Supply and Demand Market Assessment in Support of AC LNG Export Licence

Prepared for

AC LNG

Prepared by

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Disclaimer

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Executive Summary and Key Findings

AC LNG Inc. is applying to the National Energy Board (NEB) for a licence to export up to 13.5 million tonnes per annum (MTPA) (ramp up from 3 MTPA in 2019 to 13.5 MTPA from 2025) of liquefied natural gas (LNG) for a period of 25 years between 2019 and 2043. Natural gas will be liquefied at a proposed LNG terminal to be located in Nova Scotia (NS) and transported from there by LNG carriers to markets primarily in the Asia-Pacific region.

AC LNG Inc. retained ICF International to provide an independent assessment of North American, Canadian, and Western Canadian natural gas supply, demand, flows, and costs, and to draw conclusions regarding the balance of supply and demand for the period 2019-2050, within which the applied-for export would take place. ICF's analytical approach is based on over 40 years of natural gas market studies and uses the North American Gas Market Model (GMM®) which has been cited extensively in proceedings in Canada and the United States. The GMM® uses up-to-date resource assessments, production cost statistics, pipeline capacity and costs, storage capacity and costs, and detailed gas demand modeling to forecast production, flows, consumption, and prices. This report presents summary findings on gas supply, demand, and market dynamics through 2050, and draws related conclusions.

ICF's analysis and experience in the North American and regional natural gas markets supports the finding that a) the North American gas resource base is robust and can easily support the AC LNG, Inc. liquefied natural gas (LNG) facility, and b) LNG exports by AC LNG will not contribute to significant regional price increases.

Market Structure Supports Incremental LNG Exports

The combined U.S. and Canadian gas market, referred to jointly in this report at the North American gas market, is highly integrated and highly developed in terms of price formation, freedom of flows, and transparency compared to the rest of the world's gas markets. The well-functioning gas market in North America is based on free market economic principles, where gas prices are formed by the interaction of supply and demand across a continent-wide pipeline network. Gas prices are highly transparent and provide reliable signals on market conditions. Access to the gas market is widespread, with thousands of participants able to make individual consumption and production decisions based on market indicators. Gas prices effectively allocate supply across this network. ICF expects normal functioning of the North American gas market to continue well into the future. Such a market will respond to the demand for LNG exports, as well as for domestic consumption, in such way that both can be served without any major disruptions. The restrictions on LNG exports will not arise due to market disruptions or lack of resources, but will only be based on the commercial viability of individual projects.

North American and Canadian Gas Resources are Abundant and Capable of Meeting Future Domestic and Export Demand

North America's gas resources are very large, with shale resources accounting for over half of the remaining, economically recoverable gas. ICF estimates that over 4,000 Tcf of gas is producible with today's technology at a cost of production below \$14/MMBtu.[1] At this level the market can support 133

[1] Note, in this report all prices are in U.S. dollars.

years of total North American consumption, including gas demand from Middle Melford LNG exports and other LNG exports incorporated into ICF's Base Case, as well as to Mexico. Using Canadian resources alone and domestic Canadian consumption, the multiple is 238 years. In reality, as more wells are drilled, more resources will be discovered (resource appreciation), technology will improve exploration and production efficiencies, and costs of production will decline, even as more costly resources are tapped. Thus, ICF believes that the natural gas resources are more than adequate to meet domestic Canadian demand and LNG exports from Middle Melford.

Future Gas Demand can be Served at Moderate Prices

The large resource base has been a key driver underlying the general decline in gas prices since the early 2000s and the growth of gas demand for power, industrial use, and exports. ICF forecasts that by 2050, the domestic market for natural gas in North America will be at 130 Bcf/d, including exports. This translates to approximately 47.5 Tcf per year. Focusing on Canada alone, ICF forecasts a total demand for gas of 23 Bcf/d (8.4 Tcf per year), including 2.7 Bcf/d of LNG exports from British Columbia and exports to the U.S. ICF's resource supply curve shows approximately 1,500 Tcf are producible at prices at or below $5.00/MMBtu. Thus, there are substantial resources available at moderate prices to meet future demand for gas in North America and Canada.

The Supply Economics for Atlantic Canada have Changed since the Advent of Marcellus Production

This report notes that the Canadian resources available in Atlantic Canada are modest relative to the rest of the continent, approximately 100 Tcf of remaining and unproved resources out of the 4,072 Tcf total for North America. Development of the resources from Sable Island took place when gas prices were much higher and expectations were for a declining resource base in North America. With the advent of shale gas, the economics of the Atlantic Canada gas production have changed and ICF forecasts declining production, mainly for lack of market. ICF is aware that AC LNG has met with Atlantic Canada producers and may acquire some portion of their gas from local production. Nevertheless, we believe the major source of supply ultimately will be from the United States, mainly the Marcellus production. Western Canadian Sedimentary Basin (WCSB) supply can also be a source for the Middle Melford facility. In both cases, there is adequate supply from these basins to support the incremental exports from Middle Melford.

Higher than Expected Canadian Demand can be met at Relatively Small Increases in Prices

A scenario where Canadian demand was increased by 20% by 2035 was tested and compared to the ICF Base Case. In this scenario, gas supply expanded to meet the higher demand at modest price increases. New production developed in the WCSB with the AECO price of gas increasing by about 6%, from $6.07 in the Base Case to $6.42 per MMBtu in the higher demand case. Dawn prices increased by 4% or from $6.91 to $7.18 per MMBtu between the two cases. Additional production from Marcellus was imported into Ontario. Price increases at other key hubs were smaller.

LNG Exports by AC LNG will Account for a Small Percentage of Total North American Production

Exports from Middle Melford are assumed to begin in January 2019 at approximately 0.46 Bcf/d, another addition of 0.46 Bcf/d by 2021 and further addition of 1.18 Bcf/d by 2025 totalling the export volume to 2.1 Bcf/d by 2025 and continue at that level until 2043 (these rates include the annual tolerance applied-for, see sub-section 1.1 below). ICF estimates that at the full export volume Middle Melford will account for less than 2% of North American production once the project is fully operational. This percent will decline as production expands in the future.

LNG Exports from Middle Melford will have a Modest Effect on Gas Prices

LNG exports, in general, will lead to greater demand for gas than would be the case otherwise and requiring additional drilling and production to meet the incremental export requirements. This will lead to higher costs. ICF's gas price forecasts already include the effects of 12.5 Bcf/d of exports from Canadian and U.S. ports. Our estimates of the incremental cost of LNG exports over the long run are about $0.07 per Bcf/d of LNG export expansion. At 2.1 Bcf/d, Middle Melford could have a price impact of about $0.15/MMBtu on North American gas prices above those prices forecast by ICF in this report.

Gas Pipeline Capacity Planned for the Northeast Can Support Atlantic Canada Demand and Exports

The major challenge for supplying gas to the Middle Melford LNG export project will be adequate pipeline capacity from various supply sources into Nova Scotia. Pipeline capacity is being developed to support growth in production from Marcellus, including expansions into New England and Atlantic Canada to meet demand growth. ICF is aware that AC LNG has been in discussions with some of these pipeline companies.

Thus, ICF sees substantial options for providing the infrastructure needed to support expanded gas consumption in Atlantic Canada and for the Middle Melford LNG export facility.

1. Introduction

1.1 Purpose of the Report and Organization

AC LNG engaged ICF International (ICF) to develop this Supply and Demand Assessment Report to support its application for a licence for the export of liquefied natural gas (LNG) from a facility located in Middle Melford, Nova Scotia. This report describes ICF's forecast of gas supplies, including Canadian gas supply expected to be available to the Canadian market over the licence term being sought by AC LNG; and ICF's forecast of natural gas requirements (demand) for Canada (including underlying assumptions) over the requested licence term. Because the potential sources of supply include those in the United States, this report expands on the typical analysis to encompass those supplies as well and their relation to Canadian gas markets.

Below are the summary contents of the AC LNG application.

