cove Point LNG	1.8
Elba Island, GA	El Paso – Southern LNG	1.6
Lake Charles, LA	Southern Union – Trunkline LNG	2.1
Offshore Boston	Excelerate Energy – Northeast Gateway	0.8
Freeport, TX	Cheniere/Freeport LNG Dev.	1.5
Sabine, LA	Cheniere/Sabine Pass LNG	4.0
Hackberry, LA	Sempra – Cameron LNG	1.8
Offshore Boston, MA	GDF SUEZ – Neptune LNG	0.4
Sabine Pass, TX	ExxonMobil – Golden Pass (Phase I & II)	2.0
Pascagoula, MS	El Paso/Creast/Sonangol – Gulf LNG Energy	1.5

Source: FERC[97]

LNG imports in 2014 totaled 59.3 Bcf, down from 96.9 Bcf in 2013 and down from the five-year average of 300.7 Bcf.[98] LNG imports in 2015 (January-October) total 78.0 Bcf, with the highest volume in March (14.6 Bcf), already exceeding 2014. LNG imports reached a peak of 700.8 Bcf in 2007 but have decreased rapidly, save for a brief rebound in 2009 (imports increased from 351.7 Bcf in 2008 to 452.0 Bcf in 2009).[99] It is interesting to note that the largest imports originated in 2014 in Trinidad and Tobago (42.8 Bcf), Yemen (8.0 Bcf) and Norway (5.6 Bcf).[100] The terminals with the highest volumes in 2014 are Everett (28.8 Bcf), followed by Cove Point (11.5 Bcf) and Elba Island (7.2 Bcf). Thus far in 2015, the terminals with the highest volumes are Everett (45.7 Bcf), followed by Elba Island (11.8 Bcf) and Sabine Pass (6.1 Bcf).

[96] Federal Energy Regulatory Commission website, North American LNG Import/Export Terminals – Existing, http://www.ferc.gov/industries/gas/indus-act/lng/lng-existing.pdf (Accessed on February 14, 2016)
[97] ibid
[98] US Energy Information Administration website, U.S. Natural Gas Imports & Exports 2014, May 11, 2015, http://www.eia.gov/naturalgas/importsexports/annual/#tabs-prices-2 (Accessed on February 14, 2016)
[99] US Energy Information Administration website, US Liquefied Natural Gas Imports, Annual, http://www.eia.gov/dnav/ng/hist/n9103us2a.htm (Accessed on February 14, 2016)
[100] US Energy Information Administration website, Natural Gas, U.S. Natural Gas Imports by Country (Volumes in Million Cubic Feet, Prices in Dollars per Thousand Cubic Feet), http://www.eia.gov/dnav/ng/ng_move_impc_s1_a.htm (Accessed on February 14, 2016)

US Natural Gas Disposition (Domestic Demand, Exports to Canada/Mexico and LNG Liquefaction)

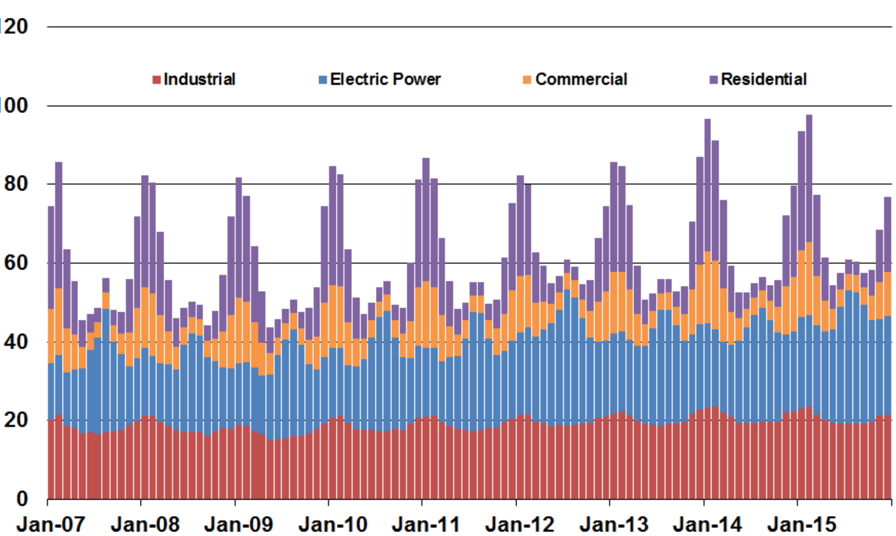
US natural gas plays an important role in the US domestic energy consumption, as well as internationally.

US Domestic Demand

Similar to Canada, domestic demand is further broken down into several sectors: residential, commercial, industrial and power generation. Figure 2.17 illustrates US monthly natural gas consumption by sector. Other end uses include lease and plant fuel consumption, pipeline and distribution, and vehicle fuel; due to their small consumption, these end uses are not illustrated in the figure.

The volatility in seasonal demand in the United States is not as large as it is in Canada. Though demand peaks in the winter, as it does in Canada, the valleys in the summer are not as deep because of power demand at that time of year to operate. Similar to Canada, the 2014 and 2015 peaks and valleys are the highest in recent history, showing that natural gas demand is growing in the US, not only in the winter but also in the summer. Seasonal variation is least in the industrial sector because of the year-round supply of natural gas that is required. Residential natural gas demand peaks in the winter when home owners require the most fuel for space heating, and then a second, lower peak occurs in summer when electricity for air conditioning is at its highest demand point of the year.

Figure 2.17: US Natural Gas Consumption by Sector (Bcfpd)



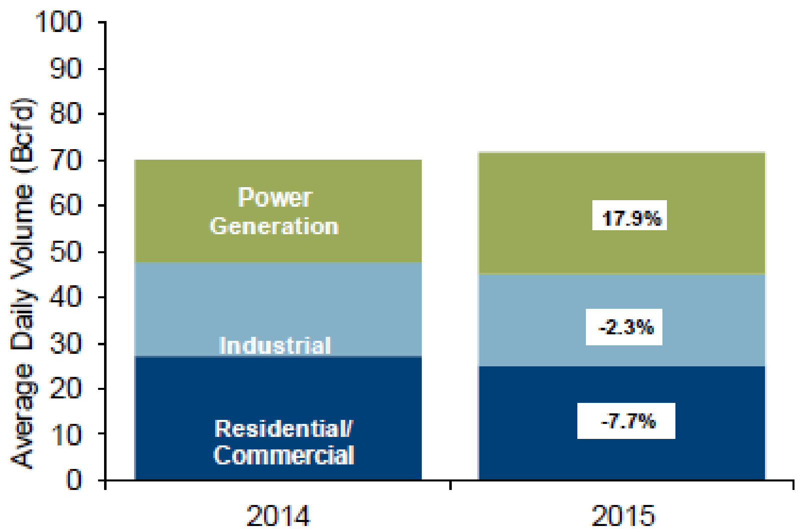
Source: EIA,[101] CERI[102]

[101] US Energy Information Administration website, Natural Gas, Natural Gas Monthly, Table 2 Natural Gas Consumption in the United States, 2010-2015, January 29, 2016, http://www.eia.gov/naturalgas/monthly/?src=Natural-f2 (Accessed on February 14, 2016)
[102] Graphic is created by CERI for its monthly Natural Gas Commodity Report

The electric power generation sector is the largest end-user of natural gas, consuming 9,671 Bcf in 2015, up from 8,149 Bcf in 2014 and up from 6,873 Bcf in 2009.[103] This accounts for approximately 35 percent of total natural gas consumed. The electric power sector averaged 26.5 Bcfpd in 2015. The second largest sector is industrial, consuming 7,507 Bcf in 2015, down from 7,624 Bcf in 2014 and up from 6,136 Bcf in 2009.[104] The industrial sector averaged 20.6 Bcfpd in 2015. Residential and commercial consumed 4,612 Bcf and 3,206 Bcf, respectively, in 2015. The residential sector averaged 12.8 Bcfpd while the commercial sector averaged 8.8 Bcfpd in 2015. The residential sector decreased from 5,087 Bcf in 2014 while the commercial sector increased from 3,467 Bcf.[105] In 2015, lease and plant fuel consumption consumed 1,581 Bcf, followed by pipeline and distribution (860 Bcf) and vehicle fuel (34 Bcf).[106]

Figure 2.18 compares US natural gas demand between December 2014 year-to-date (YTD) and December 2015 YTD. The total change in demand is 1.9 percent, the bulk of that growth coming from the power generation sector (17.9 percent). The residential/commercial sectors, on the other hand, decreased 7.7 percent while industrial use decreased 2.3 percent over the same time period.

Figure 2.18: US Natural Gas Demand
(December 2014 YTD vs. December 2015 YTD)



Source: FERC[107]

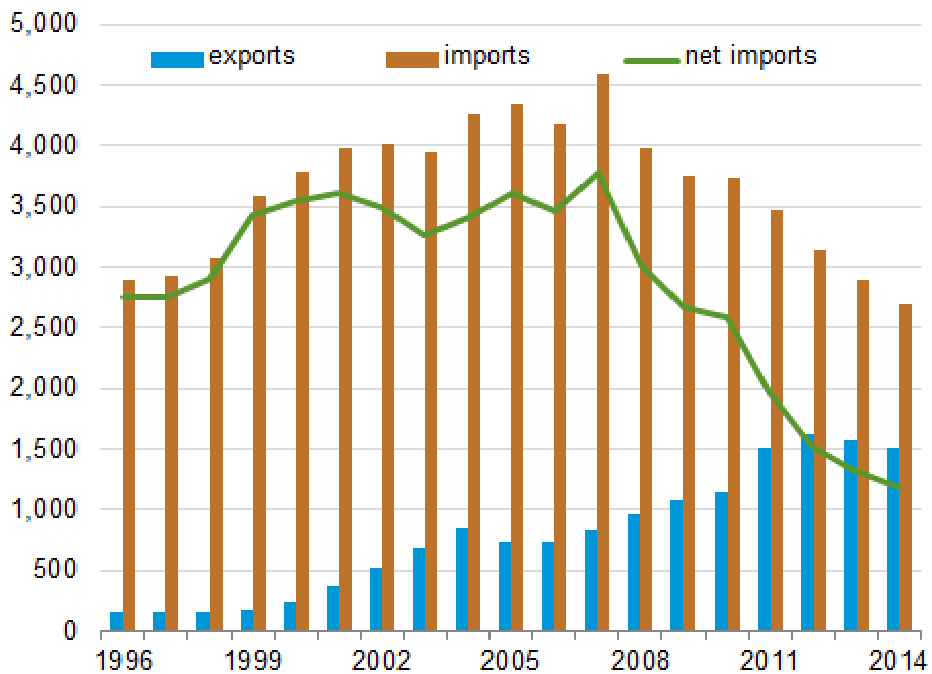
[103] US Energy Information Administration website, Natural Gas, Natural Gas Consumption by End Use (Million Cubic feet), Annual, January 29, 2016, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm (Accessed on February 14, 2016)
[104] ibid
[105] ibid
[106] ibid
[107] Federal Energy Regulatory Commission website, National Natural Gas Market Overview: US Supply and Consumption, US Natural Gas Supply and Demand December 2014 YTD vs. December 2015 YTD, https://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-sup-dmd-cns.pdf (Accessed on February 14, 2016)

Natural gas-fired generation plays an increasingly important role, accounting for 33 percent of the capacity mix in 2013, equal to coal at 33 percent and ahead of nuclear at 20 percent.[108] The role of natural gas-fired generation increased from 22 percent in 2007, while coal-fired generation decreased from 48 percent and nuclear increased from 19 percent.[109]

US Natural Gas Exports

The second component to US demand is exports to Canada/Mexico and exports of LNG. Figure 2.19 illustrates natural gas exports and imports in the US from 1996 to 2014. Exports increased from 2006 to 2012, where it subsequently decreases slightly. Imports into the US, on the other hand, decrease steadily over the same time period, coinciding with the shale boom in the US, particularly with the rapid increase in natural gas production of unconventional sources, such as the Marcellus Shale.

Figure 2.19: US Exports and Imports of Natural Gas (Bcf)



Source: CGA

In 2014, natural gas exports from the US were 1,498 Bcf, down from 1,569 Bcf in 2013 but up from the five-year average of 1,341 Bcf.[110] In 2014, US exports to Canada totaled 769 Bcf while

[108] US Energy Information Administration, Electric Power Monthly, Table 1.1 Net Generation by Energy Source, 2006-March 2016, (Accessed on May 31, 2016)

[109] ibid

[110] US Energy Information Administration website, Natural Gas, US Natural Gas Imports & Exports 2014, May 11, 2015, https://www.eia.gov/naturalgas/importsexports/annual/ (Accessed on February 14, 2016)

exports to Mexico stood at 728 Bcf.[111] The largest exporting points into Canada in 2014 were: St. Clair, Michigan (479 Bcf), Niagara Falls, NY (162 Bcf), Detroit, Michigan (46 Bcf), Waddington, NY (39 Bcf) and Marysville, Michigan (25 Bcf).[112] All are points of entry into Canada and are located in Ontario. The largest exporting points of exit into Mexico in 2014 were: Roma, Texas (154 Bcf), Clint, Texas (124 Bcf), Ogilby Mesa, California (112 Bcf), McAllen, Texas (79 Bcf) and Alamo, Texas (79 Bcf).[113]

The last component of US demand is exports of LNG. It can be further divided into three components: by vessel, by truck and re-exports (also by vessel).

The shale gas boom is not only having a profound effect on natural gas production in the Lower-48, but also on how the US views energy and its role in a rapidly changing world. Despite the fact that the first LNG facility in the US was the Kenai LNG export terminal located in the Cook Inlet area in Alaska, it is historically defined as a net importer of LNG. That, however, will soon change.

As of January 2016, there are five export facilities that are approved by the US Department of Energy and FERC and are already under construction: Sabine (Cheniere-Sabine Pass LNG), Hackberry (Sempra-Cameron LNG), Freeport (Freeport LNG), Cove Point (Dominion-Cove Point LNG) and Corpus Christi (Cheniere-Corpus Christi LNG).[114] A sixth export facility, the Sabine Pass Liquefaction LLC (a subsidiary of Cheniere Energy Partners), has been approved but is not yet under construction.[115]

March 15, 2016 marked the beginning of an era for US Gulf Coast LNG exports, with the first volumes from the Cheniere facility reaching the port of Rio de Janeiro.[116] While the other facilities are not yet complete, there are now two facilities in the US currently exporting LNG: Kenai LNG and Cheniere LNG facility.

Figure 2.20 shows the LNG export volumes in the US, excluding the very recent shipment to Brazil from the US Gulf Coast. All of the exports from January 2012 were destined for Japan and Taiwan from the Kenai facility in Cook Inlet. In 2015 (January-October) the total exports are 16.52 Bcf, up from 13.31 Bcf in 2014 and down from the five-year average of 17.5 Bcf. There were no exports from Kenai in 2013.

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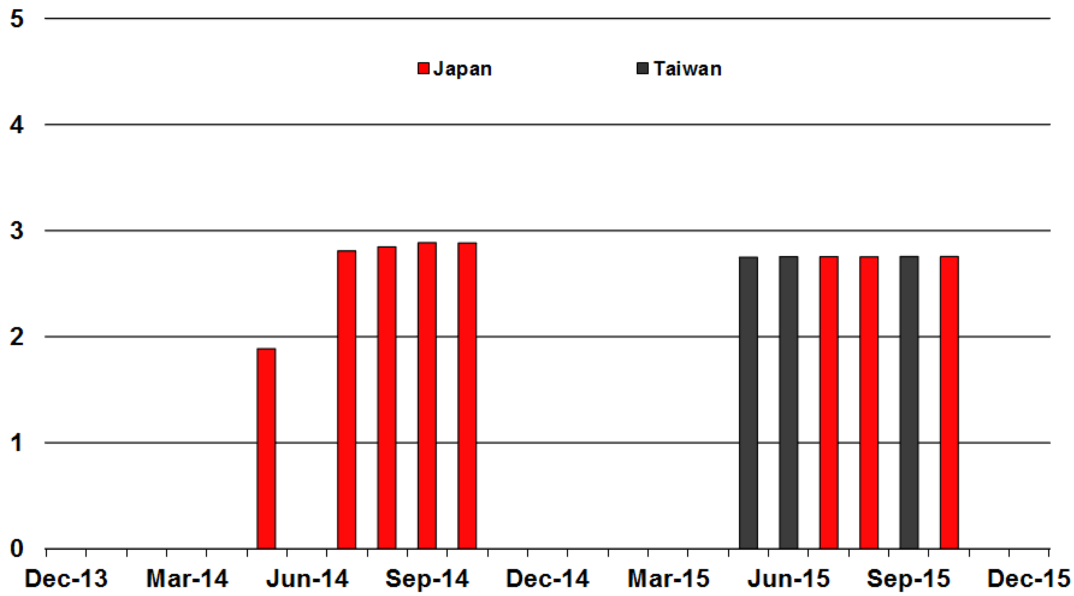
[111] US Energy Information Administration website, Natural Gas, US Natural Gas Exports and Re-Exports by Point of Exit (Million Cubic Feet), Annual, January 29, 2016, http://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm (Accessed on February 14, 2016)
[112] ibid
[113] Ibid
[114] Federal Energy Regulatory Commission website, North American LNG Import/Export Terminals: Approved as of June 18, 2015, http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf (Accessed on February 14, 2016)
[115] Cheniere Website, Sabine Pass LNG, Train 5 & 6, http://www.cheniere.com/terminals/sabine-pass/trains-5-6/
[116] Kahwar, Muhammad Ali, “LNG Export by Cheniere Energy, Inc Bodes Well for the US.” Bidnessetc, March 16, 2016, http://www.bidnessetc.com/65601-lng-export-cheniere-energy-bodes-well-us/ (Accessed March 16, 2016)

Figure 2.20: US LNG Export Volumes (Bcf)



Source: US Department of Energy, Office of Fossil Energy,[117] CERI

Re-exports of LNG occur when foreign shipments are offloaded in US storage tanks and are then subsequently reloaded onto tankers for delivery to other countries.[118] This lets marketers and suppliers wait for price signals before delivering the LNG to higher-paying markets.[119] LNG import terminals Freeport LNG, Sabine Pass LNG and Sempra-Cameron LNG are authorized to re-export delivered LNG. Thus far in 2015 (January-October), only two shipments totaling 5.54 Bcf were re-exported from Freeport, Texas to Brazil. In 2014 there was 2.7 Bcf, unchanged from 2013;[120] the five-year average is 22.4 Bcf.[121] Re-exports in 2012 totaled 18.8 Bcf (exports destined for Brazil, India and Japan), 53.4 Bcf in 2011 (exports destined for Brazil, Mexico, Belgium, India, South Korea, Spain, Japan and the United Kingdom) and 37.8 Bcf in 2010 (exports destined for Brazil, China, India, South Korea, Spain, Japan, United Kingdom and Chile).[122]

[117] US Department of Energy, Office of Fossil Energy, Natural Gas Regulation, LNG Reports, LNG Monthly Report, http://energy.gov/fe/listings/lng-reports (Accessed on February 14, 2016)
[118] US Energy Information Administration website, Natural Gas, US Natural Gas Exports and Re-Exports by Country, http://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm (Accessed on February 14, 2016)
[119] ibid
[120] US Department of Energy, Office of Fossil Energy website, Natural Gas Regulation, LNG Reports, LNG Monthly Report, http://energy.gov/fe/listings/lng-reports (Accessed on February 14, 2016)
[121] U.S. Natural Gas Imports & Exports 2014, May 15, 2015, http://www.eia.gov/naturalgas/importsexports/annual/#tabs-prices-2ibid (Accessed on February 14, 2016)
[122] US Department of Energy, Office of Fossil Energy website, Natural Gas Regulation, LNG Reports, LNG Monthly Report, http://energy.gov/fe/listings/lng-reports (Accessed on February 14, 2016)

LNG exports by truck are small, only 99 MMcf to Canada in 2014, up from 71 MMcf in 2013 and 2 MMcf in 2012.[123] While there were no LNG shipments to Mexico in 2013, the US trucked 153 MMcf of LNG in 2012, 236 MMcf in 2011 and 208 MMcf in 2010.[124] LNG exports date back to 1998 and peaked in 2001 at 465 MMcf.[125] Recall pipeline exports from the US to Mexico totaled 728.5 Bcf; LNG volumes are quite small.

Current Natural Gas Prices in Canada and the US

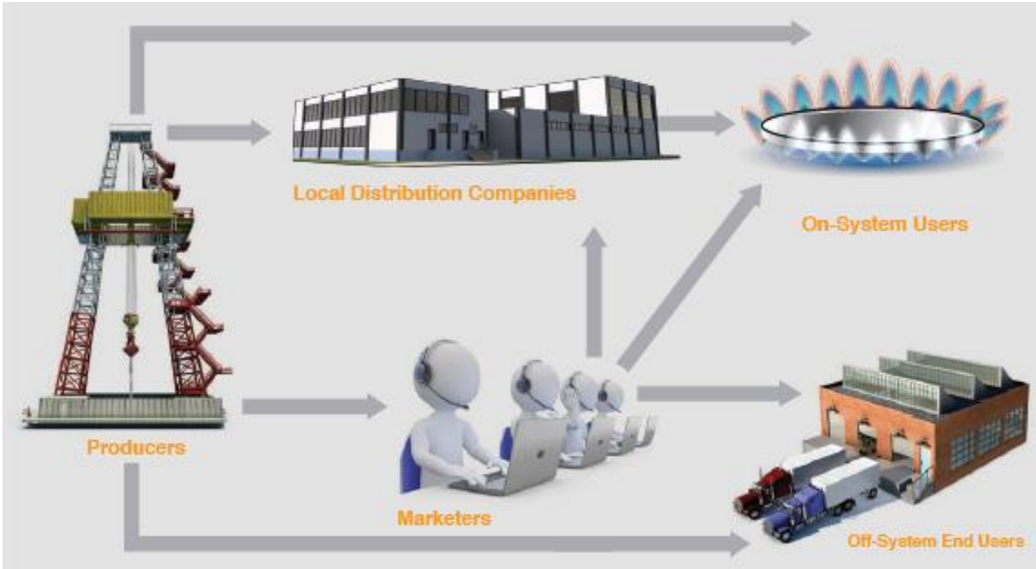
This section discusses the current prices in Canada and the US. Prices are discussed on a wholesale and retail basis. The former is in terms of spot prices at four trading hubs (Henry Hub, AECO-C, Dawn Hub and Chicago Citygate), while the latter is comprised of current prices for end-users; more specifically, residential, commercial, industrial and electric power users.

It is first prudent to review the various layers of the price of natural gas and the various commercial and financial transactions. Natural gas trading or transactions occur in several different locations, from the wellhead, or from the producer, to burner tip or the end-user. These users can be either on-system or off-system. The former are users that receive natural gas deliveries from local distributing companies (LDCs) or natural gas marketers, while the latter are users that are directly connected to an interstate pipeline. Residential and commercial end-users are typically on-system users, while larger industrial users and electric power plants are off-system users, connected directly with producers and able to purchase large volumes of natural gas.

Figure 2.21 illustrates the various commercial and financial arrangements, showing the various natural gas transactions between the thousands of producers, consumers and intermediate players (LDCs and natural gas marketers).

[123] US Energy Information Administration website, Natural Gas, US Natural Gas Exports and Re-Exports by Country (Volumes in Million Cubic Feet, Prices in Dollars per Thousand Cubic Feet), January 29, 2016,http://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm (Accessed on February 14, 2016)
[124] ibid
[125] ibid

Figure 2.21: Various Commercial and Financial Arrangements in Natural Gas



Source: API[126]

There are two simplified paths that producers can use to get their product to the end-user; likewise, there are several different ways in which an end-user can consume natural gas.

First, producers may have the ability to market their own gas directly to on-system or off-system end-users, or to sell their natural gas to LDCs (local distribution companies), large industrial buyers or to electric power plants.[127] Most residential and commercial customers, on the other hand, purchase natural gas from LDCs or gas utilities. LDCs are engaged primarily in the retail sale and/or delivery of natural gas through a distribution system.[128] LDCs play an important role in balancing the gas delivery system by using large storage facilities, as gas received by the distributor in the summer that exceeds local demand is stored until winter.[129]

Second, producers may sell their natural gas to marketers, who in turn transport and sell gas to different types of buyers.[130] Marketers sell to LDCs or to commercial or industrial customers that are either connected directly to pipelines or are served by the LDCs transportation network.[131] Buyers may be on-system or off-system users. Arranging the purchase and sales of natural gas, marketers do not own physical assets commonly used in the supply of natural gas, such as

[126] Steven Levine, Paul Carpenter and Anul Thapa, Understanding Natural Gas Markets, Prepared for the American Petroleum Institute, 2004, pp.16.
[127] Federal Energy Regulatory Commission, Energy Primer: A Handbook of Energy Market Basics, November 2015, http://www.ferc.gov/market-oversight/guide/energy-primer.pdf, pp. 32.
[128] US Energy Information Administration website, Natural Gas, Definitions, Sources and Explanatory Notes, https://www.eia.gov/dnav/ng/TblDefs/ng_pri_rescom_tbldef2.asp (Accessed on February 14, 2016)
[129] Aegent Energy Advisors website, Who Does What in the Gas Industry? http://www.aegent.ca/resources/whodoeswhat.html (Accessed on February 14, 2016)
[130] Steven Levine, Paul Carpenter and Anul Thapa, Understanding Natural Gas Markets, Prepared for the American Petroleum Institute, 2004, pp.16.
[131] ibid

pipelines or storage fields.[132] The gas marketer makes a margin by buying and selling gas in the wholesale gas market.[133] Major marketers and traders of gas in Canada include BP Canada Energy, Shell Energy North America, Navicomm and Direct Energy. There are generally five types of marketers: major nationally integrated marketers, producer marketers, small geographically-focused marketers, aggregators and brokers.[134]

While Figure 2.21 is a simplified schematic of the various transactions possible, there are many types of buyers and sellers, motivated by equally different types of financial and commercial arrangements. The North American natural gas market is characterized by large numbers of competing sellers, buyers, intermediaries, and huge trading volumes. As a result, there are different layers of prices, wholesale and retail. The next section discusses both, in the context of Canada and the US.

Wholesale Prices

Natural gas is sold on a spot market basis, under longer-term contracts with fixed pricing or terms that track market prices, and under contracts with other types of pricing provisions.[135] The market is highly liquid, price transparent, and facilitated by electronic trading platforms, a vigorous futures market, and the availability of financial instruments to enable price hedging and related activities.

Figure 2.22 illustrates the locations of the top 25 North American natural gas trading hubs, in terms of transaction volume data. Citygate locations, such as Chicago Citygate or SoCal Gas Citygate, are measuring stations at major metropolitan centers where a distributing gas utility, such as SoCal Gas, receives natural gas from a natural gas pipeline company or transmission system.[136]

[132] US Energy Information Administration website, Natural Gas, Definitions, Sources and Explanatory Notes, https://www.eia.gov/dnav/ng/TblDefs/ng_pri_sum_tbldef2.asp (Accessed on February 15, 2016)
[133] Aegent Energy Advisors website, Who Does What in the Gas Industry? http://www.aegent.ca/resources/whodoeswhat.html (Accessed on February 15, 2016)
[134] Federal Energy Regulatory Commission, Energy Primer: A Handbook of Energy Market Basics, November 2015, http://www.ferc.gov/market-oversight/guide/energy-primer.pdf, pp. 32.
[135] Steven Levine, Paul Carpenter and Anul Thapa, Understanding Natural Gas Markets, Prepared for the American Petroleum Institute, 2004, pp.16.
[136] US Energy Information Administration website, Natural Gas, Definitions, Sources and Explanatory Notes, https://www.eia.gov/dnav/ng/TblDefs/ng_pri_sum_tbldef2.asp (Accessed on February 15, 2016)

Figure 2.22: Top 25 North American Natural Gas Trading Hubs

Source: API[137]

This study discusses spot prices of natural gas, or the current wholesale price of natural gas, in four trading locations: Henry Hub (Louisiana), AECO-C (Alberta), Dawn Hub (Ontario) and Chicago Citygate (Illinois).

The natural gas futures contract is traded on the New York Mercantile Exchange (NYMEX) and clears at Henry Hub, Louisiana, a major hub for natural gas pipelines and storage facilities. Prices at other major trading hubs relate to Henry Hub and respond to local supply and demand conditions, production, storage levels and weather patterns. Interconnected with 13 different intra- and interstate pipelines, the Henry Hub is the benchmark price for North American natural gas.

AECO-C is one of North America's leading price-setting benchmarks,[138] partly due to traditionally large volumes of natural gas produced and exported from western Canada to the US. Combined with Alberta's production capacity, accounting for approximately 42 percent of Canada's exports to the US, the facility is connected with an extensive pipeline network, as well as large storage capacity.[139] It is quoted in gigajoules (GJ) and is traded on the Natural Gas Exchange (NGX).

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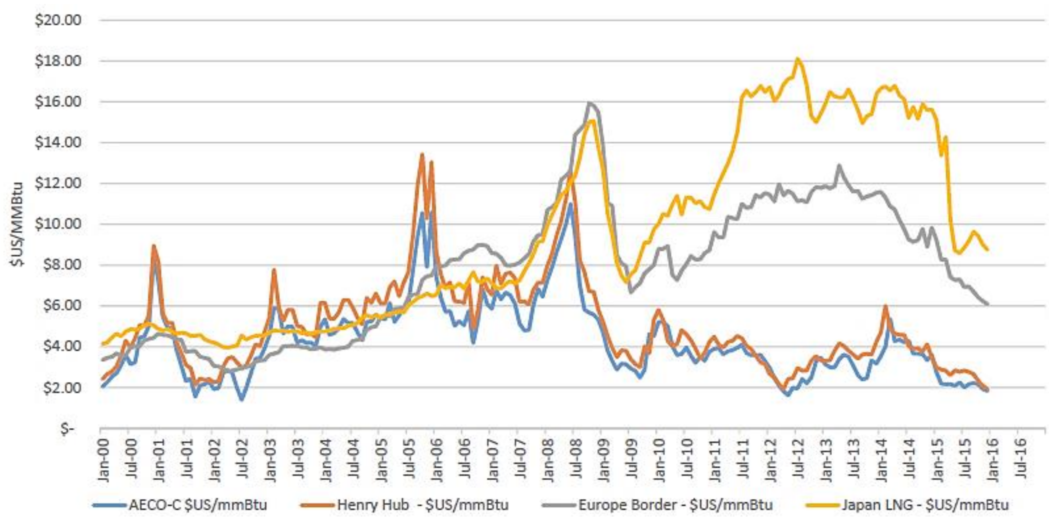
[137] American Petroleum Institute website, The Top 25 North American Gas Trading Locations, http://www.api.org/~/media/Oil-and-Natural-Gas-images/Natural-Gas-Primer-images/Hi-Res/Top-25-north-american-gas-trading-locations-fig18.jpg (Accessed on February 15, 2016)
[138] Alberta Energy website, Natural Gas Prices, http://www.energy.alberta.ca/NaturalGas/725.asp (Accessed on February 15, 2016)
[139] Alberta Energy website, What is Natural Gas? http://www.energy.alberta.ca/naturalgas/723.asp (Accessed on February 15, 2016)

Dawn Hub is located in southern Ontario, well connected to western Canadian gas fields as well as those in the US, including the Marcellus Shale and the Utica Shale. Located near Sarnia, it accounts for most of the natural gas storage in eastern Canada.[140] Natural gas pipelines that directly connect to Dawn include the Dawn-Parkway, Dawn-Ojibway, TCPL's Mainline, Vector Pipeline and ANR-Enbridge. Chicago Citygate, on the other hand, is located where several natural gas pipelines intersect, connecting Canada, the southwest and the Gulf of Mexico (including the Henry Hub). The Dawn-Parkway and Dawn-Ojibway pipelines are operated by Union Gas, also the operator of the Dawn Hub.

Due to the shale gas revolution combined with abundant reserves within Canada and the US, natural gas prices have declined steadily over the past several years and are now less expensive in North America compared to other regions – approximately three times cheaper than in Europe and approximately four times less expensive than natural gas in Asia. Figure 2.23 illustrates global natural gas prices dating back to January 2000. The figure shows AECO-C, Henry Hub, Europe Border and Japan LNG. The Europe Border price is the European Union's natural gas import price while the Japan LNG price is the average LNG import price. The European Border import price is the average border price, including the UK, and as of April 2010 includes a spot price component.[141]

Figure 2.23: Global Natural Gas Prices ($US/MMBtu)



Source: CGA[142]

[140] Ontario Energy Board website, Ontario Energy Report Q4 2014, Oil and Natural Gas, Oct-Dec 2014, http://ontarioenergyreport.ca/pdfs/OEQpercent20Oilpercent20Npercent20Gaspercent20Q4percent202014.pdf, pp. 7.

[141] Quandl website, Natural Gas Price, Europe US$/MMBtu, https://www.quandl.com/data/WORLDBANK/WLD_NGAS_EUR-Natural-gas-Price-Europe-mmbtu (Accessed on February 15, 2016)

[142] Canadian Gas Association, Gas Stats, Chart 4 Global Natural Gas Prices, Price data from graphic is sourced from the US Federal Reserve, World Bank and the CGA, http://www.cga.ca/wp-content/uploads/2016/01/Chart-4-Global-Natural-Gas-Prices.pdf (Accessed on February 15, 2016)

Natural gas prices at Henry Hub averaged US$4.37 per million British Thermal Units (MMBtu) in 2014, 19 percent above the 2013 level of US$3.67.[143] The natural gas price ranged between US$3.65 and US$5.15 per MMBtu in 2014.[144] As of February 1, 2016, the current spot price at Henry Hub is US$2.19 per MMBtu;[145] AECO-C is US$1.99 per MMBtu;[146] and the Dawn Hub is US$2.23 per MMBtu.[147]

Table 2.4 illustrates the average day-ahead natural gas prices annually and seasonally for Henry Hub, AECO-C, Dawn Hub and Chicago Citygate. The average day-ahead prices are generally higher in Dawn Hub and Chicago Citygate than in AECO-C and Henry Hub. The US$8.68 per MMBtu at Dawn Hub and US$7.42 per MMBtu in Chicago Citygate in winter 2013/2014 is the result of the polar vortex in Canada and the US Northeast. The average monthly spot prices at Dawn, for example, were US$17.05 per MMBtu in February 2014 and US$13.39 per MMBtu in March 2014.

Table 2.4: Average Day-Ahead Natural Gas Prices ($US/MMBtu)

	Dawn (ON)	Henry Hub (LA)	AECO (AB)	Chicago Citygate (IL)
2013 Annual	4.08	3.72	3.09	3.85
2013 Summer	4.15	3.76	2.94	3.84
2013/2014 Winter	8.68	4.61	4.36	7.42
2014 Annual	6.13	4.32	4.03	5.52
2014 Summer	4.36	4.18	3.90	4.24
2014/2015 Winter	3.08	3.21	2.58	3.54
2015 Annual	2.93	2.60	2.11	2.73
2015 Summer	2.88	2.67	2.16	2.69
2015/2016 Winter	2.13	2.00	1.79	2.08
2016 Annual	2.56	2.33	1.83	2.44

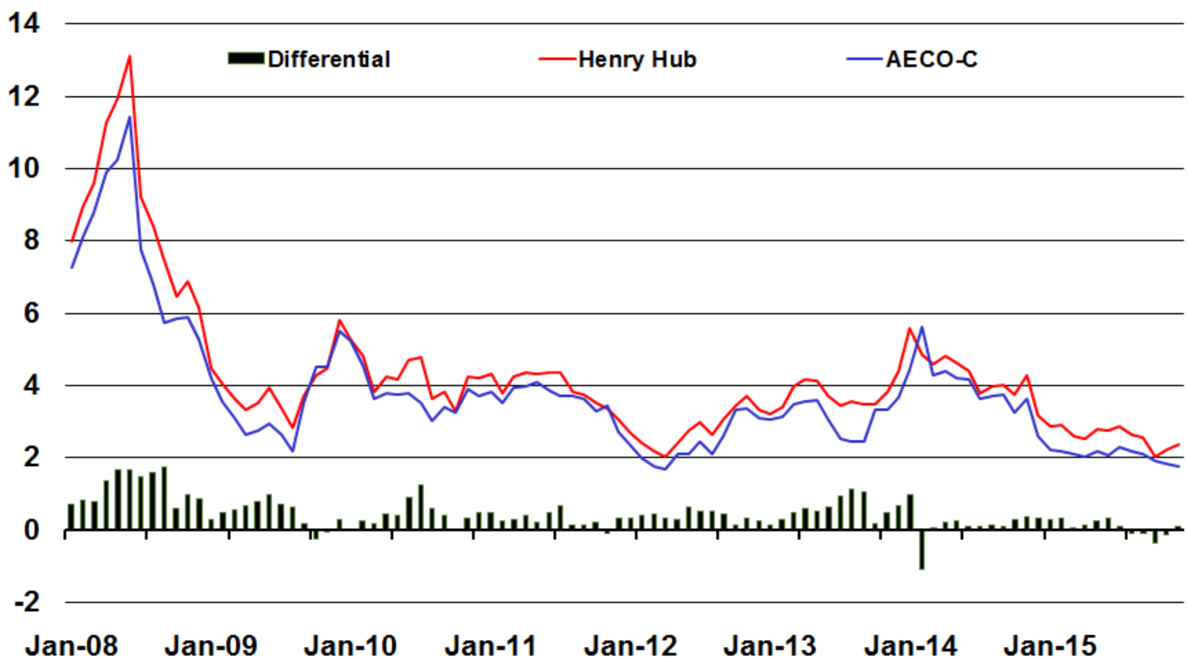
Source: FERC[148]

This study also shows three differentials: Henry Hub/AECO-C, Henry Hub/Dawn Hub and Dawn Hub/Chicago Citygate. The monthly value is the beginning of next month's spot gas price in $US/MMBtu, not daily spot prices averaged over the month. While the price data is collected from Platt's Gas Daily Price Guide, the differentials are calculated by CERI and released in its monthly Natural Gas Commodity Report.

[143] National Energy Board website, Canadian Energy Overview 2014 - Energy Briefing Note, July 2015, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/vrvw/2014/index-eng.html (Accessed on February 15, 2016)
[144] ibid
[145] Platt's website, Gas Daily Market Fundamentals, Volume 4, Issue 21, February 2, 2016, pp. 1. (Accessed on February 15, 2016)
[146] ibid
[147] ibid
[148] Federal Energy Regulatory Commission website, Market Oversight, Midwest Gas Market, January 2016, http://www.ferc.gov/market-oversight/mkt-gas/midwest/2016/01-2016-ngas-mw-archive.pdf, pp. 2. (Accessed on February 15, 2016)

Figure 2.24 illustrates the differential between Henry Hub and AECO-C. The differential in December 2015 is slightly positive at US$0.09 per MMBtu, after four months of negative differentials. The relationship as indicated by Figure 2.23 is generally positive.

Figure 2.24: Henry Hub/AECO-C Beginning of Next Month Spot Price and Differential ($US/MMBtu)



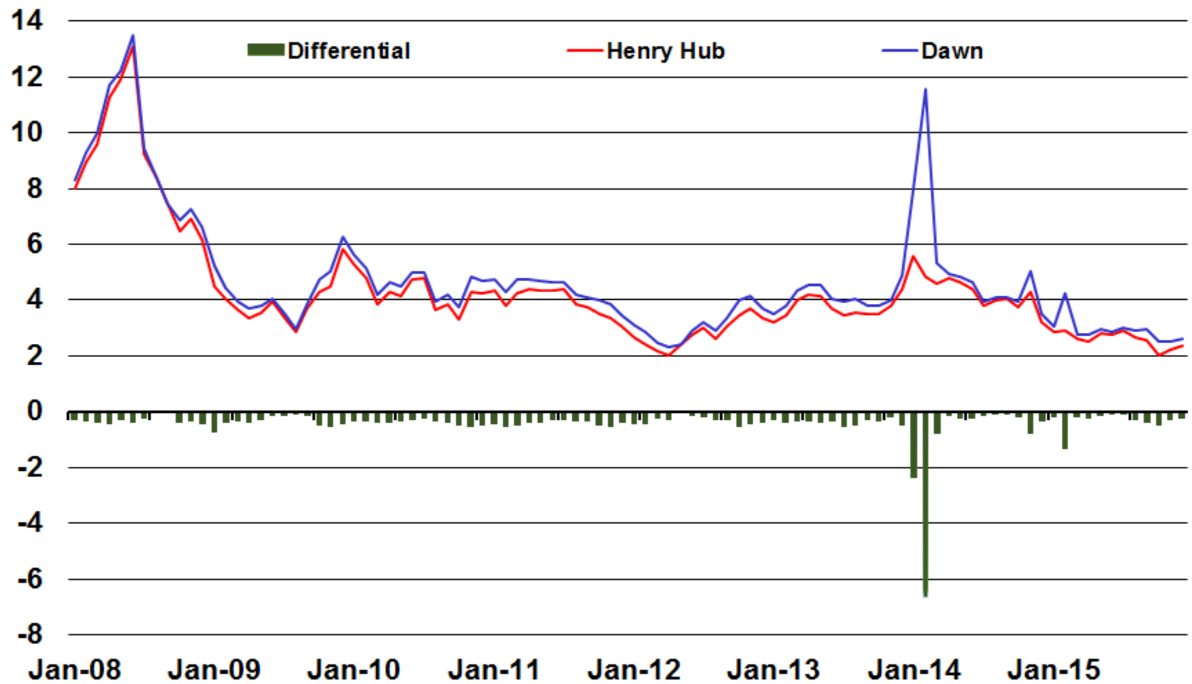
Source: CERI,[149] Platt's Gas Daily Price Guide[150]

The spike in prices at the beginning of 2008 was due to increasing oil prices and the subsequent decline was due to a combination of growing US gas production, decreasing oil prices and the financial crisis. The smaller increase in prices in early 2014 was the result of the polar vortex in Canada and the US Northeast.

Figure 2.25 illustrates the differential between Henry Hub and Dawn. The differential in December 2015 is negative at US$0.24 per MMBtu. With the exception of two occasions since January 2008, when the differential was zero (August 2008 and May 2012), the differential, as indicated by Figure 2.24 is negative, as the beginning of next month spot gas price of Henry Hub is lower than the price at Dawn. The differential, however, peaks at negative US$6.88 per MMBtu in February 2014, the result of the 2013/2014 winter and the polar vortex in Canada and the US Northeast. Below average temperatures increased demand for natural gas, leading to significant price increases. Recall, the average monthly spot price at Dawn, for example, was US$17.05 per MMBtu in February 2014 and US$13.39 per MMBtu in March 2014.

[149] Differentials calculated by CERI, Presented on CERI's monthly Natural Gas Commodity Report
[150] Platt's website, Gas Daily Price Guide (January 2008 – Present) (Accessed on February 15, 2016)

Figure 2.25: Henry Hub/Dawn Hub Beginning of Next Month Spot Price and Differential ($US/MMBtu)

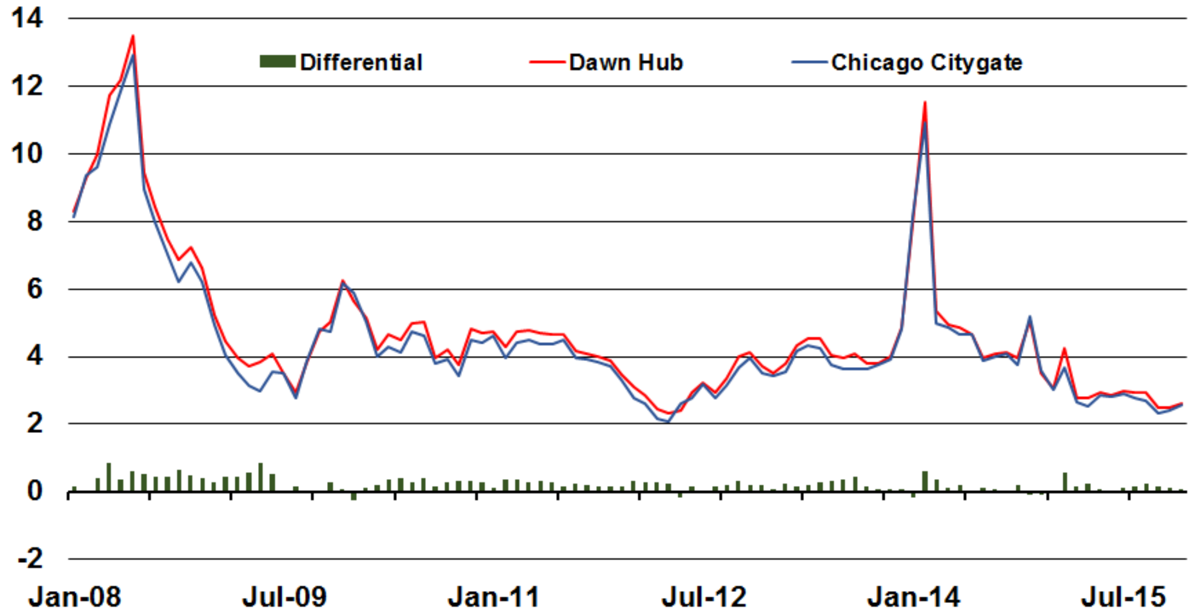


Source: CERI,[151] Platt's Gas Daily Price Guide[152]

Figure 2.26 illustrates the differential between Dawn Hub and Chicago Citygate. The differential in December 2015 is positive at US$0.05 per MMBtu. The differential, as indicated by Figure 2.25 is primarily positive – albeit slightly. Due to their proximity to each other, the differential is narrow, their prices affected by regional markets conditions. For example, both hubs were impacted by the exceptionally cold winter in 2013/2014.