AC LNG Inc. ("ACLI" or "Applicant") would like to pursue with National Energy Board ("NEB" or "Board") pursuant to section 117 of the *National Energy Board Act ("NEB Act")* for a licence authorizing the export of liquefied natural gas ("LNG") of up to 4.8 X 10^9m^3 per year expressed as a gaseous quantity for the initial two years starting from January-2019 , 9.5 X 10^9 m^3 per year from January-2021 until December 2024 and 21.4 X 10^9 m^3 for the remaining term of licence i.e. 19 years , subject to the Annual Tolerance requested below, for a term of 25 years ("Licence"), on the following terms and conditions:

- Term — A period of 25 years commencing on the date of first export under the License;
- Annual Quantity — Subject to the Annual Tolerance, the quantity of natural gas that would be 4.8 X 10^9m^3 per year expressed as a gaseous quantity for the initial two years starting from January-2019 , 9.5 X 10^9 m3 per year from January-2021 till December-2024 and 21.4 X 10^9 m^3 for the remaining term of licence i.e. 19 years, which corresponds to approximately 15.5 MTPA of LNG;
- Annual Tolerance — The quantity of natural gas that may be exported in any12-month period may exceed the annual maximum quantity by 15%;
- Term Quantity — During the term of the Licence, the maximum quantity of natural gas that maybe exported, adjusted for ramp- up volumes at the start of the term and adding the tolerance, shall not exceed 454.3 X 10^9m^3 (16.0 Tcf approx.), which corresponds to approximately 329 million tonnes (MT) of LNG;
- Export Point — The point of export from Canada would be at the outlet of the loading arm of the proposed natural gas liquefaction terminal which is anticipated to be in the region of, Middle Melford, Nova Scotia, Canada; and
- Early Expiration — Unless otherwise authorized by the Board, the term of the Licence shall expire 10 years from the date of Governor-in- Council approval of the issuance of the Licence if exports pursuant to the Licence have not commenced on or before that date, or the Board otherwise directs.

A table setting out the annual and term quantities of applied-for gas and those quantities adjusted to take account of the ramp-up volumes at the start of the term and adding the requested tolerance is attached as Appendix D.

This report addresses the Filing Requirements in the National Energy Board's (NEB) Filing Manual, Guide Q –Export and Import Authorizations (Part VI of the NEB Act and Part VI Regulations) Release 2013-03, to provide:[2]

> *(Item 2) A description of gas supplies, including Canadian gas supply, expected to be available to the Canadian market (including underlying assumptions) over the requested licence term, and*
> *(Item 3) A description of expected gas requirements (demand) for Canada (including underlying assumptions) over the requested licence term.*

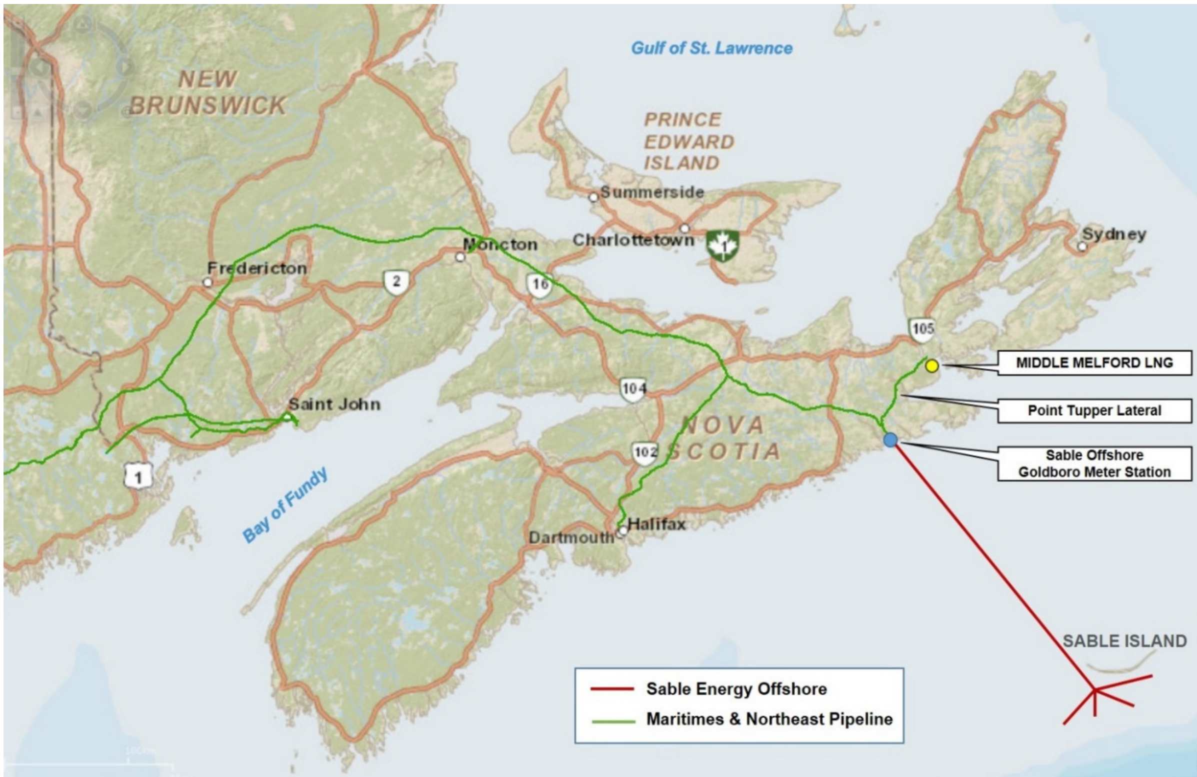
AC LNG is considering gas supply acquisitions from a variety of sources in both Canada and the United States. At present, discussions have been held with potential suppliers in Western Canada and Eastern Canada, including Newfoundland and Labrador, as well as suppliers in the Marcellus/Utica basin in the United States. AC LNG is examining the feasibility of acquiring initial volumes of natural gas from the Western Canadian Sedimentary Basin (WCSB) and from off-shore resources in Atlantic Canada, including Newfoundland and Labrador. At the same time AC LNG is reviewing possible sources of supply in the Marcellus/Utica basin, which would also support expanded facilities and other opportunities as they develop. This dynamic is elaborated upon in the resource and supply discussion below. At the same time, AC LNG is meeting with gas pipelines to acquire capacity for the volumes needed for the project from the potential supply sources. As such, the gas supply for AC LNG will be incremental to supplies from surplus Canadian production. Nevertheless, this report provides a comprehensive review of the natural gas supply and demand situation in North America to support the application to the NEB.

1.2 Overview of the AC LNG Project

The LNG facility will be located in Guysborough County, Nova Scotia, south and east of Port Hawkesbury on the Strait of Canso and near the Maritimes and Northeast Pipeline (M&NP) and close to the facilities of the Sable Offshore Energy Project (SOEP)—see Exhibit 1-1. The export project is expected to begin operations January 1, 2019 with export volumes of 168 Bcf (0.46 Bcf/d) in each of the first two years. In 2021, the volumes would increase to 336 Bcf (0.92 Bcf/d). In 2025, the volumes would increase to 756 Bcf per annum (2.1 Bcf/d) through the end of 2043. These volumes include a tolerance of 15%.

[2] See National Energy Board Act R.S.C, 1985, C. N-7, Part VI, Division 1, Section 118.

Exhibit 1-1 Location of AC LNG Facility at Middle Melford and Maritimes and Northeast Pipeline



Source: ICF International and SNL Financial

This rest of this report is divided as follows:

- The next section describes the gas resource base in North America, including Eastern Canadian resources, the Western Canadian Sedimentary Basin (WCSB), and Marcellus/Utica basin in the United States, all of which are relevant to Canadian supply and demand.
- The third section presents the ICF's demand and supply outlook for North America, with separate sections for the United States and Canada through 2050. Specifically this section describes ICF's forecast of demand based on underlying economic growth, energy demand, and prices. LNG exports are treated as a separate component of demand. This is followed by the ICF outlook for supply, which is a production outlook based on demand and price. We also provide ICF's gas price outlook for the relevant pricing points in Canada and the United States. The foundation for this analysis is the results of ICF's North American Gas Market Model (GMM®) Base Case, vintage August 15, 2014.[3] The section ends with a discussion of recent market developments and the key uncertainties around the factors that go into the forecast of future gas market development through 2050.
- The fourth section reviews the development of the Eastern Canadian and New England regional gas pipeline networks to support increased gas supply deliveries to the Middle Melford LNG facility.
- The final section summarizes our findings and conclusions.