[151] Differentials calculated by CERI, Presented on CERI's monthly Natural Gas Commodity Report
[152] Platt's website, Gas Daily Price Guide (January 2008 – Present) (Accessed on February 15, 2016)

Figure 2.26: Dawn Hub/Chicago Citygate Beginning of Next Month Spot Price and Differential ($US/MMBtu)



Source: CERI,[153] Platt's Gas Daily Price Guide[154]

Retail Prices

This section discusses various natural gas consumer sectors, including residential price, commercial price, industrial price and the electric power price. Each is quoted in different ways, representing the different business sectors and specific markets. The prices vary by political jurisdiction as well as by city.

The price of natural gas to consumers is determined by two main factors.[155] First, the cost of natural gas as a commodity, either as natural gas purchased from a producer or natural gas purchased at a market trading hub or natural gas purchased under a contract by marketers and utilities.[156] The price of natural gas is determined according to supply and demand, storage levels and taxes. Second, the cost of natural gas is determined by transmission and distribution costs, the cost of transporting natural gas, or the pipeline transportation cost, to move gas from the point of production to the local distributors and the cost of distributing the gas to consumers.[157] Recall, Canada is home to one of the world's largest natural gas pipeline networks. Of the more than 450,000 kilometers of pipelines moving natural gas from producing areas to end-users, 248,000 kilometers is distribution mains, 136,700 kilometers is service line and 67,700 kilometers

[153] Differentials calculated by CERI, however, this differential is not presented on CERI's monthly Natural Gas Commodity Report
[154] Platt's website, Gas Daily Price Guide (January 2008 – Present) (Accessed on February 15, 2016)
[155] US Energy Information Administration website, Natural Gas Explained: Natural Gas Prices, http://www.eia.gov/Energyexplained/index.cfm?page=natural_gas_prices (Accessed on February 15, 2016)
[156] ibid
[157] ibid

are transmission mains.[158] The bulk of Canada's natural gas pipeline system is comprised of distribution and service lines, delivering natural gas to the end-users.

The lowest prices of natural gas are paid by companies that purchase natural gas from the wellhead. The natural gas that has not been processed or transported is often purchased by companies from producers in large volumes.[159] The highest prices of natural gas are paid by the residential sector. Most residential and commercial customers generally purchase very small quantities of processed natural gas, delivered through an extensive distribution network, via an LDC or gas marketer. Homeowners also pay for the costs of metering, billing and distribution system maintenance.[160] Many industrial customers or purchasers of large volumes of natural gas purchase natural gas from a marketer or producer, avoiding an LDC and the accompanying additional costs.

This pattern of end-user prices is reflected in Figure 2.27, illustrating monthly US natural gas prices at the wellhead and Citygate, as well as the prices for residential, commercial, industrial and electric power end-users.

Figure 2.27: Monthly Natural Gas Prices, January 2002 - Present (US$/Mcf)

Source: EIA,[161] CERI

[158] Canadian Gas Association website, Gas Stats, Chart 16 Natural Gas Distribution System, http://www.cga.ca/wp-content/uploads/2015/06/Chart-16-Natural-Gas-Distribution-System.pdf

[159] Geology.com website, Understanding Natural Gas Prices, http://geology.com/articles/natural-gas-prices/ (Accessed on February 15, 2016)

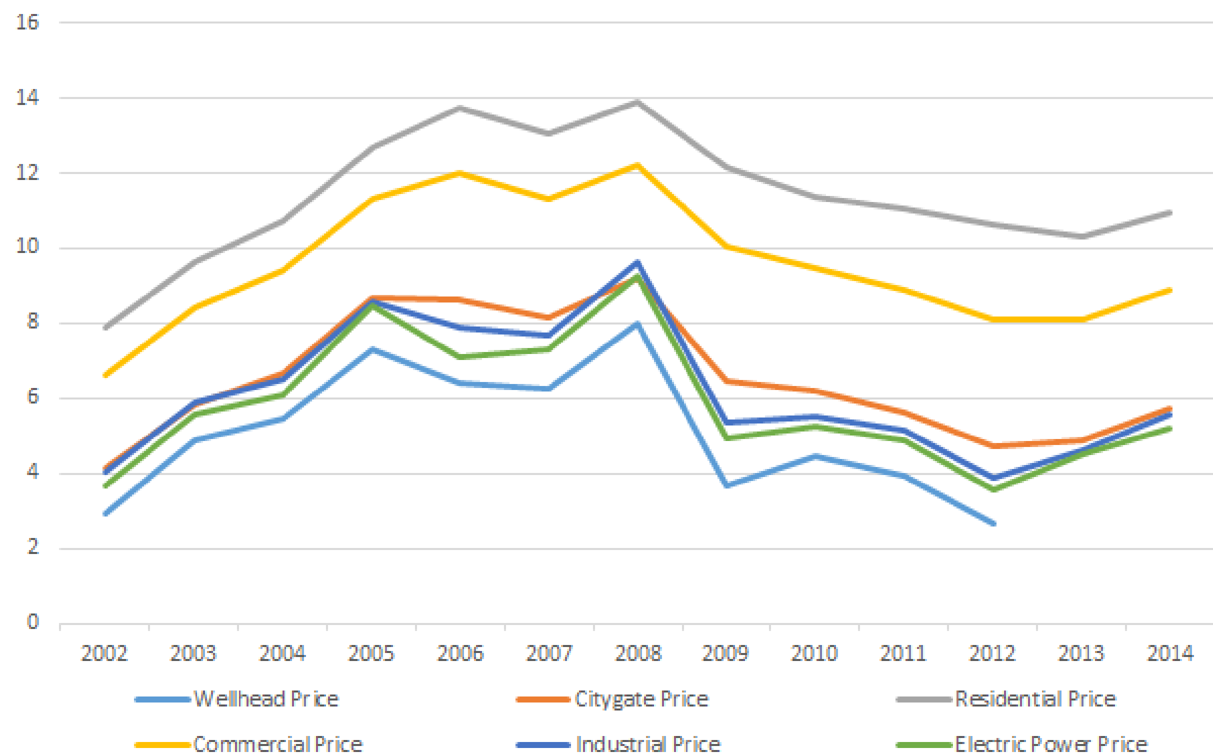
[160] ibid

[161] US Energy Information Administration website, Natural Gas Monthly, January 29, 2016, https://www.eia.gov/naturalgas/monthly/ (Accessed on February 15, 2016)

The lowest natural gas prices in November 2015 are the electric power price (US$2.76 per Mcf), the industrial price (US$3.18 per Mcf) and the Citygate price (US$3.68 per Mcf). All include either large amounts of natural gas and/or cost of distributing and transporting gas. The highest price of natural gas, on the other hand, is the commercial price (US$7.38 per Mcf) and the residential price (US$10.06 per Mcf).

Figure 2.28 illustrates annual US natural gas prices at the wellhead and Citygate, as well as the prices for residential, commercial industrial and electric power end-users. While the figure smooths out the cyclical natural of natural gas prices, particularly for residential prices, the lowest natural gas prices in 2015 are the electric power price (US$2.19 per Mcf), the industrial price (US$5.55 per Mcf) and the Citygate price (US$5.71 per Mcf). The highest price of natural gas, on the other hand, is the commercial price (US$8.90 per Mcf) and the residential price (US$10.97 per Mcf).

Figure 2.28: Annual Natural Gas Prices, January 2002 - Present (US$/Mcf)



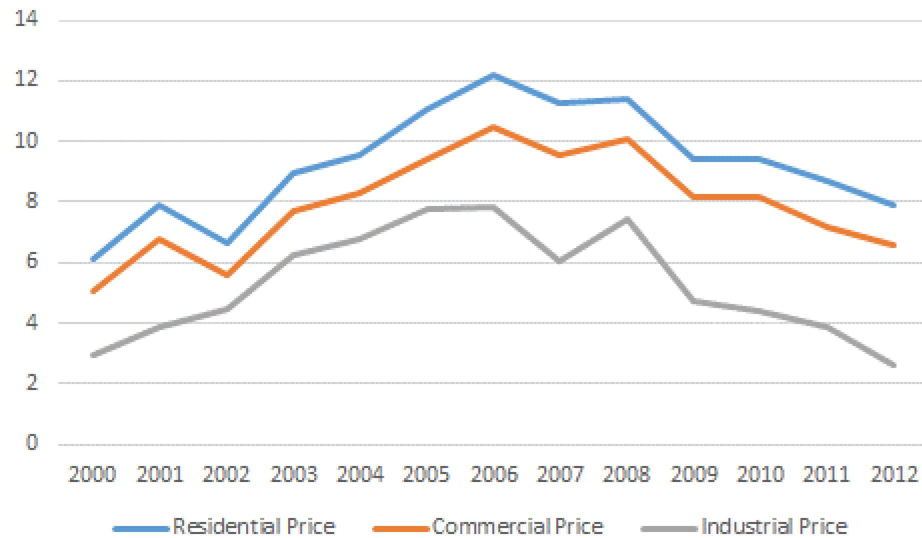
Source: EIA,[162] CERI

Figure 2.29 illustrates annual end-use natural gas prices for residential, commercial and industrial sectors in Canada. Similar to the US, residential end-use prices are higher than commercial use and industrial use. The industrial end-use price of natural gas in 2012 was C$2.63 per GJ,

[162] ibid

compared to the commercial end-use price of C$7.96 per GJ and the residential price of C$9.21 per GJ.

Figure 2.29: End-use Natural Gas Prices (C$/GJ)

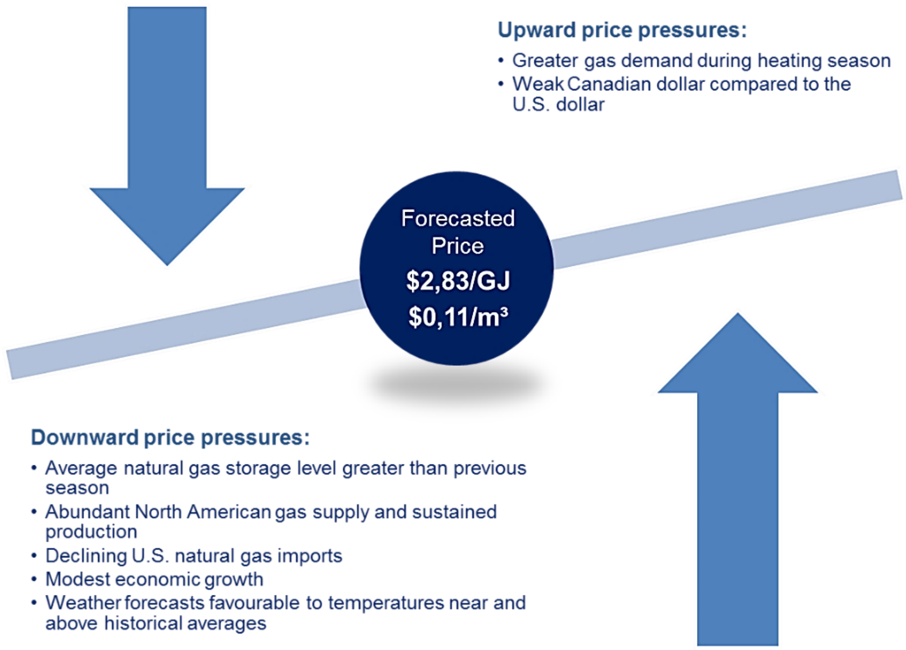


Source: NEB,[163] CERI

Residential and commercial prices tend to increase with high macroeconomic growth, availability of supply and low efficiency gains.[164] Figure 2.30 shows the main factors affecting natural gas prices during the 2015/2016 heating season in Canada and some of the price pressures on the forecasted price of natural gas. Alberta wholesale natural gas prices (AECO) are expected to be \$2.83 per GJ or \$0.11 per m^3 through March 2016.[165] Upward pressures include an increase in gas demand during the heating season as well as a weak Canadian dollar compared to the US dollar. Downward pressures include declining US natural gas imports, continued abundant North American gas supply and high storage levels.

[163] National Energy Board website, Canada's Energy Future, End-use Prices, 2012Cdn$GJ, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2013/ppndcs/pxnds-eng.html, (Accessed on March 31, 2016)
[164] National Petroleum Council website, Prudent Development, Realizing the Potential of North America's Abundant Natural Gas and Oil Resources, Chapter 3: Natural Gas Demand, http://www.npc.org/reports/NARD/NARD_Demand.pdf, pp. 281.
[165] Natural Resources Canada website, North American Natural Gas Market: 2015-2016 Heating Season Outlook, Executive Summary, https://www.nrcan.gc.ca/energy/sources/natural-gas/17894 (Accessed on February 15, 2016)

Figure 2.30: Main Factors Affecting Natural Gas Prices, 2015/2016 Heating Season

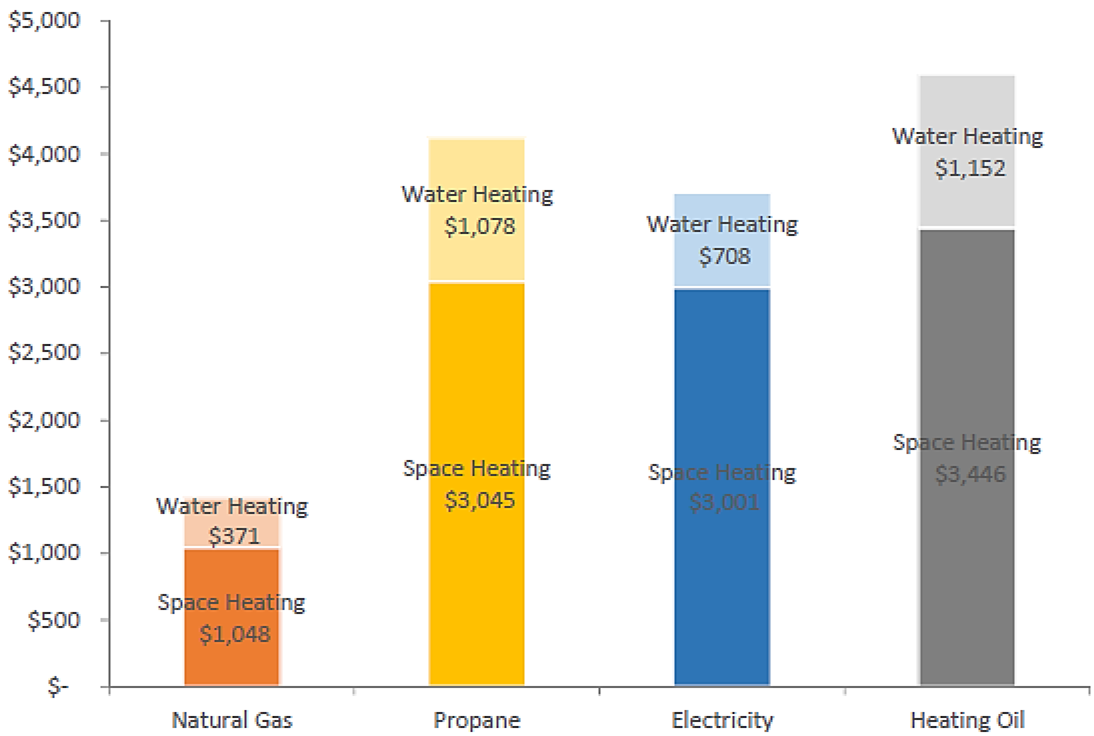


Source: NRCAN[166]

Figure 2.31 illustrates the residential space and water heating costs in Canada in 2014. The figure compares natural gas, propane, electricity and heating oil in dollars per year and illustrates that on average Canadian heating costs are lower with natural gas, reiterating the popularity of natural gas in space and water heating in Canada.

[166] Natural Resources Canada website, North American Natural Gas Market: 2015-2016 Heating Season Outlook, Executive Summary, https://www.nrcan.gc.ca/energy/sources/natural-gas/17894 (Accessed on February 15, 2016)

Figure 2.31: Residential Space and Water Heating Costs in Canada, 2014 (dollars per year)



Source: CGA[167]

[167] Canadian Gas Association website, Gas Stats, Chart 19, Residential Space & Water Heating Cost – Canada 2014, http://www.cga.ca/wp-content/uploads/2015/05/Chart-19-Residential-Heating-Costs.pdf (Accessed on February 15, 2016)

Chapter 3: Canadian Natural Gas Supply and Demand Outlook

This chapter examines CERI's Canadian natural gas supply and demand outlook. This section is divided into four parts: Canadian supply, Canadian gas demand (west versus east), storage, and climate change policies (provincial and federal). The Canadian supply section includes production forecasts for western Canada, eastern Canada, offshore, compressed natural gas and northern Canada, while the Canadian demand section includes sectoral demand and storage.

Canadian Natural Gas Supply Outlook

As of December 2014, it is estimated that Canada has 1,087 Tcf of remaining marketable natural gas resources, with 79 percent of it in the WCSB, 11 percent in northern Canada, 8 percent on the East Coast, and the remaining 2 percent on the West Coast, Ontario and Quebec.[1]

Canadian production activity mirrors the concentration of the available resources. The WCSB has seen the majority of production, representing 98 percent as of December 2015. Northern Canada has seen small but declining production due to maintenance issues, production costs and a lack of transportation infrastructure, while eastern Canada has seen declining production due to high supply costs and regulatory issues that have discouraged investment.

Without appropriate infrastructure in place, Newfoundland's associated offshore gas will not make it to market. The offshore projects in Nova Scotia are set to cease producing within the 20-year timespan and possibly within the next 5 years. The New Brunswick McCully field is set to stop production within the next 20 years, and while the resource still exists, unless the moratorium on fracturing is lifted, no more drilling will occur. Quebec is not expected to start producing, for cost and regulatory reasons. Ontario is not predicted to drill any further wells, so the wells currently producing will be the ones making up the supply by 2037. In the Yukon, conventional gas production was estimated to have 5-10 years of production left in 2014,[2] although the NEB estimates gas production until 2040.

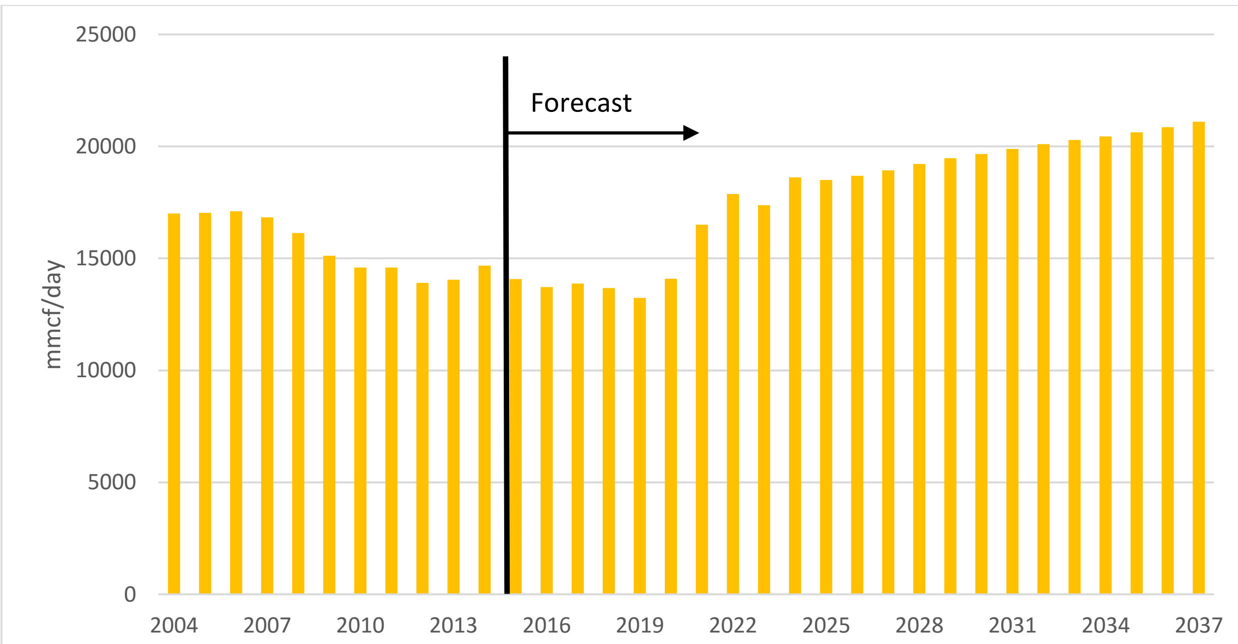
Over the next 20 years, the WCSB is expected to represent almost the entirety (99.99 percent) of Canadian production as production declines are seen in every other Canadian producing jurisdiction. The next 20 years will see increases in production in the WCSB, particularly after 2020, and large decreases in production in every other location in Canada.

[1] National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, January 2016, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html, pp. 61
[2] Yukon Legislative Assembly, Yukon Select Committee on Hydraulic Fracturing, January 31, 2014, http://www.legassembly.gov.yk.ca/pdf/rbhf_EFLO-Presentation.pdf, pp 5

While well economics play a large role in the slowing and stopping of production in these areas, regulatory issues are also at play, including the moratorium on fracturing in Quebec and New Brunswick and opposition to transportation infrastructure throughout Canada.

Total Canadian natural gas production is expected to increase over the next 20 years, attributable to a predicted rebound in the price of natural gas, and a demand for LNG. Expected production through 2037 is shown in Figure 3.1. Production is forecasted to decline in the near term until 2019 as depressed natural gas prices push drilling down in western Canada, after which point it will climb to above 21 Bcfpd by the end of the forecast period. The forecast includes potential supply to service LNG plants.

Figure 3.1: Canadian Natural Gas Production Forecast

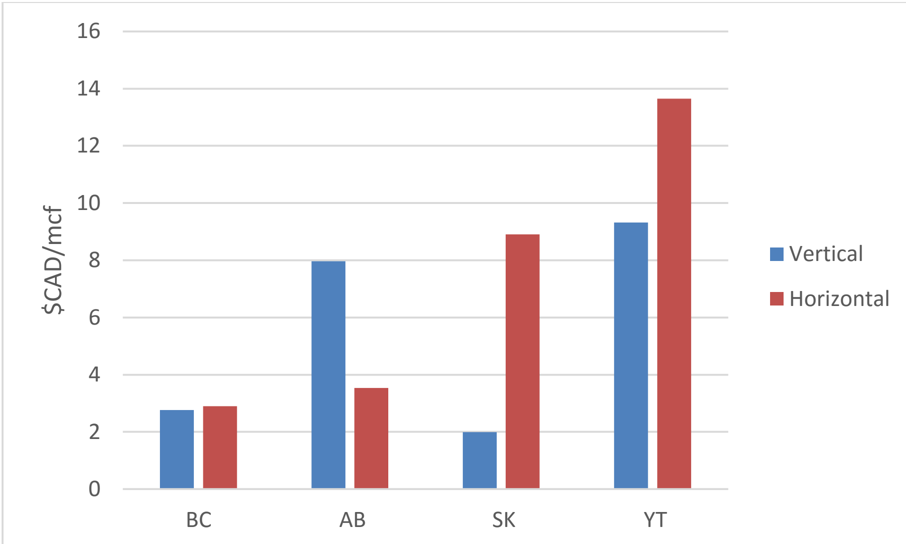


Source: CERI, PSAC, CAPP, NEB, EIA

The ramp up in production in 2020-2022 results from increased demand and improvements in well drilling leading to reduced production costs, particularly in Alberta.

Looking ahead, the production increases will occur in western Canada, namely the WCSB (British Columbia, Alberta and Saskatchewan). CERI calculated supply costs for vertical and horizontal wells in these regions and the weighted averages of the results, by region, are shown in Figure 3.2.

Figure 3.2: WCSB Supply Costs – Weighted Averages

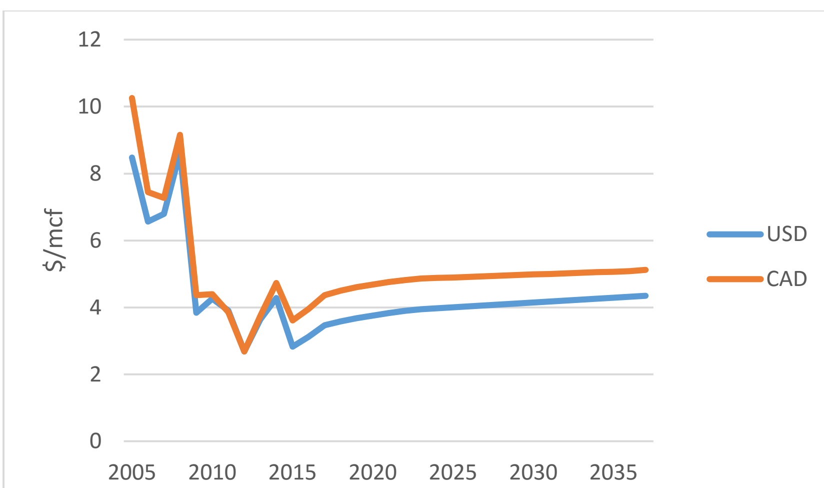


Source: CERI, PSAC, CAPP, NEB, EIA

The supply cost can be interpreted as the price of natural gas required to break even, given the capital expenditure, operating costs, royalties, taxes and a return on investment of 10 percent. If the price of natural gas is at least as high as the supply cost, the well is able to recover its full cost over its lifetime.

Figure 3.3 shows the National Energy Board's (NEB's) reference case prediction of the price of natural gas at Henry Hub through 2037 in both Canadian and US dollars.[3]

Figure 3.3: Henry Hub Price Forecast



Source: NEB

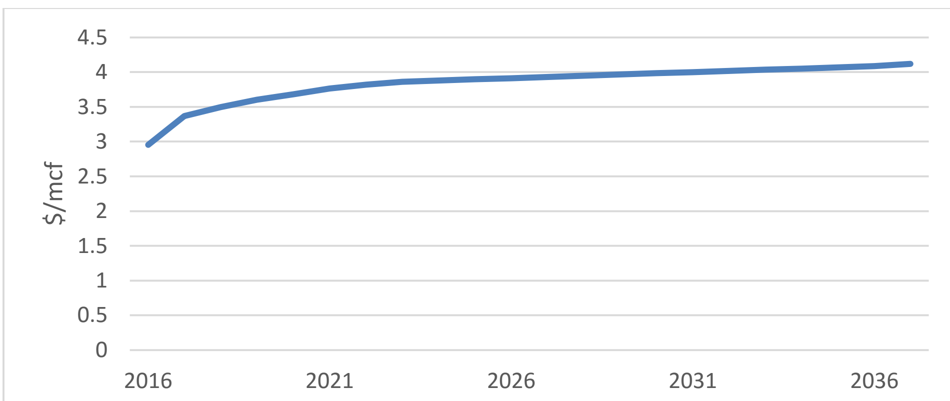
[3] National Energy Board, Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040, January 2016, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/index-eng.html

The natural gas price that is relevant to the supply cost in western Canada is the AECO-C price, converted to Canadian dollars. Both the conversion from Henry Hub to AECO-C pricing, and the conversion from US to Canadian dollars, are variable.

The biggest economic change to Canada as a result of lower oil prices has been the corresponding decline in the Canadian dollar. Since summer of 2014, the price of oil has dropped to its lowest point in years – and so has the Canadian dollar, continuing an ongoing debate on how closely the two are related. For a more detailed discussion of this relationship, please see CERI Study 156, "Low Crude Oil Prices and their Impact on the Canadian Economy", February 2016. For the purposes of this study, CERI uses an exchange rate rising from US/CDN$0.79 to US/CDN$0.85 over the forecast period. This assumption is discussed in Appendix A.

Figure 3.4 shows the forecast of natural gas at AECO-C from 2016 through 2037 in Canadian dollars. While the relationship between AECO-C and Henry Hub fluctuates, CERI assumes AECO-C sells at a discount to Henry Hub of $1.03CAD/MMBtu, or $1.00/Mcf.

Figure 3.4: AECO-C Price Forecast

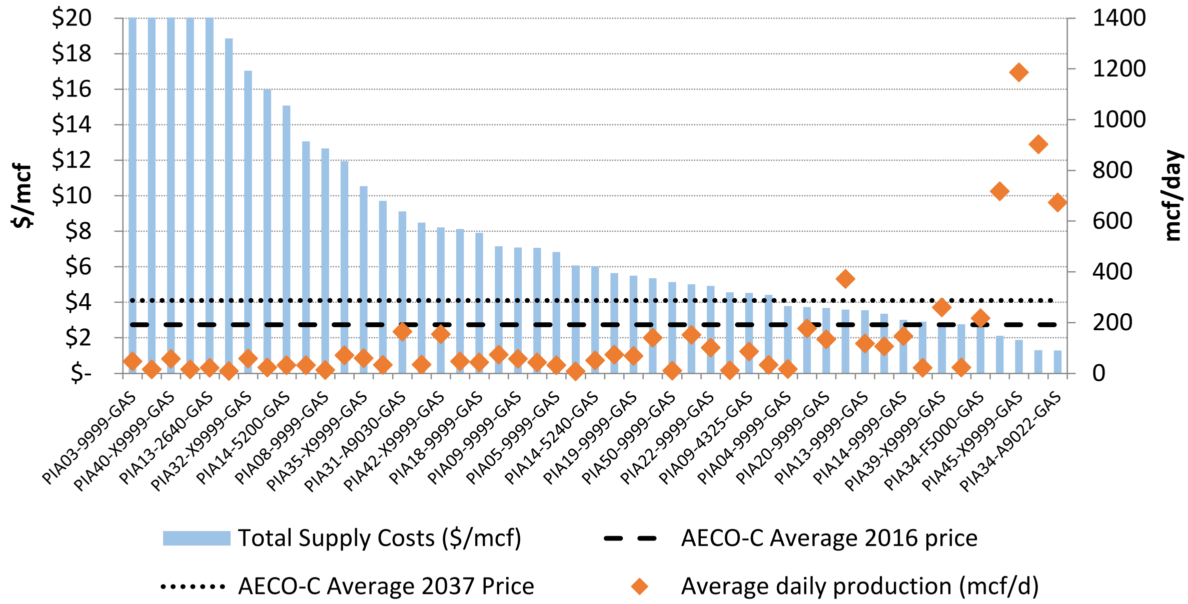


Source: NEB, CERI

These average supply costs are not necessarily indicative of future drilling, as considerable variance exists between formations.

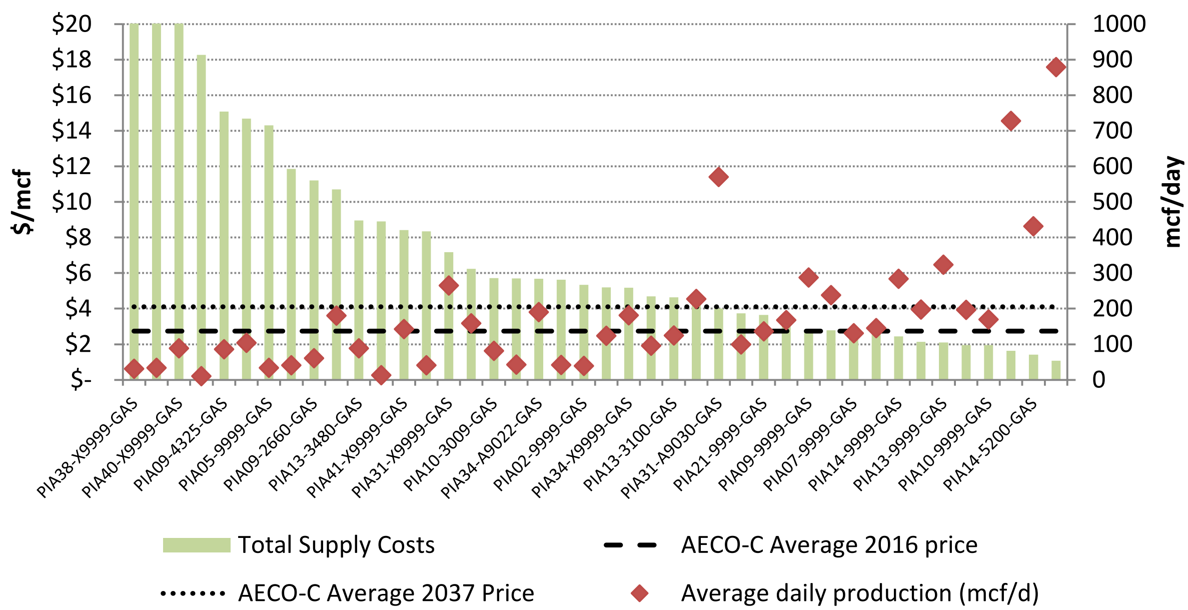
The specific well study areas that were analyzed are shown in Figures 3.5 and 3.6 against the current AECO-C price and the price forecasted for 2037. A detailed overview of supply cost methodology and the descriptions of study areas are presented in Appendices A and B, respectively.

Figure 3.5: Vertical Well Supply Costs, 2015



Source: CERI

Figure 3.6: Horizontal Well Supply Costs, 2015



Source: CERI

The most economically viable wells, both vertical and horizontal, are in the province of British Columbia, particularly its Montney formation. Since 2013, approximately 65 percent of the wells drilled in British Columbia have been in its Montney formation. The remainder of the drilling has been split fairly evenly between the rest of British Columbia's formations, with the next highest numbers coming out of its Jean Marie formation at 5 percent. The Montney has the overwhelmingly highest concentration of activity, and it is expected that this will remain the case throughout the study period due to its favorable well economics. These supply cost calculations do not incorporate the hydrogen sulfide content. That is, the effort required to handle sour gas is not a part of the calculation. As reflected in Appendix A, 5 of the 40 areas examined produce sour gas.

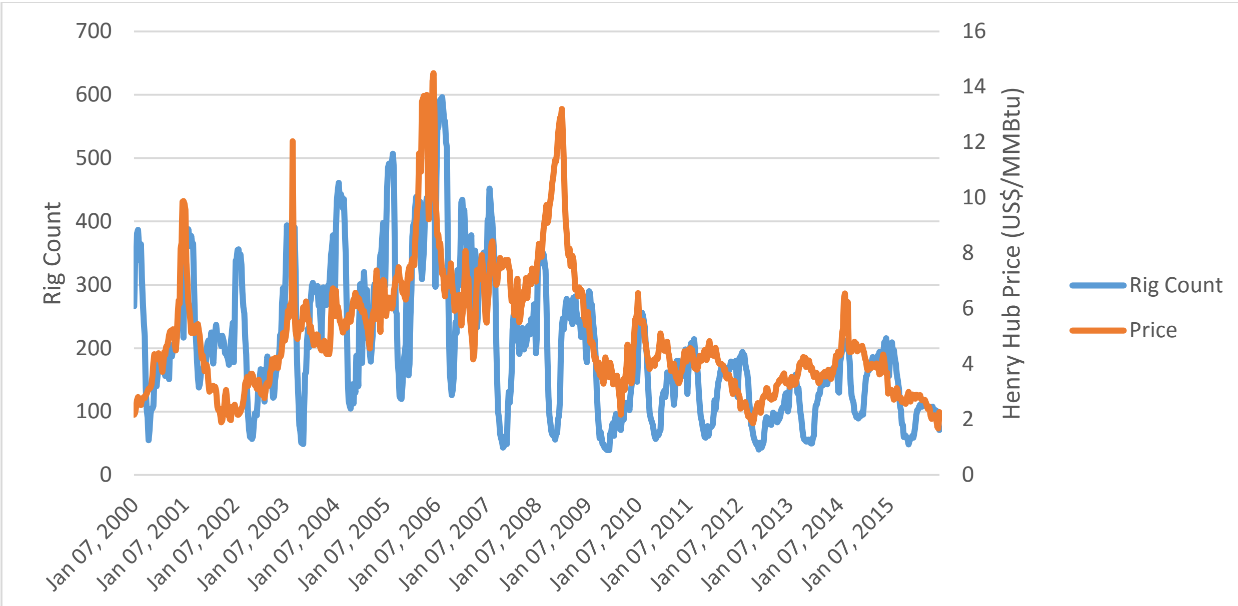
Economies of scale are relevant to the calculations of an individual producer, as many well pads will contain multiple wells. In looking at British Columbia's drilling over the past year, the Montney formation has seen, on average, more than 6 wells per pad. The more prolific formations in Alberta have seen approximately 2 wells per pad over the same period of time. British Columbia is more established in commercial development over many parts of Alberta, lending to the higher economics of scale seen in British Columbia drilling.

The presence of liquids in the gas pools impacts supply costs as well. For wells in British Columbia and Alberta, a cut of liquids is assumed where applicable, which increases the operating cost of the well but also increases revenues from the well. Increased operating costs include the gathering, processing, transport and fractionation of the liquids.

There are more Alberta wells located at the lower end of the supply cost curve for horizontal drilling rather than vertical drilling. When looking at drilling numbers in specific formations, the McMurray formation sees approximately 30 percent of the drilling activity since 2013. While this is the highest concentration of activity within a specific Alberta formation, the corridor to the east of the Rocky Mountains has collectively a higher concentration of activity. Formations include Alberta's Montney, Doig, Cardium, Banff, Glauconitic and Beaverhill as well as collective smaller pools. The weighted average supply cost of the ten Alberta areas in this region is $1.83/Mcf. These area IDs are as follows: PIA16-9999-GAS, PIA07-9999-GAS, PIA15-9999-GAS, PIA14-9999-GAS, PIA14-5240-GAS, PIA13-9999-GAS, PIA11-9999-GAS, PIA10-9999-GAS, PIA34-F5000-GAS, PIA14-5200-GAS, PIA03-9999-GAS, PIA30-X9999-GAS and PIA33-X9999-GAS. Areas PIA11-9999-GAS and PIA15-9999-GAS were among the areas with the highest volumes of liquids – over 100 bbl/mmcf.

Figure 3.7 shows that Canada's rig count has historically followed the price of natural gas with a slight lag. Significant drops in price, seen in 2005 and 2008 are followed by a reduction in drilling activity, and the price drop since 2014 is no exception.

Figure 3.7: Natural Gas Rig Count



Source: Baker Hughes, CERI

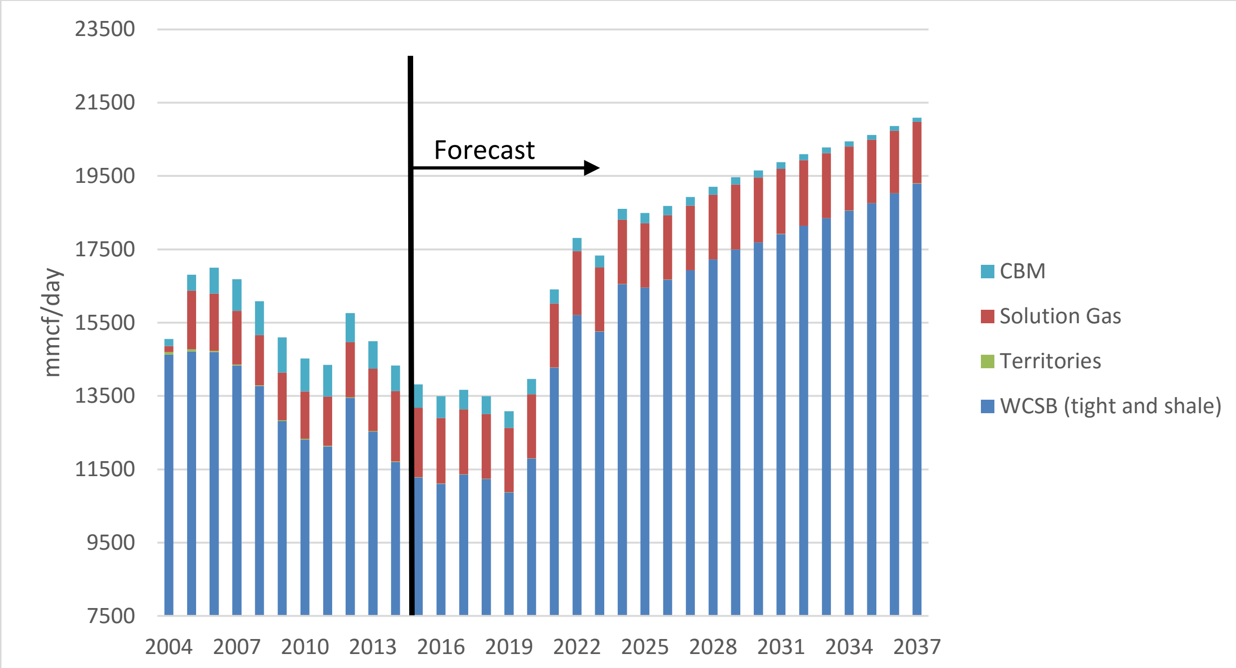
With the higher efficiencies seen from horizontal drilling, as well as the higher levels of production that are coming out of unconventional plays where horizontal drilling is used, horizontal drilling is expected to make up a higher proportion of the total drilling in the future. This will change how closely the rig count follows price, although the general trend will remain the same. With the NEB's prediction of Henry Hub pricing remaining below $5/Mcf through 2037, rig counts are not expected to reach the peaks seen in 2005 or 2008, but efficiencies in drilling technology will allow them to rise higher than current levels.

The supply of natural gas in Canada can be roughly divided into two sections: western Canada, where supply is expected to increase, and eastern Canada, where supply is expected to decrease. This study groups British Columbia, Alberta, Saskatchewan, Manitoba, the Yukon and Northwest Territories together as western Canada, and considers all provinces to the east of Manitoba, as well as Nunavut, to be eastern Canada.

Western Canadian Gas Supply

Natural gas production in western Canada primarily comes out of the WCSB – a 1,400,000 km^2 basin located in the provinces of British Columbia, Alberta, Saskatchewan and Manitoba, and part of the Northwest Territories and Yukon. As of December 2015, it represents 98 percent of the natural gas produced in Canada, and represents 79 percent of Canada's natural gas resources. The costs that determine whether or not a well area within the WCSB is economically viable are dependent on the geology of the formation, the quality of the hydrocarbon, the royalty and tax regime of the province or territory and the proximity to infrastructure. Figure 3.8 shows Western Canadian natural gas production through 2037.

Figure 3.8: Western Canadian Natural Gas Production Forecast, without LNG

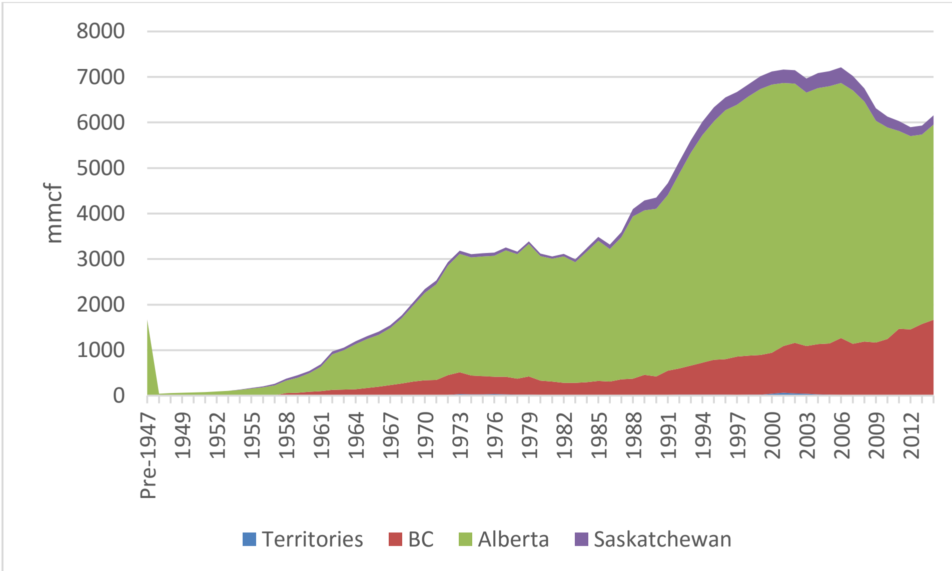


Source: CERI

This analysis differentiates between the types of production. Production includes that from tight and shale gas resources and is expected to represent the entirety of natural gas production growth in western Canada. Increases in production are expected to occur in 2020, lagging slightly behind the expected rise in the price of natural gas. Production will start to increase after 2019 as the price of natural gas is expected to recover from its current low values, with gradual and consistent increases seen throughout the rest of the study period. Production from solution gas is predicted to remain stable throughout, with volumes from coalbed methane and from the territories expected to decline, while the natural gas that will supply the LNG facilities will come from tight resources. This gas will be sourced mainly from British Columbia, specifically the northeastern part of the province where the well areas are the most economically viable. As discussed separately in this study, the assumption is that 4 Bcfpd will be produced to meet supply of the LNG projects that come online. CERI assumes the first 2 Bcfpd is produced in 2020, with the following years seeing production of the full 4 Bcfpd.

Alberta produces the vast majority of the natural gas that comes out of western Canada. Figure 3.9 shows natural gas production data from 1947 through 2014.

Figure 3.9: Western Canadian Natural Gas Production, 1947-2014



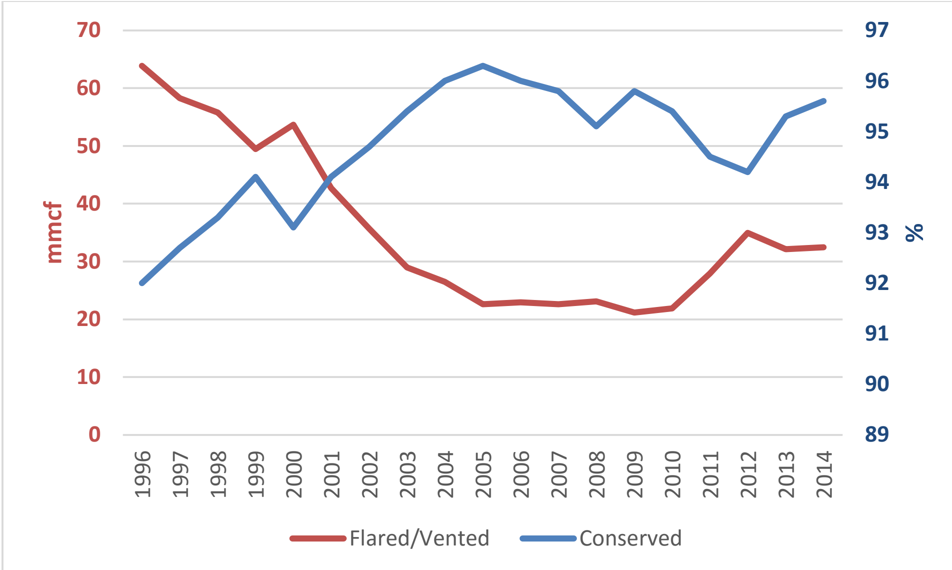
Source: CAPP,[4] CERI

This is consistent with the level of resource available in western Canada. There is an estimated 77 Tcf of recoverable resources, not including shale gas in Alberta, with an additional 500 Tcf gas-in-place of coalbed methane.[5] While the reserve potential of shale gas in the province has not been fully explored to date,[6] these resources far surpass those found in the other Western Canadian provinces. Shale plays in the province include the Duvernay, Exshaw/Lower Banff and Montney.[7]

Making up a consistent proportion of produced gas in Alberta is solution gas, that is, gas that is dissolved in oil. This gas is alternatively referred to as associated gas. Historically this gas was flared off, however in 1999 the Alberta Department of Energy introduced the Otherwise Flared Solution Gas Waiver Program[8] as an incentive for producers to conserve rather than flare the gas. Figure 3.10 shows a comparison of conserved to flared/vented gas in the province of Alberta since 1996.

[4] Canadian Association of Petroleum Producers, CAPP Statistical Handbook September 2015, Table 3.9
[5] Alberta Energy Website, What is Natural Gas? Accessed March 2016, http://www.energy.alberta.ca/naturalgas/723.asp
[6] Government of Alberta Website, About the Industry, accessed March 2016, http://www.albertacanada.com/business/industries/og-about-the-industry.aspx
[7] Natural Resources Canada website, Alberta's Shale and Tight Resources, accessed March 2016, http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17679
[8] Alberta Resource Development, Otherwise Flared Solution Gas Royalty Waiver Program, July 11, 1999, http://inform.energy.gov.ab.ca/Documents/Published/IL-1999-19.PDF

Figure 3.10: Associated Gas Conserved (%), Flared and Vented (volume)



Source: Alberta Energy Regulator

As is evident from the figure, an increase in conserved associated gas occurred after the implementation of the Otherwise Flared Solution Gas Waiver Program. The increase in flaring and venting seen from 2010 through 2012 was attributable to the combination of high oil prices and low gas prices, leading to economically favourable conditions for new crude oil production with reduced incentive for gas conservation.[9] The current low price environment is an incentive for conservation, as is evidenced by the uptick in conservation after 2012.

In August of 2015, Alberta's newly elected NDP Government announced the creation of a Royalty Review Advisory Panel. The panel suggested changes in order to optimize returns to the province while continuing to encourage industry investment in the province.[10] The resulting New Royalty Framework was announced in late January 2016, although many of the details are not yet finalized. In 2017, applicable to new wells, the royalty calculation will change in order to "reward producers who reduce drilling costs below the industry average through innovation".[11] While Alberta natural gas well economics have decreased in viability since the increase in production out of the United States, reductions in input costs such as royalties will help to encourage investment in the province.

British Columbia has the second largest production levels in western Canada. The four major gas producing regions in the province are unconventional plays: the Montney, the Horn River Basin,

[9] Alberta Energy Regulator, Upstream Petroleum Industry Flaring and Venting Report, October 2013, https://www.aer.ca/documents/sts/ST60B-2013.pdf, pp. iv
[10] Government of Alberta website, Royalty Review Panel Consultation, accessed December 2015, http://www.alberta.ca/royalties-panel-consultation.cfm
[11] Government of Alberta website, Modernized royalty system will promote jobs and investment activity, while increasing revenue to Albertans over time, January 29, 2016, http://www.alberta.ca/release.cfm?xID=401549005F415-9317-CF43-C78C039FA66A7F75

the Liard Basin and the Cordova Embayment. The estimated reserves in the province at the end of 2014 were 51 Tcf of raw natural gas,[12] with half of that being found in the Montney. The Montney represents just over half of the production activity in the province.[13]

Specific areas of the province have very favourable supply costs, which will lead to increased production out of the province over the study period. Demand for natural gas as a feedstock to British Columbia's LNG facilities will drive increased growth in this area, particularly in the Horn River and Liard Basin. This study assumes that supply will increase to match demand from the LNG plants, and this alone will increase production out of the province by 4 Bcfpd.

As highlighted in Figure 3.9, natural gas production in British Columbia has steadily increased since the 1950s, with marked increases in the 1970s, 1990s and most recently since 2009. The recent uptick in production has almost entirely been due to increased volumes out of the Montney.[14] British Columbia also has large inland and offshore sedimentary basins which have not been developed for a variety of reasons. The significant inland basins are as follow: the Nechako Basin with resources of 9,500 bcf of gas, the Bowser Basin with resources of 16,000 bcf of natural gas and 8,087 bcf of coalbed methane, and the Whitehorse Trough with resources of 1,800 bcf of natural gas.[15] Smaller basins include the Georgia Basin, the Rocky Mountain Trench and the Fernie Basin, all located along the southern border of the province. Challenging geological conditions and lack of infrastructure due to the location of the basins have discouraged production.[16]

The offshore basins are the Queen Charlotte with 25,600 bcf of natural gas, the Tofino with 9,400 bcf of natural gas and the Winona with an unknown resource.[17] Offshore exploration started in 1967 by Shell Canada, however the federal government initiated an offshore drilling moratorium, which was reiterated by the provincial government in 1989 and also by the Haida House of Assembly in 1985.[18] In 2001, the province of British Columbia announced that it would reverse the moratorium on exploration,[19] however that was never done. In 2011, the provincial energy minister referenced increased attention on British Columbia's unconventional resources as reason for why offshore development is no longer a focus for producers.[20]

[12] BC Oil and Gas Commission, Hydrocarbon and By-product Reserves in British Columbia, October 2015, pp. 4
[13] ibid, pp. 9
[14] Natural Resources Canada website, British Columbia's Shale and Tight Resources, accessed March 2016, http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17692
[15] Energy BC website, B.C.'s Fossil Fuel Potential, accessed March 2016, http://www.energybc.ca/map/sedimentarybasinsmap.html
[16] ibid
[17] ibid
[18] Library of Parliament, Offshore Oil and Gas Development in British Columbia, November 22, 2004, pp. 1
[19] ibid
[20] CBC News, B.C. offshore drilling no longer a priority, May 8, 2011, http://www.cbc.ca/news/canada/british-columbia/b-c-offshore-drilling-no-longer-a-priority-1.1082525

With the third largest amount of production in western Canada, Saskatchewan has been drilling commercial gas wells since the 1930s with significant growth in the industry seen in the 1980s.[21] Prior to the advances in horizontal drilling, the majority of gas produced in the province was dry gas from the Swift Current region.[22] Currently the major gas producing fields in Saskatchewan are the Viking and Bakken shale formations, although most of the province's focus is on oil rather than gas production.[23] While Saskatchewan's average vertical supply costs were the lowest calculated, its supply costs for horizontal drilling were the highest. With horizontal drilling trending up as a proportion of higher drilling, gas production out of Saskatchewan is not expected to contribute to the growth seen in the Western provinces.

Making up 0.8 percent of Canada's natural gas production in 2015 were the Yukon and Northwest Territories (NWT). The Yukon is home to the Kontaneelee gas field in the Liard basin, while the NWT produces out of Ikhil, Norman Wells and Cameron Hills. The Yukon has an onshore natural gas potential of approximately 17 Tcf. Although natural gas resources have been identified in eight hydrocarbon basins across the Territory, the Kontaneelee gas field has functioned as the Yukon's only source for natural gas production for more than 30 years. As such, the cumulative production of 230 Bcf of conventional natural gas resources from this gas field has generated royalties to the Yukon government and First Nations in excess of $45 million.

To date, natural gas resources in the Yukon remain stranded. While 3 wells have ably supported natural gas production in the Kontaneelee gas field, within the southeastern region of the Yukon Territory, well maintenance issues have been cited as one of the reasons that production in the Kontaneelee field was topped in October 2012. Public consultation has revealed the concerns that Yukoners have about the risks associated with hydraulic fracturing. Until 2015, these concerns have inhibited the development of natural gas resources in the Yukon. Between well commissioning issues and fracturing uncertainties, it has been suggested that the province may only continue to produce natural gas for the next decade. CERI estimates that production from the Yukon will taper off to effectively be finished at the end of the study period.

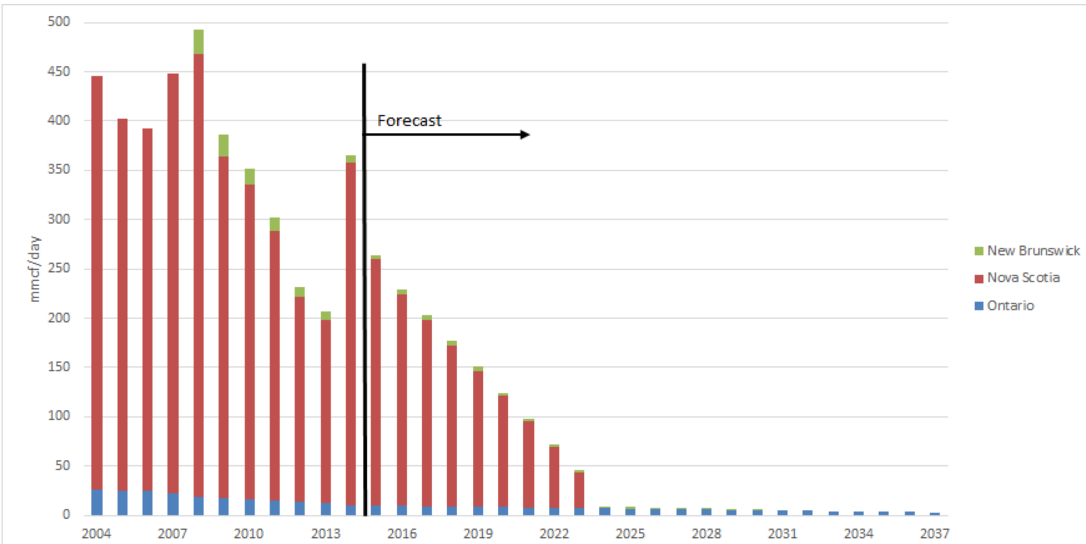
The NWT currently produces gas from three onshore wells. While offshore natural gas reserves in the Territory are estimated to contain 9 Tcf of natural gas resources, production costs and a lack of transportation infrastructure are the major reasons for inactivity in this region. It is likely that there would be considerable public concern for environmental matters were offshore development to be considered.

[21] Government of Saskatchewan website, Natural Gas, accessed December 2015, http://www.economy.gov.sk.ca/NaturalGas
[22] The Encyclopedia of Saskatchewan, accessed March 2016, http://esask.uregina.ca/entry/oil_and_gas_industry.html
[23] Pipeline News, Saskatchewan's natural gas drilling is all but dead, June 20, 2015, http://www.pipelinenews.ca/features/drilling-exploration/saskatchewan-s-natural-gas-drilling-is-all-but-dead-1.1953654

Eastern Canadian Gas Supply

Natural gas production in eastern Canada made up less than one percent of the Canadian total at the end of 2015. While significant reserves exist, particularly offshore, current economic, regulatory and political considerations see production in the region being effectively eliminated before the end of this study period. This is highlighted in Figure 3.11.

Figure 3.11: Eastern Natural Gas Production



Source: CERI

The overwhelming majority of natural gas production in eastern Canada is from Nova Scotian offshore wells. Nova Scotia is home to three offshore petroleum producing projects: the Cohasset-Panuke project which produced oil from 1992-1999, the Sable Offshore Energy project which started producing natural gas and NGLs in 1999, and the Deep Panuke Offshore Gas project which started producing natural gas in 2013.[24]

When the Sable Offshore Energy Project (SOEP) started producing, Exxon-Mobil, the major operator, predicted that the project would have a 25-year lifespan.[25] In 2010 Exxon-Mobil announced it was winding down the project, and in 2015 it announced that wells could start being plugged as early as 2017.[26] SOEP has had issues throughout the duration of the project life. Many dry holes were drilled in the Scotian Shelf, with oil and gas investment estimated at a cost

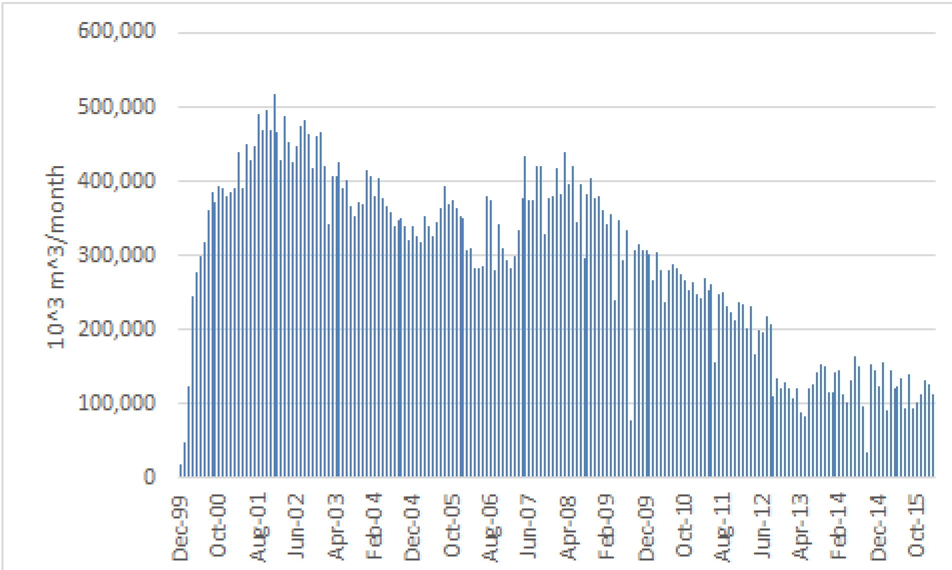
[24] Canada-Nova Scotia Offshore Petroleum Board website, Accessed January 2016, http://www.cnsopb.ns.ca/offshore-activity/offshore-projects

[25] CBC News, Exxon-Mobil prepares to decommission Sable gas field, April 8, 2013, http://www.cbc.ca/news/canada/nova-scotia/exxon-mobil-prepares-to-decommission-sable-gas-field-1.1385087

[26] Arenburg, Patricia Brooks, Sable may start shutting down in 2017, Herald Business, June 25, 2015, http://thechronicleherald.ca/business/1295318-sable-may-start-shutting-down-in-2017

of $75 million per well for many of them.[27] Initial production declines started in 2002, three years after the start of the project. Production increased until 2008, at which point the field experienced a more marked decline. The SOEP's monthly gas production from 1999 through 2015 is shown in Figure 3.12.

Figure 3.12: Sable Offshore Energy Project's Total Monthly Gas Production

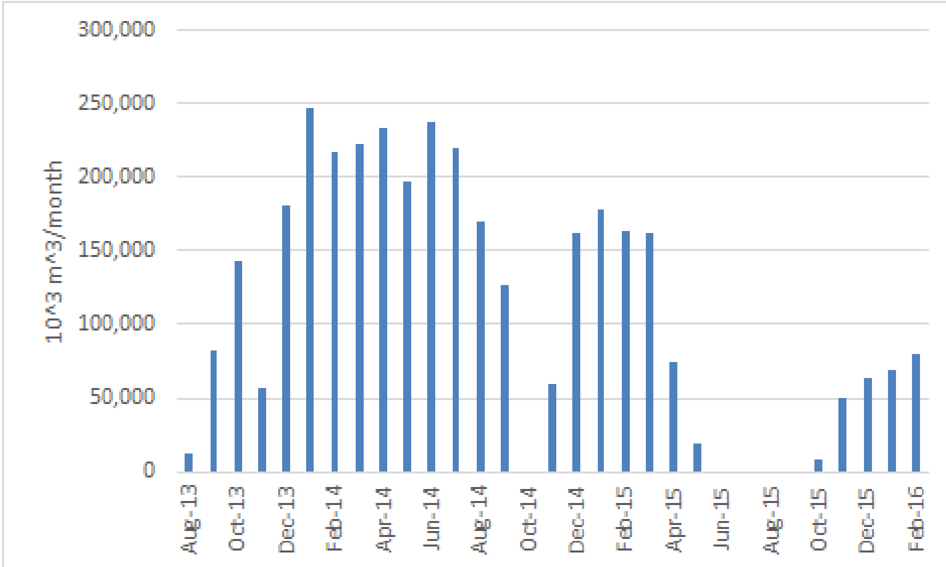


Source: Canada-Nova Scotia Offshore Petroleum Board[28]

The Deep Panuke project started in 2013 and has seen inconsistent production and declines over its two years of operation. The Canada-Nova Scotia Offshore Petroleum Board estimates a project lifespan of 13 years,[29] however the project has produced more water than was expected and operated seasonally in 2015.[30] Deep Panuke's monthly gas production from 2013 through 2015 is shown in Figure 3.13.

[27] Schaefer, Keith, Why Encana's Deep Panuke Problems Matters for New England, Oil and Gas Investment Bulletin, June 21, 2015, http://oilandgas-investments.com/2015/natural-gas/why-encanas-deep-panuke-problems-matters-for-new-england/
[28] Canada-Nova Scotia Offshore Petroleum Board website, Accessed January 2016, http://www.cnsopb.ns.ca/offshore-activity/production-data
[29] Canada-Nova Scotia Offshore Petroleum Board website, Accessed January 2016, http://www.cnsopb.ns.ca/offshore-activity/offshore-projects/deep-panuke
[30] The Chronicle Herald, Deep Panuke resumes natural gas production, October 29, 2015, http://thechronicleherald.ca/business/1319576-deep-panuke-resumes-natural-gas-production

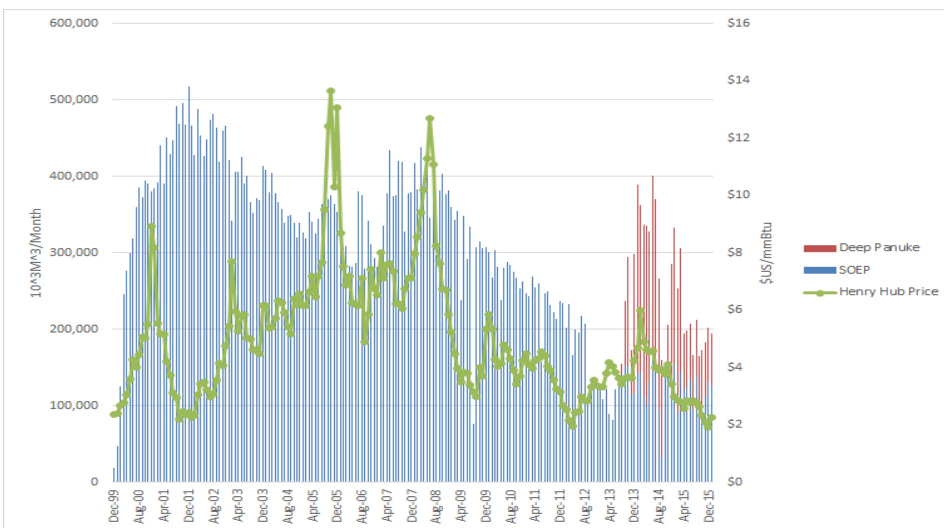
Figure 3.13: Deep Panuke's Total Monthly Gas Production



Source: Canada-Nova Scotia Offshore Petroleum Board[31]

Total historical gas production from Nova Scotia's offshore gas projects are shown in Figure 3.14, against natural gas prices.

Figure 3.14: Total Nova Scotian Offshore Natural Gas Production



Source: Canada-Nova Scotia Offshore Petroleum Board[32]

This figure highlights the production declines that occurred in the SOEP even when the spot price of gas was as high as $14/MMBtu. In today's low price environment, companies have shown

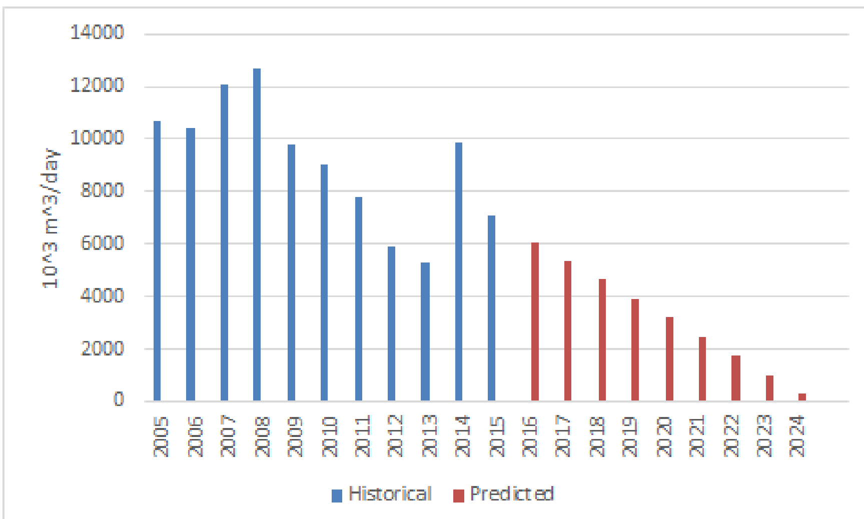
[31] Canada-Nova Scotia Offshore Petroleum Board website, Accessed January 2016, http://www.cnsopb.ns.ca/offshore-activity/production-data
[32] ibid

limited interest in natural gas exploration offshore Nova Scotia. The issues with production out of Deep Panuke indicate a similarly unsustainable environment for continued production.

In regards to future activity in the province, the government of Nova Scotia commissioned the Play Fairway Analysis in 2009, which was a study of the province's offshore hydrocarbon potential. The study identified potential of 121 Tcf of gas and 8 billion barrels of oil-in-place.[33] With regards to onshore activity, the government of Nova Scotia initiated an investigation into the impacts of fracturing in 2013,[34] and the Energy Minister announced in September of 2014 that the government would ban fracturing in the province by the end of 2014.[35] In 2015, Shell was preparing to drill exploration wells,[36] however its focus is on oil, not natural gas.[37] BP, Hess and Woodside Petroleum are also focusing on oil rather than gas.[38]

CERI has estimated that Nova Scotian offshore gas production will stop in 2025, although it may happen sooner. The predicted production values are shown in Figure 3.15.

Figure 3.15: Nova Scotian Offshore Natural Gas Production Forecast



Source: Source: Canada-Nova Scotia Offshore Petroleum Board,[39] CERI

[33] Government of Nova Scotia, Play Fairway Analysis, accessed February 2016, http://energy.novascotia.ca/oil-and-gas/offshore/play-fairway-analysis
[34] Government of Nova Scotia website, Hydraulic Fracturing Review, accessed March 2016, https://www.novascotia.ca/nse/pollutionprevention/consultation.hydraulic.fracturing.asp
[35] Government of Nova Scotia, Government to Prohibit Hydraulic Fracturing, September 3, 2014, http://novascotia.ca/news/release/?id=20140903005
[36] CBC News, Shell awaiting green light to begin Nova Scotia offshore drilling, September 25, 2015, http://www.cbc.ca/news/canada/nova-scotia/shell-offshoredrilling-novascotia-1.3243339
[37] Ruskin, Brett, Nova Scotia's offshore yields 'good evidence' of oil, not just natural gas, CBC News, September 29, 2015, http://www.cbc.ca/news/canada/nova-scotia/offshore-future-ns-1.3248646
[38] Government of Nova Scotia website, New Interests in Nova Scotia's Offshore, December 18, 2014, http://novascotia.ca/news/release/?id=20141218002
[39] Canada-Nova Scotia Offshore Petroleum Board website, Accessed January 2016, http://www.cnsopb.ns.ca/offshore-activity/production-data

The province of New Brunswick has had the second highest amount of natural gas production. The discovery of the Dover natural gas field in the 1850s was the start of New Brunswick's oil and gas industry and natural gas was first produced in 1909.[40] The province produced between 35 and 105 MMcf per year in the Stoney Creek Field until the late 1980s.[41] Corridor Resources started to explore New Brunswick's tight gas potential in 2000 in the McCully Field, in the southeast area of the province,[42] although its well results were disappointing.[43] The Government of New Brunswick estimates that the field contains 121 Bcf of conventional gas reserves and 67 Tcf of unconventional gas resource.[44] Between 2007 and 2014, the province has seen over 3,850 MMcf per year of production.[45] At the end of 2014, the Government of New Brunswick introduced a fracturing moratorium, to be in place until more research on environmental risk is completed.[46] Corridor Resources, a major operator in the McCully Field, shut-in some of their producing wells in 2012 while the Henry Hub price of natural gas was below US$2.00/MMBtu.[47] In a sustained low price environment, production of natural gas will decline. CERI assumes that New Brunswick's natural gas production will stop by 2030, under the assumption that New Brunswick's moratorium on fracturing continues.

Ontario is the third source of natural gas production in eastern Canada. With approximately 1,400 active natural gas wells, 900 of which are onshore and 500 of which are offshore, the 2014 cumulative production of marketable natural gas in the province was 125 mmcfpd,[48] accounting for less than one percent of Canada's total natural gas production. Cumulative natural gas production in the province was 1.3 Tcf of gas in 2008.[49]

Ontario's conventional gas-in-place resources are spread across four main plays; the Cambrian, the Ordovician, the Silurian Sandstone and the Silurian Carbonate.[50] The Cambrian stratigraphic pinch-out play was estimated to have potential natural gas reserves of 180 Bcf, and the structural play was estimated to have potential reserves of 42 Bcf.[51] the Ordovician play was estimated to

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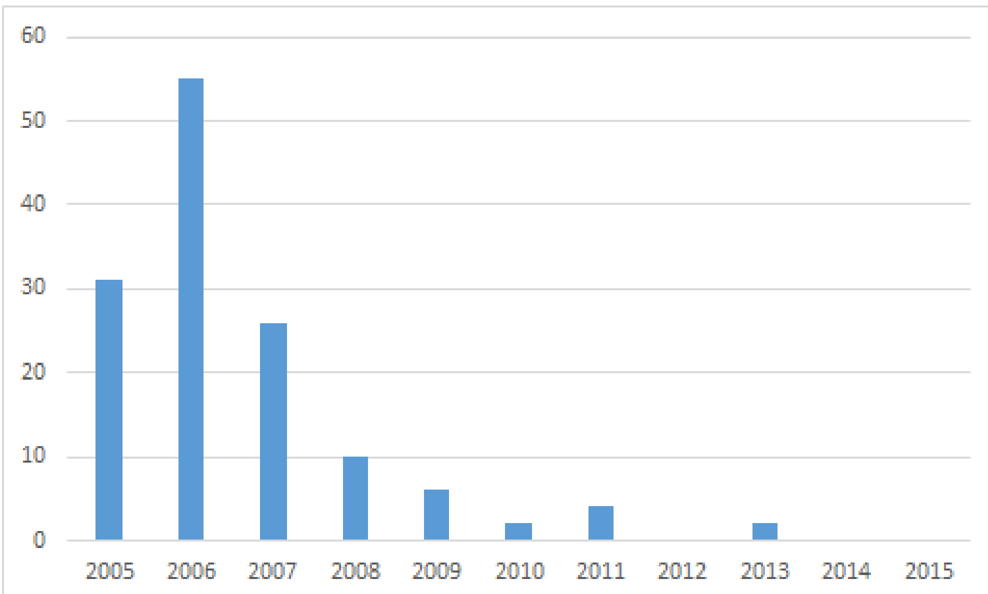
[40] Canadian Association of Petroleum Producers website, Accessed December 2015, http://www.capp.ca/canadian-oil-and-natural-gas/industry-across-canada/new-brunswick
[41] Canadian Association of Petroleum Producers, CAPP Statistical Handbook September 2015, Table 3.9
[42] Natural Resources Canada website, New Brunswick's Shale and Tight Resources, accessed December 2015, http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17698
[43] Questerre, April 22, 2016, personal communication
[44] Government of New Brunswick, New Brunswick Oil and Natural Gas, accessed December 2015, http://www2.gnb.ca/content/dam/gnb/Corporate/pdf/ShaleGas/en/History.pdf
[45] Canadian Association of Petroleum Producers, CAPP Statistical Handbook September 2015, Table 3.9
[46] Natural Resources Canada website, New Brunswick's Shale and Tight Resources, accessed December 2015, http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17698
[47] Corridor Resources, Annual Information Form, December 31, 2014, http://www.corridor.ca/wp-content/uploads/2014/05/Coridor-_2014AIF_Final.pdf, pp. 17
[48] National Energy Board, Marketable Natural Gas Production in Canada, accessed January 2016, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/stt/archive/mrktblntrlgsprdctnrchv-eng.html#archived
[49] Oil, Gas & Salt Resource Library, The Oil and Gas Plays of Ontario, Ontario Petroleum Institute, 2008, http://www.ogsrlibrary.com/downloads/Ontario-Oil-Natural-Gas-Plays.pdf, pp. 2
[50] ibid
[51] ibid, pp. 6

have potential reserves of 281 Bcf of gas.[52] The Silurian Sandstone play was estimated to have 106 Bcf of proven recoverable gas reserves,[53] and the Silurian Carbonate play was estimated to contain up to 280 Bcf of natural gas in discovered pools.[54]

As has been done in New Brunswick and Nova Scotia, an NDP private member's bill was put forward to ban hydraulic fracturing in the province in March 2015.[55] The bill passed its second reading in May 2015.[56] In discussion, the Natural Resources Minister stated that there were not currently any fracturing applications before the government.[57]

Natural gas well starts since 2005 are shown in Figure 3.16.

Figure 3.16: Natural Gas Well Count in Ontario



Source: OGSRL[58]

This figure does not include well starts for exploratory wells. CERI's forecast shows continued yet diminishing natural gas production out of the province.

In November of 2015, CERI released Study 154, "An Assessment of the Economic and Competitive Attributes of Oil and Natural Gas Developments in Quebec" which assessed the economic and competitive potential of the province of Quebec's oil and gas industry. The province has the northern section of the Utica Shale, located below the Marcellus Shale, which is seeing

[52] Oil, Gas & Salt Resource Library, The Oil and Gas Plays of Ontario, Ontario Petroleum Institute, 2008, http://www.ogsrlibrary.com/downloads/Ontario-Oil-Natural-Gas-Plays.pdf, pp. 6
[53] ibid, pp. 9
[54] ibid, pp. 10
[55] Queen's Park Notes for the Week of March 23 - 27, 2015
[56] Queen's Park Notes for the Week of May 4 - 8, 2015
[57] Queen's Park Notes for the Week of April 13 - 17, 2015
[58] Ontario Oil, Gas & Salt Resource Library, Petroleum Well Data

production in the states of Ohio, Pennsylvania and West Virginia. While the St. Lawrence Lowlands region of Quebec has seen hydrocarbon exploration for the past century, Quebec has never produced oil or gas. Operators completed a vertical test well program in Quebec's Utica Shale in 2009 and began a pilot horizontal well program the next year. Test wells were drilled; however, the provincial government is completing environmental assessments before determining whether operators can move forward with production. Original gas-in-place estimates for Quebec's Utica Shale are 155 Tcf by Questerre Energy Corporation, and 49 Tcf by Junex.[59]

CERI calculated the supply cost of a natural gas well in the Utica Shale to be $3.72/Mcf, which, while it is lower than most supply costs out of other Canadian producing areas, remains an uncompetitive cost at current natural gas prices. This analysis did not include costs associated with transportation infrastructure. Currently there are not sufficient gathering lines in the province, so future development of the province's natural gas industry would likely involve connecting gathering lines from producing fields to the existing pipeline network. Quebec has two depleted reservoirs operating underground natural gas storage reservoirs, Pointe-du-Lac and Saint-Flavien.[60]

Whether or not Quebec develops a natural gas industry will depend on environmental, political and economic factors. This study assumes that there is no production out of Quebec for the study period.

Newfoundland has significant offshore natural gas potential, however all produced gas is associated with oil production. The Hibernia field, in the Jeanne d'Arc Basin, was discovered in 1979 and started Newfoundland's offshore oil industry,[61] with oil first produced in 1997.[62] More projects followed, with Terra Nova starting production in 2002[63] and White Rose starting production in 2011.[64] Through drilling exploratory wells for oil, 7 gas and 17 oil reservoirs have been discovered offshore,[65] with 12.6 Tcf of marketable natural gas.[66] To date, no targeted gas

[59] Petroleum & Natural Gas Resource Potential of Quebec Shales - Exploration & Production, Junex, Presented by Peter Dorrins, January 24, 2012, p. 3.
[60] Gaz Métro website, Corporate Structure, Accessed April 2016, http://www.corporatif.gazmetro.com/lentreprise/structure-corporative.aspx?culture=en-ca
[61] Canada-Newfoundland & Labrador Offshore Petroleum Board website, Accessed January 2016, http://www.cnlopb.ca/offshore/
[62] Hibernia website, accessed January 2016, http://www.hibernia.ca/milestones.html
[63] Suncor Website, Terra Nova - East Coast Canada, accessed January 2016, http://www.suncor.com/en/about/4001.aspx
[64] Husky Energy website, Projects, accessed January 2016, http://www.huskyenergy.com/operations/growthpillars/atlantic/projects.asp
[65] Government of Newfoundland and Labrador website, Offshore Development Summary, accessed December 2015, http://www.nr.gov.nl.ca/nr/energy/statistics/peschart.html
[66] Natural Resources Canada website, Newfoundland and Labrador's Shale and Tight Resources, accessed December 2015, http://www.nrcan.gc.ca/energy/sources/shale-tight-resources/17700

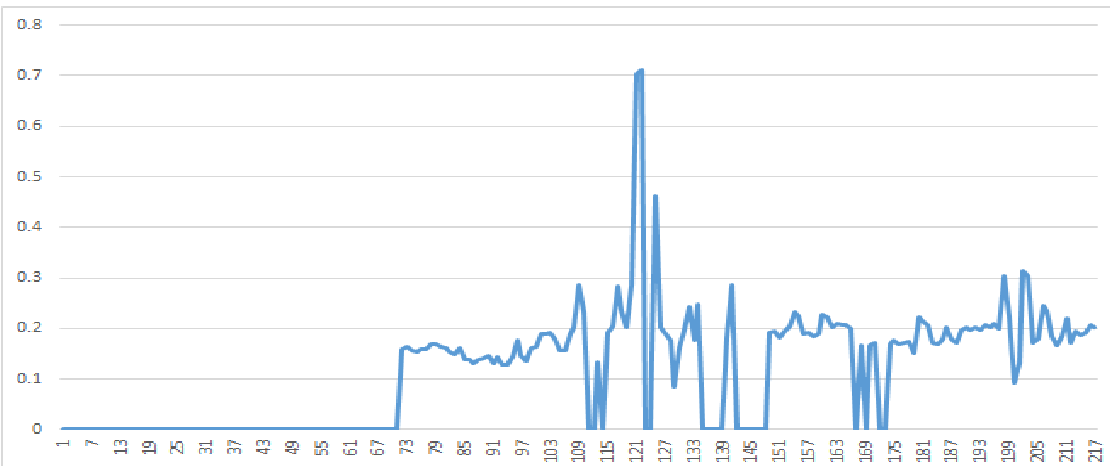
drilling has been done. As of March 31, 2016, the province's total production of oil has been 1.6 billion barrels, with 2.4 Tcf of solution gas.[67]

Any associated gas that is produced is currently used as fuel for oil production, re-injected to maintain well pressure, enhanced oil recovery (EOR), or stored for potential future commercial use. Hibernia and Terra Nova use EOR while it's being considered for White Rose. White Rose currently stores the gas for potential future use. The Hebron project, due to start producing oil in 2017,[68] will use both natural gas as a fuel and store the remainder for potential future use.

CERI examined the oil and gas production from the Hibernia field[69] and observed that approximately half of the consistently producing wells saw approximately 20 percent gas recovery in barrels of oil equivalent (in BOE), while the remaining half showed an increase in this ratio to over 100 percent in some cases. As mentioned above, Hibernia uses its solution gas for EOR.

Figures 3.17 and 3.18 show two of these wells.

Figure 3.17: Gas:Oil Production (BOE:B) from Well HIB-B-016-041 by Month of Operation



Source: Canada-Nova Scotia Offshore Petroleum Board, CERI

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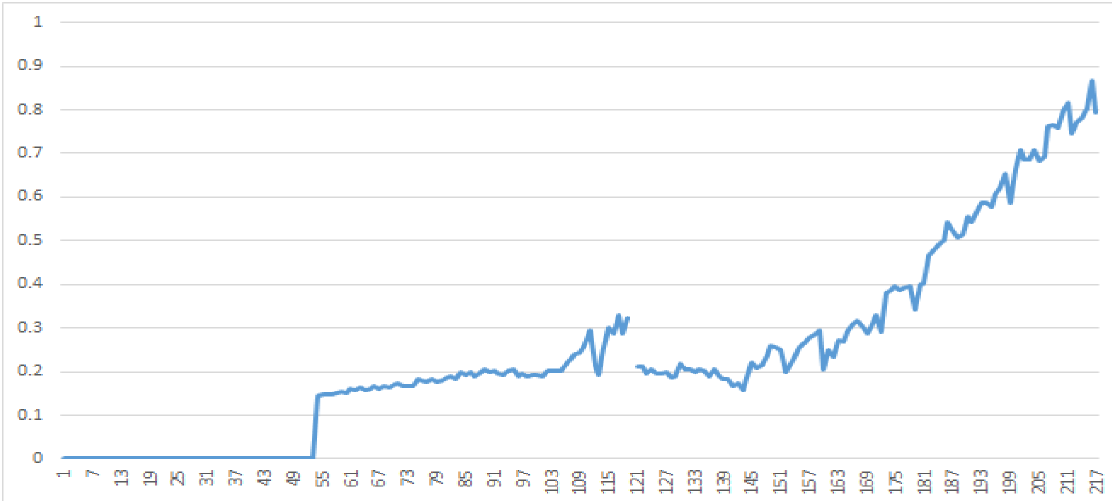
[67] Canada-Newfoundland & Labrador Offshore Petroleum Board website, Accessed May 2016, http://www.cnlopb.ca/pdfs/off_prod.pdf
[68] Hebron Project website, accessed February 2016, http://www.hebronproject.com/project/milestones.aspx
[69] Canada-Newfoundland & Labrador Offshore Petroleum Board website, Accessed January 2016, http://www.cnlopb.ca/pdfs/off_prod.pdf

Figure 3.18 : Gas:Oil Production (BOE:B) from Well HIB-B-016-029 by Month of Operation



Source: C-NLOPB, CERI

In 2012, Ziff Energy Group calculated that the costs of producing offshore gas would be 4 to 5 times the North American domestic gas price.[70] While offshore natural gas development has been successfully done in Nova Scotia, the regions are not comparable due to the presence of icebergs off the coast of Newfoundland which would necessitate burying the required pipelines deep beneath the seabed, as well as Nova Scotia's existing infrastructure.[71]

In the cases where the natural gas is stored, there are associated costs whose responsibility is not entirely clear. This is highlighted by a current conflict between a majority and minority owner of the White Rose project which has gone to the Supreme Court of Newfoundland and Labrador for resolution.[72] Without considering regulatory and political issues, as long as the storage costs remain favourable to the costs that would be required to develop the infrastructure required for natural gas development, offshore Newfoundland will remain solely a producer of oil. CERI does not assume any natural gas production out of Newfoundland for the span of the study period.

Canadian Natural Gas Demand Outlook

This section will delve into more detail describing the use of natural gas in Canada. The sectoral demand outlook includes residential, commercial and industrial demand with electricity demand for natural gas described separately. Special attention is paid to large industrial users of natural gas.

[70] Ziff Energy Group, Natural Gas as an Island Power Generation Option, October 30, 2012, http://www.powerinourhands.ca/pdf/naturalgas.pdf, pp. 2

[71] Roche, Pat, Choosing Hydro Megaprojects Over Offshore Gas a Mistake, Book Argues, Daily Oil Bulletin, September 15, 2014, http://www.dailyoilbulletin.com/article/2014/9/15/choosing-hydro-megaproject-over-offshore-gas-mista/

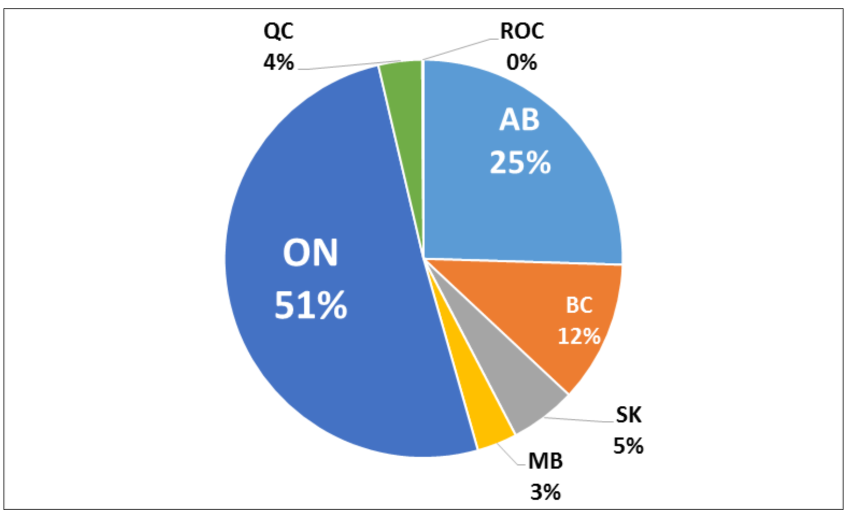
[72] Roberts, Terry, Nalcor bringing $14M fight over gas storage costs to court, CBC News, May 29, 2015, http://www.cbc.ca/news/canada/newfoundland-labrador/nalcor-bringing-14m-fight-over-gas-storage-costs-to-court-1.3090599

Residential Sector

Sales of natural gas in Canada have risen consistently for several decades. In the residential sector, this is cost-driven, with natural gas being less than half the cost of propane, electrical heat, or heating oil (see Figure 2.31). Historically, the energy used to heat homes and provide hot water has depended on the energy sources available in the region – more locally-available sources are generally cheaper than other options. For example, in Quebec, hydroelectricity has been used since the development in the last century of the James Bay and other hydroelectricity projects. Hydroelectricity is also found as a heating source in Atlantic Canada and to a certain extent in Manitoba and British Columbia. Many residents of Atlantic Canada still rely on electricity, fuel oil, and even wood to heat their homes, as natural gas has only been available there since 2004.[73] However, in the provinces west of Quebec, extensive pipeline infrastructure has developed in recent decades, bringing natural gas from western Canada and the eastern United States and distributing to individual residences. As natural gas is the least expensive form of heating fuel available in Canada today, its growth in the residential sector is limited only by infrastructure constraints and perhaps by some consumers' residual reluctance to switch from other sources which they know well and have used for generations.[74]

More than half of Canada's residential sector natural gas demand is in Ontario, with Alberta taking a 25 percent share. Quebec's share of residential natural gas demand is only 4 percent, reflecting the extensive use of hydropower in the province, as noted earlier (see Figure 3.19).

Figure 3.19: Canada's Residential Natural Gas Demand by Province, 2015 (%)



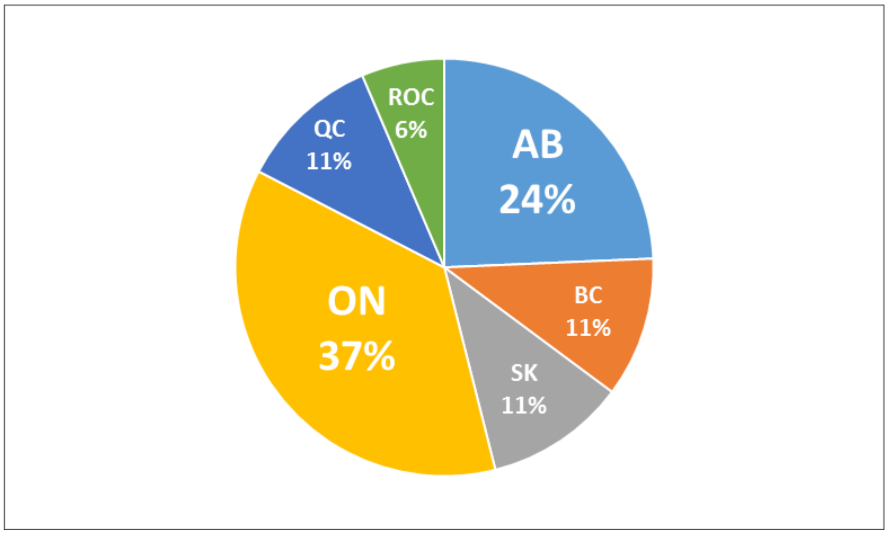
Source: NEB, CERI

[73] "The Ways We Heat Our Homes" Statistics Canada.
http://webcache.googleusercontent.com/search?q=cache:0wFooqmjct8J:www41.statcan.gc.ca/2007/1741/ceb1741_003-eng.htm&hl=en&gl=ca&strip=1&vwsrc=0

Commercial Sector

Natural gas use in Canada's commercial sector closely follows residential use patterns. Commercial enterprises such as schools, hotels, businesses, and restaurants also use natural gas for space heating, water heating, and occasionally for air conditioning. Where natural gas is widely available it is widely utilized, but in parts of the country where other energy sources are predominant and less expensive, natural gas is not yet in widespread commercial use. As Figure 3.20 shows, Ontario, the most populous province, and a province with extensive natural gas infrastructure in place, consumed the most natural gas for commercial purposes, with a 37 percent share, Alberta is second at 24 percent, and Quebec, British Columbia, and Saskatchewan each consumed an 11 percent share. Commercial usage of natural gas was not as prevalent in other parts of the country because fewer commercial enterprises are located in those provinces; also because other forms of energy are used.