[3] A description of GMM® is provided in Appendix 1.

2. Natural Gas Resources

This section presents ICF's view of the natural gas resource base in North America and discusses the implications of the "shale revolution" on North American gas markets. We also provide separate assessments of the resources in Canada, focusing on the Western Canadian Sedimentary Basin (WCSB) and Eastern Canada (focused on Atlantic Canada) and the United States, particularly the Marcellus/Utica formation.

2.1 North American Gas Resource Overview

The locations of the major North American gas reservoirs are shown in Exhibit 2-1. The gas reservoirs are prolific and are spread out across North America.

Exhibit 2-1 Major North American Gas Reservoirs

Map source: Canadian Association of Petroleum Producers, "Facts on Natural Gas."
http://www.capp.ca/UpstreamDialogue/NaturalGas/Pages/default.aspx

The major energy resource story of the last seven years in North America has been the rapid emergence of shale gas as the major source of gas and oil supply across the continent. Ten years ago LNG imports were thought to be the next major supply source in the face of declining conventional production and high gas prices. The technological innovations combining horizontal drilling and hydraulic fracturing in shale formations has unlocked a vast resource (shale often was called the source rock for hydrocarbons) and has made accessible an enormous quantity of natural gas and oil in North America. LNG import terminals planned and built are now being converted to export facilities. North America is likely to become a net exporting region for oil and gas.

The significance of the shale gas revolution lies in two factors: the geographic distribution of the shale resources across North America and the enormous size of the resource.

As shown in Exhibit 2-2, shale resources are broadly distributed geographically, with some of the largest shale formations, the Marcellus and Utica, located in the Northeastern United States. This location is having a dramatic effect on pipeline flows dynamics across North America. Being located so close to the consuming markets of the Northeastern United States, Ontario and Quebec, pipelines that once carried gas into these markets from the far south and west are seeing their throughput fall, and in some cases, their systems reversed.

Exhibit 2-2 North American Shale Plays

Source: U.S. Energy Information Agency, 2011.

The second important feature of the shale resource base is its size, shown in Exhibit 2-3. All estimates of the shale resource have set the resource base at many hundreds of trillion cubic feet. ICF has developed an independent estimate of North American gas resource base derived from detailed basin and play information across North America made available from producers. We currently estimate that the U.S. and Canadian resource base is comprised of slightly over 4,000 Tcf of total remaining resource, economically producible using today's technology. Just over half of this, or 2,172 Tcf, is from shale.

Of the total gas resource, approximately 880 Tcf are in Canada, of which about 520 Tcf are shale resources. The bulk of Canadian resources are in the WCSB including British Columbia, about 744 Tcf. Another 89 Tcf are in the Eastern Canada, on-shore and off-shore. The on-shore resources (almost 17 Tcf) are mostly unconventional, principally coal bed methane (CBM) and shale.

Exhibit 2-3 U.S. and Canada Natural Gas Resource Base[1] (Tcf) Producible at $14 per MMBtu or Less

	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resource	Shale Resource[2]	Unconventional Resource[3]
Alaska	9.4	153.6	163.0	0.0	0.0
West Coast Onshore	2.9	24.6	27.5	0.3	15.8
Rockies & Great Basin	81.8	388.3	470.1	37.9	359.0
West Texas	20.4	47.7	68.1	17.5	44.2
Gulf Coast Onshore	97.6	684.7	782.3	476.9	619.9
Mid-continent	65.3	205.0	270.3	133.9	161.7
Eastern Interior [4,5]	45.2	1,053.7	1,098.9	986.1	1,055.1
Gulf of Mexico	10.7	238.6	249.3	0.0	0.0
U.S. Atlantic Offshore	0.0	32.8	32.8	0.0	0.0
U.S. Pacific Offshore	0.8	31.7	32.5	0.0	0.0
WCSB	68.8	664.0	732.8	508.8	598.7
Arctic Canada	0.0	45.0	45.0	0.0	0.0
Eastern Canada Onshore	0.8	15.9	16.7	10.3	16.1
Eastern Canada Offshore	0.3	71.8	72.1	0.0	0.0
Western British Columbia	0.5	10.9	11.4	0.0	0.0
US Total	**334.1**	**2,860.6**	**3,194.7**	**1,652.5**	**2,255.7**
Canada Total	**70.4**	**807.6**	**878.0**	**519.1**	**614.8**
US and Canada Total	**404.5**	**3,668.1**	**4,072.6**	**2,171.6**	**2,870.5**

Source: ICF International

1. ICF updated its gas resource assessment in December 2011; while these regional totals may not fully reflect the current assessment, the U.S./Canada economically recoverable resource is similar.
2. Shale Resource is a subset of Total Remaining Resource.
3. Unconventional resource includes shale, tight, and CBM resource and is a subset of Total Remaining Resource.
4. Eastern Interior includes Marcellus, Huron, Utica, and Antrim shale.

Within the United States, there are about 3,195 Tcf of remaining reserves producible with current technology, of which 1,653 Tcf is from shale. The U.S. Northeast shale basins, which include the Marcellus, Huron, and Utica in the Appalachia, and the Antrim in Michigan, have about 986 Tcf of shale gas resources. Other large concentrations of resources and shales are along the Gulf Coast and in the WCSB, mostly in Alberta and British Columbia.[4]

Below, we compare ICF's estimate of reserves with those of other entities. Compared to other estimates, ICF has considerably higher estimates. For example, the ICF Lower-48 shale gas assessment of 1,964 Tcf can be compared to the U.S. Energy Information Administration's (EIA) 495 Tcf or the Potential Gas Committee's (PGC) 1,073 Tcf.

Exhibit 2-4 Comparison of ICF Estimate with Others for Lower 48 States (Tcf)

Group	Shale Gas	Tight Oil	Tight Gas	Coal Bed Methane	Conventional	Unproved Total
ICF (current)	1,964	155	438	66	707	3,330
EIA (current)	495	40	368	120	487+	1,660
USGS (current)	393	---	190	71	---	---
Potential Gas Committee, 2013	1,073	---	Incl. in conventional	101	955	2,129
EIA AEO, 2011	827	---	369	117	703	2,016
Potential Gas Committee, 2011	687	---	Incl.in conventional	102	858	1,647
MIT, 2011	631	---	173	115	951	1,870
Advanced Resources Inc., 2010	660	---	471	85	831	2,047

Source: ICF International

Notes:
Technically recoverable gas; excludes proved reserves
PGC assessment does not break out tight and conventional.
PGC may have tight oil associated with shale gas.
EIA reports total L-48 associated gas only (146 Tcf). This is assumed to include tight oil associated but not stated.
MIT assessment of conventional gas shown here includes Alaska

There are several reasons for the magnitude of the differences:

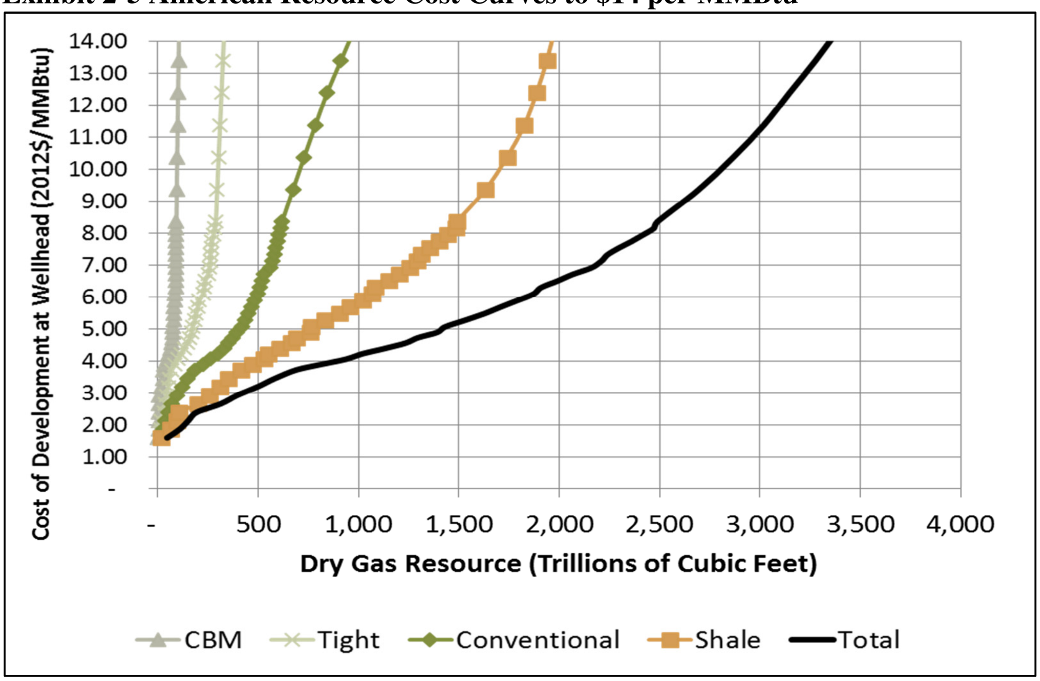
- ICF includes all major shale plays that have significant activity. Although in recent years, EIA has published resources for most major plays, the ICF analysis is more complete. Examples of plays assessed by ICF but not by EIA include the Paradox Basin shales and West Texas Barnett and Woodford. ICF also has a more comprehensive evaluation of tight oil and associated gas.
- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have a large liquids area.

[4] While we differentiate U.S. and Canadian resources, the U.S. and Canadian markets are highly integrated and supply moves freely across the border in response to demand in both countries. Gas prices in ICF's GMM reflect the entire U.S.-Canadian gas market balance.

- ICF employs a bottom-up engineering evaluation of gas-in-place and oil in place (OOIP). Assessments based upon in-place resources are more comprehensive.
- ICF includes infill drilling and new technologies that increase the volume of reservoir contacted. Infill drilling impacts are critical when evaluating unconventional gas.
- For conventional new fields, ICF includes areas of the Outer Continental Shelf that are currently off-limits, such as the Atlantic and Pacific OCS.
- ICF evaluates all hydrocarbons at the same time (dry gas, natural gas liquids (NGLs), and crude and condensate). While not affecting gas volumes, it provides a comprehensive assessment.
- ICF employs an explicit risking algorithm based upon the proximity to nearby production and factors such as thermal maturity or thickness.

The resource base by itself only gives information about the technically available resources, and the cost of extraction of these resources determines the economically available resources. “Cost of Supply” curves are used to denote the amount of resources that can be economically extracted at different production costs at the wellhead. Exhibit 2-5 shows ICF’s estimated cost of supply curves by major resource type: conventional, shale, coal bed methane (CBM), and tight.[5] It shows that approximately 1,500 Tcf of gas (equivalent to about 57 years at current domestic consumption rates) is producible for $5 per MMBtu or less. Looking at the total resource base, about 3,400 Tcf are producible at $14 per MMBtu or less (which is the current approximate price for LNG in Japan). These estimates are based on current technology, and do not reflect expectations for technology improvements that will increase supply and lower costs or the effects of increased drilling which inevitably add to the resource base as more resources are found.

Exhibit 2-5 American Resource Cost Curves to $14 per MMBtu



Source: ICF August 2014 Base Case

[5] Tight gas refers to gas in very hard low permeability rock, usually sandstone, which requires hydraulic fracturing to develop. CBM is gas entrained in deep underground coal seams. Tight, CBM, and shale are unconventional; conventional gas requires no special actions to produce once the well is completed.

While AC LNG is in discussions with potential suppliers in both Canada and the United States, the ICF analysis focuses on three potential sources: the WCSB, Atlantic Canada, and the Marcellus/Utica Basins. Each of these basins is discussed in additional detail below. Exhibit 2-6 summarizes the resource base, estimated production and prices from ICF's GMM August 2014 Base Case, and distance from Middle Melford for the Marcellus, the WCSB, and Atlantic Canada.

Exhibit 2-6 Basin Comparison

Source	Resource Base (Tcf)	Production Forecast in 2020 (Bcf/d)	Distance from Middle Melford (km)	Comment
Appalachia	1,070	18.8	1,330	Large resource capable of meeting regional demand and supplying other regions, including Gulf Coast.
WCSB & B.C.	744	7.9	4,580 (direct route from Empress)	Horn River and Montney will be dedicated to west coast LNG; other supply adequate, but subject to price pressure from local demand growth
Atlantic Canada	89	0.180	65 (from Goldboro)	Not enough supply for the project; could be used for a portion of the supply

Source: ICF International

2.2 Canadian Supply

2.2.1 Western Canadian Sedimentary Basin

Exhibit 2-7 summarizes ICF's analysis of technically and economically recoverable resources in Canada. ICF's estimates are near the lower range of the recent NEB estimate, which range from 885 Tcf to 1,566 Tcf, with the reference case of 1,139 Tcf.[6] However, the NEB includes all resources (without regard for economic recovery).

WCSB resources have seen a dramatic shift in production outlook in the last 5 years. Production from conventional resources has declined while at the same time demand for gas in Alberta has increased for power generation and oil sands development. (See our market assessment below.) Much of the new resource base is now in unconventional supply – shale, coal bed methane (CBM), tight gas – and much of this resource is located in the northwestern Alberta and British Columbia in the Horn River and Montney Basins.

ICF forecasts a continuing decline in gas from conventional, CBM, and tight resources and a large increase in production from shale. Most of the shale gas, however, is destined for LNG exports from British Columbia. See Exhibit 2-8.

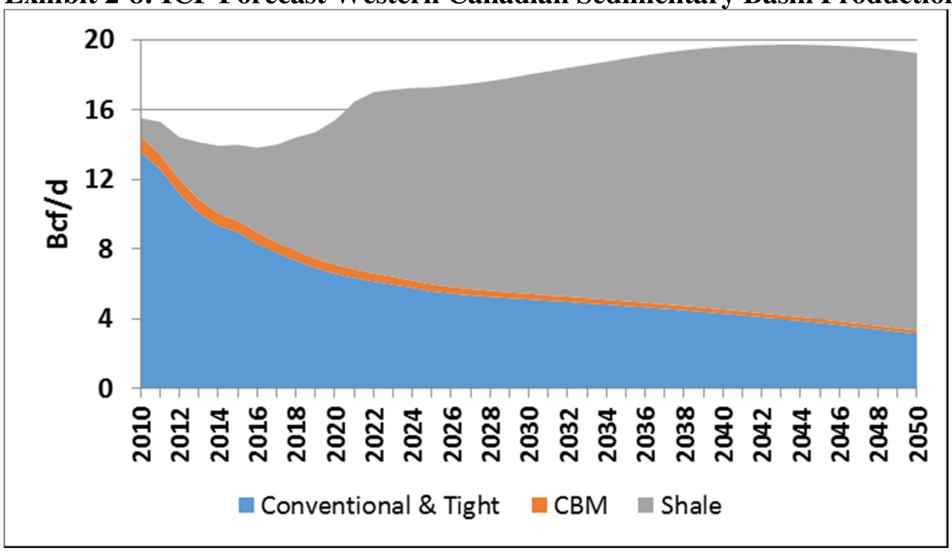
[6] http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2013/nrgftr2013-eng.html

Exhibit 2-7 Canada Natural Gas Resource Base (Tcf) Producible at $14 per MMBtu or Less

	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resource	Shale Resource	Unconventional Resource
WCSB except B.C.	68.8	664.0	732.8	508.8	598.7
Arctic Canada	0.0	45.0	45.0	0.0	0.0
Eastern Canada Onshore	0.8	15.9	16.7	10.3	16.1
Eastern Canada Offshore	0.3	71.8	72.1	0.0	0.0
Western British Columbia	0.5	10.9	11.4	0.0	0.0
Canada Total	**70.4**	**807.6**	**878.0**	**519.1**	**614.8**

Source: ICF International. See Exhibit 2-1 for locations of reservoirs.

Exhibit 2-8: ICF Forecast Western Canadian Sedimentary Basin Production

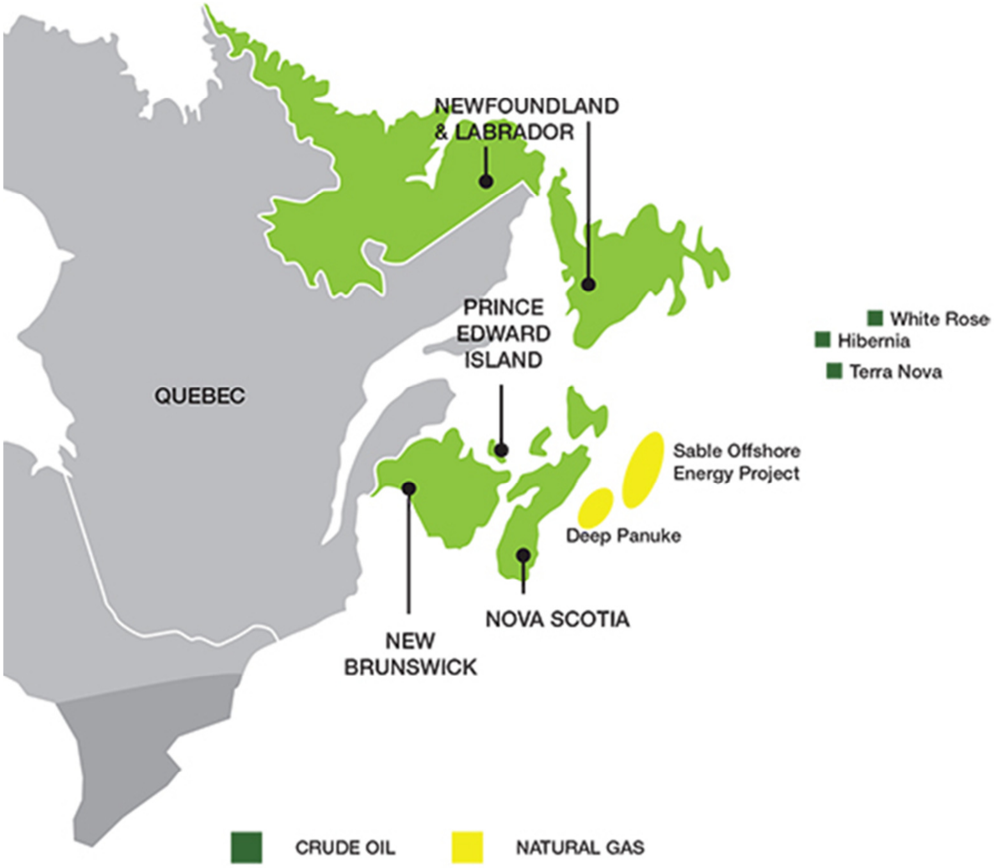


Source: ICF International

2.2.2 Atlantic and Eastern Canada

The Atlantic Canada region includes offshore shelf and deep water areas offshore Nova Scotia, Newfoundland, and Labrador, as well as significant onshore basins (Figure 1). Oil or gas discoveries have been made off of all three offshore areas, with commercial gas production established offshore Nova Scotia and commercial oil production offshore Newfoundland. Several gas discoveries off of Labrador were made decades ago and have not been developed. The region has been relatively quiet, with declining production for quite some time. However, there is a great deal of new interest and activity in the region, primarily due to new oil discoveries off of Newfoundland, and an emerging deep water oil play off of Nova Scotia. These emerging oil plays are similar to prolific plays in the Gulf of Mexico and elsewhere. Given the importance of local resources for the AC LNG project, we describe these resources in more detail below.

Exhibit 2-9 Atlantic Canada Oil and Gas Provinces



Source: Canadian Association of Petroleum Producers *http://www.capp.ca/rce/atlantic-offshore/*

Offshore Nova Scotia

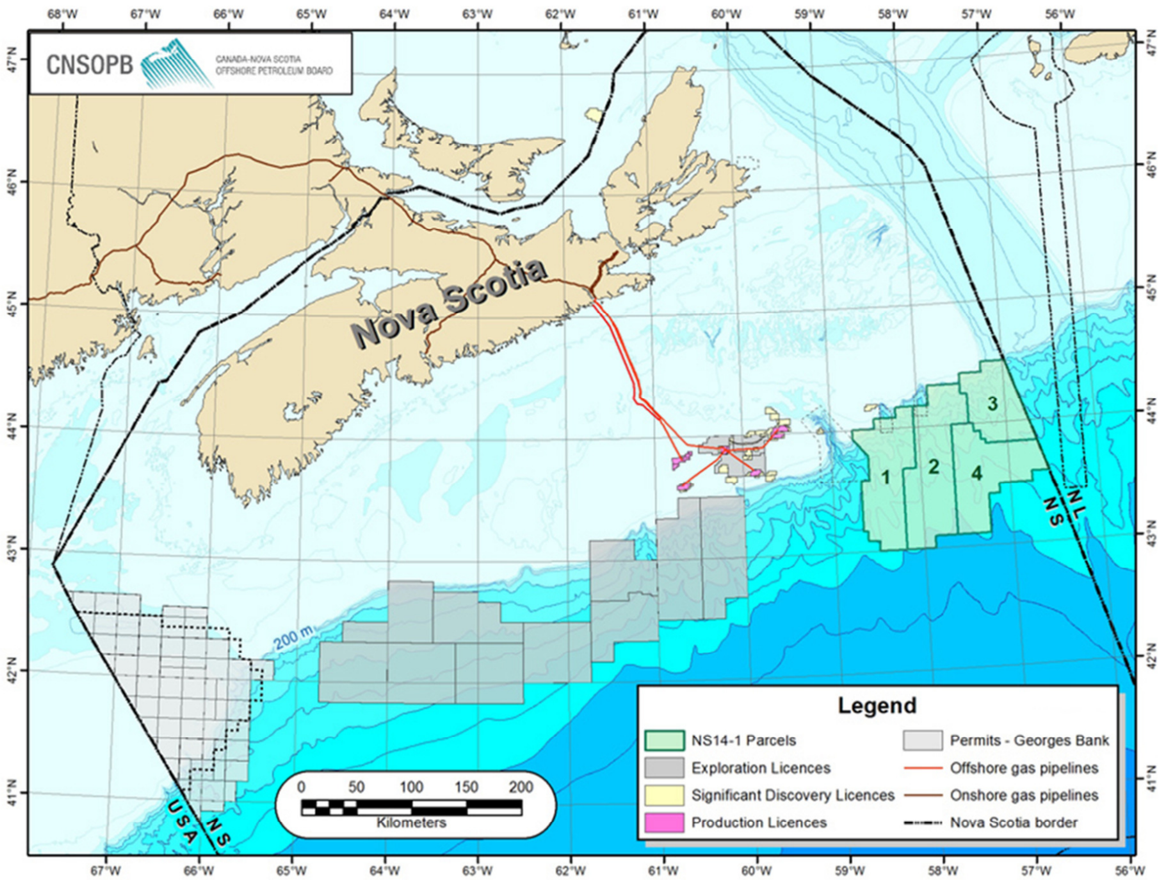
In 2013, marketed offshore Atlantic Gas production was 175 MMcf per day, all of which was from Nova Scotia. Gas production has declined from about 300 MMcf per day in 2010. Gas production offshore Nova Scotia is from the Sable Offshore Energy Project (SOEP) and Deep Panuke in shallow water, as described below. Encana's Deep Panuke field started production late in 2013, so its impact is not indicated in the 2013 numbers, and 2014 annual production will be much higher. There have been 24 significant discoveries offshore Nova Scotia on the shelf, including an oil field that is no longer producing (Cohasset-Panuke).