Figure 3.20: Canada's Commercial Natural Gas Demand by Province, 2015 (%)



Source: NEB, CERI

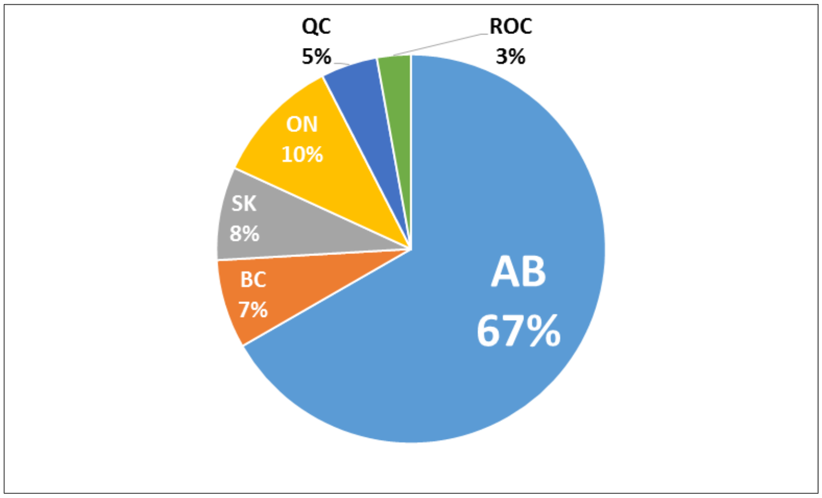
Industrial Sector

The Canadian industrial sector consumes as much natural gas as the residential and commercial sectors combined (see Figure 3.21). The gas is used as a raw material in the petrochemical industry to make fertilizers, fabrics, plastics, and other products and chemicals. Many manufacturing processes use natural gas for heat to make steel, glass, cement, and other commodities. In Canada's oil sands industry, natural gas is used in large volumes to extract and upgrade bitumen. As of 2015, small amounts of natural gas are being converted to Liquefied Natural Gas (LNG), but this may change in the near future if LNG liquefaction and export facilities are built in British Columbia and Atlantic Canada. The industrial sector accounts for approximately 40 percent of natural gas use in Canada.[75]

[75] http://www.canadasnaturalgas.ca/supply-demand/

Figure 3.21 shows that Alberta demands a full two-thirds of natural gas for industrial purposes in Canada, indicating the size and scope of the oil sands and petrochemical industries in the province. Ontario, Saskatchewan and British Columbia demand approximately equal shares. Although Quebec's industrial sector is significant, demand for natural gas there is not nearly as large as it is in Alberta – again, because the province's vast hydro resources are sufficient to meet the lion's share of industrial energy demand.

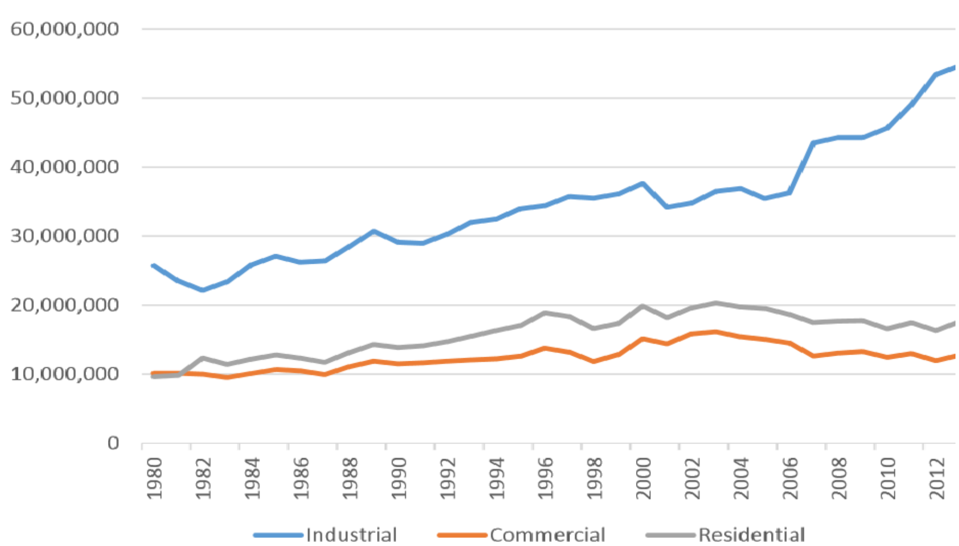
Figure 3.21: Canada's Industrial Natural Gas Demand by Province, 2015 (%)



Source: NEB, CERI

The industrial sector has been the largest consumer of natural gas in Canada. Figure 3.22 shows clearly how industrial sales of natural gas have risen dramatically over the past decade, while commercial and residential sales fell.

Figure 3.22: Sales of Natural Gas by Sector – Canada (thousands m^3)



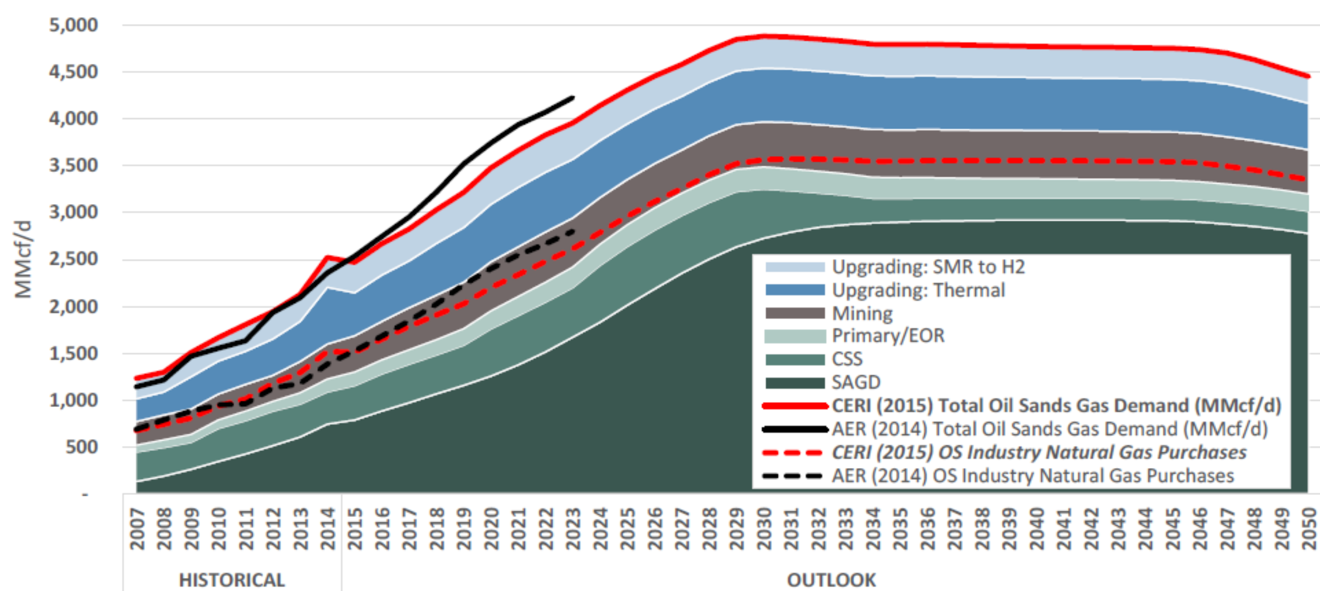
Source: Statistics Canada 129-00003; Canadian Gas Association

Natural Gas Use in the Oil Sands Industry

One of the largest users of natural gas in the industrial sector is the oil sands industry. As the oil sands industry is projected to grow, so will the demand for natural gas, unless there is a technological breakthrough that would dampen this demand. From modest volumes of approximately 0.7 Bcfpd consumed in 2000, oil sands demand has grown markedly to just under 2 Bcfpd consumed in 2014.[76] Natural gas is used in all the extraction methods employed in the oil sands – both mining and in situ – and it is also fundamental to upgrading crude bitumen to synthetic crude oil. Mining does not require as much natural gas as some of the energy-intensive in situ techniques, but much more of the oil sands is amenable to in situ rather than mining recovery. It can be expected, as a result, that future oil sands development will require ever greater volumes of natural gas.

Nevertheless, economic conditions, federal and provincial policies, technological advances, and the quality of the plays developed will have a say in how much more natural gas will be used in the oil sands over the forecast period. CERI's Study 151, "Oil Sands Energy Requirements and Greenhouse Gas (GHG) Emissions Outlook (2015-2050)", from August 2015 forecasts that natural gas usage in the oil sands will increase rapidly in the coming decade, from approximately 2.5 Bcfpd in 2015, peaking at just under 5 Bcfpd in 2029, and trending down to approximately 4.5 Bcfpd by 2050[77] (see Figure 3.23).

Figure 3.23: Oil Sands Industry Gas Demand for Thermal Energy and Hydrogen Production by Project Type, 2007-2050



Source: CERI

[76] NEB. "Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040". January 2016. Page 21.
[77] CERI Study 151 "Oil Sands Energy Requirements and Greenhouse Gas (GHG) Emissions Outlook (2015-2050)". August 2015. Page 21.

Natural Gas and Natural Gas Liquids Use in the Petrochemical Industry

Another significant component of industrial sector natural gas demand is the petrochemical industry, which requires natural gas for processes such as steam cracking and natural gas liquids (NGLs) for feedstock.[78] NGLs are often part of the mix when natural gas is extracted. The Montney shale in British Columbia, for example, is a NGLs-rich play; Horn River, on the other hand, is a dry gas play with very little besides methane being produced. Though the majority of Canadian liquids are extracted from natural gas streams, liquids are also a by-product of bitumen upgrading and oil refining. CERI's Study 153, "Examining the Expansion Potential of the Petrochemical Industry in Canada" from August 2015 projects a growth in NGL's production, however it will be strongly dependent on the natural gas production growth in liquids-rich areas, such as Montney.

Electricity Sector

Going forward, natural gas will become a larger part of the overall Canadian electricity fuel mix. Saskatchewan and Alberta will be switching from coal-fired to natural gas-fired generation, and British Columbia plans to add some natural gas to back up its increasing hydro capacity. In the east, Ontario will rely, to a certain degree, on natural gas as it refurbishes its fleet of nuclear reactors, and the Atlantic Provinces intend to gradually replace its oil-fired and coal-fired plants. According to the NEB, by 2040, hydropower will retain the largest percentage of the energy mix, accounting for over 50 percent, but natural gas' share will grow the largest, from 15 percent of the mix in 2014 to 22 percent of the mix in 2040.[79] With total generation growing at a rate of about 1 percent per year, natural gas will be the fastest growing generation fuel at an annual growth rate of about 4 percent.

Natural gas is important for fulfilling Canada's baseload and peak power needs;[80] the role of natural gas in electrical generation looks set to increase for a number of reasons including the high costs required to build nuclear and hydro infrastructure and the lower levels of GHG's emitted compared to coal power plants.

Much news has been made about the recent shift away from coal-fired electricity generation to natural gas-fired generation in many North American jurisdictions. Environmental improvement has been a main motivator for this change: in terms of units of energy produced, natural gas emits the least carbon dioxide of any of the three fossil fuels combusted for electric power (coal and fuel oil are the other two). Natural gas emits 45 percent less CO_2 than coal and 27 percent less than fuel oil.[81] Burning natural gas also releases lower amounts of mercury, nitrogen oxides,

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[78] NGL hydrocarbons are: ethane (used primarily as petrochemical feedstock), propane (usually used for space heating and other applications such as barbecues), butane (mostly used as a petrochemical feedstock), and pentanes plus (useful for blending with bitumen to move the product to market).

[79] NEB. Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040. Page 79.

[80] Also known as "peakers" peak load power plants are facilities that operate only in times of high or "peak" electricity demand.

[81] https://www.eia.gov/environment/emissions/co2_vol_mass.cfm

sulfur dioxide, and particulates. At a time when the world is looking to reduce anthropogenic influence on the climate, moving from coal to gas for electric power is gaining momentum.

It should also be noted that fuel oil power plants do not represent a sizeable proportion of generating units in Canada. As of 2015, fuel oil comprises only 2.5 percent of the total Canadian installed electricity generating capacity, is used primarily for peak demand and in areas where "other generation options are not widely available, such as Yukon, NWT, and Nunavut."[82] The NEB states that oil-fired generation accounts for only half a percent of total generation and is not set to grow over the coming decades. The situation is similar in the United States, where the EIA reports that fuel oil represents only 1 percent of all generation in that country.[83]

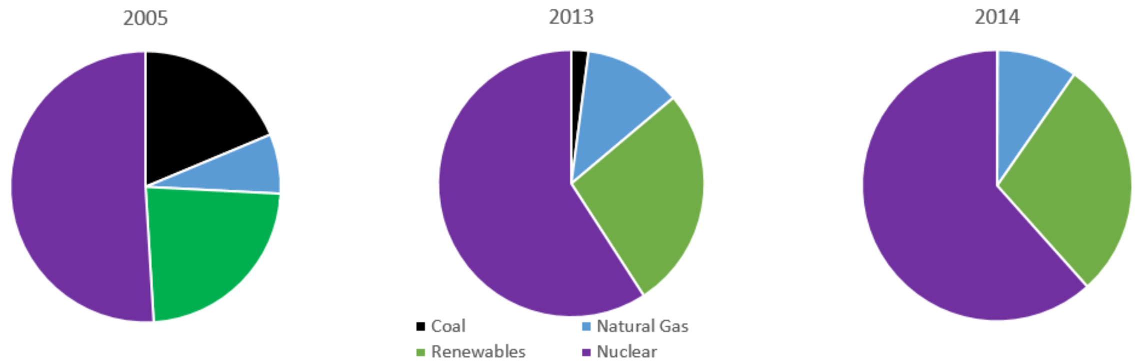
The Government of Canada in 2012 put in place new regulations that forbid the construction of coal-fired electricity generation plants unless fitted with Carbon Capture and Storage (CCS) technology. The rules also stipulate that plants built before 1975 must be closed by 2020 and plants constructed after 1975 are required to be shut by 2030 unless retrofitted with the CCS technology.[84] This technology must capture approximately half of CO_2 emissions in order to comply, while natural gas can achieve similar benchmarks without CCS. Therefore, unless CCS costs come down, it is unlikely that the retrofits or new-build coal plants will be constructed.[85] It is possible that stricter regulations will be enacted by the Government of Canada after the Paris COP-21 meetings.

Ontario has already ceased coal-fired electricity generation. In 2014 the province closed its last coal-fired power plant. The provincial legislature then passed a law in November 2015 that permanently bans coal-fired generation, the first North American province, territory, or state that has enacted such legislation.[86] Figure 3.24 compares the electricity mix one decade ago, the year before all coal-fired generation was eliminated (2013) and the year of that elimination (2014). Since 2005, electricity production in Ontario has not changed significantly, totaling 155 terawatt hours (Twh) in 2005,[87] and 154 Twh in both 2013 and 2014.[88] But the mix is now much different. Nuclear and renewables represented 74 percent of the mix twenty years ago; that number increased to 90 percent in 2014. Natural gas, the last hydrocarbon being burned in

[82] NEB. Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040. Page 83.
[83] EIA. "What is U.S. electricity generation by energy source?" https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3 Accessed March 18, 2016.
[84] McCarthy, Shawn. Globe and Mail. "Ottawa unveils new coal-fired plant emissions rules". September 5, 2012. http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/ottawa-unveils-new-coal-fired-plant-emissions-rules/article4522237/ ; Parsons, Craig. "Market Outlook Report". Genalta Power. February 2015. Page 9.
[85] AESO 2014 Long Term Outlook. Page 13.
[86] https://news.ontario.ca/ene/en/2015/11/ontario-permanently-bans-coal-fired-electricity-generation.html
[87] http://www.powerauthority.on.ca/integrated-power-system-plan/supply-mix-summary-december-2005
[88] http://www.ieso.ca/Pages/Power-Data/2014-Electricity-Production-Consumption-and-Price-Data.aspx

Ontario's electricity system, took a 7 percent share in 2005, 11 percent in 2013, and 10 percent in 2014.[89]

Figure 3.24: Ontario Electricity Mix (2005, 2013, 2014)



Source: IESO, CERI

The shift from coal to natural gas has been done with much fanfare in Ontario, but it is happening in other provinces, too. In 2016, 44 percent of Alberta's electricity generation capacity is from natural gas, 38 percent from coal, 9 percent from wind, and the rest is a combination of hydro, biomass, and waste heat.[90] Capacity has been growing rapidly – over 9,000 megawatts (MW) has been added since 1998 to a system that presently has 16,242 MW of installed generation.[91] Hydroelectric capacity has been developed as far as is economically feasible in the province, and nuclear has never been up for serious consideration, so future growth depends to a great degree on natural gas (renewables will also play a role). In fact, the Alberta Electric System Operator (AESO) projects that the province will require an additional 5,000 MW of generation capacity additions by 2024, and natural gas will grow by 13 percent to represent 57 percent of the total provincial electricity mix.[92]

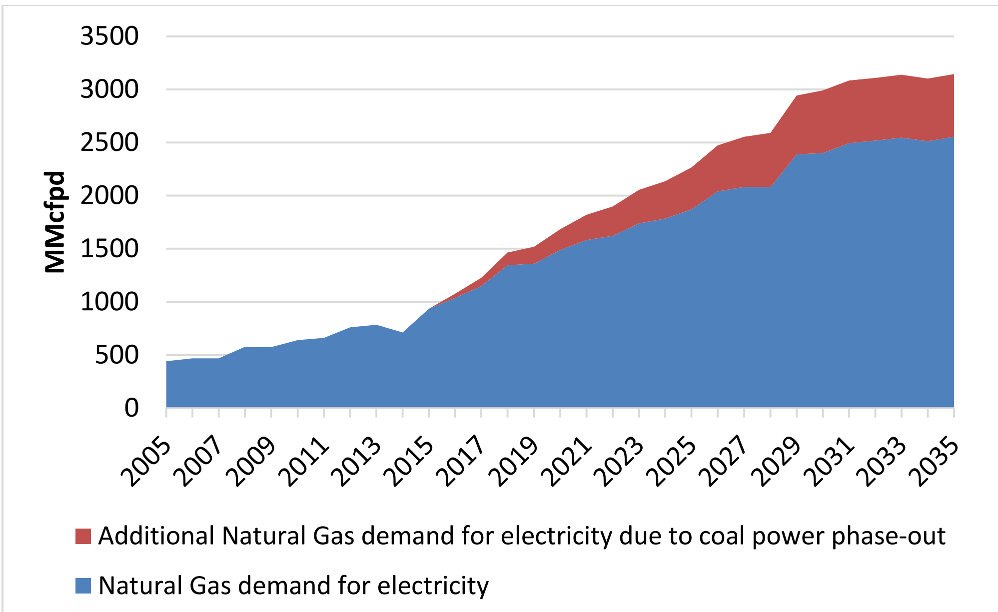
There have been recent policy changes in Alberta that will affect the electricity sector, especially the coal-fired generators in the province. Under the Alberta Climate Leadership Plan, announced by the provincial government in late 2015, the aim is to shut all coal-fired plants by 2030. To a certain extent, the province and industry have no choice but to close most of the plants because federal regulations mandate that all coal plants in the country must meet GHG emissions standards or retire once they have reached 50 years of operation. According to the provincial

[89] Government of Ontario, Ministry of the Environment and Climate Change. "Climate Change Discussion Paper, 2015". Page 33.
[90] AESO, "Current Supply Demand Report". http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet; Government of Alberta. "Electricity Facts". http://www.energy.alberta.ca/Electricity/681.asp Accessed February 5, 2016.
[91] Government of Alberta "Electricity Statistics": http://www.energy.alberta.ca/electricity/682.asp Accessed February 5, 2016.
[92] AESO. 2014 Long Term Outlook. P. 16.

government, 12 of Alberta's 18 coal-fired generating plants would therefore need to be closed by 2030 because of federally-mandated GHG reductions.[93]

Figure 3.25 illustrates the additional natural gas demand that would be created in Alberta if all coal plant closures occur between 2016 and 2030. Demand would increase by approximately 15 petajoules per year (PJ/year) for 15 years, or around 39 MMcfpd each year for 15 years. While the Government of Alberta's policy will be explained in more detail later, these calculations assumes that 70 percent of coal-fired generation will be replaced by natural gas. A constant average yearly rate of coal-fired generation removed from the grid is assumed.

Figure 3.25: Electricity Sector Natural Gas Demand – Alberta



Source: NEB, AESO, CERI

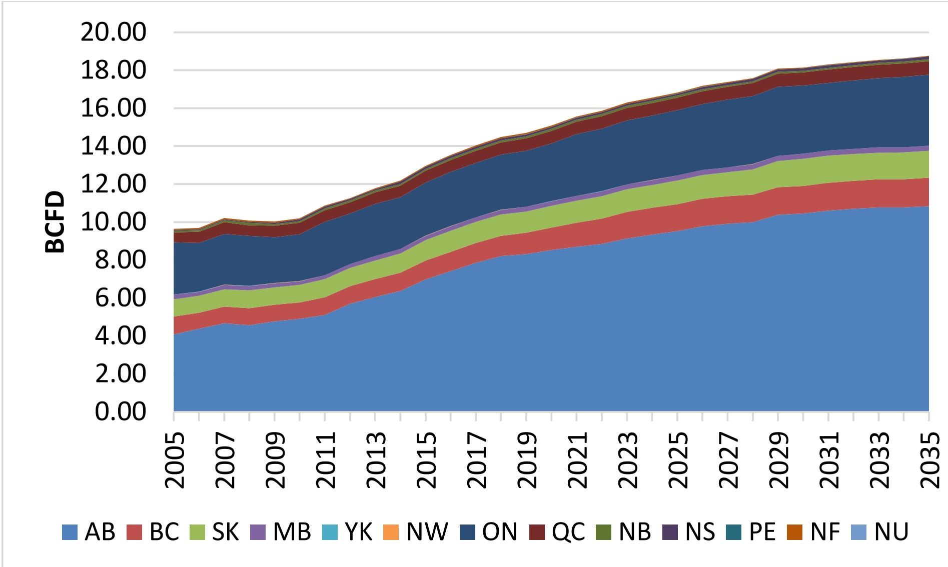
Natural Gas Demand Outlook

Figure 3.26 presents a future outlook for natural gas demand in Canada. The forecast is assembled from the NEB's latest Energy Future Report (Reference Case), and augmented by CERI to incorporate recent climate change policies (such as the above-mentioned coal-fired electricity generation replacement in Alberta) and LNG demand. It is evident that Alberta will continue to demand most of the natural gas, because of its large industrial base, with Ontario the next largest consumer.[94]

[93] "Climate Leadership Plan: Coal and Electricity". http://www.alberta.ca/climate-coal-electricity.cfm Accessed February 5, 2016.

[94] The NEB's Reference Case scenario does not include the shut down of Alberta's coal-fired electricity plants in its most recent analysis because the policy had not been announced when the NEB released Energy Future 2016. However, in the interim the Province of Alberta announced officially that coal will be retired. The data in this report has been adjusted to reflect the new policy.

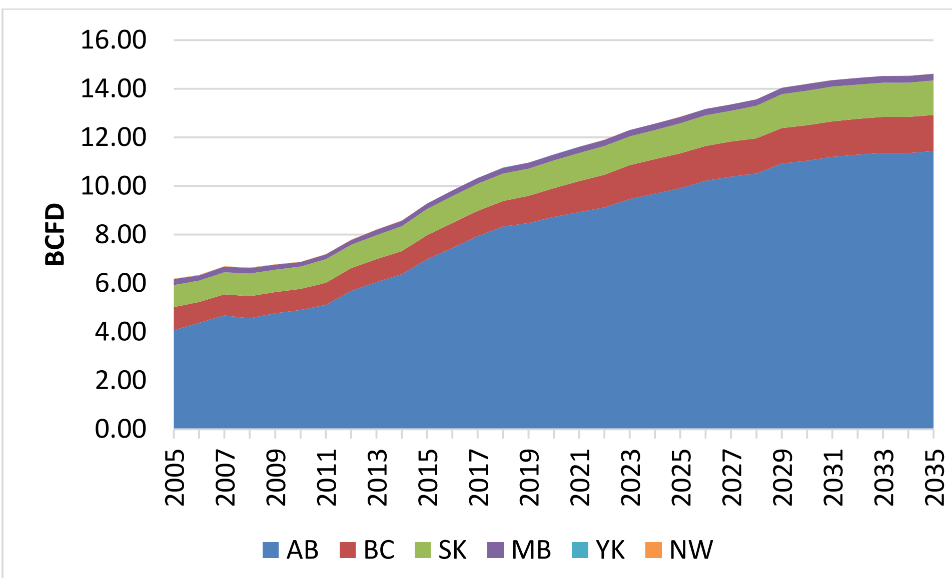
Figure 3.26: Canadian Primary Natural Gas Demand Outlook by Province[95]



Source: NEB, CERI

Breaking down the above data to western and eastern Canadian demand, demand in both Alberta and Ontario is and will continue to be much greater than that of their regional neighbors (see Figures 3.27 and 3.28).

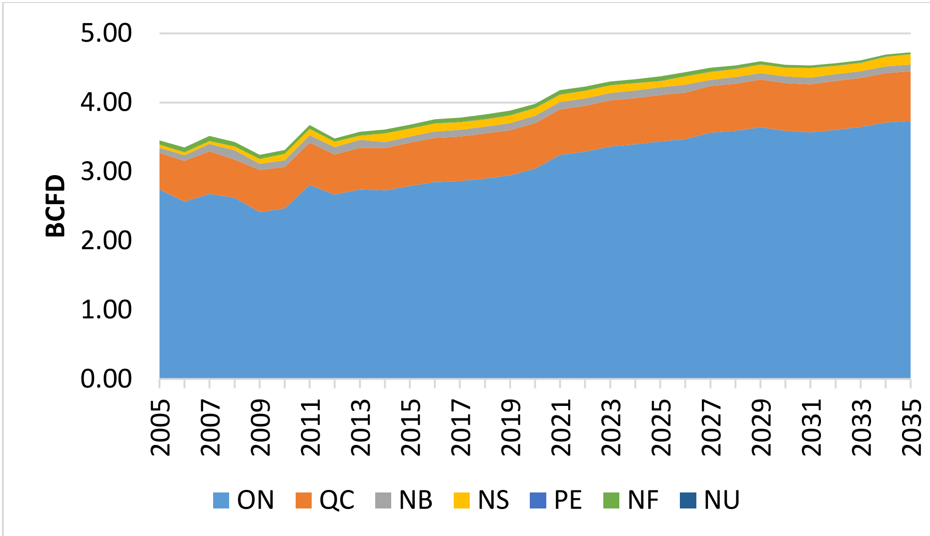
Figure 3.27: Western Canadian Primary Natural Gas Demand Outlook by Province



Source: NEB, CERI

[95] This is the primary natural gas demand which includes non-marketed natural gas used directly by those that produce it. Examples of this include flared gas, natural gas produced and consumed by in situ oil sands producers, and natural gas produced and consumed by offshore oil production.

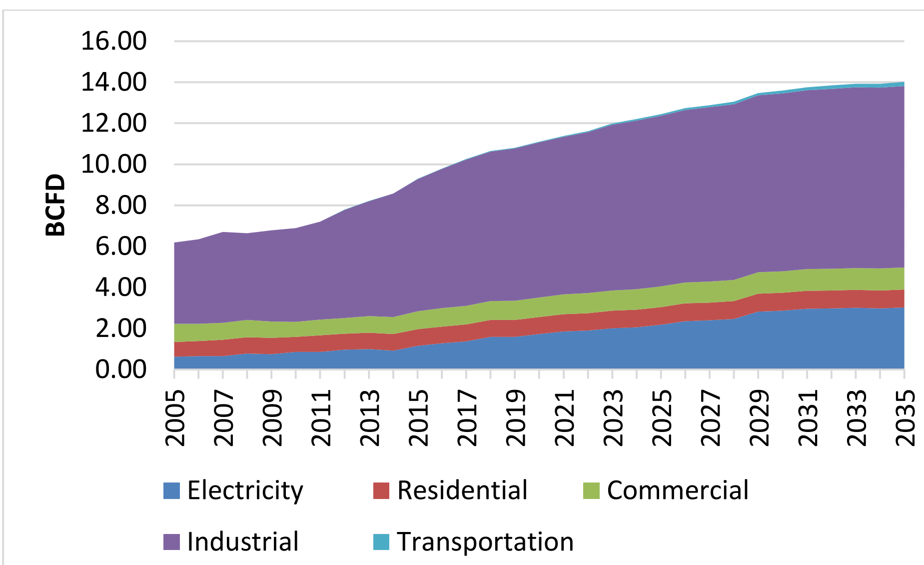
Figure 3.28: Eastern Canadian Primary Natural Gas Demand Outlook by Province



Source: NEB, CERI

Natural gas demand by sector in western Canada is dominated, of course, by industrial demand from Alberta (see Figure 3.29). Residential, commercial, transportation, and electricity generation demand for natural gas are comparatively small. Transportation demand, largely through natural gas-powered trucks and tractor trailers, starts to take hold by the middle of the next decade, but even by 2035, it will likely represent an insignificant portion of total demand.

Figure 3.29: Western Canadian Natural Gas Demand Outlook by Sector[96]

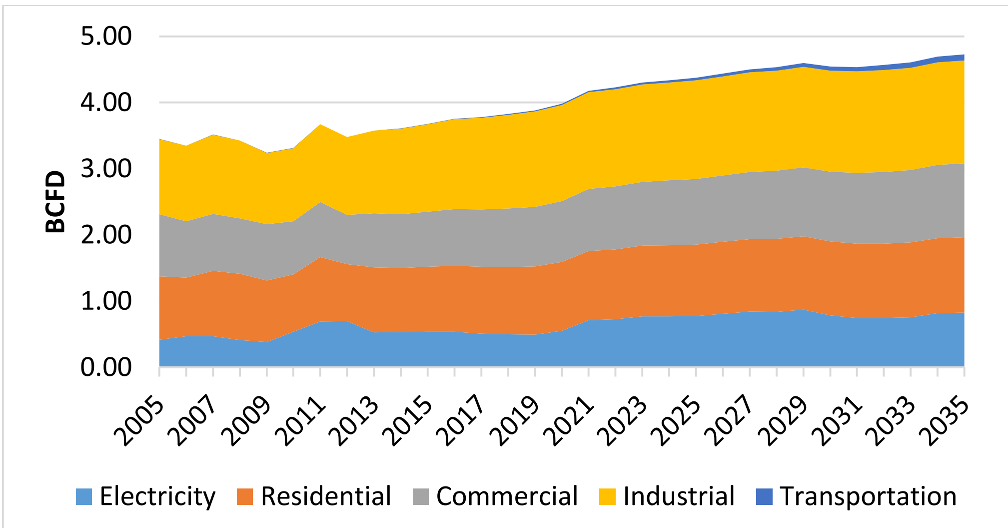


Source: NEB, CERI

[96] It should be noted that Alberta's planned retirement of coal-fired generation is accounted for in the electricity sector natural gas demand outlook.

The demand by sector story in eastern Canada is noticeably different from that of western Canada, with demand much more evenly distributed among sectors (see Figure 3.30). That trend is likely to continue until 2035 as there are no major changes to energy usage on the horizon. Similar to western Canada, natural gas for transportation in eastern Canada does not appear to be changing the demand picture over the long run. Overall consumption is not expected to rise in eastern Canada as in western Canada. By 2035 Western Canadian primary natural gas demand will be close to 14 Bcfpd, as opposed to 9.75 Bcfpd in 2016; Eastern Canadian primary natural gas demand will climb close to 5 Bcfpd from 3.75 Bcfpd in 2016.

Figure 3.30: Eastern Canadian Natural Gas Demand Outlook by Sector



Source: NEB, CERI

Canadian Natural Gas Storage

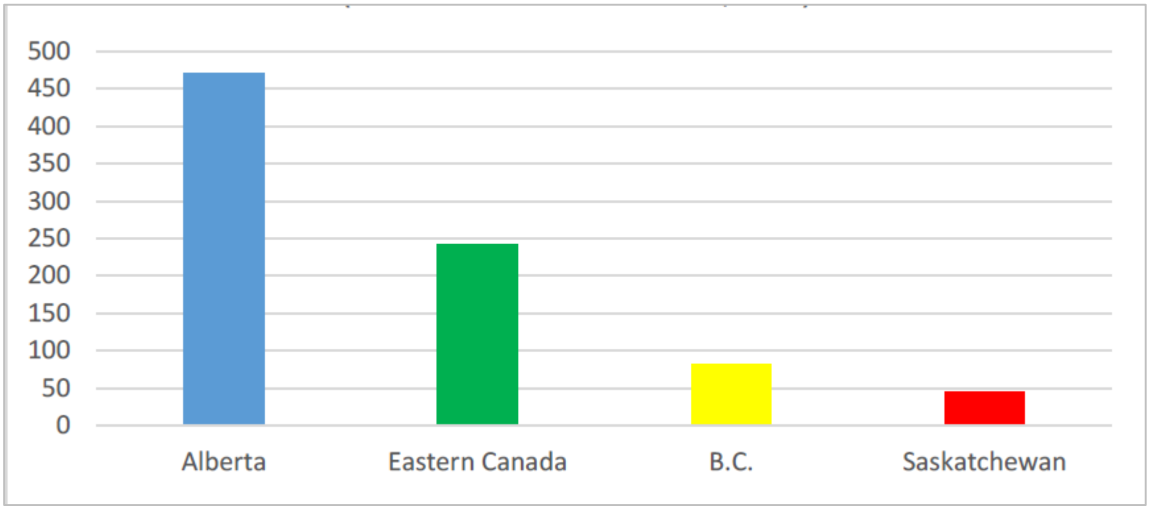
Underground natural gas storage facilities are a vital and complementary component of the North American natural gas transmission and distribution system. While mainline gas transmission lines provide the crucial link between producing area and marketplace, underground gas storage facilities help maintain the North American natural gas transmission and distribution system's reliability and its capability to transport gas supplies efficiently and without interruption. Natural gas storage facilities are essential to balance the dramatic divergence between the seasonal and daily variability of gas consumption and the inflexibility of gas production in North America.

A major reason that natural gas storage is required in North America is to mitigate the severity of spikes and drops in demand. For the most part, storage is found in depleted oil and gas reservoirs and salt caverns. Natural gas storage facilities are situated in many regions across the US[97] and Canada. In Canada, the bulk of storage is located in western Canada with 472 Bcf of capacity, with Alberta dominating in greatest volumes, and smaller capacities seen in British

[97] US has approximately 3.9 Tcf storage: 1.2 Tcf in the Gulf, 2.2 Tcf in the East, 0.5 Tcf in the West. CGA. Natural Gas Storage. 2014.

Columbia and Saskatchewan. Storage in eastern Canada is located primarily in southwestern Ontario, including the Dawn Hub, well connected to North American gas markets. These Ontario facilities have a working storage capacity of just over 241 Bcf (see Figure 3.31). Altogether, natural gas storage capacity in Canada totals over 820 Bcf, with additional Alton Natural Gas Storage – currently under construction in Nova Scotia and will be connected to the Maritimes and Northeast Pipeline – servicing eastern Canada and the US.[98]

Figure 3.31: Canadian Storage Capacity (Bcf)



Source: CGA, "Natural Gas Storage" Bulletin

There are two major storage hubs worth mentioning separately: the Union Gas Dawn Facility in southern Ontario, and the AECO hub, comprising of two facilities, in Alberta.

The Dawn Facility has a capacity of 159.5 Bcf of storage, making it Canada's largest underground storage facility.[99] It has a peak withdrawal rate of 5.2 Bcfpd (5.7 PJ/day).[100] Union Gas and Imperial Oil first agreed to store gas in the 1940s, and storage began in 1942.[101] The facility is comprised of 23 depleted reservoirs.[102] Of the three types of storage (depleted reservoirs, aquifers and salt caverns), depleted reservoirs require the least maintenance and are inexpensive to develop and operate.[103] The Dawn Facility can receive gas from western Canada, the US mid-continent, the Rockies and the Gulf of Mexico. It can also supply gas to the US Midwest, eastern

[98] Alton Natural Gas Storage website, accessed March 28, 2016, http://altonnaturalgasstorage.ca/about/site
[99] Spectra Energy Website, accessed March 28, 2016, http://www.spectraenergy.com/Operations/Canadian-Natural-Gas-Operations/Storage/Dawn-Hub/
[100] Union Gas website, accessed March 28, 2016, https://www.uniongas.com/storage-and-transportation/about-dawn
[101] Union Gas Website, accessed March 28, 2016, https://www.uniongas.com/about-us/our-legacy/dawn-hub/Timeline
[102] Union Gas Website, accessed March 28, 2016, https://www.uniongas.com/storage-and-transportation/about-us
[103] Niska Partners, Gas storage industry primer, 2010, https://www.niskapartners.com/wp-content/uploads/2010/04/GasStorageIndustryPrimer.pdf

Canada and the US Northeast.[104] This accessible location is important in the value of the storage. The availability of multiple pipelines allows for higher capacity to withdraw gas in periods of high prices. Further, the differential in prices at the various export locations allow for price optimization.

As mentioned previously, the province of Quebec is home to two storage caverns, Pointe-du-Lac and Saint-Flavien. Point-du-Lac has a working capacity of 0.8 Bcf[105] and Saint-Flavien has a working capacity of 4.2 Bcf.[106] The combined capacity is quite small relative to the storage elsewhere in the country. The province of Quebec utilizes storage capacity in Ontario's Dawn Facility to supplement its small capacities. This incurs a distribution cost, leading to increases in the price of gas in Quebec, even when the commodity itself is inexpensive, such as gas coming from the Marcellus Shale.[107] These incurred costs serve to discourage the development of natural gas projects within the province.

The AECO Hub's two facilities are the Suffield, located in southeastern Alberta, and the Countess, in southcentral Alberta.[108] The total capacity of the hub is 154 Bcf, with a peak withdrawal rate of 3.05 Bcfpd.[109] The storage hub was initially developed in Suffield in the 1980s, and the Countess facility was added in 2003.[110] The facilities, like Dawn, consist of depleted reservoirs: five at Suffield and two at Countess. The Suffield and Countess facilities are connected by the Nova Gas Transmission Limited pipeline.[111] The toll is setup so that both facilities receive the same price for gas – that is, the AECO-C price. While the AECO hub primarily receives gas produced in western Canada, it can export to the US Pacific, US Midwest and eastern Canada. Like Dawn, the accessibility plays into the hub's storage value.

Western Canadian storage is used primarily for managing producer and pipeline supplies, whereas storage in eastern Canada is used almost exclusively by LDCs and large end-use customers to meet winter demand in the provinces of Ontario and Quebec.

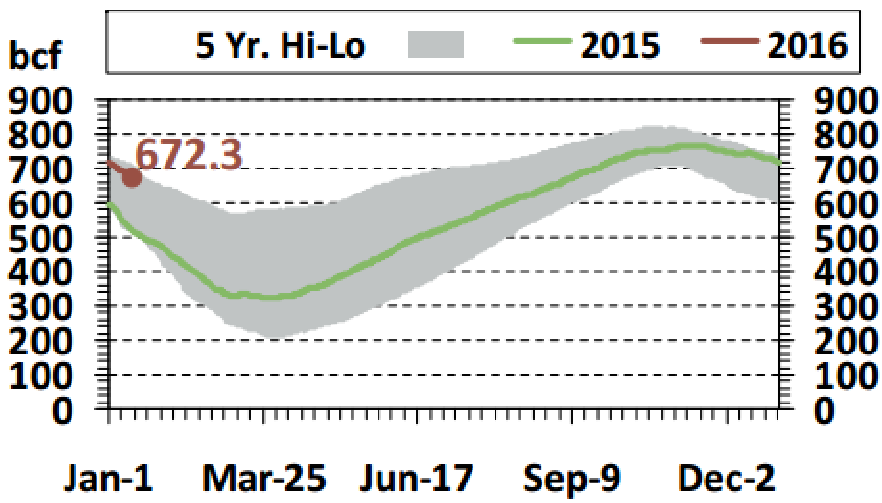
The regulation of storage facilities falls under provincial regulation. If a storage facility is part of the regulated assets owned by an LDC, then the rates it may charge its users are regulated by the provincial energy regulator. If a storage facility is not owned by an LDC, or is not part of the regulated assets-base of the LDC then its rates are usually market-based as determined by a

[104] Union Gas Website, accessed March 28, 2016, https://www.uniongas.com/storage-and-transportation/about-dawn
[105] Intragaz website, Pointe-du-Lac Site, accessed April 2016, http://www.intragaz.com/en/activities_pdl.html
[106] Intragaz website, Pointe-du-Lac Site, accessed April 2016, http://www.intragaz.com/en/activities_flavien.html
[107] Questerre, April 22, 2016, personal communication
[108] Niska Partners Website, accessed March 28, 2016, https://www.niskapartners.com/our-business/natural-gas-storage/aeco-hub/
[109] Niska Partners Website, accessed March 28, 2016, https://www.niskapartners.com/our-business/natural-gas-storage/aeco-hub/
[110] Access Gas website, accessed March 28, 2016, http://www.accessgas.com/index.php/aboutus-wc/companyhistory-wc
[111] Niska Partners website, accessed March 28, 2016, https://www.niskapartners.com/our-business/natural-gas-storage/aeco-hub/

contract between a buyer and storage seller. Storage rates in producing regions, like western Canada, are mostly market-based, whereas in consuming regions, like eastern Canada, more storage rates are regulated.

The North American gas market continues to be oversupplied. By April 2015, the remaining storage deficit from the cold winter of 2013/2014 was replenished and inventories returned to 5-year average levels.[112] More recently, increased levels of natural gas production, along with the warm temperatures of the 2015 and 2016 winters have led to high natural gas storage levels at a time when gas is typically withdrawn. Figure 3.32 highlights January 2016 storage levels compared to those seen in 2015, as well as the 5-year spread. The speed of storage refill over the summer and fall of 2016 will provide a directional indication of the extent to which gas production is exceeding demand. If storage reaches capacity and gas delivery exceeds demand, gas prices may decline and gas production may face a risk of shut in to reduce supply to balance markets. Low gas prices could incentivize coal to gas switching to help absorb the gas overhang. On the other hand, a warmer than usual summer may withdraw more gas into the power generation sector to run air-conditioning units, thus slow the pace of gas injections, subsequently increasing gas prices and encouraging gas deliveries.

Figure 3.32: Canada's Working Natural Gas Storage



Source: FirstCapital Energy Corp.[113]

Canada Environment and Greenhouse Gas Policies

Climate change concerns have stroked an urge in various governments to take action on mitigating present and future GHG emissions. As was already mentioned natural gas among other hydrocarbons is the least-emitting fuel and considered a transition or bridge fuel for the future generation of energy (see Table 3.1).

[112] NEB. "Short term Canadian Natural Gas Deliverability 2015-2017". June 2015.

[113] FirstEnergy Capital Corp, World Crude and Natural Gas Markets: Staring into the Abyss (Highway to Hell)? January 19, 2016, http://legacy.firstenergy.com/UserFiles/Commodities-Breakfast-2016-01-19.pdf

Table 3.1: Pounds of CO_2 Emitted per million British Thermal Units (Btu) of Energy for Various Fuels

Coal (anthracite)	228.6
Coal (bituminous)	205.7
Coal (lignite)	215.4
Coal (subbituminous)	214.3
Diesel fuel and heating oil	161.3
Gasoline	157.2
Propane	139.0
Natural gas	117.0

Source: IEA

Furthermore, on a per-capita basis, Canada emits more GHG's, by a wide margin, than most other industrialized nations. These facts are not lost on Canadian policy makers. The federal government and each provincial and territorial government either have policies in place, or are working on policies to mitigate GHG emissions. The following is a summary of the policy work being done.

Federal Government of Canada

The Federal government has made combatting climate change a priority. On December 12, 2015, Canada and 194 other countries reached the Paris Agreement, an ambitious and balanced agreement to fight climate change. This new Agreement will strengthen the effort to limit the global average temperature rise to well below 2°C and pursue efforts to limit the increase to 1.5°C. To contribute to global efforts, the Government of Canada has promised to provide national leadership and join with the Provinces and Territories to take action on climate change, put a price on carbon, and reduce carbon pollution. Following the Paris meetings, the plan is to establish a pan-Canadian framework for combatting climate change by setting a national target, and that all governments will work together to achieve and to ensure that the provinces and territories have targeted federal funding and the flexibility to design their own carbon pricing policies. The Government of Canada has also promised to invest in green infrastructure and clean technologies by announcing a $2 billion Low Carbon Economy Trust to fund projects that reduce carbon; fulfil G20 commitments and phase out subsidies for the fossil fuel industry; work with the Provinces and Territories to develop a Canadian Energy Strategy to protect Canada's energy security; encourage energy conservation; and bring cleaner renewable energy into the electricity grid.

One action has already been taken. Prime Minister Trudeau met with President Obama in Washington in March 2016. High on their agenda was climate change and GHG emissions, and they agreed to several matters. First, they settled on reducing methane emissions by 40 to 45 percent below 2012 levels by 2025. They also decided to work towards new greenhouse gas emissions standards for heavy duty vehicles, and to seek reduced emissions from airplanes, among other things.[114] Another outcome of the Washington meeting was that the two leaders agreed to work "as soon as possible" on implementing the Paris Agreement on climate change, a document that was signed by both nations.[115]

Provincial Governments

Provincial governments' plans involve an array of options that are or will be adopted in the near future. Two common strategies that are evaluated are carbon tax and cap-and-trade program.