Current Exploration Activity and Government Initiatives in Nova Scotia

There is no offshore Nova Scotia oil production. However, in recent years there has been a great deal of interest generated by a new - but as yet unproven – deep water oil play off of Nova Scotia. Current leaseholders include Shell, BP Canada, ExxonMobil Canada, Chevron, Encana, and Hess (which recently partnered with BP). The area of interest is shown in light gray in Exhibit 2-10 and lies in water depths of 100 to 3,000 meters. Industry has committed to spending billions of dollars in coming years in this area. To date, no wells have been drilled in the play and it is still in the seismic and geological exploration stage, although drilling should begin in 2015.

Geologically, the play is a "subsalt" play with similarities to the prolific deep water Gulf of Mexico, and to equally prolific subsalt plays on the western and eastern margins of the Atlantic Ocean. Subsalt deep water plays are prolific in the Gulf, Brazil, Angola, and elsewhere.

Exhibit 2-10 Nova Scotia Offshore Region and Deepwater Play Area



Source: Canada Nova Scotia Offshore Petroleum Board website http://www.cnsopb.ns.ca/

BP plans to invest $1 billion developing their acreage in the play and obtained 7,800 square miles of 3D seismic data this year and plans to acquire 4,100 square miles in 2015. BP's acreage is about 300 km offshore. In 2015, Shell will drill the first of seven planned wells in the western part of the play. Shell has committed to invest $925 million by 2019. In 2014, Shell completed its seismic mapping of the area with over 6,000 miles of data. Recently, ConocoPhillips and Suncor each acquired an interest in the Shell acreage. Shell will be operator with 50 percent interest.

The Nova Scotia Department of Energy in recent years has been involved in supporting the development of offshore oil and gas resources. Over a period of about twenty years, drilling activity had declined and little interest was being expressed by oil and gas companies in the offshore. In 2008, Nova Scotia committed about $18 million for research, including the development of a geological analysis of offshore potential (the Play Fairway Analysis). The study concluded that there is an un-risked, in-place resource potential in the deep water play of 120 Tcf of gas and 8 billion barrels of oil.

Sable Offshore Energy Project (SOEP)

The SOEP is a shallow water gas field operated by ExxonMobil Canada. The development is located 180km southeast of Nova Scotia, and is shown near the shelf edge in Exhibit 2-10. The field started production in 1999. As of late 2014, gross production was at 175 MMcf per day and estimated recoverable remaining reserves are 500 Bcf. At its peak, the field produced 500 MMcf per day. ExxonMobil has a 50.8% stake in SOEP, while 9% is held by ExxonMobil subsidiary Imperial Oil. The other partners in the project are Shell Canada Ltd. (31.3%), Canadian Energy Trust Pengrowth (8.4%) and Canada's Mosbacher Operating with the remaining 0.5%. SOEP is expected to be abandoned within the next few years due to declining production.

Deep Panuke

Encana Corporation discovered the Deep Panuke gas field in 1998. The field is located on the shelf in about 44 meters of water near the SOEP project. The reservoir produces about 300 MMcf per day of sour gas (018% hydrogen sulfide) with no liquids. Production began in 2013. Design capacity of the current project is 300 MMcfd. With estimated recoverable sales gas of 632 Bcf, Encana expects the project to continue for about 13 years.

Offshore Newfoundland and Labrador

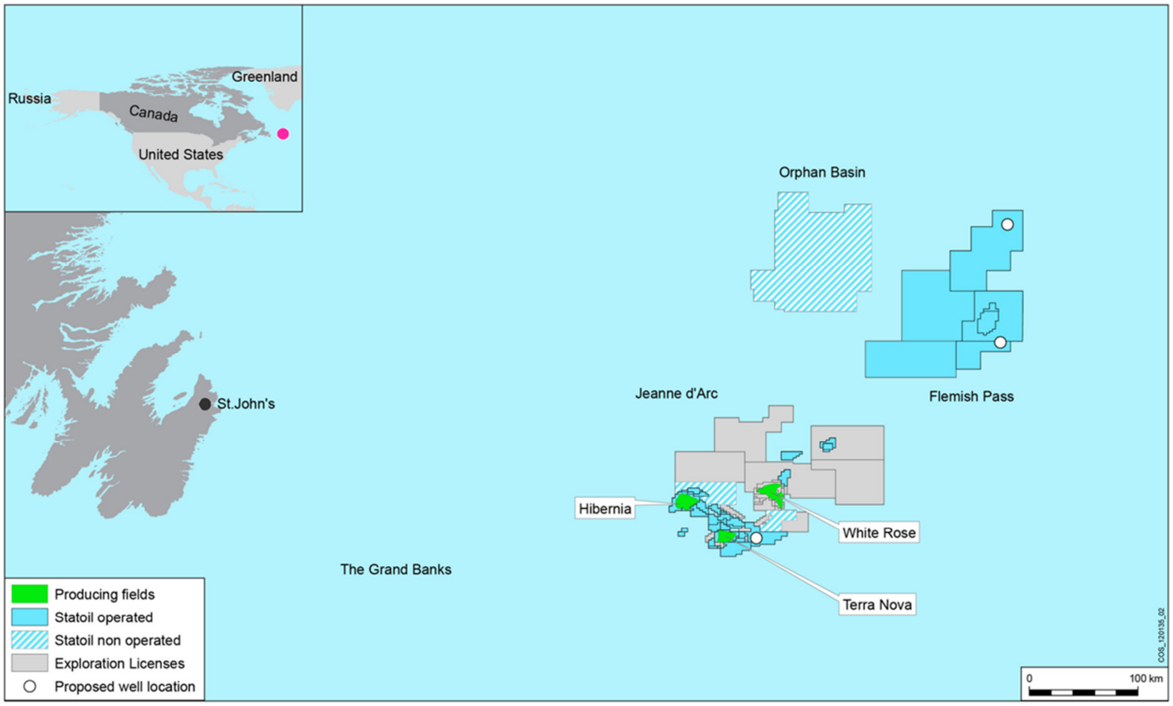
Offshore Newfoundland is the location of Hibernia, Terra Nova, White Rose, and North Amethyst oil fields. Hebron Field is scheduled to start in 2017. Hibernia is a 1.2 billion barrel field and the others are in the range of hundreds of millions of barrels each. While decades have elapsed since the discovery of these fields, recent discoveries have greatly increased industry interest in the area as a potential major petroleum province of unexpected significance. Several undeveloped gas discoveries are also present.

Production in 2013 from the area was approximately 230,000 barrels per day, down from 380,000 barrels per day in 2007. Gas production in 2013 (all re-injected or used at the platform) was 430 MMcf per day. Hibernia produces about half of the total oil and gas production for the region. There is no existing gas pipeline connecting the oil fields to onshore facilities.

The new oil discoveries are in the Flemish Pass area to the northeast of Hibernia, as shown in Exhibit 2-11. In 2013, Statoil reported that its new Bay du Nord field could yield 300 to 600 million barrels of oil. Two earlier nearby discoveries were also in the range of hundreds of millions of barrels. The area is about 300 miles east of St. Johns in 3,600 feet of water.

Because of this success, a very large amount of seismic data acquisition in taking place. This includes work by TGS and Petroleum Geo-Services, Shell, BP, and Nalcor Energy. Also, in 2013, the Canada-Newfoundland Offshore Petroleum Board put forth a new land tenure system that gives operators more time to evaluate data before making exploration decisions. This has apparently been a big factor in the renewed interest in the area.

Exhibit 2-11 Newfoundland Grand Banks/Flemish Pass Area



Source: Statoil **http://www.statoil.com/en/NewsAndMedia/News/2011/Pages/Nov2011licencesOffshoreNewfoundland.aspx**

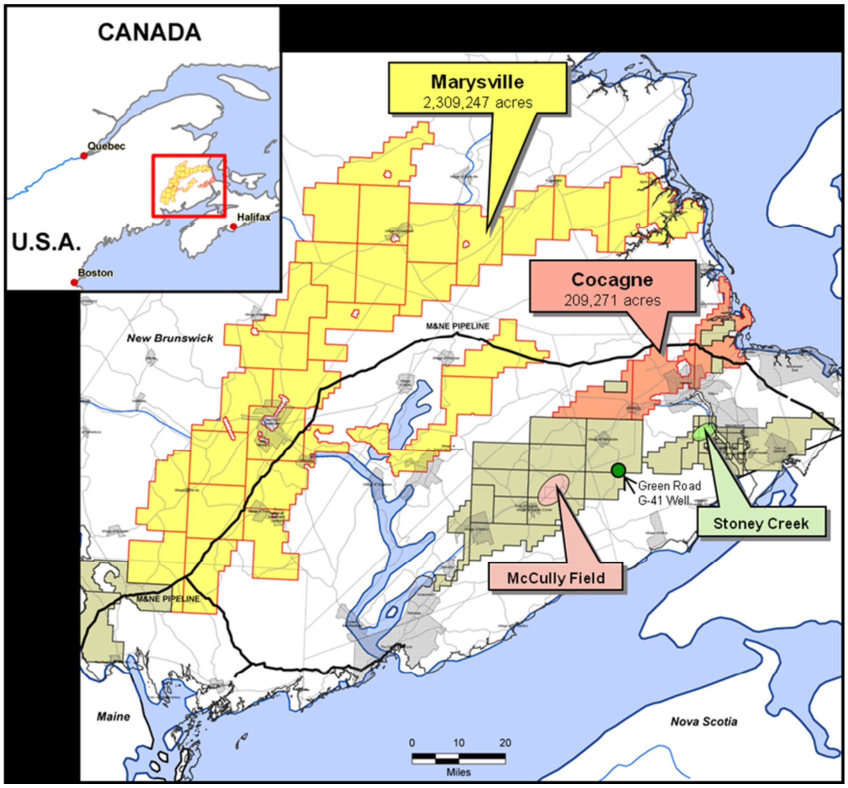
New Brunswick Onshore Gas

The onshore areas of Nova Scotia and New Brunswick have unconventional gas potential in the form of conventional gas, shale gas, "tight" gas, and coalbed methane. New Brunswick has seen about 40 wells drilled since 1990 and currently the province produces at about 11 MMcf per day of conventional/tight gas and had proved reserves of 135 Bcf at year-end 2012.[7,8] Gas production is trending downward. Most of the current production is from McCully Field (8 MMcf per day) but there is no commercial shale gas or coalbed methane production.

Exhibit 2-12 shows the locations of McCully Field, Stoney Creek Field and shale gas lease areas in New Brunswick. McCully Field is operated by Corridor Resources. Stoney Creek oil field is a minor deposit with negligible production. The area shown in yellow on the map is the Southwestern Energy leasehold for the Frederick Brook Shale play, which is not yet been proven commercial.

[7] CAPP website, http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/NewBrunswick.aspx
[8] CAPP province level reserves statistics.

Exhibit 2-12 New Brunswick Lease Areas and MNE Pipeline



Source: Southwestern Energy, 2014 investor slide.
http://www.swn.com/investors/LIP/latestinvestorpresentation.pdf

The McCully gas field was discovered in September 2000 with estimated initial recoverable reserves of 121 Bcf.[9] This is a conventional or tight gas reservoir. Published provincial reserves total 135 Bcf and are mostly from this field. Corridor is said to have plans to double McCully production over the next few years. [10]

Corridor has been testing the Frederick Brook Shale in McCully Field since 2006. This is also the formation that Southwestern is interested in to the north. Eleven wells had been drilled in McCully as of 2012 including two horizontal tests.[11] One vertical well has been producing at the low rate of 200 Mcfd since 2008. The wells have been drilled to about 12,000 feet. Fractured, slightly over-pressured shale formation was found with excellent gas shows. Total organic content is said to be 1 to 2% (slightly low) and thermal maturity is said to be 1.5 to 2.5 (dry gas window). Gross thickness is 3,000 feet. However, neither of the horizontal wells established production.

GLJ Petroleum Consultants in 2009 assessed 67 Tcf of gas in place in the Frederick Brook. In-place gas content was assessed at 625 Bcf per square mile, which is very high, but this is mostly due to thickness.[12] ICF assessed the Frederick Brook Shale as having about 50 Tcf of "unrisked" gas in place over an area of

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[9] CERI, November, 2011 Report,
http://s3.amazonaws.com/zanran_storage/www.ceri.ca/ContentPages/2535173201.pdf
[10] Corridor Resources 2013 Year End Reserves – GLJ Petroleum Consultants.
[11] Macquarie investor report on Corridor Resources, July, 2012
[12] Macquarie investor report on Corridor Resources, July, 2012

120 square miles. Determination of recoverable resources remains very uncertain due to the lack of well production information in any part of the play.

Nova Scotia Onshore Unconventional Gas

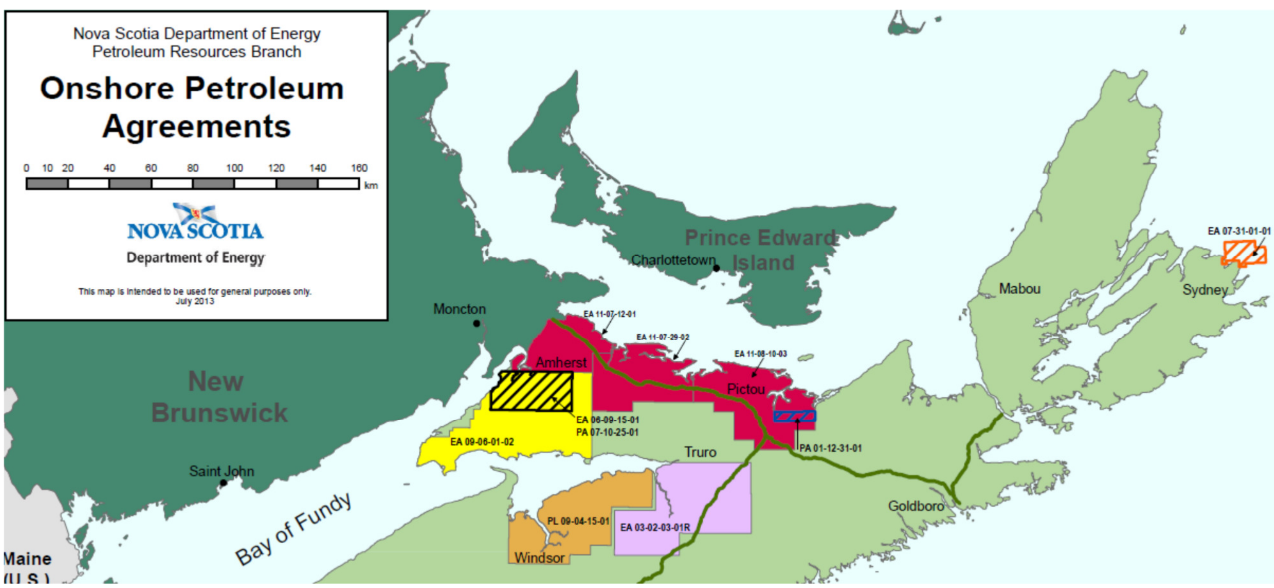
There is currently no reported Nova Scotia onshore gas production or proved reserves.