British Columbia – British Columbia implemented a *Climate Action Plan* in 2008 that has been updated several times since. At the centre of the province's actions is the Revenue-Neutral Carbon Tax, which is presently set at $30/tonne of CO2eq. The revenues are directed towards lowering income and corporate taxes and apply to the purchase of hydrocarbons and coal.[116]

British Columbia (along with Manitoba, Quebec, and Ontario) is a partner of the Western Climate Initiative (WCI) which intends to have all partners implement cap-and-trade emissions trading. To date, only the State of California and Quebec have implemented regulations based on WCI recommendations.

Alberta – Carbon pricing will remain a key provincial tool to address climate change. As part of the *Specified Gas Emitters Regulation* enacted in 2007, Alberta currently requires facilities that emit 100,000 tonnes or more of GHG emissions to annually reduce their site-specific emissions by 12 percent. The latest *Climate Leadership Plan* specifies that emissions intensity reduction will increase to 15 percent in 2016, with an increase to 20 percent by 2017. The carbon levy will increase from the current \$15/t CO_2eq. to \$20/t CO_2eq. in 2017 and \$30/t CO_2eq. in 2018. Post-2018 the tax will increase with inflation. The new plan is based on product-based emission performance standards, which will drive "best in class" performance. The government states the "carbon price would cover 78 to 90 percent of provincial emissions, which would be the highest

[114] Wherry, Aaron. "12 things Trudeau and Obama agreed on". CBC News. March 10, 2016. http://www.cbc.ca/news/politics/trudeau-obama-agreements-1.3485496 Accessed March 17, 2016.

[115] [115] Globe and Mail. "Trudeau in Washington". March 10, 2016. http://www.theglobeandmail.com/news/politics/trudeau-in-washington-thursday/article29049173/ Accessed March 10, 2016.

[116] Government of British Columbia. "Revenue-Neutral Carbon Tax". http://www2.gov.bc.ca/gov/content/environment/climate-change/policy-legislation-programs/carbon-tax Accessed March 10, 2016.

in Canada." The province expects the price will generate sufficient revenue to support a variety of green measures, such as R&D and new infrastructure.[117]

The Alberta government has also committed to phasing-out coal-fired electricity by 2030. By 2030, coal will no longer be part of the energy mix in the province, replaced by cleaner-emitting sources of energy such as natural gas, wind, and solar power – two-thirds of coal *capacity* by renewable energy, one-third by natural gas with a goal of 30 percent of *generated electricity* to come from renewables by 2030. In the meantime, coal-fired generators in the province will pay $30/t for GHG emissions based on an industry-wide performance standard.

The province has also placed a maximum 100 megatonne (MT) annual cap on oil sands emissions with provisions for cogeneration and new upgrading capacity. Currently the oil sands industry emits roughly 70 MT per year, the new limit still provides room for growth and development while ensuring Alberta meets its emission targets. Lastly, Alberta will reduce its methane emissions by 45 percent by 2025 as part of its Climate Leadership Plan.

Saskatchewan – Saskatchewan has indicated it will follow the Federal Government's lead on climate change and work with the other provinces to develop "the legislative and regulatory tools needed to help identify and achieve provincial targets, recognizing both regional challenges and opportunities".[118] In the past, Saskatchewan has made some important steps in research and development on GHG emissions mitigation. The Boundary Dam Carbon Capture and Storage project in Estevan, for example, came online in 2014 and will eventually capture approximately 1,000,000 tonnes of CO_2 per year, equivalent to taking 250,000 cars off the road.[119]

Manitoba – Manitoba announced in December 2015 its own *Climate Change and Green Economy Action Plan,* which is an initial, modest effort to sketch out various ways to reduce emissions in the province. Manitoba is already one of the lowest-emitting provinces in Canada, with 98 percent of its electricity generation coming from hydro-electricity.[120] Of the few other facilities, Manitoba has closed two coal-fired power plants and converted two others to natural gas.

Manitoba is a partner in the WCI and therefore has made a commitment to the initiative to eventually implement a "multi-sector, market-based mechanism" (i.e. "cap and trade") to reduce emissions.

Ontario – In late 2015 the Ontario government announced a new *Climate Change Strategy* with the goal of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050. The

[117] Government of Alberta. "Climate Leadership Plan." http://www.alberta.ca/climate-leadership-plan.cfm Accessed March 10, 2016.
[118] Government of Saskatchewan. "Climate Change". http://environment.gov.sk.ca/climatechange Accessed March 10, 2016.
[119] "Boundary Dam Carbon Capture Project". http://saskpowerccs.com/ccs-projects/boundary-dam-carbon-capture-project/ Accessed March 10, 2016.
[120] Government of Manitoba. "Manitoba's Climate Change and Green Economy Action Plan". Page 6. https://www.gov.mb.ca/conservation/climate/pdf/mb-climate-change-green-economy-action-plan.pdf Accessed March 10, 2016.

province intends to accomplish this in stages, first by reducing levels to 15 percent below 1990 levels by 2020 and then reducing to 37 percent below 1990 levels by 2030.[121] Cap-and-trade will be a cornerstone of Ontario's efforts, as it plans to join Quebec and California in their system.

Long a leader in low-GHG energy development efforts in Canada, Ontario has built a fleet of nuclear reactors and has subsidized much solar and wind power in the province through its Feed-in-Tariff (FIT) program. The province, as noted earlier, eliminated all of its coal-fired generation in 2014.

These changes have come at a price, from massive capital cost overruns on the Darlington nuclear facility, to above market rates for the FIT, to natural gas-fired electricity generation infrastructure expenses. The province points out that "since 2003, Ontario's coal closure plan and renewable energy policies have put us on track to eliminate 30 megatonnes of greenhouse gas emissions in 2020…equivalent to taking up to seven million cars off the roads".[122] The high costs of these developments have caused electricity rates to increase and have resulted in some public resentment. From 2003 until 2015, blended electricity rates (taking into account on-peak and off-peak rates) increased 137 percent.[123] The government is pushing green energy development further, announcing that the 2013 fleet of wind turbines and solar farms will be close to triple by 2021.[124]

Quebec – Another leader in GHG emission reduction policy is the province of Quebec, which is the only jurisdiction in the WCI besides California that has implemented a cap-and-trade program. The province has high expectations for the plan, which it claims "will considerably reduce Quebec's GHG emissions, covering close to 85 percent of them by 2015"… and "will generate more than $3 billion in revenues by 2020".[125] Quebec benefits from vast hydropower resources, accounting for 99 percent of its electricity generation and which contribute minimally to GHG emissions.

In September 2015 Quebec updated its earlier greenhouse gas emissions targets. The plan now is to decrease emissions to 37.5 percent below 1990 targets by 2030.[126] This represents a bold step away from potential hydrocarbon development in the province. A 2015 CERI study indicates

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[121] Government of Ontario. Page 9.

[122] Government of Ontario. https://www.ontario.ca/page/climate-change-strategy Page 8. Accessed March 10, 2016.

[123] CBC. "Ontario sees hydro rates jump – again." November 1, 2015. http://www.cbc.ca/news/canada/toronto/ontario-hydro-rate-increase-1.3298396 Accessed March 10, 2016; http://www.ontario-hydro.com/index.php?page=historical_rpp_rates Accessed March 10, 2016.

[124] McKitrick, Ross and Tom Adams. "How green energy is fleecing Ontario electricity consumers". Financial Post. October 29, 2014. http://business.financialpost.com/fp-comment/how-green-energy-is-fleecing-ontario-electricity-consumers Accessed March 10, 2016.

[125] Gouvernement du quebec. "Quebec: A leader in the fight against climate change!". http://www.mddelcc.gouv.qc.ca/changementsclimatiques/index-en.htm Accessed March 10, 2016.

[126] CBC. "Quebec sets bold new greenhouse gas reduction targets". September 17, 2015. http://www.cbc.ca/news/canada/montreal/quebec-greenhouse-gas-reduction-1.3231951 Accessed March 10, 2016.

that any new production of shale natural gas and oil in the promising Utica and Macasty basins would make it difficult for the province to reach its 2030 emissions reduction goals.[127] Add into the equation the consumption of those resources within the province, and the 2030 goals become challenging; the hydrocarbons would need to be exported, or the emissions traded, in order for there to be any kind of future for domestically-produced oil and gas within Quebec.

Atlantic and Northern Canada – The Atlantic provinces and the northern territories, with their low populations and minimal industrial bases, are not emitting anywhere close to the same levels of GHG's as the more industrialized regions of the country. But climate change and emissions are of concern, nevertheless. In fact, all of these provinces and territories have some sort of climate change policy in place, and because populations in these areas have already suffered from climate change effects such as melting snow packs or large weather events, these plans also include adaptation strategies. Table 3.2 is by no means comprehensive, but indicates general measures and goals.

Table 3.2: Atlantic Canada and North GHG Goals and Measures

Province or Territory	Year	GHG goals	Adaptation measures	Other measures
New Brunswick	2014	10% below 1990 by 2020; 75-85% below 2001 by 2050	12 risk & vulnerability studies; Atlantic Climate Adaptation Solutions Association (ACASA)	demand side efficiency; smart grid
Nova Scotia	2009; 2013	10% below 1990 by 2020; electricity GHG "hard caps"	Adaptation fund; ACASA	update coal emissions standards
Prince Edward Island	2008	10% below 1990 by 2020	ACASA	~30% of energy from wind; biomass usage increasing in public sector
Newfoundland and Labrador	2011	10% below 1990 by 2020; 75-85% below 2001 by 2050	ACASA	More hydro development planned; Office of Climate Change, Energy Efficiency & Emissions Trading
Nunavut	2011	no publicly stated reduction goals	Pan-territorial Adaptation Strategy	Alternative energy resource study
Northwest Territories	2011	no publicly stated reduction goals	Pan-territorial Adaptation Strategy	$15 million per year gov't spending on alternative energy
Yukon	2015	carbon neutral by 2020;	Pan-territorial Adaptation Strategy	Microgeneration policy; rebate program; residential & commercial energy incentives programs

Source: Various government documents; David Suzuki Foundation

Throughout the country, provincial governments and the federal government have plans in place to deal with GHG's. To realize these goals, however, large sums of money will need to be spent. The province of Ontario is one of the few jurisdictions that has advanced its plans far enough that the public is seeing first-hand how much GHG reduction will affect taxpayer's pocketbooks; nevertheless, the government is pushing ahead with several green initiatives, which indicates that there is still a reasonable degree of popular support to spend further on environmental programs.

[127] Rozhon, Jon and Paul Kralovic. "An Assessment of the Economic and Competitive Attributes of Oil and Natural Gas Development in Quebec." Canadian Energy Research Institute. Study No. 154. www.ceri.ca Accessed March 10, 2016.

There is no common agreement on the means to a greener, lower-emitting nation. Some provinces, like Alberta and British Columbia are implementing carbon taxes, while others like Quebec and Ontario are looking to cap-and-trade policies to effect change. Though the policies differ from province to province, it is evident that the political will is strong to move towards a greener, less GHG-intensive economy in 2016 and beyond. What remains to be seen is whether or not that political will can be sustained as green energy costs rise – at least over the short- to medium term – in the world's largest per-capita, energy-consuming nation. Many experts have argued, and it bears repeating here, that along the lengthy, expensive road from a hydrocarbon world to a renewable energy world, low-emitting natural gas represents a bridge fuel – not as low in emissions as renewable energy sources but preferable to the GHG-intense production and consumption of coal and oil. Canada's environmental and greenhouse gas mitigation policies, in the main, reflect that bridging role for natural gas.

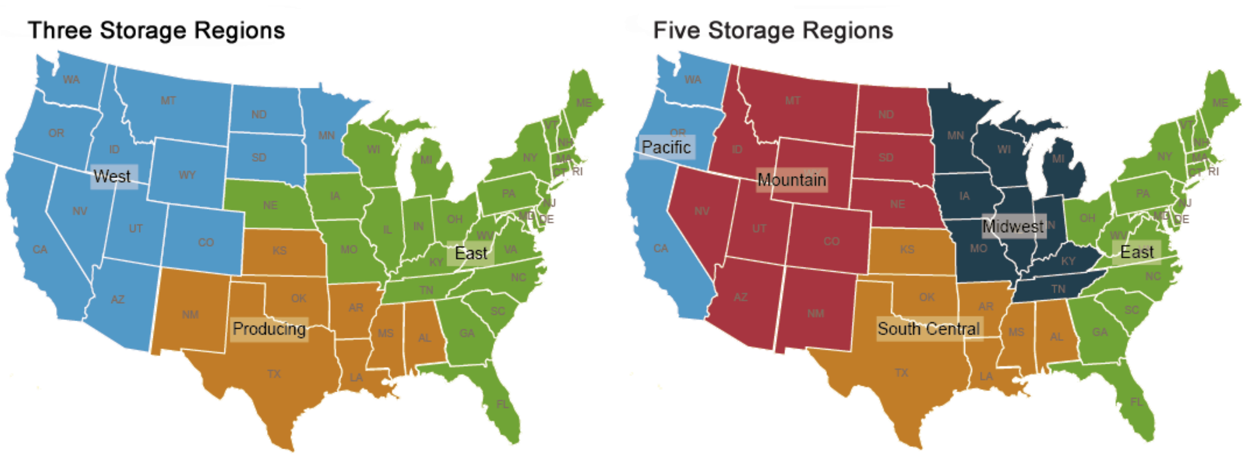
Chapter 4: US Natural Gas Supply and Demand Outlook

This chapter presents the US gas supply and demand outlook. The projections are sourced from the recent US Energy Information Administration's (EIA) Annual Energy Outlook 2015, High Oil and Gas Resource Scenario. The chapter is divided into two parts: US supply and US demand. The latter is further divided into power generation, coal retirement policies and sectoral demand.

US Natural Gas Supply Outlook

The EIA reclassified its regional storage regions in November of 2015 to reflect changes in the industry due to the increase in shale production. The regions are now the Pacific, Mountain, South Central, Midwest and East.[1] Figure 4.1 shows a comparison between the old classification with three storage regions, and the new system with five regions.

Figure 4.1: US Natural Gas Storage Regions



Source: EIA[2]

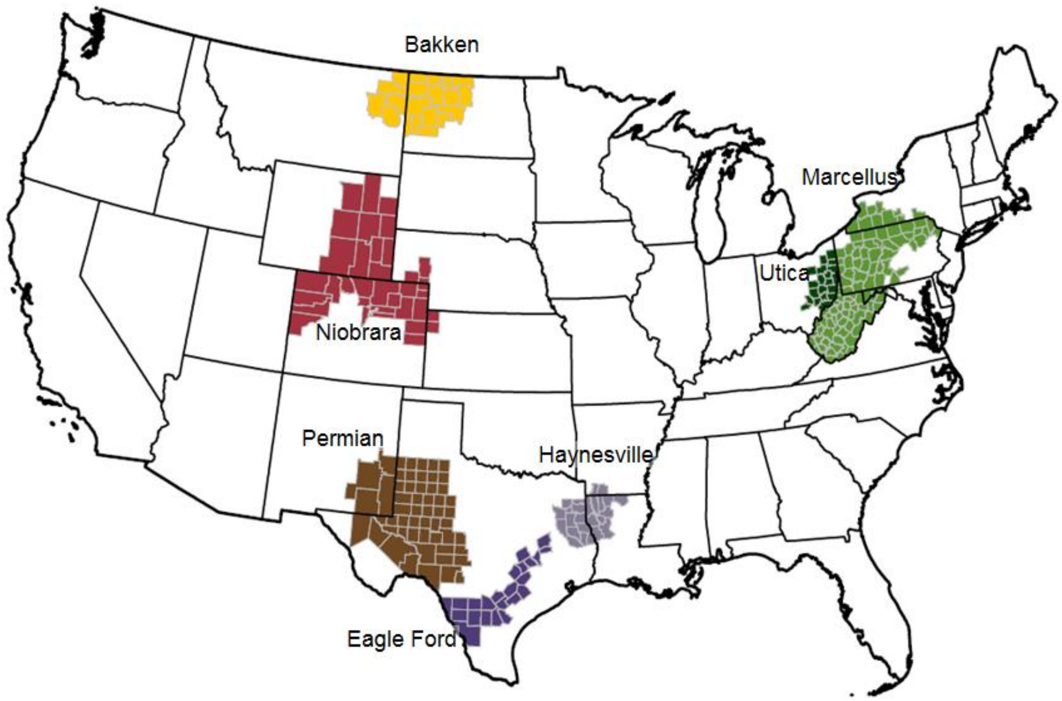
Since 2011, growth in US natural gas production has happened in seven regions: the Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, Permian and Utica.[3] These are shown in Figure 4.2. These producing regions are located in the Mountain, South Central and East storage regions.

[1] U.S. Energy Information Administration, New classifications of natural gas storage regions will begin November 19, November 16, 2015, https://www.eia.gov/todayinenergy/detail.cfm?id=23772

[2] U.S. Energy Information Administration, Underground Natural Gas Working Storage Capacity, accessed March 2016, http://www.eia.gov/naturalgas/storagecapacity/

[3] U.S. Energy Information Administration, Drilling Productivity report, accessed March 16, 2016, https://www.eia.gov/petroleum/drilling/#tabs-summary-2

Figure 4.2: Growth in the US Gas Plays



Source: EIA[4]

Mountain

The Mountain natural gas storage region encompasses the Bakken and Niobrara formations, as well as the New Mexico section of the Permian basin. Between the Bakken and Niobrara formations, the region saw 5,905 MMcfpd of natural gas production in March of 2016.[5]

The Bakken is located in the states of Montana and North Dakota, and the provinces of Manitoba and Saskatchewan. In 2013, the United States Geological Survey estimated the shale play to have 3.4 Tcf of undiscovered, technically recoverable natural gas.[6] While the Bakken was discovered in the 1950s, it did not see large scale production until 2010 when advances in hydraulic fracturing and horizontal drilling made production profitable.[7] It is primarily an oil shale. The rate of natural gas production is shown in Figure 4.3.

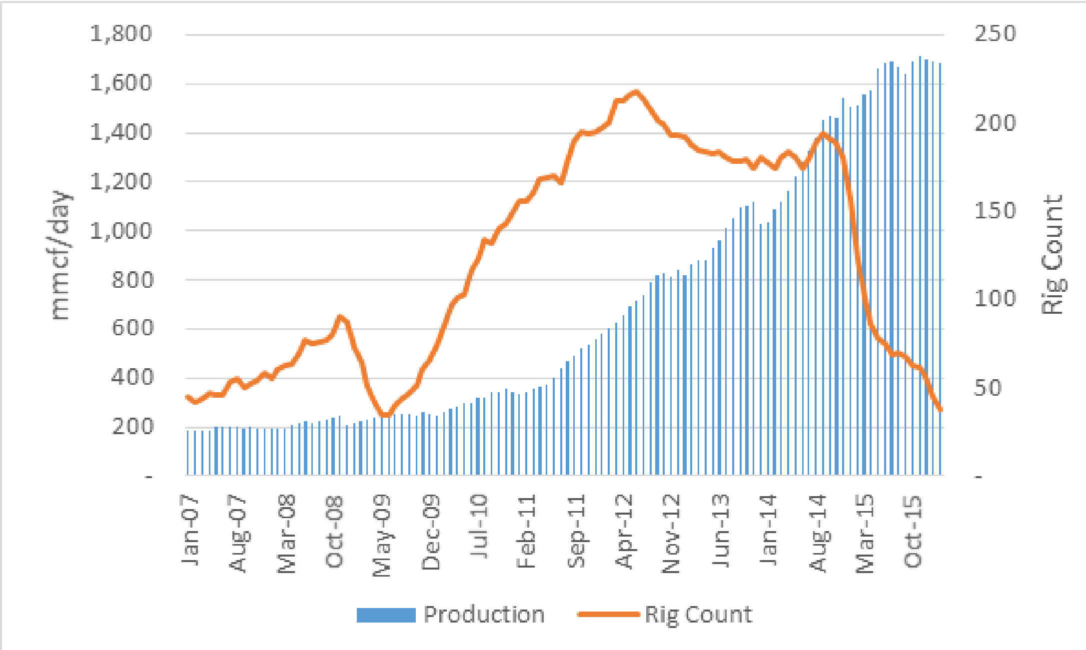
[4] U.S. Energy Information Administration, Drilling Productivity report, accessed March 16, 2016, https://www.eia.gov/petroleum/drilling/#tabs-summary-2

[5] ibid

[6] U.S. Geological Survey, USGS Releases New Oil and Gas Assessment for Bakken and Three Forks Formation, May 2, 2013, http://www.usgs.gov/blogs/features/usgs_top_story/usgs-releases-new-oil-and-gas-assessment-for-bakken-and-three-forks-formations/

[7] Fox News, New Drilling Method Opens Vast U.S. Oil Fields, February 10, 2011, http://www.foxnews.com/us/2011/02/10/new-drilling-method-opens-vast-oil-fields.html#

Figure 4.3: Natural Gas Production and Rig Count in the Bakken Region



Source: EIA[8]

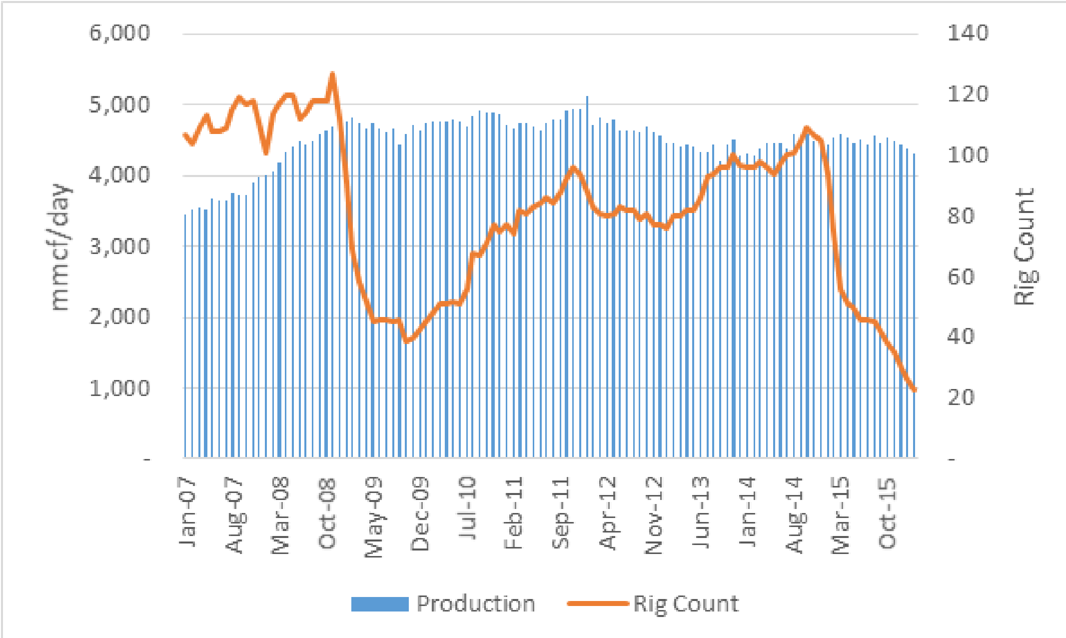
Production peaked in July of 2015 at 1,690 MMcfpd and has declined slightly since. The rig count falls off sharply in mid-2014, coincident with the fall in oil and gas prices.

Shale is known to have a high decline rate, and the Bakken is no exception. Natural gas wells in the play are seeing decline rates of around 50 percent.[9] The plateau and decline of production as of March 2015, as shown in Figure 4.3, is a function of the sharp reduction in active rig count as of early 2014, and the high rate of decline characteristic with the play. Until gas prices rise, production out of the Bakken is not expected to increase.

The Niobrara shale is found in Colorado, Kansas, Nebraska and Wyoming. Like the Bakken, it is primarily an oil shale. Development of oil in the Niobrara is more recent than in the Bakken, and these plays are often compared to each other; the Niobrara has been referred to as the "NeoBakken".[10] However, the Niobrara shale has out-produced the Bakken in terms of natural gas. Figure 4.4 shows natural gas production since 2007.

[8] U.S. Energy Information Administration, Bakken Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/bakken.pdf
[9] U.S. Energy Information Administration, Drilling Productivity Report, accessed March 2016, http://www.eia.gov/petroleum/drilling/
[10] OilShaleGas, accessed March 2016, http://oilshalegas.com/niobrarashale.html

Figure 4.4: Natural Gas Production and Rig Count in the Niobrara Region



Source: EIA[11]

Again, a plateau in production is observed – in this case, much sooner than in the Bakken. Similarly, the rig count dropped significantly in mid-2014, coincident with the fall in oil prices. As with the Bakken, growth is not expected as long as the price of gas remains as low as it does.

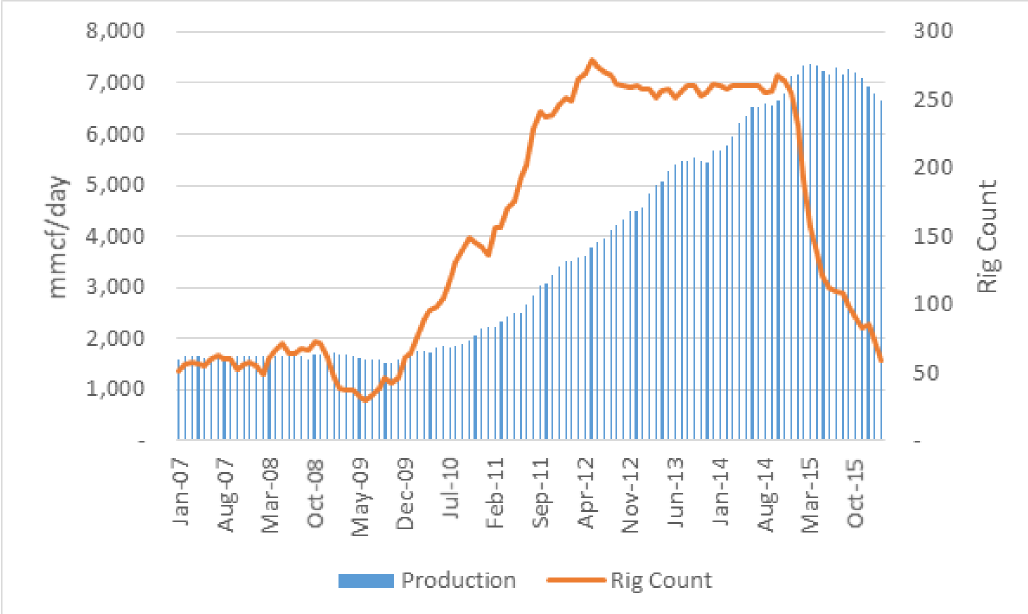
South Central

The South Central storage region contains the Eagle Ford and Haynesville shales as well as the majority of the Permian Basin Shale.

The Eagle Ford Shale, located in Texas, has been a significant producer of natural gas since 2008, when a well was drilled with an initial production rate of 7.6 MMcfpd.[12] The shale play saw $30 billion in development in 2013; the highest amount of capital invested in oil and gas development.[13] The composition of the shale makes it very conducive to fracturing. It has a high composition of carbonate, making it brittle and easy to fracture.[14] Natural gas production and rig count data are shown in Figure 4.5.

[11] U.S. Energy Information Administration, Niobrara Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/niobrara.pdf
[12] Geology.com, Eagle Ford Shale, accessed March 2016, http://geology.com/articles/eagle-ford/
[13] Eagle Ford Shale website, accessed March 2016, http://eaglefordshale.com/
[14] Railroad Commission of Texas website, Eagle Ford Shale Formation, accessed March 2016, http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/

Figure 4.5: Natural Gas Production and Rig Count in the Eagle Ford Region



Source: EIA[15]

Declines in rig activity occurred in 2014, with declines in production lagging approximately a year behind. A 2010 study by Schlumberger shows the Eagle Ford basin to have a high rate of initial production, followed by a steep rate of decline when compared to other basins.[16] This can be attributed to its high reservoir pressure. This same study showed that wells in the Eagle Ford Basin required a gas price of $6/Mcf to break even, assuming a discount rate of 10 percent in 2009. This is a lower break-even price than was calculated in 2008, so it is likely that the well economics would have improved since that time, however not likely to the extent of being profitable of current Henry Hub prices below $2/Mcf.

The Haynesville Shale, located in Louisiana, Arkansas and Texas, was discovered in 2008.[17] The EIA lists the Haynesville as the second largest shale gas resource in the Lower-48 with 74.7 Tcf of technically recoverable resource, representing 10 percent of the total.[18] Like the Eagle Ford, the Haynesville has high reservoir pressure, leading to high rates of initial production and steep decline curves.[19] Its production of natural gas, and rig activity, is shown in Figure 4.6.

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[15] U.S. Energy Information Administration, Eagle Ford Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/eagleford.pdf

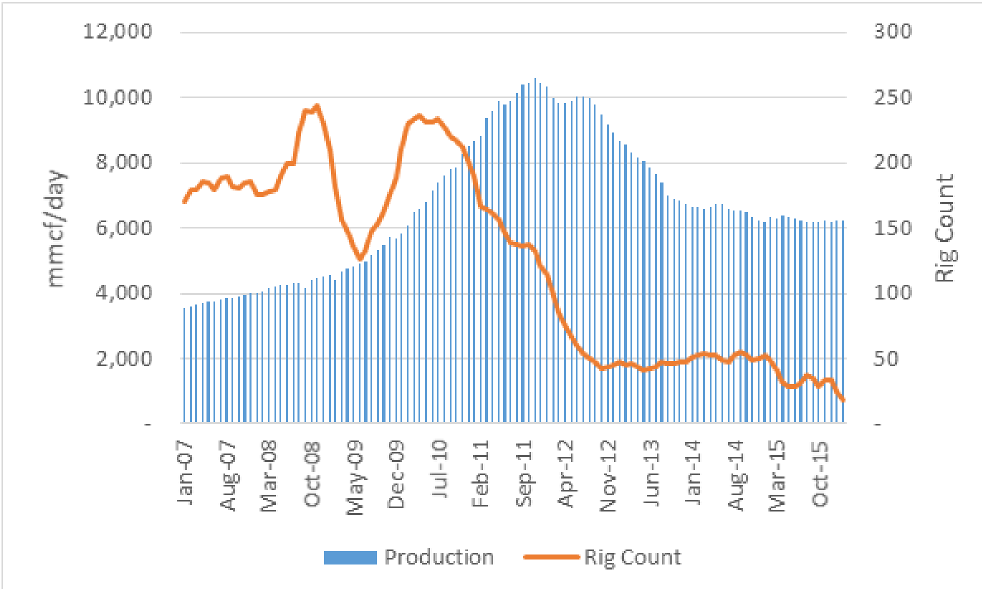
[16] Schlumberger, "Shale Gas Production Trend Comparison Over Time and Basin", 2010, Society of Petroleum Engineers, pp 10.

[17] Natural Gas Intelligence, Information on the Haynesville Shale, accessed March 2016, http://www.naturalgasintel.com/haynesvilleinfo

[18] U.S. Energy Information Administration, Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays, July 8, 2011, http://www.eia.gov/analysis/studies/usshalegas/

[19] Schlumberger, "Shale Gas Production Trend Comparison Over Time and Basin", 2010, Society of Petroleum Engineers, pp 10.

Figure 4.6: Natural Gas Production and Rig Count in the Haynesville Region



Source: EIA[20]

In contrast to the shales discussed thus far, production and rig activity in the Haynesville started to decline prior to the drop in oil prices. The Haynesville is primarily a producer of dry gas, and the reduced activity was reflective of relative profitability of liquids plays.[21] The dry nature of the gas bodes well for the future production of the play, however, as conversion of the gas to LNG is easier. The proximity of the play to the Gulf of Mexico makes this particularly attractive.[22]

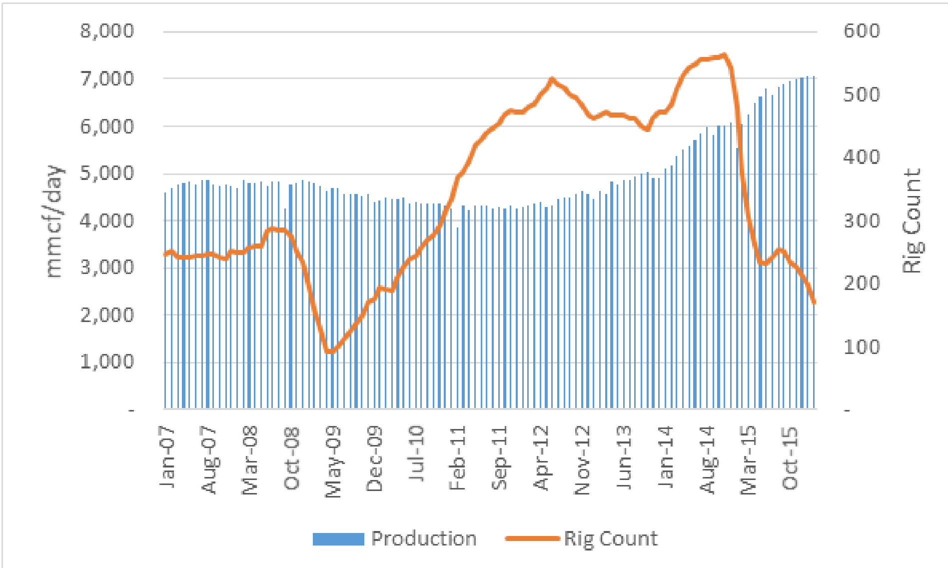
Schlumberger's 2010 report estimates a break-even price in the Haynesville of approximately $6/Mcf – comparable to that of the Eagle Ford. A 2015 analysis by Forbes estimates a required price of $6.50/Mcf.[23] Both analyses show the current price of natural gas to be unprofitable, which is mirrored in the decline in drilling activity seen since 2015.

The Permian Basin, located in Texas and New Mexico, saw its first well drilled in 1925.[24] It has produced over 75 Tcf of gas, while experiencing periods of increasing and decreasing activity.[25] Advances in horizontal drilling spurred the most recent period of high activity, as reflected by the

[20] U.S. Energy Information Administration, Haynesville Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/haynesville.pdf
[21] Natural Gas Intelligence, Information on the Haynesville Shale, accessed March 2016, http://www.naturalgasintel.com/haynesvilleinfo
[22] ibid
[23] Berman, Art, Haynesville Shale Needs $6.50 Gas to Break Even: The Business Model is Broken, Forbes, November 22, 2015, http://www.forbes.com/sites/arthurberman/2015/11/22/haynesville-shale-needs-6-50-gas-to-break-even-the-business-model-is-broken/#5031cbe23ba8
[24] Oil & Gas Financial Journal, Unconventional Oil and Gas, accessed March 2016, http://www.ogfj.com/unconventional/permian-shale.html
[25] Railroad Commission of Texas, Permian Basin Information, accessed March 2016, http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/permian-basin/

uptick in drilling activity in 2010 as shown in Figure 4.7. Like the other shales in the Mountain and South Central regions, rig activity declined in 2014 with the drop in oil prices. However, this drop in rig count has not yet resulted in a decline in production.

Figure 4.7: Natural Gas Production and Rig Count in the Permian Region



Source: EIA[26]

This can be attributed to the fact that the decline rate in the Permian – an estimated 33 percent[27] – is far lower than those in the other shales in the Mountain and South Central regions. The years of vertical drilling prior to the advent of horizontal drilling in the region means that many of the producing wells are still vertical. These are associated with lower decline rates.

When assessing the shale producing areas in the Mountain and South Central regions against the projected natural gas price, they are not expected to see an increase in drilling or production, barring technological advances that drive supply costs down.

East

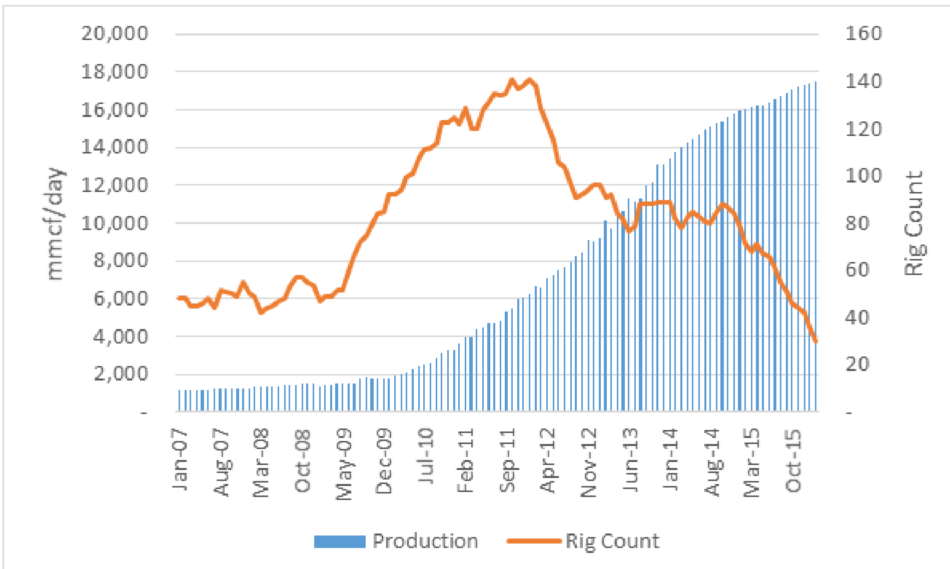
The Eastern storage region is home to the Marcellus and Utica shales, and this region has largely driven the accelerated growth in natural gas production that has changed the supply dynamics of natural gas in North America.

The Marcellus shale is the largest producing shale in the US, producing over 17 Bcfpd in the first months of 2016.[28] In 2002, the US Geological Survey estimated 70.2 Tcf of undiscovered natural

[26] U.S. Energy Information Administration, Permian Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/permian.pdf
[27] Stafford, James, Back to Basics: Why Conventional Drilling Makes Sense in 2015, OilPrice, January 13, 2015, http://oilprice.com/Energy/Crude-Oil/Back-To-Basics-Why-Conventional-Drilling-Makes-Sense-in-2015.html
[28] U.S. Energy Information Administration, Marcellus Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/marcellus.pdf

gas in the area.[29] In 2012, the EIA estimated 140 Tcf of technically recoverable resource.[30] Horizontal drilling began in the Marcellus in 2005, and by 2013 it was the largest gas-producing play. As illustrated in Figure 4.8, the rig count in the Marcellus peaked in early 2012, declined until the middle of the year, and saw a second decline in mid-2014. These declines highlight supply-demand dynamics as they occurred for different reasons. Until 2012, drilling had happened so quickly that there was an excess of wells that needed to be completed and tied into infrastructure, spurring the initial rig decline. The decline in 2014 was, as with the other shale plays, an effect of the fall in the price of oil.

Figure 4.8: Natural Gas Production and Rig Count in the Marcellus Region



Source: EIA[31]

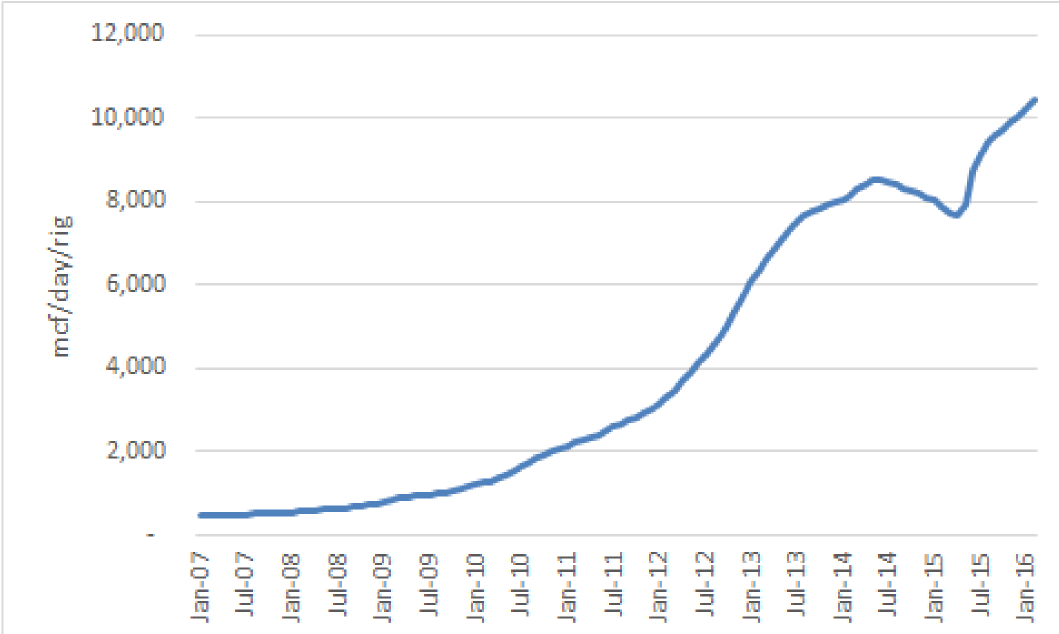
Standing out over other plays, the Marcellus has had the largest increases in the efficiency of natural gas production per rig as shown in Figure 4.9. This has led to a continuous increase in natural gas production out of the region, despite the declines in rig activity, as shown in Figure 4.8.

[29] U.S. Geological Survey, Assessment of Undiscovered Oil and Gas Resources of the Appalachian Basin Province, 2002, http://pubs.usgs.gov/fs/fs-009-03/FS-009-03-508.pdf

[30] U.S. Energy Information Administration, Annual Energy Outlook 2012 with Projections to 2035, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf, pp. 58

[31] U.S. Energy Information Administration, Marcellus Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/marcellus.pdf

Figure 4.9: New Well Natural Gas Production per Rig in the Marcellus Region



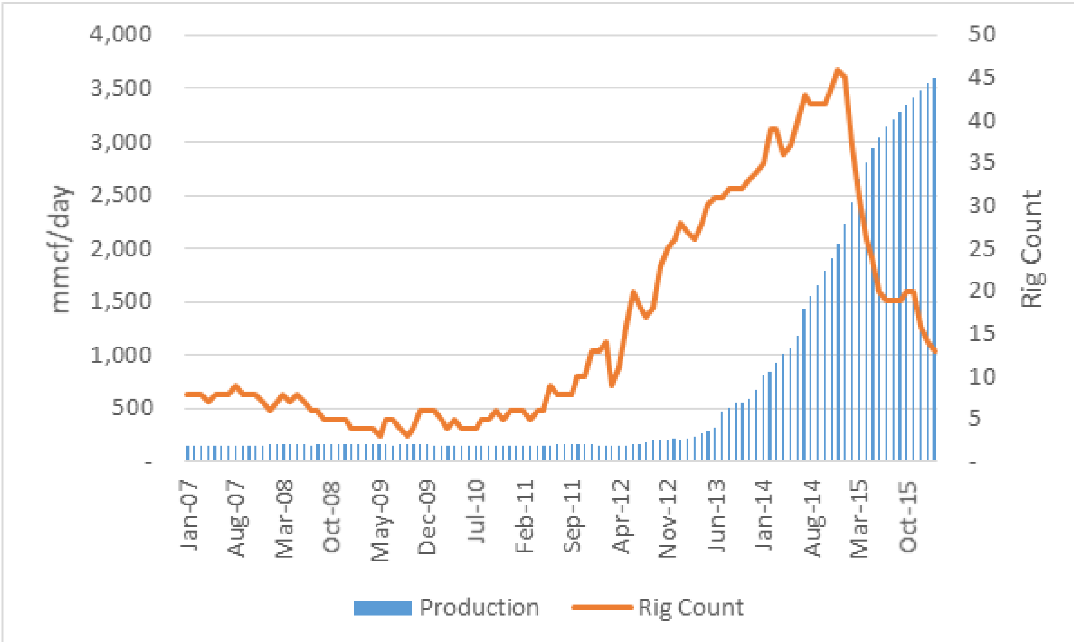
Source: EIA[32]

The Utica shale is located to the west of, and underneath, the Marcellus, in the states of Ohio, West Virginia, Pennsylvania, Kentucky, Maryland, New York, Tennessee, Virginia, and into the province of Quebec. Horizontal drilling and hydraulic fracturing was employed in the Utica in 2010, although significant increases in production were not seen until 2013.[33] In 2012, the EIA estimated that the Utica contained 15.7 Tcf of technically recoverable resources.[34] Thus far, the majority of activity in the shale has occurred in the state of Ohio.

Rig activity is shown in Figure 4.10, showing the fall in activity coincident with the fall in oil price. Like the Marcellus, the efficiency of production per rig has increased significantly in recent years, leading to a continuous increase in natural gas production.

[32] U.S. Energy Information Administration, Marcellus Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/marcellus.pdf
[33] U.S. Energy Information Administration, Utica Region Drilling Productivity report, March 2016, https://www.eia.gov/petroleum/drilling/pdf/utica.pdf
[34] U.S. Energy Information Administration, Annual Energy Outlook 2012 with Projections to 2035, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf, pp. 58

Figure 4.10: Natural Gas Production and Rig Count in the Utica Region



Source: EIA

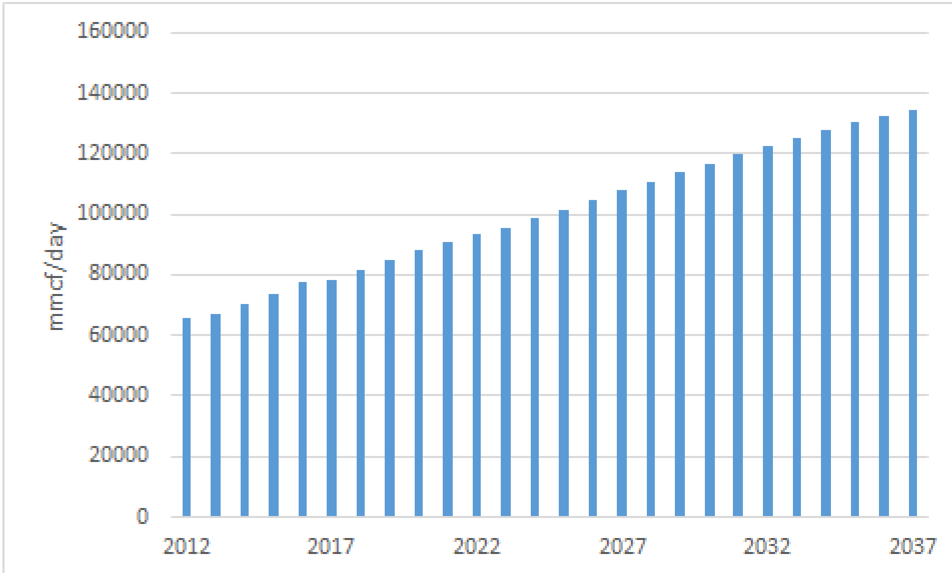
The Utica shale has many of the same advantages that the Marcellus has, with the added benefit of proximity to infrastructure that has already been developed. In fact, the well economics of the Utica, particularly the dry resource, may be better than those of the Marcellus,[35] which would exacerbate the high levels of production that have come from the Marcellus.

In July 2015, the EIA reported that the Marcellus and Utica have made up 28 percent of the growth in US shale production since 2012.[36] In February 2016, the Marcellus and Utica represented 45 percent of the production of the top five US shale plays.[37] Unlike the shale in the Mountain and South Central regions, the East region shale is expected to drive the growth of natural gas production in the US over the period of this study.

The EIA's Annual Energy Outlook 2015 projects natural gas production in a variety of scenarios, with their High Oil and Gas Resource case matching the gas price assumptions used in this study. Hence, this scenario was adopted in this study. This scenario shows the production of natural gas rising almost linearly over the next 20 years, to a value of 134 bcfd in 2037.

[35] Litvak, Anita, Utica Shale: the best and worst of shale plays? PowerSource, November 9, 2015, http://powersource.post-gazette.com/powersource/companies/2015/11/09/If-the-Utica-Shale-is-the-next-big-play-it-could-be-bad-news-for-the-natural-gas-market-Marcellus-Pennsylvania-fracturing/stories/201511080098
[36] U.S. Energy Information Administration, Marcellus, Utica provide 85 percent of U.S. shale gas production growth since start of 2012, July 28, 2015, https://www.eia.gov/todayinenergy/detail.cfm?id=22252
[37] U.S. Energy Information Administration, Drilling Productivity report, accessed March 16, 2016, https://www.eia.gov/petroleum/drilling/#tabs-summary-2

Figure 4.11: US Natural Gas Production Forecast



Source: EIA[38]

Production is expected to increase by 72 percent from 2016 through 2037. The production of dry gas takes into account onshore production, shale gas production and production of associated gas. While the increases in total production are almost constant, shale gas development represents most of the growth, with declines seen in onshore production. Specifically, the production of shale gas is expected to increase by 117 percent from 2016 to 2037. The EIA incorporated assumptions of higher recovery due to increases in technological efficiencies into their modeling.[39] These increases in efficiency allow for increased production amidst the low price environment.

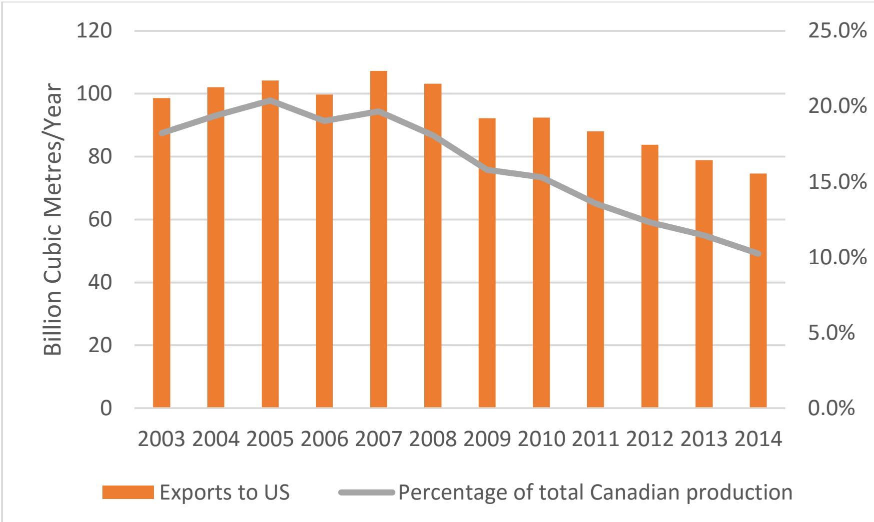
US Natural Gas Demand Outlook

US imports of Canadian natural gas have been in decline in recent years, both as a percentage of overall Canadian natural gas production and in terms of total volumes as seen in Figure 4.12. This development is mainly attributable to technological advances made over the past decade that have enabled more efficient extraction from previously uneconomic formations in the US. Canadian natural gas has historically found captive markets in Boston, New York, Chicago, and other northern urban centres. But the new US gas production benefits from lower transportation costs than Canadian gas, the majority of which is located in the Western Canadian Sedimentary

[38] U.S. Energy Information Administration, Annual Energy Outlook 2015, April 14, 2015, http://www.eia.gov/forecasts/aeo/
[39] ibid, page 21

Basin, thousands of kilometres from the major US demand centres.[40] Canadian gas is increasingly being pushed out of US markets by abundant, inexpensively-delivered US domestic supply.

Figure 4.12: Canadian Natural Gas Exports to US as Percentage of Total Production



Source: BP Statistical Review of World Energy, CERI

As for domestic demand for natural gas in the US, besides the Reference case, the EIA presents four alternative scenarios in their most recent Annual Energy Outlook 2015. Here, two cases are presented: the Reference case and High Oil and Gas Resource case. Figure 4.13 presents a comparison of gas consumption for these two cases. Over the forecast period, the demand under the Reference case remains relatively flat, growing at only 0.5 percent per year, reaching 80 Bcfpd by 2037; demand in the High Oil and Gas Resource case grows at a higher rate of 1.3 percent per annum, exceeding 100 Bcfpd by 2038. The main differences between the two cases are gas price forecast and the estimated ultimate recovery. Under the High Oil and Gas Resource case, estimated ultimate recovery (EUR) per shale gas, tight gas, and tight oil well is 50 percent higher, and well spacing is 50 percent closer (i.e., the number of wells left to be drilled is 100 percent higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays, and the EUR for tight and shale wells increases by 1 percent/year beyond the Reference case annual increase to reflect additional technology improvements.[41] For the purposes of this study, the EIA's Oil and Gas High Resource case is used because the natural gas price forecast in this scenario resembles most closely the NEB's Reference Case forecast of natural gas prices, which was used to forecast Canadian natural gas production as well as supply costs.

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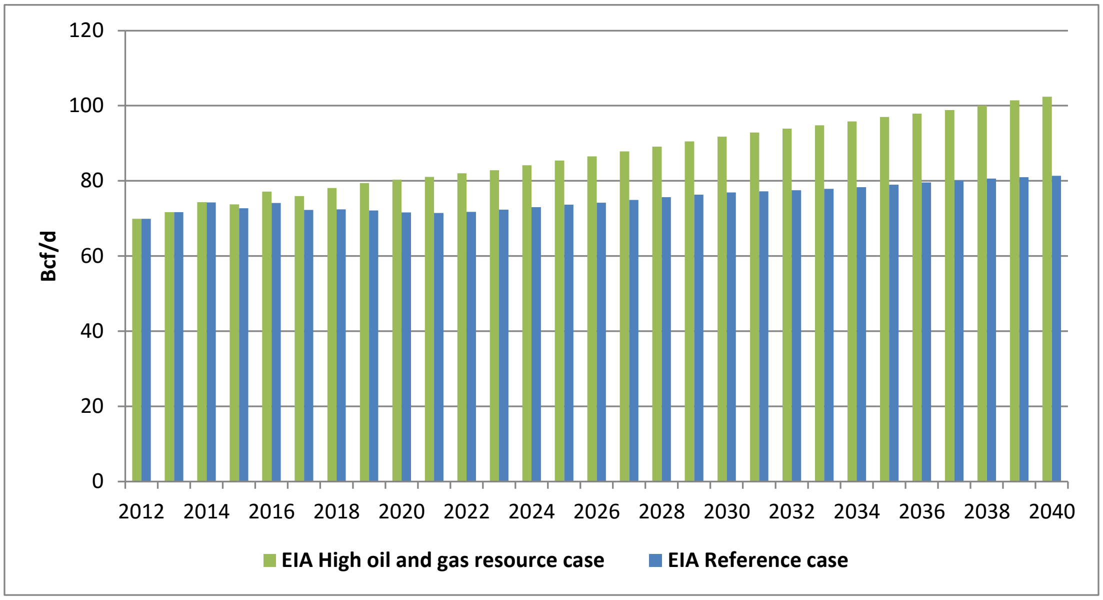
[40] In fact, in recent years, Eastern Canadian demand centres have benefited from low-priced US imports that enter the country by way of the Dawn and Niagara hubs, displacing some of the Western Canadian gas that arrives via the TransCanada Mainline.

[41] For more details on AEO2015 cases, see "Assumptions to the Annual Energy Outlook 2015". September 2015. http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554%282015%29.pdf. Accessed on March 31, 2016.

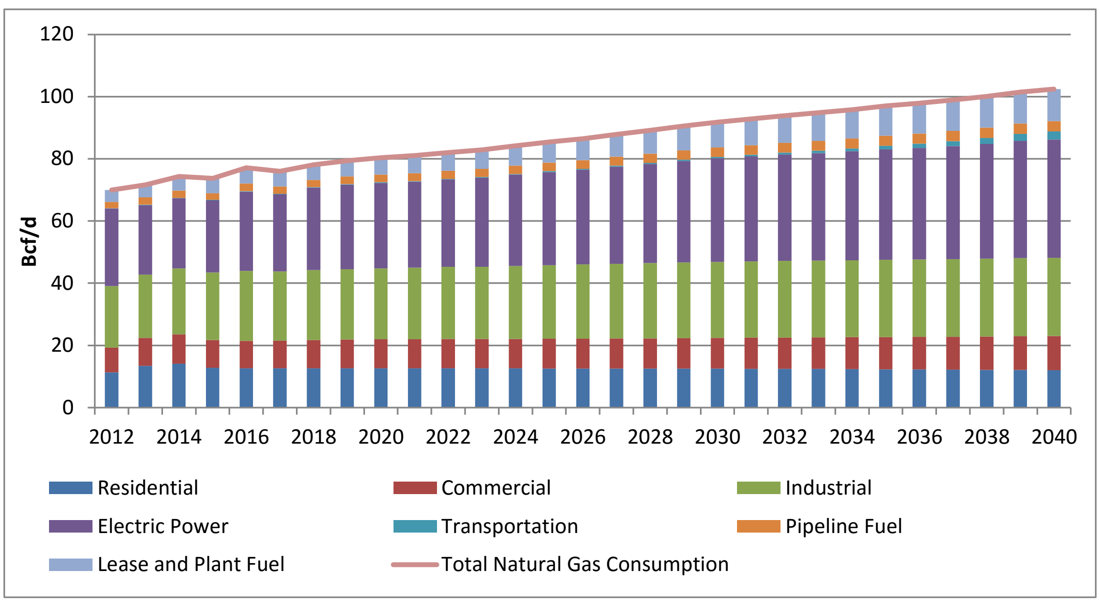
Figure 4.13: US Total Natural Gas Demand by Scenario



Source: EIA, CERI

US gas demand forecast (Oil and Gas High Resource Case) by sector is presented in Figure 4.14.

Figure 4.14: US Natural Gas Demand by Sector (Oil and Gas High Resource Case)



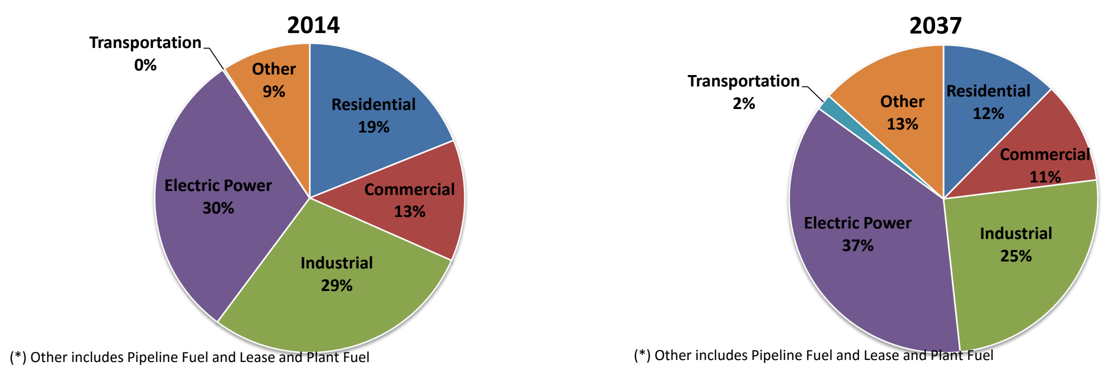
Source: EIA, CERI

Only one sector sees diminishing demand for natural gas. Consumption of natural gas in the residential sector continues to decrease, dropping by 1.9 Bcfpd or 13 percent between 2014 and 2037. There has been a shift in the way energy is used in US households. In the past, heating and cooling accounted for well over half of all residential energy consumption. However, as insulation improves, more efficient furnaces are used, and more energy efficient windows are installed, the overall consumption of gas in that sector is expected to drop. On the other hand, major non-weather related items such as appliances and electric lights, which both require electricity are therefore taking on a larger role in the residential energy demand mix.[42]

All other sectors' demand for natural gas is increasing for the forecast time period. While the smallest share of total demand, the transportation sector's use of natural gas will grow at a highest percentage rate among all sectors, increasing from an almost non-existent 0.15 Bcfpd in 2014 to 1.6 Bcfpd in 2037 (and subsequently to 2.6 Bcfpd in 2040). Natural gas vehicles penetration in the transportation sector is the culprit for this increase. While commercial and industrial sectors' demand for gas is increasing by 12 and 18 percent from 2014 to 2037, respectively, more natural gas than ever before is going to be delivered to the electrical power sector in the US. As the US retires its coal-fired fleet, more natural gas will be used for the purposes of electricity generation, in combination with renewable power. Over time, the demand for gas in that sector will grow by 13.8 Bcfpd from 2014 to 2037, or 61 percent, up to 36.3 Bcfpd in 2037 from 22.6 Bcfpd in 2014.

Figure 4.15 illustrates the potential evolution of sectoral demand shares of total natural gas demand in the US for the foreseeable future. As can be seen in the figure, the electric power sector will take up nearly 40 percent of total gas consumption by 2037. Over the next two decades, volumes of natural gas used for electric power will increase substantially, making the electric power sector the largest end-user, edging out the industrial sector's usage. In 2014, industrial and electric power had equal shares of gas use.

Figure 4.15: US Natural Gas Demand by Sector Shares



Source: EIA, CERI

Residential and commercial sectors' shares will shrink by 2037, while the transportation sector's share will grow to 2 percent. The "other" sector, comprised of pipeline fuel and lease and plant fuel, will occupy an increasing share, growing by 4 percent from 2014 to 2037. The percentages will change over time, with electric power gaining the largest share in the mix. This has to do with the increasing move away from coal-fired generation plants and the more or less static

[42] EIA. "Heating and cooling no longer majority of U.S. home energy use." March 7, 2013. https://www.eia.gov/todayinenergy/detail.cfm?id=10271 Accessed January 15, 2016.

position of hydroelectricity and nuclear power.[43] Hydroelectricity has not grown simply because the entire economically feasible large infrastructure has been built already; with all major rivers dammed, there is little room for sizeable expansion. Nuclear has neither expanded nor shrunk much in the 30+ years since Three Mile Island and Chernobyl. Gas-fired generation, cleaner than coal and perceived as safer than nuclear, has and will continue to carve out an ever-larger niche in the US electrical power mix, as indicated by EIA data.

The Lower-48 states are tightly laced with natural gas transmission and distribution pipelines, so natural gas-fired electricity generation is found throughout the country, and there are few transportation infrastructure barriers to building more gas-fired plants in the future.

US Environmental and Greenhouse Gas Policies

For more than a generation, the state of California has been the vanguard of US pollution control and environmental protection efforts. California was a prime mover of the Western Climate Initiative (WCI) and remains the only US state that is an active participant in that plan. Central to California efforts has been Bill AB-32, also known as "The Global Warming Solutions Act" which was passed in 2006 and has served as a benchmark for subsequent climate action in other jurisdictions including the federal government in Washington.

Goals of the California plan include:[44]

a) Reduce greenhouse gas emissions to 1990 levels by 2020 and 40 percent below 1990 levels by 2030;
b) Double energy efficiency savings at existing buildings;
c) Reduce GHG emissions from natural and working lands;
d) Implement a cap-and-trade program (i.e. the WCI);
e) Improve appliance efficiency standards and have 33 percent of all electricity come from renewables by 2020.

Seven years after Bill AB-32 was passed in 2006, President Obama announced the federal Climate Action Plan. This 2013 document represented an early stage in what promises to be an evolution of policies and measures, influenced by other plans, such as the Paris Agreement. There was, as a result, some leeway built into the plan; initial GHG reduction targets were designed to be in the range of 17 percent below 2005 emissions by 2020 and 26 to 28 percent below 2005 emissions levels by 2020 to 2025.[45]

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[43] For approximately 30 years, there has been little construction activity in the US nuclear energy industry, with few reactors built over that time. However, as many as six new reactors could come on line by 2020, according to the World Nuclear Association. http://world-nuclear.org/info/Country-Profiles/Countries-T-Z/USA--Nuclear-Power/ Accessed January 14, 2016.

[44] California Climate Change. http://www.climatechange.ca.gov/ Accessed March 18, 2016.

[45] Damassa, Thomas, Mengpin Ge, and Taryn Fransen. World Resources Institute. "The U.S. Greenhouse Gas Reduction Targets." December 2014. http://www.wri.org/publication/us-greenhouse-gas-reduction-targets Accessed March 18, 2016.

President Obama's plan is wide in scope, targeting methane releases from the oil and gas industry, expanding renewables development, increasing fuel economy standards, increasing energy consumption efficiency, and working toward climate change adaptation are all elements of the overall plan. The plan also stresses that the federal government must lead the efforts by reducing its own greenhouse gas emissions, and sourcing its energy from renewables wherever possible.[46]

There has been opposition to President Obama's plan, eventually leading to a decision by the Supreme Court to stay the implementation of clean power provisions that would see carbon dioxide emissions cut by more than 30 percent by 2030.[47] The court stated the plan may not be implemented prior to legal challenges being heard. Opponents to the plan contend that it would force electricity providers to spend billions of dollars to retool coal-fired and gas-fired generators – not in their best interests should the plan one day be overturned.

As long as the stay remains in place, it is difficult to determine how much coal-fired generation will be displaced by natural gas-fired generation, and how much natural gas-fired generation will be displaced by renewables. This report, in the absence of any resolution on this matter, has not adjusted its data to reflect potential outcomes of the stay.

Finally, the US signed the Paris Agreement in 2015. Though the document is not binding, the US was a strong backer. The US will be working towards implementation, which is slated for 2020 unless there is a change in policy direction in the US after the Presidential election. The US will be expected to do its part in moving towards the following goals:

a) Limiting global temperature rise to between 1.5 and 2 degrees Centigrade;
b) Providing $100 billion annually to developing countries to promote greener economies;
c) Publishing GHG targets every 5 years; and
d) Creating a carbon-neutral world between 2050 and 2100.[48]

All of the above-mentioned plans will need to leverage the benefits of low-emitting natural gas, at least over the short-term before renewables assume a more prominent position in the energy mix of nations.

US Federal Government

The latest iteration of federal policy, finalized in December 2015, is President Obama's "Clean Power Plan", which intends to fund research and development into cleaning fossil fuel emissions from sources such as cars and power plants, expanding the role of renewable energy sources in

[46] Executive Office of the President. "The President's Climate Action Plan." June 2013. https://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf Accessed March 18, 2016.
[47] Biesicker, Michal and Sam Hananel. "U.S. Supreme Court puts Obama's Clean Power Plan on hold". CBC News. http://www.cbc.ca/news/world/supreme-court-obama-climate-change-1.3441266 Accessed March 18, 2016.
[48] Watters, Haydn. CBC. "5 key points in Paris Agreement on climate change." http://www.cbc.ca/news/world/paris-agreement-key-climate-points-1.3362500 Accessed March 18, 2016.

the nation's energy mix, building clean energy infrastructure, improving energy efficiency, and taking measures to prepare for the impacts of climate change.

The goal of the plan is to reduce carbon emissions by 32 percent from 2005 levels by 2030. The government plans to offset costs by efficiency and other gains; the Administration predicts the plan will save the average US family $85 a year on their energy bills in 2030, will conserve enough energy to power 30 million homes in 2030, and will save consumers $155 billion from 2020 to 2030.[49] The consultancy Energy Ventures Analysis released a study claiming the plan will in fact cost consumers $214 billion in increased electricity prices and $64 billion to replace lost power capacity serving 24 million homes.[50] Opposition has also been voiced by the American Petroleum Institute,[51] the coal industry,[52] and numerous members of congress,[53] who believe that the plan could harm state economies.

California

The Assembly Bill 32 (more popularly known as AB-32) is comprehensive legislation passed in 2006 that "set the stage for [California's] transition to a sustainable, low-carbon future".[54] Bill 32 requires California to reduce GHG emissions to 1990 levels by 2020, or approximately 15 percent below the emissions level expected in a "business as usual" scenario. To finance the plan, the state of California collects an AB-32 fee from organizations that are sources of GHG's. It also collects from 250 organizations that emit 330 million metric tons of GHG emissions per year. Proceeds are also collected from the state's cap-and-trade program that has been operational since 2012.[55] This program is part of the Western Climate Initiative that California initiated in 2007 and in which the state presently holds membership along with Quebec, Ontario, Manitoba, and British Columbia.

The strategy in California is to reduce emissions in 9 focus areas: energy; transportation; agriculture; water; waste management; natural and working lands; short-lived climate pollutants;

[49] https://www.whitehouse.gov/climate-change Accessed April 20, 2016.
[50] EPA's Clean Power Plan: An Economic Impact Analysis. Energy Ventures Analysis. http://nma.org/attachments/article/2368/11.13.15%20NMA_EPAs%20Clean%20Power%20Plan%20%20An%20Economic%20Impact%20Analysis.pdf Accessed April 22, 2016.
[51] "The Right Road to Clean Power". American Petroleum Institute. http://www.api.org/~/media/files/policy/environment/the-right-road-to-clean-power.pdf. Accessed April 20, 2016.
[52] "Coal Lobbyists call EPA's Clean Power Plan "irrational and illegal". World Coal. http://www.worldcoal.com/power/08122014/Coal-lobbyists-attack-EPA-Clean-Power-Plan-1652/ Accessed April 20, 2016.
[53] "Obama's Clean Power Plan receives mixed reaction from Washington lawmakers." WEAU.com http://www.weau.com/home/headlines/Obamas-Clean-Power-Plan-receives-mixed-reaction-from-Washington-lawmakers-320682192.html Accessed April 20, 2016.
[54] California Environmental Protection Agency, Air Resources Board. "Assembly Bill 32 Overview". http://www.arb.ca.gov/cc/ab32/ab32.htm Accessed April 22, 2016.
[55] California Environmental Protection Agency, Air Resources Board. "Cap-and-Trade Program. http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm Accessed April 22, 2016.

green buildings; and the cap-and-trade program.[56] In energy, the state plans to have 33 percent of energy come from renewable sources (i.e. Renewable Portfolio Standard) by 2020. It is also adopting regulations that reduce GHG's in new passenger vehicles from 2009 through to 2016. The state claims that it is "getting real reductions to put us on track for reducing GHG emissions to achieve the AB-32 goal of getting back to 1990 levels by 2020".[57] California has now also extended the length of time that it will be making GHG mitigation efforts, from 2020 to 2030. It has also restated the goal to 40 percent below 1990 levels by 2030.

Other States' Renewable Portfolio Standards (RPS)

Renewable Portfolio Standards are regulations that stipulate increased production of energy from renewable sources such as wind, tidal, geothermal, biomass, and solar energy. In the United States, 37 of the 50 states (as well as the District of Columbia and various territories) have implemented some form of RPS. The structure, enforcement mechanisms, size and applications of Renewable Portfolio Standards vary from state to state, as the US Energy Information Administration notes.[58] States notable for their advanced RPS targets and implementation include Oregon, Hawaii, Vermont, and California.[59] Table 4.1 lists the states that have RPS targets. The list is general and in many cases does not reflect longer-term goals that the states have set.

[56] California Environmental Protection Agency, Air Resources Board. "AB 32 Scoping Plan". http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm Accessed April 22, 2016.
[57] "AB 32 Scoping Plan"
[58] "Most states have Renewable Portfolio Standards." *Today in Energy*. EIA. February 2, 2012. http://pbadupws.nrc.gov/docs/ML1409/ML14093A271.pdf Accessed April 22, 2016.
[59] "Higher Oregon renewable portfolio standard targets likely to boost wind power". *Today in Energy*. EIA. April 22, 2016. http://pbadupws.nrc.gov/docs/ML1409/ML14093A271.pdf

Table 4.1: Renewable Portfolio Standards by State

State	Title	Established	Renewables goal
Alaska	not codified in legislation	2010	50%
Arizona	Renewable Energy Standard	2006	15% by 2025
California	Renewables Portfolio Standard	2002	33% by 2020
Colorado	Renewable Energy Standard	2004	30% by 2020
Connecticut	Renewables Portfolio Standard	1998	27% by 2020
Delaware	Renewables Energy Portfolio Standard	2005	25% by 2026
Hawaii	Renewable Portfolio Standard	2001	30% by 2020
Illinois	Renewable Portfolio Standard	2007	25% by 2026
Indiana	Clean Energy Portfolio Goal	2011	10% by 2025
Iowa	Alternative Energy Law	1983	105 MW
Kansas	Renewable Energy Goal	2015	20% by 2020
Maine	Renewables Portfolio Standard	1999	40% by 2017
Maryland	Renewables Energy Portfolio Standard	2004	20% by 2022
Massachusetts	Renewable Portfolio Standard	1997	15% by 2020
Michigan	Renewable Energy Standard	2008	10% by 2015
Minnesota	Renewables Energy Standard	2007	26.5% by 2025
Missouri	Renewable Electricity Standard	2007	15% by 2021
Montana	Renewable Resource Standard	2005	15% by 2015
Nevada	Energy Portfolio Standard	1997	25% by 2025
New Hampshire	Electric Renewable Portfolio Standard	2007	24.8% by 2025
New Jersey	Renewables Portfolio Standard	1999	24.5% by 2020
New Mexico	Renewables Portfolio Standard	2002	20% by 2020
New York	Renewable Portfolio Standard; Reforming the Energy Vision (REV)	2004	40% by 2030
North Carolina	Renewable Energy and Energy Efficiency Portfolio Standard	2007	12.5% by 2021
North Dakota	Renewable and Recycled Energy Objective	2007	10% by 2015
Ohio	Alternative Energy Resource Standard	2008	25% by 2026
Oklahoma	Renewable Energy Goal	2010	15% by 2015
Oregon	Renewable Portfolio Standard	2007	25% by 2025
Pennsylvania	Alternative Energy Portfolio Standard	2004	18% by 2021
Rhode Island	Renewable Energy Standard	2004	14.5% by 2019
South Carolina	Renewables Portfolio Standard	2014	2% by 2021
South Dakota	Renewable, Recycled and Conserved Energy Objective --- ACHIEVED	2008	10% by 2015
Texas	Renewable Generation requirement -- ACHIEVED	1999	10 TW by 2025
Utah	Renewables Portfolio Goal	2008	20% by 2025
Vermont	Renewable Energy Standard	2015	12% by 2032
Virginia	Voluntary Renewable Energy Portfolio Goal	2007	12% by 2022
Washington	Renewable Energy Standard	2006	15% by 2020
West Virginia	Alternative and Renewable Energy Portfolio Standard -- REPEALED	2015	
Wisconsin	Renewable Portfolio Standard	1998	10% by 2015
Washington, DC	Renewable Portfolio Standard	2005	20% by 2020
Guam	Renewable Energy Portfolio Goal	2008	25% by 2035
Northern Mariana Islands	Renewables Portfolio Standard	2007	20% by 2016
Puerto Rico	Renewable Energy Portfolio Standard	2010	20% by 2035
US Virgin Islands	Renewables Portfolio Targets	2009	25% by 2020

Source: National Conference of State Legislatures

There is much skepticism in the United States about GHG reduction strategies in general and Renewable Portfolio Standards specifically. States including Florida, Louisiana, Tennessee, Wyoming, and Idaho do not have RPS' at all, and opposition to the Clean Power Plan from industry, congress, and the courts indicate that the plan must overcome significant hurdles in order to be implemented.

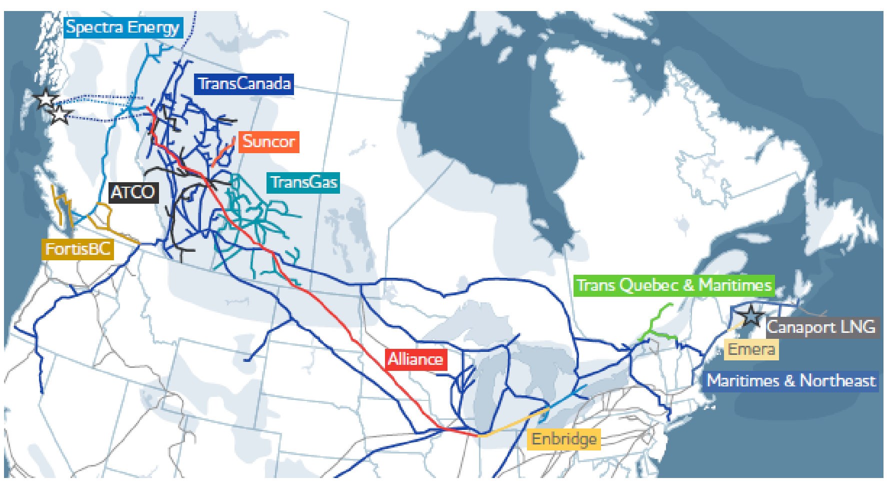
Chapter 5: Canadian Natural Gas Exports and Imports – Pipelines and LNG Projects

This chapter presents CERI's outlook for exports and imports of natural gas between Canada and the US, as well as internationally as LNG. The chapter is divided into two parts: i) an overview of export and import pipelines between Canada and the US, followed by an exports/imports forecast; and ii) LNG projects and their outlook. It is, however, beyond the scope of this study to analyze and review individual projects, but rather the likelihood of change in LNG projects.

Natural Gas Exports

Natural gas pipelines are used to transport natural gas from producing fields and wells to processing plants, to distribution centers. Figure 5.1 illustrates the major natural gas transmission pipelines, connecting the WCSB producers to consuming markets across Canada and the US. While natural gas can be transported by truck, vessel (via LNG) and pipeline, it is the latter that dominates the movement of the commodity in North America. Figure 5.1 does not show the distribution pipelines delivering natural gas to customers through local distribution companies (LDCs) or the extension network of gathering and processing pipelines delivering raw natural gas to processing facilities.[1]

Figure 5.1: Major Natural Gas Transmission Pipelines

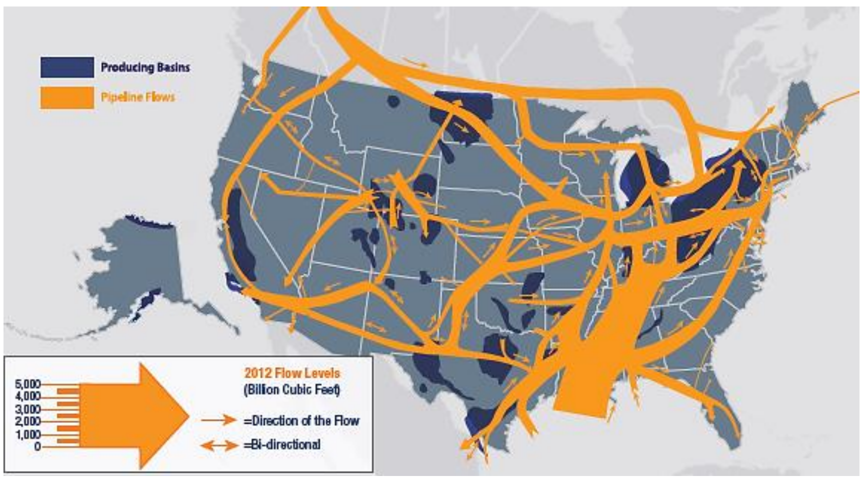


Source: CEPA[2]

[1] Go with Natural Gas website, Gathering, Transmission and Distribution http://www.gowithnaturalgas.ca/operating-with-natural-gas/fuel/natural-gas-as-an-energy-source/gathering-transmission-and-distribution/ (Accessed on March 17, 2016)
[2] Canadian Energy Pipeline Association, Natural Gas Pipelines, http://www.cepa.com/map/pdf/ng-cepa2014.pdf (Accessed on March 17, 2016)

Figure 5.2 shows the major flow of natural gas in North America. Before reviewing the major export and import pipelines in Canada, it is prudent to illustrate the flow levels and patterns on the continent. The figure highlights issues for western Canadian natural gas producers. Increasing shale gas production in the Marcellus Shale, and to a lesser extent the Utica Shale, natural gas production in the US northeast certainly impacts the flow of natural gas within the US as well as with Canada. As previously mentioned, production in the Appalachian Basin, the largest hydrocarbon-bearing basin in the Lower-48, is altering pipeline flows in the US Northeast, and in turn affecting traditional suppliers to the region, such as western Canada, the US Rockies and the US Gulf Coast.

Figure 5.2: Natural Gas Pipeline Flows in Canada and the US



Source: API[3]

Not only is the US Northeast less dependent on other regions, but US Northeast natural gas is spilling into the US Midwest, the US Southeast and central Canada. While western Canadian natural gas does not flow to the US Southeast, producers are impacted by gas flowing into the US Midwest and Ontario. In the case of the US Midwest, natural gas from the Marcellus has impacted several projects in the region, such as modifying the Rockies Express (REX) Pipeline. The original mandate of the pipeline was to deliver gas from Colorado to eastern Ohio and the higher-priced, consuming markets on the East Coast. Rockies gas, however, is also being pushed out of the US Northeast, and the eastern portion of the REX now transports natural gas westward from Ohio to Midwest markets. Interestingly, this has negatively impacted western Canadian producers,[4] increasing competition for its product to the US Midwest region.[5]

[3] American Petroleum Institute, Understanding Natural Gas Markets, http://www.api.org/~/media/files/oil-and-natural-gas/natural-gas-primer/understanding-natural-gas-markets-primer-low.pdf, pp. 6.
[4] Platts.com, Appalachian pipeline developers facing challenges, October 19, 2015, https://online.platts.com/PPS/P=m&e=1445300335487.4865187501751742788/GD_20151019.xml?artnum=c5b31e8bb-035b-459b-adfe-6881a8b5f13f_3 (Accessed on March 17, 2016)
[5] National Energy Board, Market Snapshot: Decreasing Canadian Natural Gas Exports to the U.S. Midwest and East Regions, September 16, 2015, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2015/09-03dcrsngxprt-eng.html (Accessed on March 17, 2016)

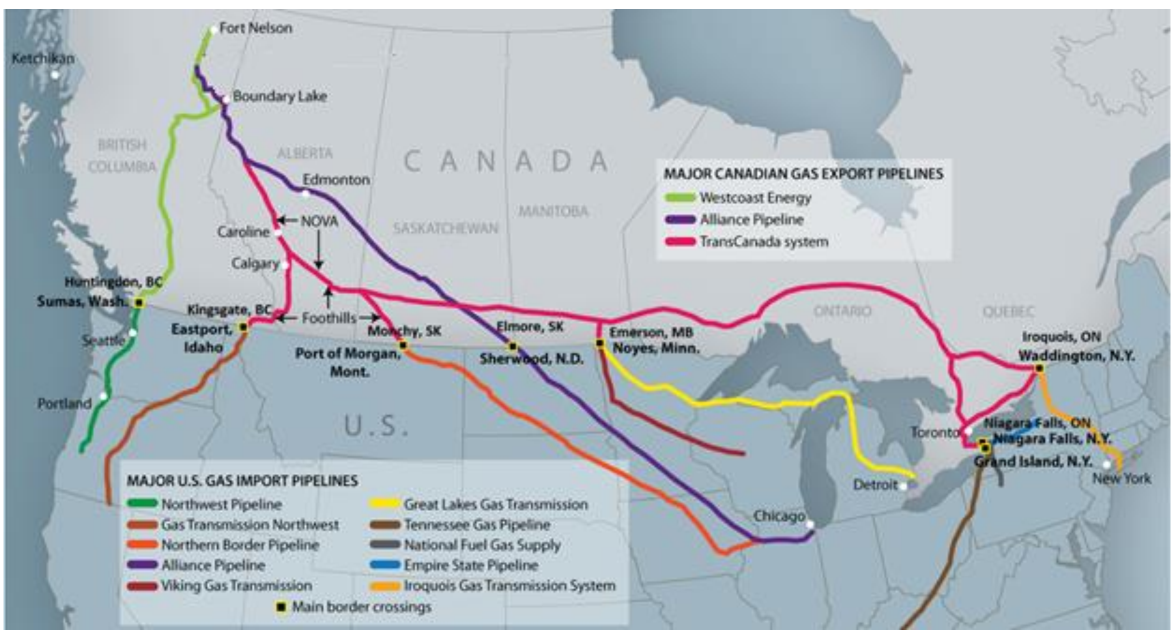
The following section delves deeper into Canada's natural gas pipeline infrastructure, focusing on major export and import pipelines and is divided into two sections. The first section reviews export pipelines in western Canada followed by pipelines in eastern Canada. Export pipelines in western Canada include Spectra Energy/Westcoast Energy (Huntingdon), NGTL System/Foothills Pipelines (Kingsgate), Alliance Pipeline (Elmore), TransCanada Pipelines-Foothills Pipelines (Monchy) and TransCanada Pipelines (Emerson). The eastern Canada export pipelines include TransCanada Pipelines-Iroquois Pipeline (Iroquois), Maritimes & Northeast (St. Stephen) and Trans Quebec and Maritimes (East Hereford). The second section discusses the top five import pipelines, including Vector Pipeline (Courtright), TransCanada Pipelines (Niagara Falls), Union Gas (Ojibway [Windsor]), TransCanada Pipelines (Sarnia) and Union Gas (St. Claire).

Major Natural Gas Export Pipelines in Canada

As well as discussing the aforementioned export pipelines in western and eastern Canada, this section reviews briefly the TCPL Canadian Mainline, connecting western and eastern Canada, as well as several important proposed pipelines, including the Energy East Pipeline and several proposed natural gas pipelines to support British Columbia's LNG export projects.

Figure 5.3 illustrates major Canadian natural gas export pipelines, including five export and import points in western Canada and three points of entry/exit in eastern Canada.

Figure 5.3: Canadian Natural Gas Export Pipelines



Source: Arctic Gas[6]

[6] Arctic Gas website, Major Canada, US Export-Import Gas Pipeline, http://www.arcticgas.gov/sites/default/files/images/US_CanadaGasPipelineRoutes-full.png (Accessed on March 17, 2016)

Table 5.1 illustrates five major export pipelines in western Canada, the largest exporting points of exit (and the name of the operator in Canada-US).

Table 5.1: Western Canadian Natural Gas Export Pipelines

Point of Entry & Exit	Canadian Operator	Length	Capacity	US Operator
Huntingdon, BC/ Sumas, WA	Westcoast Energy	2,800 km	2.4 Bcfpd[7]	Various Pipelines[8]
Kingsgate, BC/ Eastport, ID	NGTL System/ Foothills Pipelines	24,544 km & 1,241 km	Varies & 2.1 Bcfpd[9]	Gas Transmission Northwest (GTN)
Monchy, SK/Port of Morgan, MT	Foothills Pipelines	1,241 km	2.1 Bcfpd[10]	Northern Border Pipeline
Elmore, MB/ Sherwood, ND	Alliance Pipelines	3,719 km (total)	5.35 Bcfpd[11] (total)	Alliance Pipelines USA
Emerson, MB/ Noyes, MN	TransCanada Pipeline	14,114 km (total)	Varies	Great Lakes Gas Transmission (GLGT) and Viking Gas Transmission

Source: EIA[12]

The Westcoast natural gas pipeline system is primarily in British Columbia, but extends into Alberta, Yukon and the Northwest Territories. The 2,800-kilometer system connects to several pipelines at Sumas in Washington, including the Northwest Pipeline, feeding Canadian natural gas into the Pacific Northwest.

Kingsgate, located in southeastern British Columbia, lies on the border with Eastport, Idaho. While the Gas Transmission Northwest (GTN) is owned by a subsidiary of TCPL, there are several natural gas pipelines that cross at Kingsgate, including the Foothills Pipeline and the NGTL System (NOVA Gas Transmission). Both are owned and operated by TCPL. The TCPL partnership with the NGTL System includes 24,544 km of pipe, delivering and receiving natural within Alberta and

[7] Alliance website, Informational Postings, https://noms.wei-pipeline.com/info/ (Accessed on March 17, 2016)
[8] Pipelines include: Northwest Pipeline, Sumas Pipeline USA, Sumas International Pipeline, Sumas-Cascade Pipeline and Ferndale Pipeline
[9] TransCanada Pipeline website, Informational Postings - Operationally Available Capacity – BC, http://www.transcanada.com/Foothills/info_postings/operationally_available.html (Accessed on March 17, 2016)
[10] ibid
[11] Alliance Pipeline website, Our System, https://www.alliancepipeline.com/AboutUs/OurSystem/Pages/default.aspx (Accessed on March 17, 2016)
[12] US Energy Information Administration website, About US Natural Gas Pipelines, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/impex_list.html (Accessed on March 17, 2016)

British Columbia.[13] The 1,241 km Foothills System, is divided into three parts: Foothills Alberta (Zone 6 & 7), Foothills BC (Zone 8) and Foothills Saskatchewan (Zone 9).[14,15]

Monchy, Saskatchewan and Port of Morgan, Montana is the point of entry and exit for the Foothills Pipeline and the Northern Border Pipeline, delivering natural gas from the Foothills Pipeline system in Saskatchewan to the US Midwest market. The former is owned and operated by TCPL while the latter is partially-owned by TCPL and ONEOK Partners.[16]

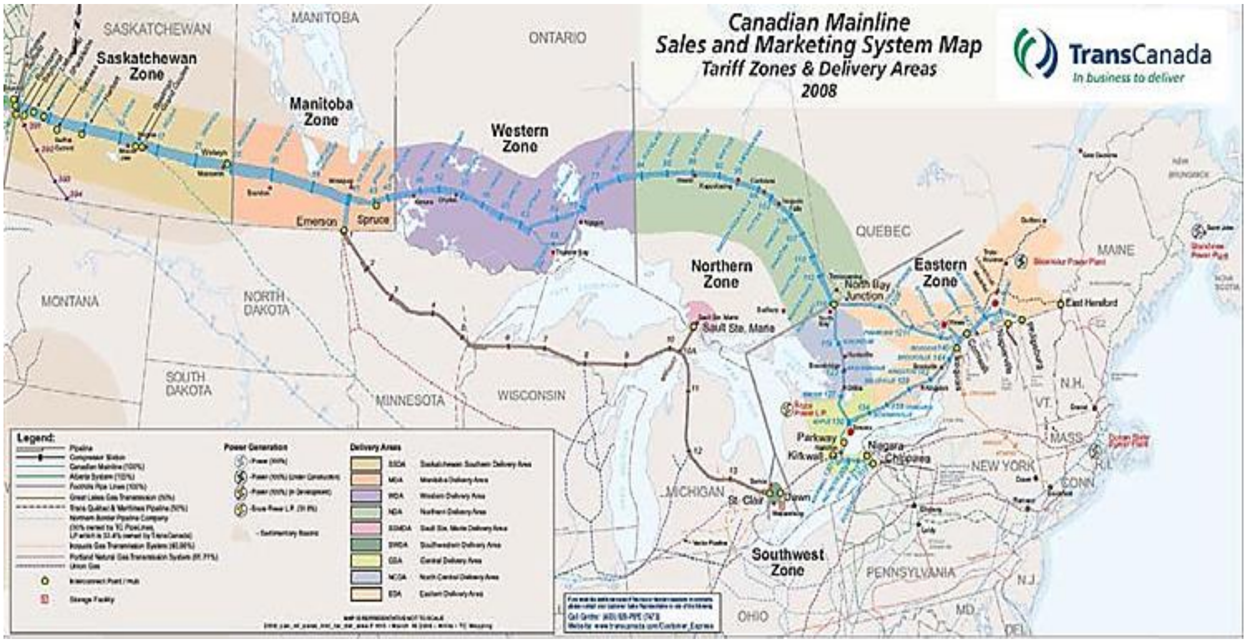
The Alliance Pipeline transports natural gas from northeastern British Columbia and northwestern Alberta, through Saskatchewan, to the US Midwest. The Canadian portion of the Alliance is comprised of 338 kilometers of 42-inch diameter pipe and 1,222 kilometers of 36-inch diameter pipe.[17] The contract capacity of the Canadian portion is 4.6 Bcfpd, while the contract capacity of the US portion is 1.5 Bcfpd.[18] The Alliance delivers approximately 1.6 Bcfpd to the Chicago market.[19]

Branching off the 14,114-kilometer Canadian Mainline, TCPL exports natural gas south to the US at Emerson, Manitoba. This natural gas connects with TCPL's Great Lakes Gas Transmission Company (GLGT) and Viking Gas Transmission. The GLGT transports gas from Emerson and St. Clair, Ontario; it is operated by TCPL.[20] Viking, on the other hand, transports natural gas from Noyes, Minnesota to Marshfield, Wisconsin.

The Canadian Mainline can be divided into the Prairie Segment, Northern Ontario Line, North Bay Shortcut (NBSC) and the Eastern Triangle. The Canadian Mainline is illustrated in Figure 5.4, including the branch off the Mainline in the Prairie Segment to Emerson.

[13] TransCanada Pipeline website, Natural Gas Pipelines, http://www.transcanada.com/natural-gas-pipelines.html#NGTL (Accessed on March 17, 2016)
[14] ibid
[15] TransCanada Pipeline website, Foothills system Map, December 2007, (Accessed on March 17, 2016)
[16] Northern Border Pipelines website, http://www.northernborder.com/ (Accessed on March 17, 2016)
[17] Alliance Pipeline, Our System, https://www.alliancepipeline.com/AboutUs/OurSystem/Pages/default.aspx (Accessed on March 17, 2016)
[18] ibid
[19] ibid
[20] TransCanada Pipeline website, Natural Gas Pipelines, http://www.transcanada.com/natural-gas-pipelines.html#GLGT (Accessed on March 17, 2016)

Figure 5.4: TransCanada's Canadian Mainline Pipeline



Source: TransCanada Pipelines[21]

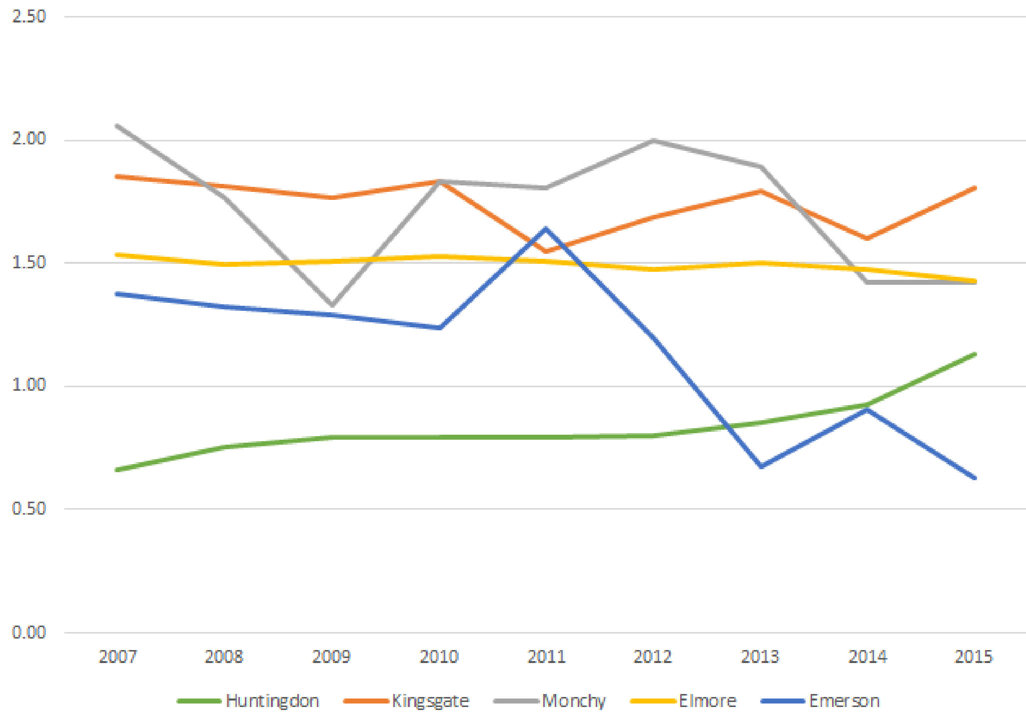
Figure 5.5 illustrates historical average exports of natural gas by pipeline from western Canada to the US by year, showing the largest exporting points of exit.[22] An average of 1.8 Bcfpd of natural gas was exported through Kingsgate in 2015, up from 1.6 Bcfpd in 2014 but down from 1.85 Bcfpd in 2007. An average of 1.43 Bcfpd of natural gas was exported through Elmore in 2015, down from 1.48 Bcfpd in 2014 and down from 1.53 Bcfpd in 2007. An average of 1.42 Bcfpd of natural gas was exported through Monchy in 2015, unchanged from 1.42 Bcfpd in 2014 and down from 2.06 Bcfpd in 2007. Natural gas exports at Huntingdon increased from 0.66 Bcfpd in 2007 to 1.13 Bcfpd while exports through Emerson decreased from 1.38 Bcfpd in 2007 to 0.6 Bcfpd in 2015. The aforementioned pipelines are southbound flow only. It is important to note that the Ruby pipeline has affected Canadian exports of natural gas. The 1,090-kilometer pipeline delivers Rocky Mountain gas from Opal, Wyoming to Malin, Oregon, into California and the Pacific Northwest markets, competing directly with gas from the WCSB.[23] The pipeline entered service in 2011, partly explaining the decrease in exports at Emerson.

[21] National Energy Board, TransCanada Pipelines, TransCanada Pipelines Limited - Audit Report OF-Surv-OpAud-T211-2012-2013 01 - Appendix I - Maps and System Descriptions - Figure 1: Canadian Mainline (Accessed on March 17, 2016)

[22] US Department of Energy website, Fossil Energy, Table 1 Natural Gas Pipeline Points of Entry/Exit and Transporters, http://www.fe.doe.gov/programs/gasregulation/analyses/qrsections/pdf/Table_1_POEE-Trasporters__Rev_8-27-12.pdf (Accessed on March 17, 2016)

[23] National Energy Board website, Canadian Pipeline Transportation System - Energy Market Assessment, April 2014 (Accessed on April 21, 2016)

Figure 5.5: Average Western Canadian Natural Gas Export Volumes (Bcfpd)



Source: NEB,[24] CERI

There are three important export pipelines in central Canada and the Maritimes: TCPL/Iroquois Pipeline, TransQuébec & Maritimes (TQM)/Portland Natural Gas Transmission and Maritimes & Northeast Pipeline (PNGTS).

Table 5.2 documents the three major export pipelines in eastern Canada, the largest exporting points of exit (and the name of the operator in Canada-US).

[24] National Energy Board website, Commodity Statistics, Monthly Summary by Port - Volumes, https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx (Accessed on March 17, 2016)

Table 5.2: Eastern Canadian Natural Gas Export Pipelines

Point of Entry & Exit	Canadian Operator	Length	Capacity	US Operator
Iroquois, ON/ Waddington, NY	TransCanada Pipeline	14,114 km	1.2 Bcfpd[25]	Iroquois Gas Transmission
East Hereford, QC/ Pittsburg, NH	TransQuébec & Maritimes[26]	572 km	0.2 Bcfpd[27]	Portland Natural Gas Transmission
St. Stephen, NB/ Calais, Maine	Maritimes & Northeast Pipeline Canada/Brunswick Pipeline	1,400 km (Total) & 145 km	0.55 Bcfpd (Canada) & 0.83 Bcfpd (US)[28]	Maritimes & Northeast Pipelines USA

Source: EIA[29]

The Iroquois Pipeline begins at the Canada-US border at Waddington, New York and extends through to Commack, New York and from Huntington to the Bronx, New York.[30] The pipeline transports gas to one of North America's largest markets. Commencing operations in 1992, the pipeline delivers Canadian natural gas to the New York area.[31] The Iroquois connects on the northern terminus with TCPL's Canadian Mainline. With growing production from the Marcellus Shale, the Iroquois Pipeline has seen a decrease in export volumes from Canada to the US.[32] The pipeline is likely to be reversed, bringing US gas into Ontario and Quebec.

Figure 5.6 illustrates TCPL's Eastern Triangle, the Eastern Zone of the Canadian Mainline. The Figure also shows the Eastern Triangle, between North Bay, Parkway and Iroquois (near Ottawa). The nearest trading hub is Dawn, located at the bottom left corner.

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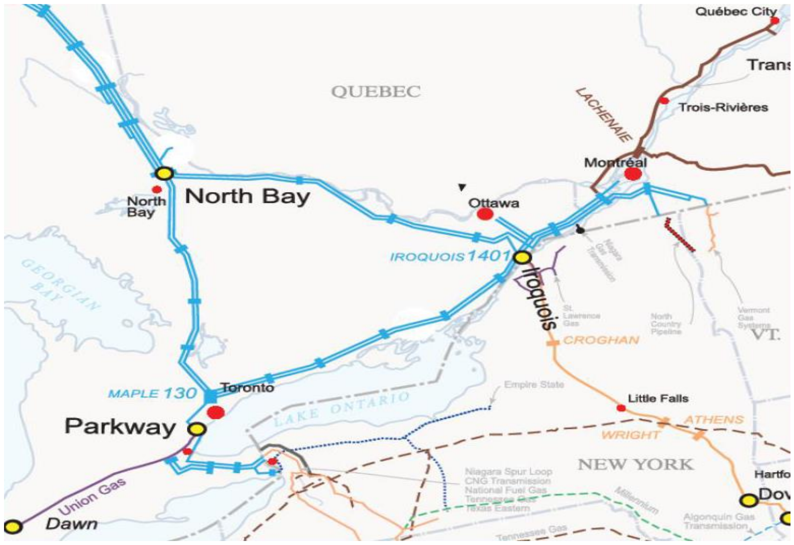
[25] National Energy Board website, Canadian Pipeline Transportation System – Energy Market Assessment, April 2014, https://www.neb-one.gc.ca/nrg/ntgrtd/trnsprttn/2014/index-eng.html (Accessed on March 17, 2016)
[26] TransQuébec & Maritimes is 50 percent owned by TCPL and 50 percent owned by Gaz Metro
[27] National Energy Board website, Canadian Pipeline Transportation System – Energy Market Assessment, April 2014, https://www.neb-one.gc.ca/nrg/ntgrtd/trnsprttn/2014/index-eng.html (Accessed on March 17, 2016)
[28] Spectra Energy website, Canadian Natural Gas Transmission Pipelines, Maritimes & Northeast Pipeline, http://www.spectraenergy.com/Operations/Canadian-Natural-Gas-Operations/Canadian-Natural-Gas-Transmission-Pipelines/Maritimes-Northeast-Pipeline/ (Accessed on March 17, 2016)
[29] Energy Information Administration website, About US Natural Gas Pipelines, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/impex_list.html (Accessed on March 17, 2016)
[30] Iroquois Pipeline website, About Us, http://www.iroquois.com/environmental-gas.asp (Accessed on March 17, 2016)
[31] ibid
[32] National Energy Board, Market Snapshot: Pipelines Transitioning to Bring More U.S. Natural Gas to Ontario and Québec, 2015-02-05, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/snpsht/2015/02-01gsflw-eng.html (Accessed on March 17, 2016)

Figure 5.6: TransCanada's Eastern Triangle



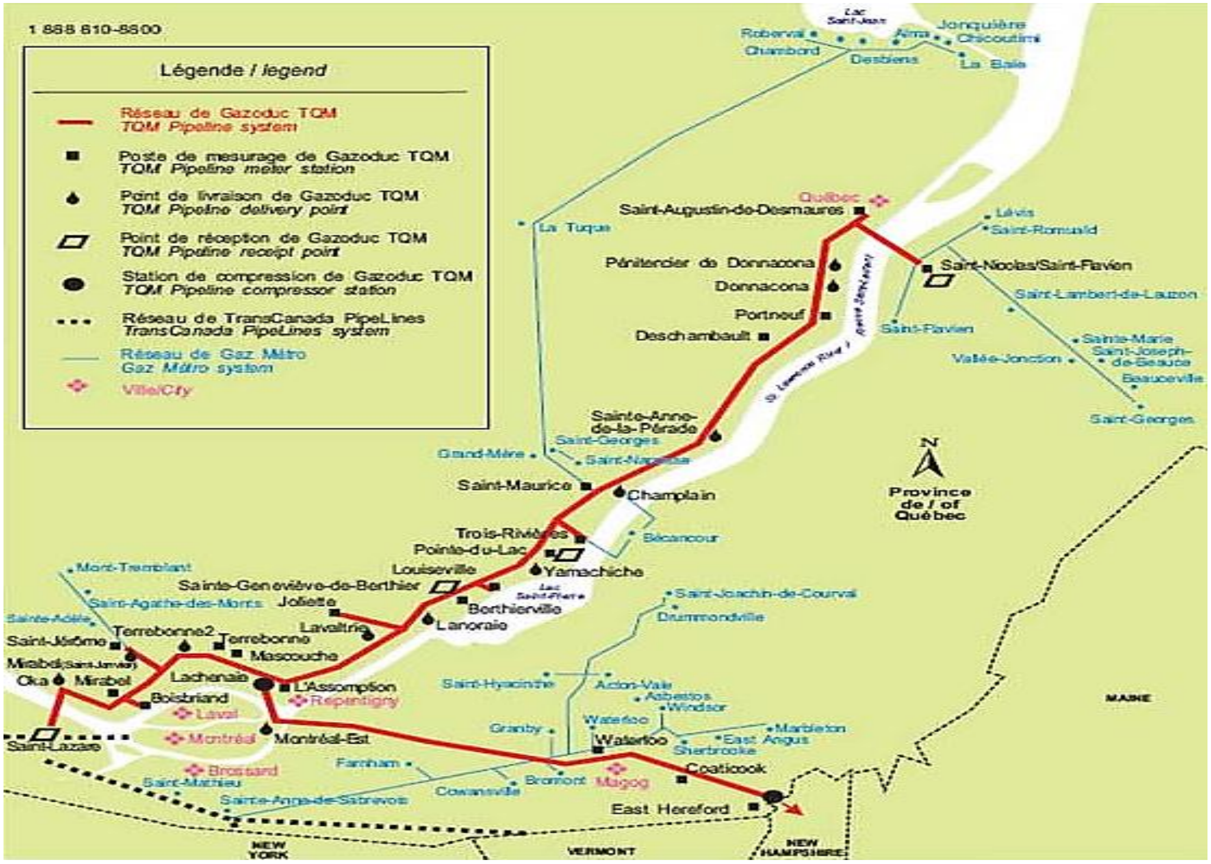
Source: HEC Montreal[33]

The TQM Pipeline is a 572-kilometer pipeline that connects with TCPL's Canadian Mainline near the Ontario/Québec border at Saint-Lazare, Québec and extends to Saint-Nicolas, near Québec City, while the other portion extends from Terrebonne to East Hereford, on the New Hampshire border, connecting to the PNGTS System in the northeast US.[34] The TQM Pipeline is 50 percent owned and operated by TCPL.

The route of the TQM Pipeline is illustrated in Figure 5.7, shown in red while the Gaz Metro System is shown in blue. The PNGTS begins in Pittsburg, New Hampshire, where the TQM Pipeline ends. The PNGTS pipeline joins Maritimes & Northeast at Westbrook, Maine and continues to Dracut, Massachusetts, delivering Canadian natural gas to the Boston area. The pipeline provides natural gas to gas utilities, paper mills and power plants in Maine, New Hampshire, Vermont and Massachusetts.[35]

[33] HEC Montreal, Identification des marchés potentiels internes et externes pour la ressource produite et des effets de déplacement potentiels au Québec (G-ECN-04), Pierre-Olivier Pineau and Sylvain Audette, June 8, 2015, pp. 17.
[34] TQM Pipeline, System Map (September 2014), http://www.gazoductqm.com/en/system_map.html (Accessed on March 17, 2016)
[35]TransCanada Pipeline website, Portland Natural Gas Transmission System, http://www.transcanada.com/customerexpress/4320.html (Accessed on March 17, 2016)

Figure 5.7: TQM Pipeline



Source: TransQuébec and Maritimes[36]

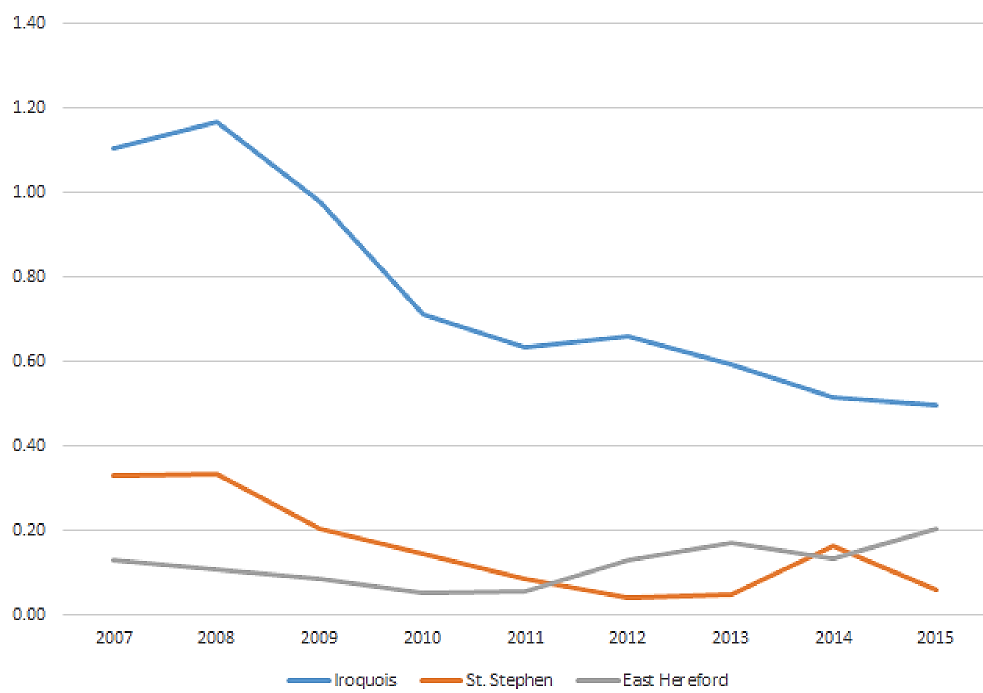
The 1,400-kilometer Maritimes and Northeast Pipeline (M&NP) crosses into the US via St. Stephen, NB and is joined by the PNGTS at Westbrook. M&NP terminates in Dracut and Beverley, Massachusetts. The pipeline transports natural gas produced offshore Nova Scotia (Sable Offshore Energy Project and Deep Panuke), onshore New Brunswick, as well as LNG-sourced natural gas from Brunswick Pipeline to Maine, New Hampshire and Massachusetts. The Brunswick Pipeline is a 145-kilometer pipeline from Saint John, New Brunswick to St. Stephen, New Brunswick, which joins the M&NP at Baileyville, Maine. Similar to Huntingdon and Emerson, St. Stephen is a bi-directional point of entry and exit. While the direction of flow on the M&NP and the PNGTS is north to south, this could change with the two proposed LNG export facilities in Nova Scotia. Both proposed facilities, the Pieridae LNG and Bear Head LNG, may potentially be supplied by shale gas from the Marcellus.

Figure 5.8 illustrates historical average exports of natural gas by pipeline from Canada to the US by year, showing the largest exporting points of exit. An average of 0.50 Bcfpd of natural gas was exported through Iroquois in 2015, down from 0.52 Bcfpd in 2014 and down from 1.10 in 2007. The Iroquois pipeline interconnects with the Dominion Transmission Pipeline at Canajoharie, NY,

[36] TQM Pipeline, System Map (September 2014), http://www.gazoductqm.com/fr/pdf/22-TQM-System-Map-Carte-Sep-2014.pdf (Accessed on March 17, 2016)

the Tennessee Gas Pipeline at Wright, NY and the Algonquin Gas Transmission Pipeline at Brookfield CT.[37] It is likely that the Iroquois pipelines' exports will not only decrease further but begin to import gas from the Marcellus Shale, with the pipeline reversing flow as early as November 2017.[38] The South-to-North Project (SoNo) is expected to have a capacity of 650,000 Bcfpd with Waddington, NY becoming the delivery point and the aforementioned interconnections with Dominion, Tennessee Gas and the Algonquin becoming receipt points for Marcellus gas heading north.[39] The Iroquois will become a bi-directional pipeline. The Texas Eastern Transmission (Tetco) pipeline, traditionally delivering natural gas from the US Gulf Coast to the New York City area, via Pennsylvania, West Virginia and Ohio, is also reversing flow, delivering gas from the Appalachian region to the Gulf Coast and delivering gas from the Marcellus and Utica Shales to New York. This further displaces natural gas flowing south on the Iroquois Pipeline. An average of 0.20 Bcfpd of natural gas was exported through East Hereford in 2015, up from 0.13 Bcfpd in 2014. An average of 0.06 Bcfpd of natural gas was exported through St. Stephen, down from 0.16 Bcfpd in 2014 and down from 0.33 Bcfpd in 2007.

Figure 5.8: Average Eastern Canadian Natural Gas Export Volumes (Bcfpd)



Source: NEB,[40] CERI

[37] Iroquois Pipeline website, Interconnecting Pipeline Links, http://www.iroquois.com/natural-gas-pipeline-services.asp, (Accessed on April 22, 2016).
[38] Iroquois Pipeline website, SoNo, South-to-North Project, http://www.iroquois.com/project/sono/SoNo_OpenSeasonBrochure_1_12_15.pdf (Accessed on April 22, 2016).
[39] ibid
[40] National Energy Board website, Commodity Statistics, Monthly Summary by Port - Volumes, https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx (Accessed on March 17, 2016)

Table 5.3 shows major proposed pipelines in Canada, impacting the transportation of natural gas across Canada and exporting natural gas to consuming markets.

Table 5.3: Proposed Pipelines

Name	Capacity	From	To	Associated LNG Facility
Energy East Pipeline	1.1 million Bpd	Hardisty, AB	Saint John, NB	none
Pacific Northern Gas Transmission Pipeline	0.61 Bcfpd	Summit Lake	Kitimat	Kitimat LNG
Pacific Trail Pipeline	1.4 Bcfpd	Summit Lake	Kitimat	Kitimat LNG
Coastal GasLink Pipeline	2.0 Bcfpd	Dawson Creek	Kitimat	LNG Canada
Prince Rupert Gas Transmission	2.0 Bcfpd	Ft. St. John	Prince Rupert	Pacific Northwest LNG
Westcoast Connector Gas Transmission	4.2 Bcfpd[41]	Northeast BC	Prince Rupert	Prince Rupert LNG
Eagle Mountain – Woodfibre Gas Pipeline	0.23 Bcfpd	Coquitlam	Squamish	Woodfibre

Source: CERI[42]

The proposed TransCanada Energy East project is a 4,600-kilometer pipeline from Hardisty, Alberta to Saint John, New Brunswick. TransCanada's Energy East project is an oil pipeline, planning to provide feedstock to refineries in Montreal, Levis and Saint John and opening access to the East coast of Canada for future waterborne exports of crude. The line will have a capacity of 1.1 million barrels per day.[43] Figure 5.9 illustrates the route of the Energy East pipeline. The blue line indicates the large portion (approximately 3,000 kilometers) of the project that involves converting the existing natural gas pipeline to oil, from Burstall, Saskatchewan to near Cornwall, Ontario. The green line illustrates new pipeline construction, from Hardisty, Alberta to Saskatchewan and from eastern Ontario to New Brunswick.[44] Irving Oil is planning to build a new C$300 million terminal at its existing Canaport LNG facility to export the oil from the Energy East Pipeline.

[41] The project envisions a total design capacity of 8.4 Bcfpd.
[42] CERI Study 148, "LNG Liquefaction for the Asia-Pacific Market: Canada's Place in a Global Game", June 2015, pp. 18.
[43] Financial Post website, Keystone Oil Pipeline and the Energy East, http://business.financialpost.com/2014/03/27/keystone-oil-pipeline-energy-east-irving/?__lsa=fad7-eae5 (Accessed on March 17, 2016)
[44] Energy East project website, About the Project, http://www.energyeastpipeline.com/about/the-project/ (Accessed on March 17, 2016)

Figure 5.9: Energy East Pipeline Planned Route

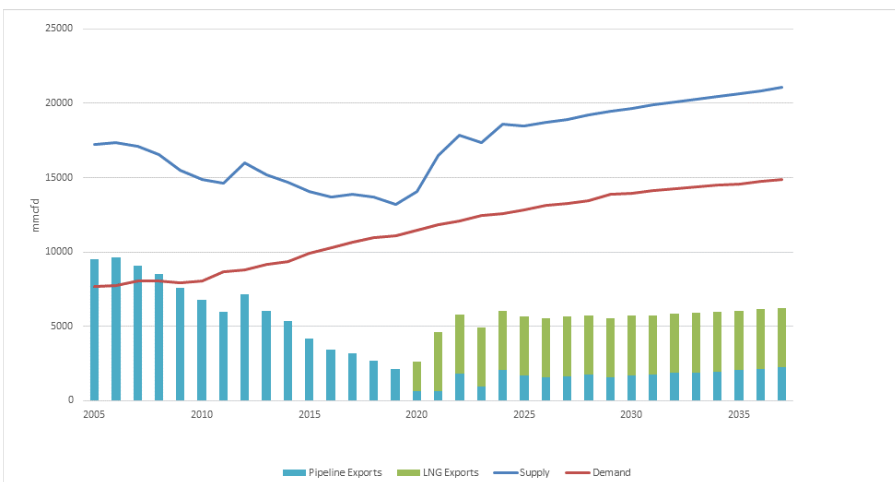
Source: Energy East Pipeline[45]

All other proposed pipeline projects illustrated in Table 5.3 will be connecting the gas producing areas of British Columbia, and possibly Alberta, with proposed LNG facilities on the west coast of Canada for global gas exports. TransCanada projects, such as Coastal GasLink Pipeline and the Prince Rupert Gas Transmission Pipelines, have major interconnections with the NGTL system.

Canadian Exports Outlook

Canadian natural gas production will outpace domestic demand in the country. Figure 5.10 illustrates total Canadian supply and demand outlooks and shows export potential over the study period.

Figure 5.10: Canadian Supply and Demand[46] Outlook



Source: CERI, NEB

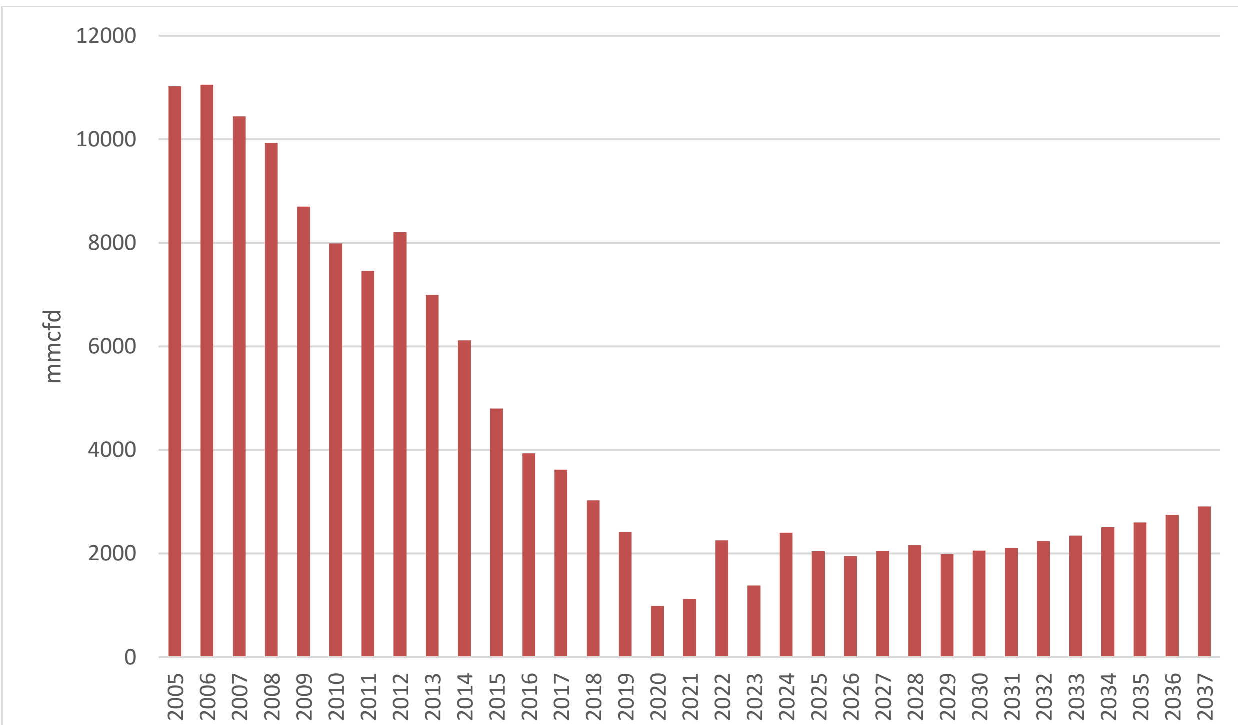
[45] Energy East project website, Route Map, http://www.energyeastpipeline.com/home/route-map/ (Accessed on March 17, 2016)

[46] This value of natural gas demand is lower than the primary natural gas demand value discussed in Chapter 3 because it does not include non-marketed natural gas used directly by those that produce it. Examples of this include flared gas, natural gas produced and consumed by in situ oil sands producers, and natural gas produced and consumed by offshore oil production.

Pipeline and LNG exports are shown separately in the graph for ease of reference. Exports will decrease until 2019, following lower supply as a result of low gas price forecast. After 2020, once the price of natural gas has risen to a point that overcomes well supply costs in western Canada, supply and therefore exports increase. Exports stabilize around 2026 and increase slightly through the remainder of the study period, reaching 6 Bcfpd by 2037. LNG exports grow to 4 Bcfpd of natural gas post-2020, and CERI expects supply to increase to satisfy this demand. This study does not predict any particular individual LNG project, but just assumes a total liquefaction capacity of 4 Bcfpd by 2021. Pipeline exports stabilize at a lower amount of approximately 2 Bcfpd. Figure 5.10 differentiates between the cases with and without the associated LNG values.

Regionally, 98 percent of Canada's natural gas supply came out of western Canada for a total of 13.8 Bcfpd in 2015. The same western Canadian region had a demand of 9.3 Bcfpd, for an excess supply of 4.5 Bcfpd. Looking forward, western Canada continues to supply volumes greater than demand through the life of this projection. Figure 5.11 shows export volumes from western Canada through 2037.

Figure 5.11: Natural Gas Exports from Western Canada



Source: CERI

The factors influencing pipeline natural gas exports from western Canada are Canadian supply and demand and US supply and demand. Canadian supply is more heavily impacted by the drop in natural gas prices than US supply, due to the higher supply costs seen in Canada. Both Canadian and US demand for natural gas is expected to rise; US production of natural gas is predicted to rise at a fairly linear rate. The variation in export trends seen in Figure 5.11 are due to fluctuation in Canadian supply, specifically supply out of western Canada. The drop in natural gas prices is responsible for decreased production, and therefore decreased exports from western Canada through 2019. While prices are expected to start to increase as of 2016, increases in production, and therefore exports, lag this recovery. CERI expects to see increases in drilling activity in western Canada starting again in 2020, which result in an increase in exports from western Canada. Those exports to the US will not reach historical highs as increased competition from US producer's decreases western Canadian exports to the US Midwest and Pacific coast states.

In 2015, TransCanada estimated that their Mainline transported an average of approximately 4,000 MMcfpd of natural gas in the previous year.[47] Statistics from the NEB[48] show that exports to the United States via TransCanada's mainline (through Kingsgate, Monchy, Elmore and Emerson) averaged 3,355 MMcfpd. The remaining 645 MMcfpd supplied Eastern Canadian markets in 2015. Total exports to the United States from western Canada were 3,889 MMcfpd in 2015.

Natural gas production out of the Marcellus and Utica basins will continue to supply markets in eastern Canada through 2037, so gas flows from western Canada to eastern Canada are not expected to increase throughout the duration of this study's timeframe. If TransCanada's Energy East pipeline is successfully built, sections of the Mainline will be converted from gas service to oil service, thereby reducing the total capacity for flow.

The flow on TransCanada's Mainline can also be expected to drop if transportation tolls increase to the extent that importing US gas is a favorable option. While much of the flow is dictated by long-term contracts, if the tolls are prohibitive as the contracts reach the end of their terms, this flow may drop off.

Natural Gas Imports

The largest import pipelines in Canada are in Ontario and Quebec. Recall, US gas imports into Canada, delivered primarily through Ontario and Québec points of entry, have increased from 938.1 MMcfpd in 2006 to 2.1 Bcfpd in 2014.[49]

The points of entry/exit (Canadian operator-US operator) are Courtright (Vector Pipeline Canada and Vector Pipeline US), Niagara Falls (TransCanada Pipeline and Tennessee Gas Pipeline-National Fuel Gas Supply), Ojibway (Windsor) (Union Gas-Panhandle Eastern Pipeline), Sarnia (TransCanada Pipelines-Great Lakes Gas Transmission Company) and St. Clair (Union Gas-Michigan Consolidated).

[47] TransCanada, TransCanada Investor Day, http://www.transcanada.com/docs/Investor_Centre/2015-TransCanada-Investor-Day-Presentation.pdf, slide 38

[48] National Energy Board website, Gas Monthly Summary by Port- Volumes, http://www.neb-one.gc.ca/CommodityStatistics/GasStatistics.aspx (Accessed on March 20, 2016)

[49] National Energy Board website, Gas Monthly Summary by Port- Volumes, http://www.neb-one.gc.ca/CommodityStatistics/GasStatistics.aspx (Accessed on March 17, 2016)

Table 5.4 illustrates the top five import pipelines in Canada, the largest importing points of entry (and the name of the operator in Canada-US), as well as by capacity and length of pipeline.

Table 5.4: Natural Gas Import Pipelines

Point of Entry and Exit	Canadian Operator	Length	Capacity	US Operator
Courtright, ON/St. Clair, MI	Vector Pipeline Canada	560 km (total)	0.65 Bcfpd[50]	Vector Pipelines US
Niagara Falls, ON/Niagara Falls, NY	TransCanada Pipeline	14,114 km	0.4 Bcfpd[51]	Tennessee Gas Pipeline & National Fuel Gas Supply
Windsor (Ojibway)/Detroit, MI	Union Gas Limited	--	--	Panhandle Eastern Pipeline
Sarnia, ON	TransCanada Pipeline	14,114 km	Varies	Great Lakes Gas Transmission Company
St. Clair, ON/St. Clair, MI	Union Gas Limited	--	--	Michigan Consolidated

Source: EIA[52]

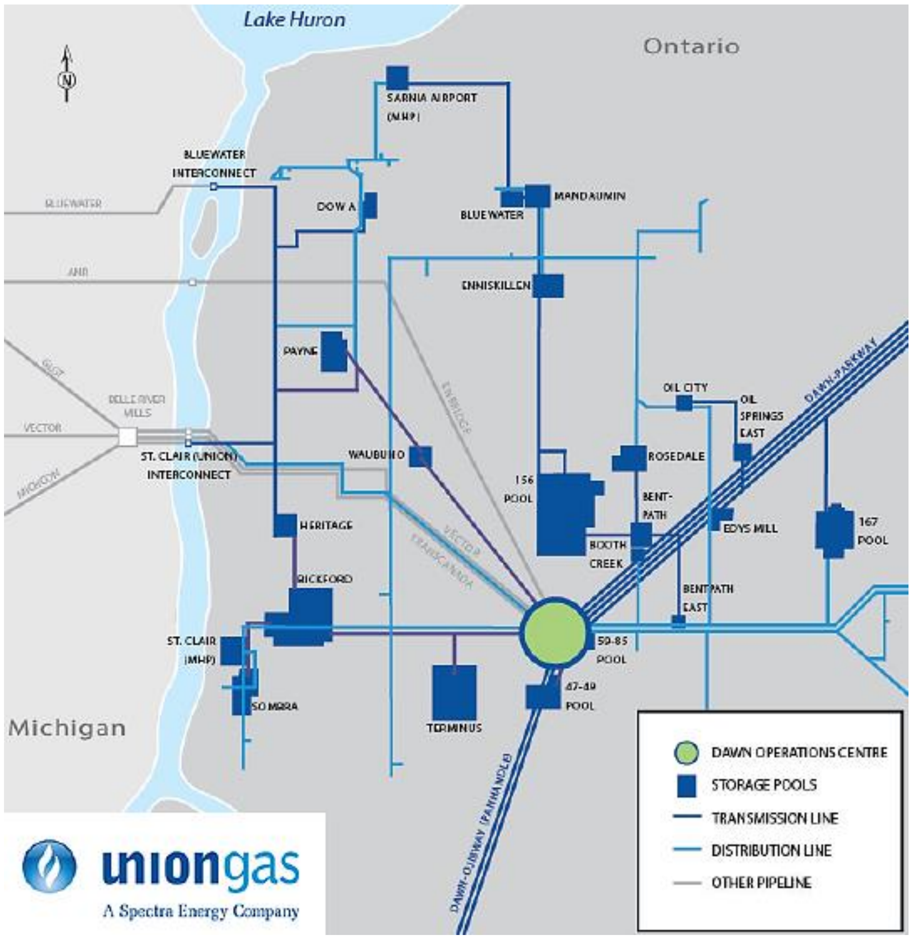
Of the five pipelines, four connect through Sarnia and area, in close proximity of the Dawn storage hub.[53] Two of these pipelines, via St. Clair and Windsor (Ojibway), are owned and operated by Union Gas – the operator of the Dawn storage facility. The Ojibway (Windsor) is also operated by Union Gas in Canada as it crosses at Detroit-Windsor; it links with the Dawn hub as well.[54] The Sarnia point of entry and exit should not be confused with Sarnia (Bluewater), a point of entry and exit connecting the Union Gas Pipeline with the Bluewater Pipeline, crossing at Marysville, Michigan.[55]

Figure 5.12 illustrates Dawn Hub's storage operations and the various natural gas pipelines in the area, including the points of entry/exit at Sarnia, Windsor (Ojibway) and Sarnia (Bluewater). The

[50] Natural Gas Intel website, Vector Proposes NatGas Mainline Expansion to Carry Appalachia Supplies, Carolyn Davis, October 7, 2014 http://www.naturalgasintel.com/articles/99958-vector-proposes-natgas-mainline-expansion-to-carry-appalachia-supplies (Accessed on March 17, 2016)
[51] National Energy Board website, Canadian Pipelines System – Energy Market Assessment, April 2014, https://www.neb-one.gc.ca/nrg/ntgrtd/trnsprttn/2014/index-eng.html (Accessed on March 17, 2016)
[52] Energy Information Administration website, About US Natural Gas Pipelines, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/impex_list.html (Accessed on March 17, 2016)
[53] US Department of Energy website, Fossil Energy, Table 1 Natural Gas Pipeline Points of Entry/Exit and Transporters, http://www.fe.doe.gov/programs/gasregulation/analyses/qrsections/pdf/Table_1_POEE-Trasporters__Rev_8-27-12.pdf (Accessed on March 17, 2016)
[54] ibid
[55] ibid

figure shows transmission pipelines, as well as distribution pipelines and other pipelines in the region.

Figure 5.12: Dawn Hub Infrastructure

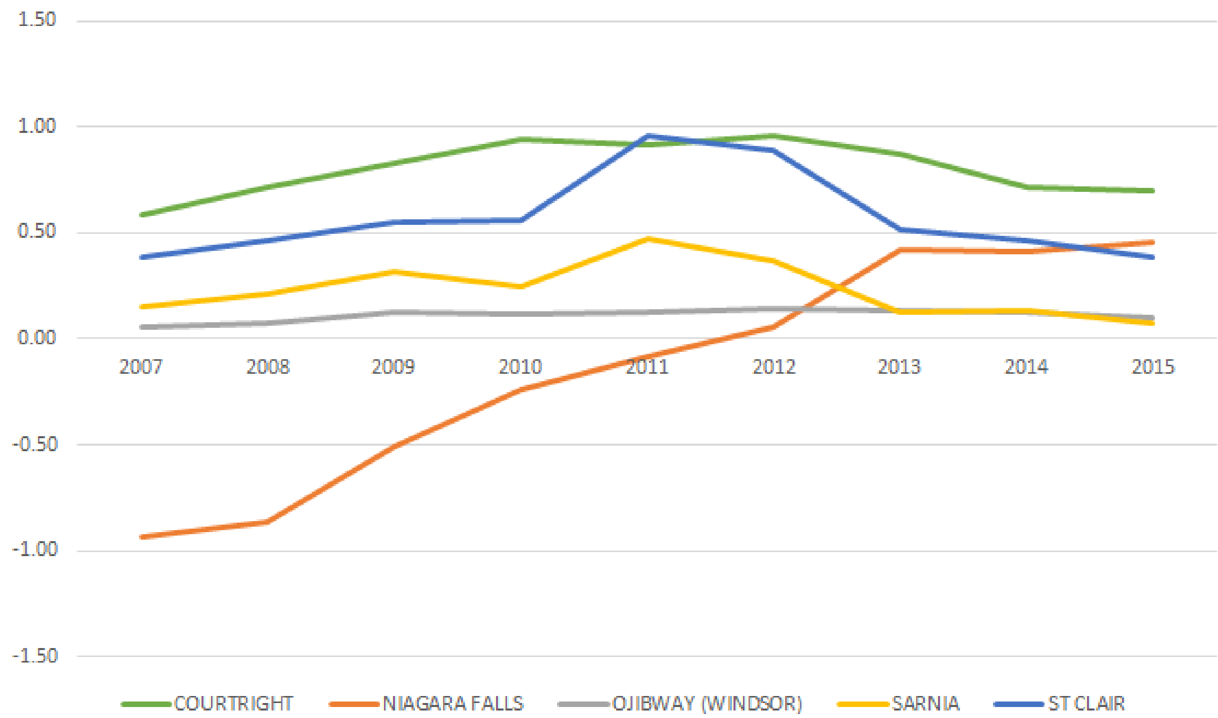


Source: Union Gas[56]

Figure 5.13 illustrates the average imports of natural gas by pipeline into Canada by year. The figure shows the top five largest import points of entry.

[56] Union Gas website, Union Gas Operations Centre Storage Pools and Pipelines, https://www.uniongas.com/~/media/storage-transportation/maps/PDF/Unionpercent20Gaspercent20Dawnpercent20Operationspercent20Centrepercent20Storagepercent20Poolspercent20andpercent20Pipelines.pdf?la=en (Accessed on March 17, 2016)

Figure 5.13: Average Canadian Natural Gas Import Volumes (Bcfpd)



Source: NEB,[57] CERI

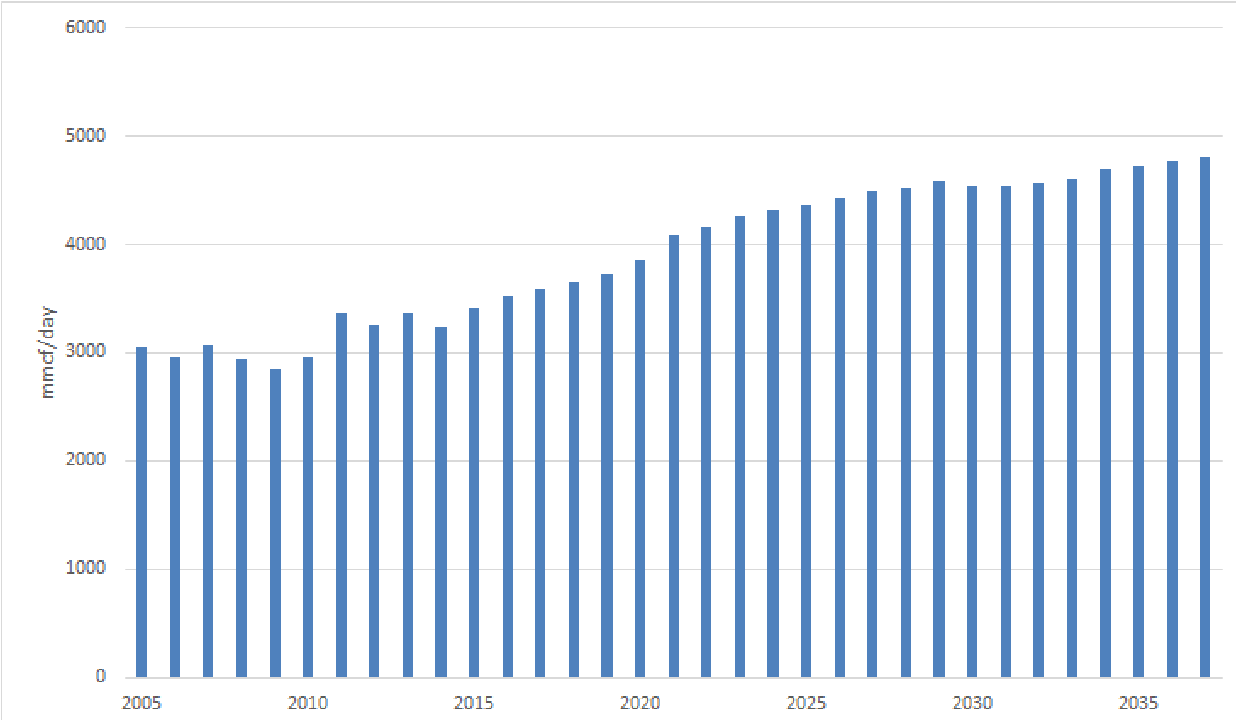
An average of 0.70 Bcfpd of natural gas was imported through Courtright in 2015, down from 0.72 Bcfpd in 2014 but up from 0.58 Bcfpd in 2007. An average of 0.45 Bcfpd of natural gas is imported through Niagara Falls in 2015, up from 0.41 Bcfpd in 2014. In 2007, Niagara Falls was an export point, exporting 0.94 Bcfpd; the pipeline reversed its flow in November 2012, illustrating the change of natural gas flows due to the increase in production in the Marcellus Shale. An average of 0.39 Bcfpd of natural gas is imported through St. Clair, down from 0.47 Bcfpd in 2014 and is unchanged from 0.39 Bcfpd in 2007. An average of 0.07 Bcfpd natural gas is imported through Sarnia, down from 0.14 Bcfpd in 2014 and down from 0.16 Bcfpd in 2007. An average of 0.10 Bcfpd of natural gas is imported through Ojibway (Windsor), down from 0.13 Bcfpd in 2014 and up 0.06 Bcfpd in 2007.

Natural Gas Imports Outlook

In 2015, demand for natural gas in eastern Canada was 3,678 MMcfpd. Natural gas production out of eastern Canada was 264 MMcfpd, and 800 MMcfpd was exported via the M&NP in 2015. Even with the Western Canadian volume of 645 MMcfpd, a large portion of Eastern Canadian gas demand was supplied by the United States: 3,569 MMcfpd in 2015. Total imports to eastern Canada through 2037 are shown in Figure 5.14.

[57] National Energy Board website, Commodity Statistics, Monthly Summary by Port – Volumes, https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx (Accessed on March 17, 2016).

Figure 5.14: Natural Gas Imports Potential to Eastern Canada



Source: CERI

The growth in imports to eastern Canada from 2014 through 2037 will be supplied from the Utica and Marcellus. In fact, the growth in supply from these basins will be larger than the growth in imports, as Eastern Canadian production of natural gas is expected to largely disappear and imports from western Canada are not expected to grow.

LNG Projects

Currently, there are thirteen liquefaction or regasification facilities in the US and a single facility in Canada. Aside from the Kenai LNG Export Terminal and the recently on-stream Cheniere Sabine LNG, the remaining twelve terminals in North America are regasification terminals. Nine of those terminals are under the Federal Energy Regulatory Commission (FERC) jurisdiction, the organization responsible for the regulation of natural gas pipelines, storage and LNG, while the other two offshore facilities are under the jurisdiction of the United States Maritime Administration (MARAD) and the United States Coast Guard (USCG). The Canaport LNG facility, in Saint John, New Brunswick, is under the jurisdiction of Canada's National Energy Board.

US LNG Exports

Patterns of natural gas consumption will continue to change, especially now that the US is on the verge of becoming a major LNG exporter. Less than a decade ago, the US was in the process of approving and building LNG import (regasification) facilities to supply natural gas throughout the country. That was a point in time before technological innovations such as hydraulic fracturing and horizontal drilling caused gas in tight/shale formations to become economically feasible to extract. Since conventional natural gas was declining at that time, it seemed logical to invest in regasification. The nature of the North American natural gas market, however, changed rapidly, and when massive volumes from the Marcellus and other shale plays began to flood the continental market, it appeared the US would soon be able to fulfill domestic demand from domestic resources; the regasification facilities would become stranded assets.

In fact, increased domestic natural gas supply caused prices to plummet and they have stayed below US$5/Mcf since 2010.[58] The ostensibly stranded regasification facilities turned out not to be white elephants after all; five so far are being repurposed as export (liquefaction) facilities, and since much of the engineering and infrastructure was undertaken years ago, these brownfield projects hold a significant capital cost advantage over greenfield facilities being proposed or constructed elsewhere in North America and the world.

In January 2016, FERC announced one greenfield and four brownfield LNG liquefaction projects were under construction in the US: Sabine Pass Trains 1 through 5 (Cheniere Energy), Corpus Christi (greenfield, Cheniere), Cameron LNG (Sempra Energy), Cove Point LNG (Dominion Cove Point LNG), and Freeport LNG (Freeport LNG Development). All of these Atlantic and Gulf Coast projects are slated to be operational by 2019, and if/when they run at full capacity, they will bring as much as 10.6 Bcfpd to world LNG markets.[59] A number of other projects are planned for both the Gulf Coast and the Pacific Coast, some of which have been approved by FERC, but companies are waiting for higher oil prices before making Final Investment Decisions (FID's). CERI Study 148, released in 2015, calculated that if all proposed LNG liquefaction projects in the US were built, in excess of 35 Bcfpd of export capacity could be in place by the middle of the next decade.[60] Barring unforeseen circumstances, it is unlikely all projects will go ahead, but a potential range of LNG export capacity somewhere between 10 Bcfpd and 30 Bcfpd is within the realm of possibility for the US over the coming decade.

March 15, 2016 is marked as the beginning of an era for US Gulf Coast LNG exports, with the first volumes from the Cheniere facility reaching the port of Rio de Janeiro.[61] Other facilities will likely follow.

Though export capacity will be built, will the world be demanding US LNG?

Australia is an up and coming LNG power. Six liquefaction facilities are operational in Australia as of January 2016, and four more are under construction (not including Shell's Prelude project).[62] The advantage that Australia holds is that the vast majority of their natural gas volumes are covered under long-term supply contracts to Asian utilities and companies. If all of the Australian

[58] EIA. https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm Accessed January 21, 2016
[59] http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf Accessed January 21, 2016.
[60] Rozhon, J. and Allan Fogwill. "LNG Liquefaction in the Asia-Pacific Market: Canada's Place in a Global Game." June 2015. Study 148. P 25. www.ceri.ca Accessed January 21, 2016.
[61] Kahwar, Muhammad Ali. "LNG Export by Cheniere Energy, Inc Bodes Well for the US." Bidnessetc. March 16, 2016. http://www.bidnessetc.com/65601-lng-export-cheniere-energy-bodes-well-us/ Accessed March 16, 2016.
[62] http://www.appea.com.au/oil-gas-explained/operation/australian-lng-projects/ Accessed January 21, 2016.

liquefaction is built and comes online as scheduled, more than 10 Bcfpd of LNG will be delivered to customers by the end of 2017. If all proposed projects are built, an additional 4.91 Bcfpd will be produced sometime in the post-2018 timeframe.[63] Thus, Australia will see a solid 10 Bcfpd of LNG exports on the low end and an upper limit of approximately 15 Bcfpd over the coming decade.

Middle East LNG capacity, based mainly in Qatar, is not expected to grow; Qatar placed a moratorium on further LNG development some years ago. With the exception of a small LNG facility planned for Israel, and another for Iraq (combined, these projects would produce around 1 Bcfpd), nothing else is on the horizon.[64] Replete with untapped natural gas resources, Iran now awaits funding to develop its hydrocarbon infrastructure. It appears Iran LNG liquefaction projects would not go ahead until well into the 2020s, but with onshore and offshore gas and tidewater access on the Persian Gulf, there is much potential for the Islamic Republic to become an LNG player over the long haul. Over the coming decade, however, it appears that the region's production will remain at approximately 13.5 Bcfpd.[65]

Another area with significant LNG liquefaction plans is Russia. Under construction in Russia's far north, with eventual access to Asia carved out by icebreaking LNG tankers, is the Yamal LNG plant. The project has struggled to raise adequate financing because of US sanctions against the project's major shareholder, Novatek. Chinese entities have picked up some of the cost, however, and investment for the project has reached $15 billion of the total US$27 billion required.[66] The Kremlin has backed Yamal since the beginning, with construction that has been ongoing since 2013 – first gas is scheduled for some point in 2017. When this project reaches full capacity, it will produce as much as 2.2 Bcfpd.[67] This is in addition to the 1.3 Bcfpd currently being produced and exported from the Sakhalin 2 facility in the far east of the country. Other Russian plants are being planned both for the Baltic region and for Eastern Russia, but none are under construction yet and may see long postponements due to political and economic factors. Other than the Sakhalin facility, the only other liquefaction plant currently operating in Europe/Eurasia is Norway's Shohvit project, which produces 0.5 Bcfpd.

Thus, Russian and European LNG liquefaction production and export will likely stay within a range of 1.5 Bcfpd and 3.5 Bcfpd.

Africa has had several liquefaction projects running for years in Nigeria, Angola, Egypt, and Equatorial Guinea. LNG development in Mozambique has government backing, but investment decisions by Anadarko, Mitsui, and Eni, the major players, have been postponed. Palma LNG

[63] Rozhon and Fogwill. P. 16.
[64] Rozhon and Fogwill. P. 39.
[65] Rozhon and Fogwill. P. 41. BP Statistical Review of World Energy, 2015. P. 28.
[66] Reuters. "Russian government approves sale of Yamal stake to China fund". January 22, 2016.
http://www.appea.com.au/oil-gas-explained/operation/australian-lng-projects/ Accessed January 22, 2016.
[67] Rozhon and Fogwill. P. 37.

would produce between 3.4 and 6.7 Bcfpd beginning in 2020 (at the earliest), making it that country's largest industrial project.

Nigeria, Tanzania, and Cameroon are three African countries with great promise and plans to build LNG liquefaction facilities. The Nigerian plans are biggest of all, though funding for both the Olokola Plant and Brass LNG has been either tenuous or withdrawn completely. If the two projects receive FIDs in the next few years, they would together offer volumes in excess of 4 Bcfpd. In Tanzania, the central government has begun buying up and seizing land in the southern part of the country to build a 1.1 Bcfpd liquefaction facility.[68] Here, too, FID's by the major companies involved (BG, Statoil, Exxon Mobil and others) have been postponed. Plans in Cameroon are more modest, but include the region's first floating LNG liquefaction platform. African LNG exports are expected to grow over the coming decade in a range of 4 to 15 Bcfpd over present volumes.

There are only two projects presently under construction in Oceania (except Australia). These are both floating LNG projects with a combined capacity of 0.4 Bcfpd. Some previously planned ventures have been cancelled outright, such as the Gulf LNG project in Papua New Guinea, while others have not received FIDs, such as the Abadi Floating LNG project in Indonesia. Currently, there is about 9.5 Bcfpd of operating capacity in the region and as much as an additional 2-3 Bcfpd could be built within the foreseeable future. However, this is a region with large and increasing domestic LNG needs – mostly to serve small communities on many islands that comprise Malaysia and Indonesia – and it is not expected that there will be any increase in net export volumes from the area, which stood at approximately 6.5 Bcfpd in 2015.[69]

South America also has a small industry, with the largest facilities located in Trinidad and Tobago and Peru. Peru's output is mostly locked up in a long-term contract signed with Mexico, and Trinidad and Tobago is facing "rising domestic demand that may combine with declining feedstock production to eventually result in lower LNG exports".[70] There are no other liquefaction facilities being planned for the region, so for the next decade exports from South America (excluding Peru exports to Mexico) are unlikely to rise above the approximately 2 Bcfpd exported in 2014.[71]

Competing with all of the above LNG projects are existing pipelines from Central Asia and Burma that are sending more than 2 Bcfpd into China. And by 2019, first gas is expected in northeast China from a massive Russian pipeline called Power of Siberia 1. Together with the Power of Siberia 2 (also known as the "Altai" pipeline), Russia will have the capability next decade to send more than 8 Bcfpd in piped natural gas to China.

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[68] Kabendera, Erick, "Tanzania: 19,000 Acres Available for LNG Plant in Lindi", The East African, January 16, 2016. http://allafrica.com/stories/201601180824.html (Accessed January 22, 2016).

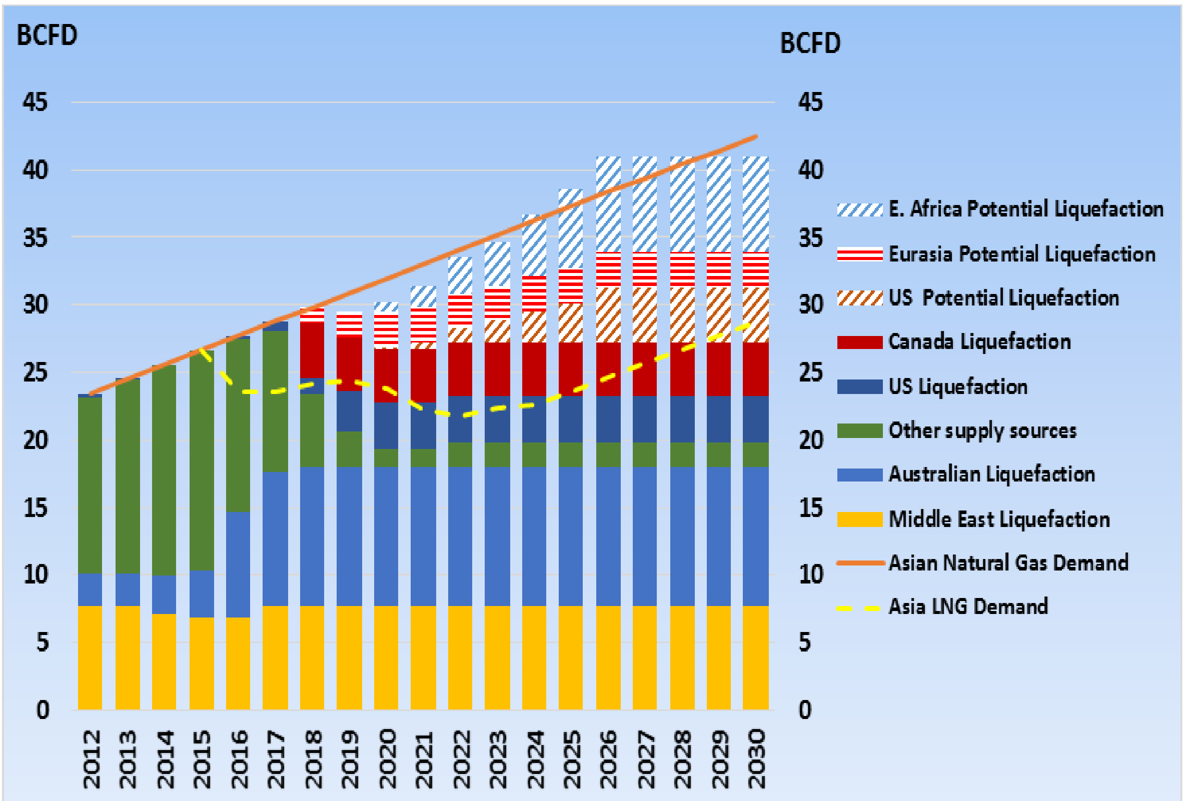
[69] BP Statistical Review of World Energy, 2015, pp. 28.

[70] International Gas Union, World LNG Report – 2015 Edition, http://www.igu.org/sites/default/files/node-page-field_file/IGU-Worldpercent20LNGpercent20Report-2015percent20Edition.pdf (Accessed February 5, 2016).

[71] BP Statistical Review of World Energy, 2015, pp. 28.

Figure 5.15 pieces together the natural gas picture in Asia over the next fifteen years. The solid line indicates total natural gas demand in Asia, as projected by the International Energy Agency (IEA) in their World Energy Outlook 2015, New Policies Scenario. The dashed line is a projection of Asian LNG demand, taking into account pipeline imports. Thus, the area between the two lines estimates pipeline imports into China, which could reach as much as 13 Bcfpd if all projects go ahead as planned and capacities are reached.

Figure 5.15: Asia Natural Gas and LNG Supply and Demand



Sources: CERI, IEA, Wood Mackenzie.

The figure's stacked bars show LNG liquefaction capacity that is today, and likely will be in the future, directed to Asia. Not all countries intend to send all of their LNG to Asia, and those amounts have been factored into the analysis. The US, for example, is expected to send about 55 percent of LNG volumes to Europe.[72] It appears that Asian natural gas demand will easily be met if the Russian pipelines are finished and become fully operational. A number of planned liquefaction projects in the US, East Africa, and Eurasia could be cancelled (represented by the striped, stacked bars in the graph).

[72] Shiryaevskaya, Anna. "More Than Half of US LNG Is Destined for Europe, WoodMac says." Bloomberg Business. January 14, 2016. http://www.bloomberg.com/news/articles/2016-01-15/more-than-half-of-u-s-lng-is-destined-for-europe-woodmac-says Accessed February 3, 2016.

With ongoing and predicted cancellation or postponement of so many projects throughout the world, few companies or governments are forecasting bright days ahead for the LNG industry. Thus, the US companies that will be selling LNG to customers worldwide should anticipate low prices and a buyer's market – at least for the next few years. As of this writing, the price of oil is hovering in the US$40-$50 range, which augurs poorly for any producer that has contracts dependent on the price of crude; certainly, the price must be higher for greater profits to be made. For the US, however, contracts have been almost exclusively tied to Henry Hub gas instead of crude. Until the recent tumble in oil prices, Henry Hub offered the US LNG export industry a price advantage over the crude-tied contracts signed elsewhere in the world. That flexibility led to hybrid contracts now being signed where part of the gas is tied to Henry Hub and part of it tied to the price of crude oil.

Perhaps of even greater benefit to US producers and shippers is the destination flexibility of Henry Hub contracts – where almost all Australian contracts are fixed-destination (as are contracts signed for other supply, such as Yamal), US companies can ship almost anywhere in the world. As mentioned earlier, the US should see about 55 percent of its LNG exports going to Europe. However, the contract flexibility means volumes could be shifted elsewhere if markets dictate. Regasification facilities are being built the world over – more than 90 facilities are either on-stream or under construction; a further 35 are planned or proposed.[73] The US, more than any other exporter, is poised to take advantage of destination flexibility.

Canadian LNG

Canadian LNG development poses a competitive challenge to the US industry if that development indeed moves forward. When CERI Study 148 was released in mid-2015, it appeared two major projects in British Columbia would most likely proceed. On the east coast, several large projects were being planned to ship LNG to customers in Europe, India, and elsewhere. As of early 2016, only one Canadian project on either the Pacific or Atlantic coasts has reached an FID, the Petronas-backed Pacific NorthWest LNG project in Prince Rupert, but even that FID is contingent on receiving a provincial tax and royalty agreement (which has been done) and an environmental clearance from the Canadian Environmental Assessment Agency (still pending). Petronas has announced major spending cuts in its worldwide operations, leading to speculation that Pacific NorthWest LNG could be postponed.[74] The other major British Columbia development that has a fair chance of proceeding is Shell's LNG Canada. This project still awaits an FID (Shell announced

[73] http://www.globallnginfo.com/worldpercent20lngpercent20plantspercent20&percent20terminals.pdf Accessed February 10, 2016.

[74] Bennet, Nelson. "Petronas confirms capital spending reductions." Business Vancouver. January 22, 2016. https://www.biv.com/article/2016/1/petronas-confirms-capital-spending-reductions/ Accessed January 22, 2016.

in February 2016 that its FID would be delayed by approximately nine months[75]), but it has obtained environmental certificates and the support of local First Nations.[76]

One smaller project, Woodfibre, is still in the planning stages, but because its cost structure is far less than those of the larger projects – C$1.7 billion – it will not require as high an LNG price as would some of the larger projects. A second smaller LNG proposal, the C$500 million Douglas Channel project, also looked promising. However, the proponents decided that the environment today and over the next few years is not suitable to go ahead with construction.[77] Thus, for the purposes of this report, we assume a total liquefaction capacity of 4 Bcfpd by 2021.

None of the East Coast proposals have been cancelled yet, either. But no project is any closer to getting built – none have FID's although Stolt LNGaz, Bear Head LNG, Pieridae LNG, Energie Saguenay, and Canaport LNG have all received NEB approvals.[78] The East Coast projects will need to source gas from the US, requiring pipeline infrastructure either to be adapted to deal with increased volumes or to be newly built.

Figure 5.16 illustrates the location of Pieridae LNG and Bear Head LNG (indicated by the red dots). The former is sometimes referred to as Goldboro LNG. The figure also illustrates the connectedness of the projects to nearby pipelines. Both are linked to the 1,400-kilometer M&NP, indicated in orange. Recall, the M&NP crosses into the US via St. Stephen and terminates in Dracut and Beverley, Massachusetts. The PNGTS terminates at the Quebec border and the TransQuébec Maritime Pipeline (TQM). The latter continues to Montreal and Québec City. Currently the direction of flow on the M&NP and the PNGTS is north to south. As previously mentioned, this will likely have to change. Shale gas from the Marcellus will likely have to flow north to supply the two Nova Scotia facilities.[79] It should be noted that the M&NP currently does not have transportation agreements in place with any of the LNG proponent companies.

[75] Jiang, Brent. "Uncertainty hangs over future of B.C. LNG projects amid supply glut". Globe and Mail. February 16, 2016. http://www.theglobeandmail.com/news/british-columbia/uncertainty-hangs-over-future-of-bc-lng-projects-amid-supply-glut/article28776841/ Accessed February 17, 2016.

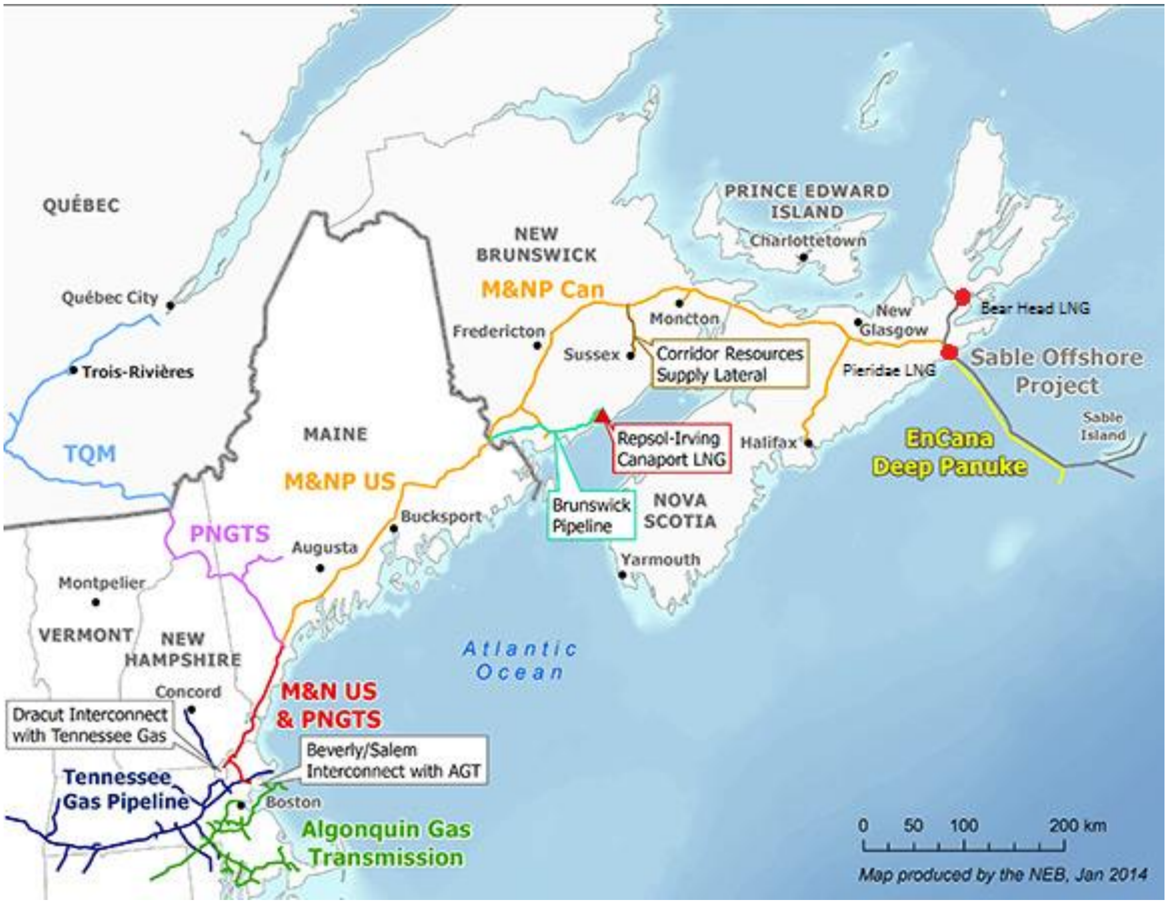
[76] Bennet.

[77] http://douglaschannellng.com/ Accessed March 16, 2016.

[78] National Energy Board. "Export and Import Licence Applications." https://www.neb-one.gc.ca/pplctnflng/mjrpp/lngxprtlcnc/index-eng.html Accessed January 22, 2016.

[79] Platts website, US DOE export decision moves Nova Scotia LNG project aheadhttp://www.platts.com/latest-news/natural-gas/houston/us-doe-export-decision-moves-nova-scotia-lng-21503025

Figure 5.16: Proposed Eastern Canada LNG Liquefaction Projects



Source: NEB[80]

[80] National Energy Board, Canadian Energy Dynamics 2013 - Energy Market Assessment, https://www.neb-one.gc.ca/nrg/ntgrtd/mrkt/archive/mrkt/dnmc/2013/mg/fg13-eng.jpg, Accessed March 20, 2016.

Chapter 6: Conclusions

The North American natural gas market has been transformed by the emergence of unconventional gas developments, specifically shale gas production in the United States. The so-called “shale revolution” with advances in horizontal drilling, 3-D seismic technology and hydraulic fracturing has enabled gas production growth from gas basins that were once thought uneconomic, and will transform the US from a net importer to a net exporter of natural gas as soon as 2017.

The polar vortex of the 2013-2014 winter caused temperatures to plummet and resulted in significant withdrawals from natural gas storage, causing gas prices to increase and remain elevated until mid-2014, at which point it was clear that gas deliveries were sufficient to avoid significant storage shortages. Despite the declining prices in the second half of 2014, Canadian and US natural gas supply continued to increase to refill the remaining storage deficit. By April 2015 inventories had returned to 5-year average levels. More recently, increased levels of natural gas production, along with the warm temperatures of the 2015/2016 winters have led to high natural gas storage levels at a time when gas is typically withdrawn. The speed at which storage could be refilled over the summer and fall of 2016 will provide a directional indication of the extent to which gas production is exceeding demand. If storage reaches capacity and gas delivery exceeds demand, gas prices may decline and gas production may face a risk of shut in to reduce supply to balance markets. Low gas prices could incentivize coal to gas switching to help absorb the gas overhang. On the other hand, a warmer than usual summer may withdraw more gas into the power generation sector to run air-conditioning units, thus slow the pace of gas injections, subsequently increasing gas prices and encouraging gas deliveries.

Furthermore, the more than 50 percent drop in oil prices since mid-2014, on top of the already low prices that western Canadian natural gas had been commanding, has carried a significant impact on the North American natural gas market in the form of reduced revenues, constrained cash flows, and significantly less gas-targeted drilling. Decreased capital expenditures are expected to reduce gas well drilling resulting in decreased gas production until 2019, but focusing drilling efforts on the most economic prospects by producers in both Canada and the US may improve per-well performance. In a low commodity-price environment, those companies that are able to supply gas at the low end of the cost curve are going to be able to produce gas. Additional drilling could occur in western Canada as some producers may start to deliver supplies for future LNG export projects. In eastern Canada, while significant resources exist, particularly offshore, economic, regulatory and political considerations see production in the region being effectively eliminated before the end of this study period.

Natural gas demand by sector in western Canada is dominated, of course, by industrial demand from Alberta. The demand by sector story in eastern Canada is noticeably different from that of western Canada, with demand much more evenly distributed among sectors. That trend is likely to continue until 2037 as there are no major changes to energy usage on the horizon. One potential source of demand growth in Canada is the Canadian LNG industry. If a Final Investment Decision is made to proceed with one or two projects in 2016-2017, this could accelerate this activity and result in increased Canadian supply over the projection period. Other sources of potential demand growth include the petrochemical industry and oil sands.

Lower oil and gas prices, over-supply, and increased competition in key markets will challenge the competitiveness of Canadian natural gas exports. The unprecedented growth in natural gas production, led by the US eastern shale basins of Marcellus and Utica shales, has changed the North American gas flows and has certainly pushed the Canadian gas exports out of the markets that had traditionally been sourcing western Canadian gas. More specifically, these markets are the US Northeast, US Midwest, as well as central and eastern Canada.

Lower cost Marcellus gas is closer to markets in central Canada, the US Northeast and US Midwest, giving it cost advantages over Western Canadian gas. Already, Marcellus shale gas has significantly displaced Canadian exports from the US Northeast market. Growing production of Marcellus shale gas will gain additional pipeline access to the US Midwest beginning in 2016.[1] An increasing amount of Marcellus gas is also expected to flow into central Canada displacing some demand that was previously satisfied by Western Canadian production.

Looking ahead 20 years, the price of natural gas is expected to rebound, although not reach the levels seen in 2008. Canada is expected to remain a net exporter of natural gas through 2037, although the timing and utilization of additional pipeline capacity from Marcellus and Utica to the US Midwest will be a key factor affecting markets that have relied mostly on Canadian gas.

[1] EIA. http://www.eia.gov/todayinenergy/detail.cfm?id=24732. Accessed on March 31, 2016.

Appendix A: Production Forecast and Supply Cost Methodology

The supply forecast in this study is an update from that done in CERI Study 149, "Western Canada Natural Gas Forecasts and Impacts (2015-2035)", released in July 2015. CERI completed supply cost calculations, explained below, which informed the supply forecast.

The supply cost calculations done in this study were used in CERI Study 136, "Conventional Natural Gas Supply Costs in Western Canada", completed in June of 2013. The supply cost method has not changed, and the assumptions have been updated to reflect their changes over time.

The WCSB supply costs represent the natural gas price (in real 2015 dollars) required to recover all capital expenditures, operating costs, royalties, taxes, and a specified return on investment for each well.

The supply cost is calculated with a cash flow model where net cash flow equals total revenue less any costs and other payments such as taxes and royalties.

The net cash flow is discounted back over the lifetime of the well (on average 25 years) to the first time period (2015) using a specified discount rate of 10 percent (real), thereby allowing the price of natural gas to vary and solve for the supply cost. The supply cost is the gas price that sets the Net Present Value (NPV) of the cash flows to zero.

The production of hydrocarbon fluids impacts supply cost with an assumption of a cut of 1 percent ethane, 90 percent propane, 99 percent butane and 99 percent pentanes plus. The hydrocarbons increase operating costs but also act as a further revenue stream.

Historical trends of the number of wells per pad are incorporated into the supply costs. Factors for economics of scale are used for areas where the average pad has seen multiple (in some cases more than 6) wells/pad.

Production Inputs

Historical well data was used to calculate the 2015 production inputs. Information was collected from the *Alberta Energy Resources Conservation Board (ERCB)*, Saskatchewan Energy and Mines (SEAM) and the British Columbia Oil and Gas Commission (BCOGC) that details the historic production of hydrocarbon fluids as well as general well characteristics, such as completion date, initial production rate, total depth, true vertical depth and location.

Cost Inputs

- Drilling and completion costs were estimated from data provided by the Petroleum Services Association of Canada (PSAC).[1] Drilling and completion costs per metre drilled were estimated for each area and then applied to each area given the assumed well depth.
- Geological, geophysical, tie-in costs (infrastructure) and land costs were all derived from data sourced from the Canadian Association of Petroleum Producers (CAPP).[2]
- Operating costs were estimated from CAPP[3] at the provincial level.
- Royalties were derived for all wells consistent with the regulations for natural gas royalties across the three provinces.[4,5,6]
  - Alberta's 2015 Royalty Review is important to note. Royalties on new natural gas wells will be at 5 percent until cumulative revenues equal the well's Drilling and Completion Cost Allowance. This Drilling and Completion Cost Allowance is a function of the well's vertical depth and lateral length, giving credit for the higher cost associated with drilling deeper than a set threshold. As of the completion of this study, the parameters of the Drilling and Completion Cost Allowance had not yet been released to the public. For the modeling of natural gas supply costs, the royalty was assumed to be constant at 5 percent. This will likely be accurate for the first portion of the forecast but will be subject to change in the years after the Drilling and Completion Cost Allowance has been met.
- Within the supply cost model, federal corporate income tax rates were assumed constant at 15 percent. Alberta and Saskatchewan income tax rates were assumed to be constant at 12 percent and British Columbia income tax rates were assumed to be constant at 11 percent.
- Supply costs for the Yukon were calculated using wells from the Horn River Basin in northern British Columbia as proxy, due to their similarities in geology and location. The calculation was modified to reflect the royalty rate of 1 percent rising to 5 percent[7] and the corporate tax rate of 15 percent.[8]

[1] PSAC, 2016 Well Cost Study Upcoming Winter Costs – Published November 3, 2015
[2] CAPP, Statistical Handbook for Canada's Upstream Petroleum Industry September 2015
[3] ibid
[4] Government of British Columbia website, Natural Gas Royalties, February 2016, http://www2.gov.bc.ca/gov/content/taxes/natural-resource-taxes/oil-natural-gas/oil-gas-royalty/understand/natural-gas#royalty-rate
[5] Alberta Energy website, Alberta Natural Gas Royalty Guidelines (2009), February 2016, http://www.energy.alberta.ca/NaturalGas/3109.asp
[6] Government of Saskatchewan website, Crown Royalty and Freehold Production Tax Rate Formula Factors and Royalty Rate Calculator, February 2016, http://www.economy.gov.sk.ca/royaltytaxfactors
[7] Indigenous and Northern Affairs Canada website, High Investment Potential in Canadian Northern Oil and Gas, June 1994, https://www.aadnc-aandc.gc.ca/eng/1100100037174/1100100037175
[8] Canada Revenue Agency website, Yukon - Territorial corporation tax, accessed December 2015, http://www.cra-arc.gc.ca/tx/bsnss/tpcs/crprtns/prv/yk/menu-eng.html

Other Economic Assumptions

- The inflation rate is assumed to be 2 percent per annum, which is within the Bank of Canada's target inflation of 1-3 percent.
- The results are presented in **Canadian dollars** in real terms in 2015 dollars. The Canadian dollar was assumed to grow from 79 cents/USD to 85 cents/USD over the next 20 years.
- **Supply costs are calculated as plant-gate costs,** that is, they do not include transportation or processing costs.
- Gas supply costs are presented as Canadian dollars per thousand cubic feet of natural gas ($/mcf).
- The natural gas price is assumed to increase at 2 percent per annum, consistent with the Energy Information Administration's annual average growth rate forecast (from 2014 to 2040) in the *Annual Energy Outlook 2015*.[9]
- Supply volumes of coalbed methane production in western Canada and natural gas from Ontario are from the National Energy Board's Canada's Energy Future 2016.[10]

[9] EIA Annual Energy Outlook 2015, April 2015
[10] National Energy Board, Canada's Energy Future 2016, February 2016

Appendix B: Supply Study Areas

Table B.1 describes the study areas used to estimate production and supply costs. Figures B.1-B.3 show the maps of drilling natural gas wells in British Columbia, Alberta and Saskatchewan.

Table B.1: Supply Study Areas

Area ID	Province	Area Description	Gas Description
PIA01-9999-GAS	Alberta	Suffield Medicine Hat Area	Sweet Gas
PIA02-9999-GAS	Alberta	Bow Island Area	Sweet Gas
PIA03-9999-GAS	Alberta	Foothills Area west of Calgary	Sour Gas
PIA04-9999-GAS	Alberta	Hussar to Princess Area	Sweet Gas
PIA05-9999-GAS	Alberta	Didsbury to Hussar Area	Sweet Gas
PIA06-9999-GAS	Alberta	Nevis and Ghostpine Area	Sweet Gas
PIA07-9999-GAS	Alberta	Bens Lake to Princess (North Lateral) Area	Sweet Gas
PIA08-9999-GAS	Alberta	Bens Lake to Canendish (East Lateral)	Sweet Gas
PIA09-9999-GAS	Alberta	Edson to Caroline (Plains Mainline)	Sour Gas
PIA10-9999-GAS	Alberta	McLeod to Caroline (Foothills Mainline)	Sour Gas
PIA11-9999-GAS	Alberta	Edmonton Area	Sweet Gas
PIA12-9999-GAS	Alberta	Bens Lake upstream to Calling Lake	Sweet Gas
PIA13-9999-GAS	Alberta	Gold Creek to Edson Area	Sour Gas
PIA14-9999-GAS	Alberta	Vahalla to Gold Creek Area	Sweet Gas
PIA15-9999-GAS	Alberta	Judy Creek, Kaybon to Edson and McLeod	Sweet Gas
PIA16-9999-GAS	Alberta	Doe Creek to Teepee Creek Area	Sweet Gas
PIA17-9999-GAS	Alberta	Heart River Wolverine Creek Area	Sweet Gas
PIA18-9999-GAS	Alberta	Darling Creek to Slave Lake Compressor	Sweet Gas
PIA19-9999-GAS	Alberta	Fort McMurray Area	Sweet Gas

Area ID	Province	Area Description	Gas Description
PIA20-9999-GAS	Alberta	Owl Lake Area	Sweet Gas
PIA21-9999-GAS	Alberta	Thunder Creek to Tanghe Creek	Sweet Gas
PIA22-9999-GAS	Alberta	Zama Lake to Meikle Compressor	Sweet Gas
PIA23-9999-GAS	Alberta	Princess to Empress Mainline	Sweet Gas
PIA30-X9999-GAS	British Columbia	Pine River Lateral	Sweet Gas
PIA31-X9999-GAS	British Columbia	Tupper Creek/Noel Area	Sweet Gas
PIA32-X9999-GAS	British Columbia	Groundbirch Area	Sweet Gas
PIA33-X9999-GAS	British Columbia	Dawson Creek	Sweet Gas
PIA34-X9999-GAS	British Columbia	Fort St John Area	Sweet Gas
PIA35-X9999-GAS	British Columbia	Chinchauga River	Sweet Gas
PIA36-X9999-GAS	British Columbia	Ring Area	Sweet Gas
PIA37-X9999-GAS	British Columbia	Kahntah Area	Sweet Gas
PIA38-X9999-GAS	British Columbia	Shekilie Area	Sweet Gas
PIA39-X9999-GAS	British Columbia	Peggo-Pesh Area	Sweet Gas
PIA40-X9999-GAS	British Columbia	Helmut North Area	Sweet Gas
PIA41-X9999-GAS	British Columbia	Fort Nelson to CS2	Sweet Gas
PIA42-X9999-GAS	British Columbia	Fort Nelson to NWT Border	Sweet Gas
PIA45-X9999-GAS	British Columbia	CS2 To Summit Lake Area	Sour Gas
PIA50-9999-GAS	Saskatchewan	Southwest	Sweet Gas
PIA51-9999-GAS	Saskatchewan	Central West	Sweet Gas
PIA52-9999-GAS	Saskatchewan	Central Northwest	Sweet Gas

Source: CERI

Figure B.1: Map of British Columbia Study Areas

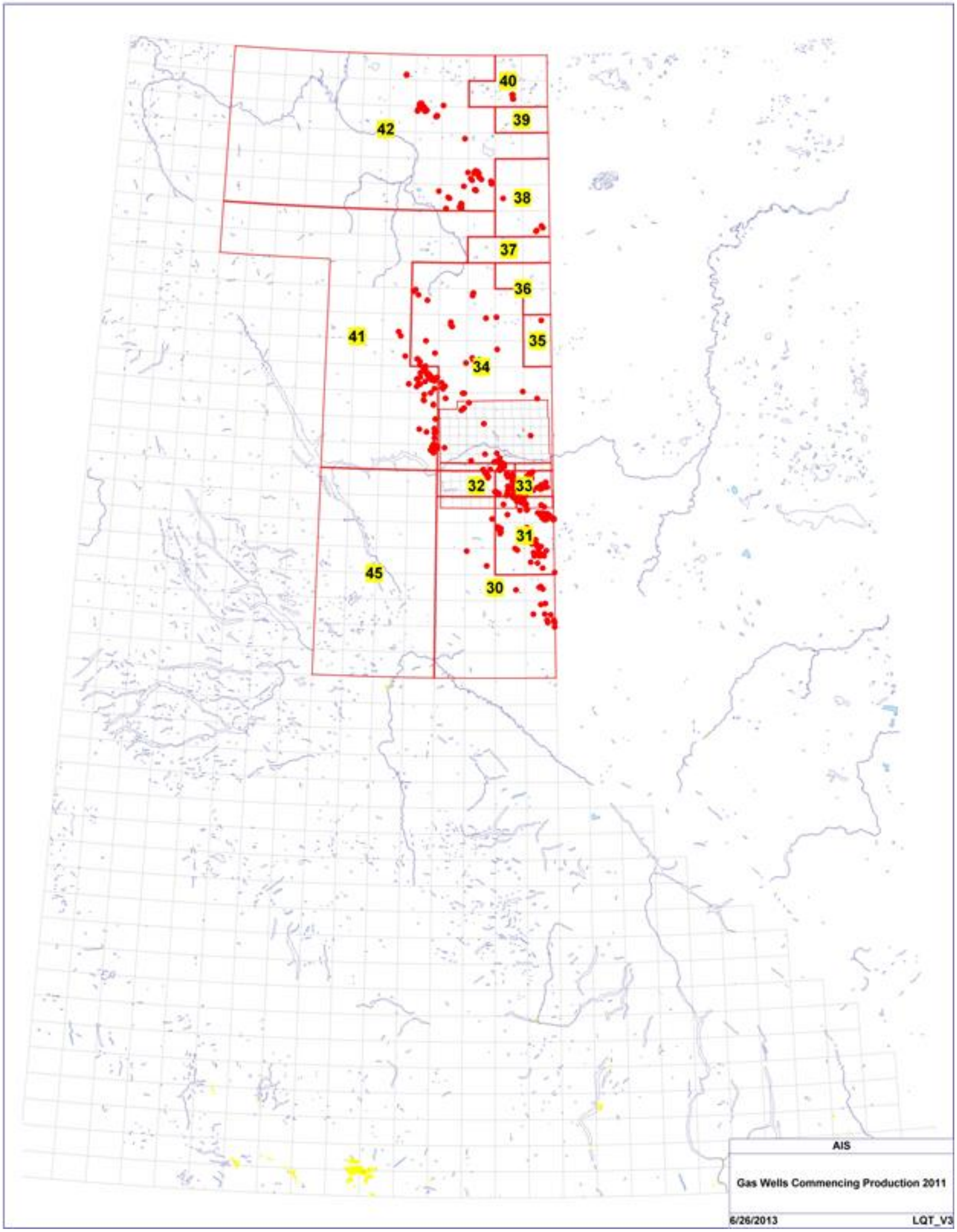


Figure B.2: Map of Alberta Study Areas

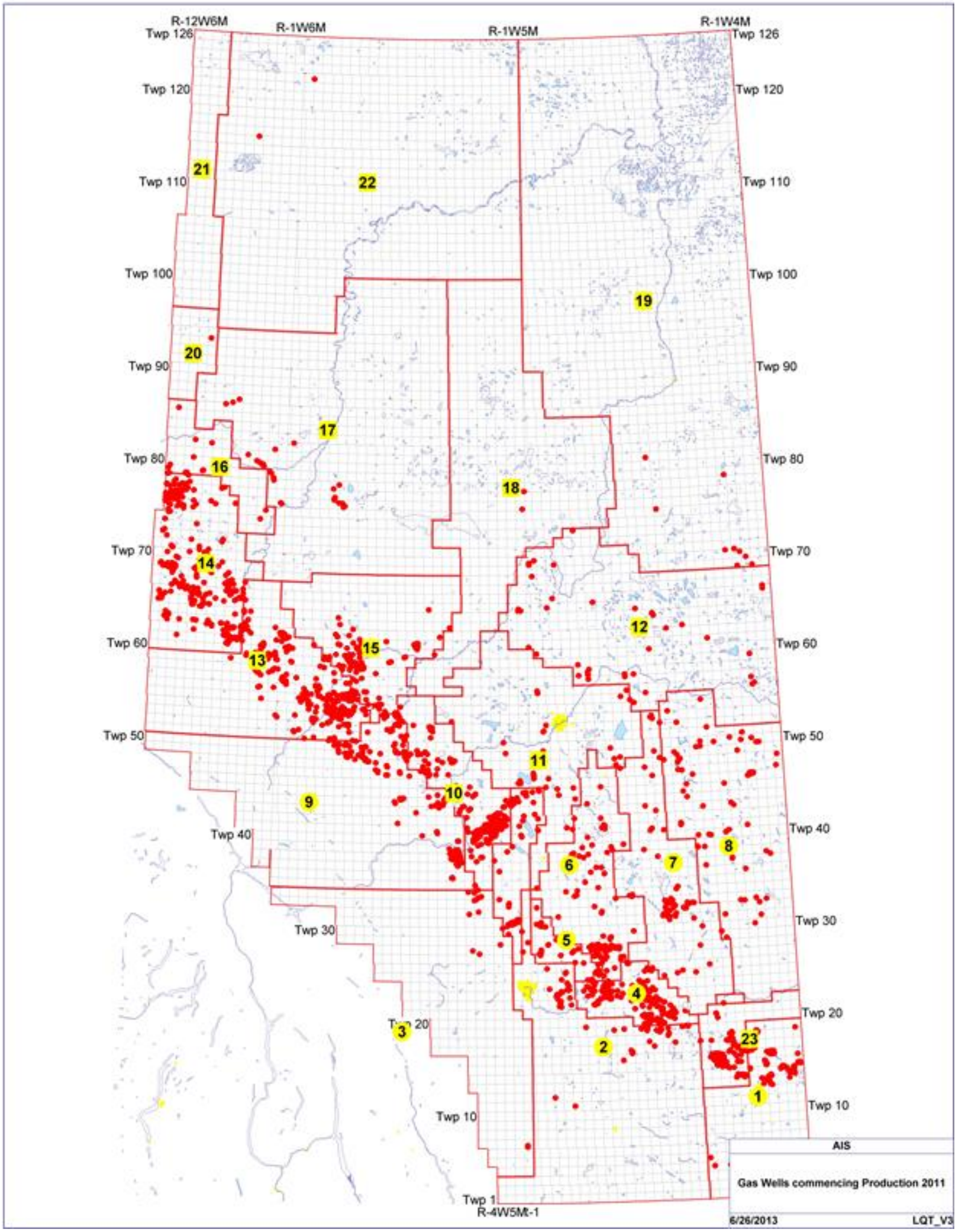


Figure B.3: Map of Saskatchewan Study Areas