Elmworth Energy (a subsidiary of Triangle Petroleum) has been exploring Frederick Brook shale gas potential in Nova Scotia, and has drilled vertical several tests in the Windsor Block (shown in tan in Exhibit 2-13) with no commercial success.[13] Initial drilling was in 2007. The firm has a 10 year production lease to develop the resource. ICF currently does not include an assessment of the Frederick Brook Shale in Nova Scotia.

In April 2012 Nova Scotia government implemented a pause hydraulic fracturing through the summer of 2014 pending additional studies of the potential impacts. This moratorium was extended indefinitely in late 2014. The government cited environmental opposition and the need for time to develop regulations.[14]

There are several lease concessions for coalbed methane in Nova Scotia. These are shown in Exhibit 2-13 with a diagonal pattern. Operators include East Coast Energy in the Stellarton area, Donkin Tenements in the Sydney Basin/Cape Breton area, and Stealth Ventures in the Springhill area. No commercial CBM production has been established but operators report potentially commercial levels of gas in place. Stealth Ventures hired Sproule Consultants to estimate their coalbed methane resources and the recoverable resource in their lease areas was estimated at 1.6 Tcf.[15] ICF has assessed a recoverable CBM resource of 4 Tcf in Nova Scotia.

Exhibit 2-13 Nova Scotia Onshore Petroleum Agreement Areas



Source: Nova Scotia Department of Energy, July 2013 (latest map)
http://energy.novascotia.ca/sites/default/files/Onshore-Offshore-Rights%20map.pdf

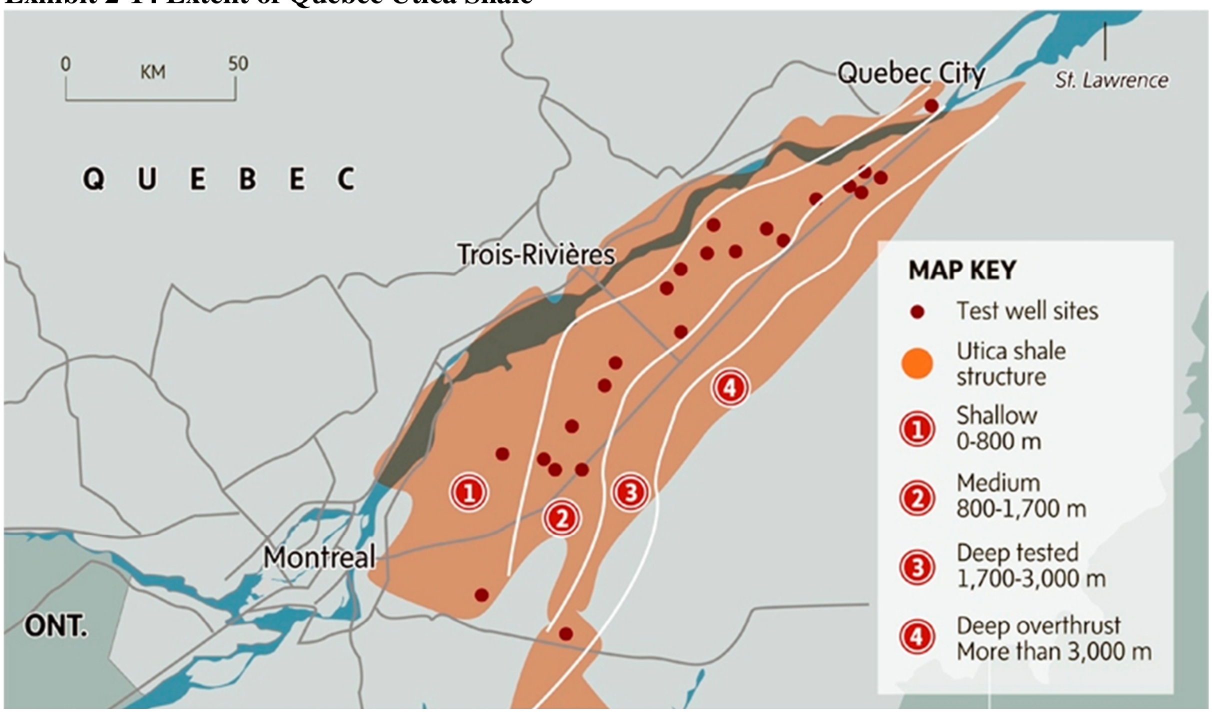
[13] http://www.naturalgasintel.com/articles/99883-nova-scotia-moves-to-continue-fracking-moratorium
[14] http://www.naturalgasintel.com/articles/99883-nova-scotia-moves-to-continue-fracking-moratorium
[15] Nova Scotia 2009 onshore prospect profile

Quebec Utica Shale

The province of Quebec currently has no reported gas production or proved reserves. The Utica Shale formation, which produces gas from several hundred horizontal gas wells in Ohio, is present in the Quebec Lowlands between Montreal and Quebec City. As shown in Exhibit 2-14, the formation includes areas of shallow, potentially more liquids-rich areas to the west and deeper, dry gas areas to the east. There is no current drilling activity due to a moratorium on drilling. Quebec was the first province in Canada to impose a fracking moratoria in 2011, which continues to be in place.

Leaseholders include Junex, Talisman, Questerre, and Forest Oil. Junex stated that a total of 30 wells have been drilled since 2006, with 11 horizontals,[16] and that their acreage has 49 Tcf of gas in place, which may imply a multi-Tcf recoverable resource. ICF has assessed the Quebec Utica at 9 Tcf of risked recoverable potential, with potentially several Tcf of economic resources, should viability be established.

Exhibit 2-14 Extent of Quebec Utica Shale



Source: Questerre Energy http://www.questerre.com/en/shale-gas/

ICF Assessment

After several decades with relatively minor new oil and gas developments, Atlantic Canada is now the focus of a large amount of interest and activity, primarily driven by deep water oil plays. It is possible that in the coming 5 to 10 years, the region will emerge as a major oil and associated gas province, which has implications for potential LNG export supply. While there has been little encouragement in the area of shale gas development, there remains a possibility of it becoming a significant contributor to gas production as well.

[16] Junex Petroleum http://www.junex.ca/home

Exhibit 2-15 and Exhibit 2-16 summarize the current ICF assessment of discovered and undiscovered gas resources in Atlantic and Eastern Canada, respectively. Remaining discovered resources total 1.75 Tcf and include the remaining reserves at SOEP, Panuke, the Eagle discovery, and McCully field in New Brunswick. (The gas discoveries in offshore Labrador are not included here.)

Exhibit 2-15 ICF Summary of Eastern Canada Discovered Gas Resources (Bcf)

Play	Province	Location	Initial Recoverable (Public Data)	Initial Recoverable (ICF)	Remaining Recoverable (ICF)
SOEP	Nova Scotia	Offshore	3,188	2,250	500
Deep Panuke	Nova Scotia	Offshore	892	690	690
Eagle Gas	Nova Scotia	Offshore	488	488	488
McCully	New Brunswick	Onshore	121	121	71
Total discovered			**4,689**	**3,549**	**1,749**

Source: Future of Natural Gas Supply, Department of Energy, Nova Scotia.

Exhibit 2-16 ICF Summary of Eastern Canada Unproved Gas Resources.

Eastern Canada Unproved Gas Resources	Recoverable Tcf Dry Gas
Onshore	
Growth in Existing Fields	0.2
New fields	1.7
Coalbed methane	3.9
Shale	
New Brunswick Frederick Brook	1.3
Quebec Utica	9.0
Onshore Total	**16.1**
Offshore	
Stranded Fields	15.0
Growth in Existing Fields	0.4
New fields	
Nova Scotia Shelf	7.8
Nova Scotia Deepwater	22.1
Newfoundland Shelf	5.6
Newfoundland Deepwater	3.3
Labrador	27.3
Maritimes	1.7
Offshore Total	**83.0**
Eastern Canada Total	**99.1**

Source: ICF International

Undiscovered resources include shale gas, coalbed methane, and offshore conventional gas. The Frederick Brook shale has 67 Tcf of total resource in place and is assessed at 1.3 Tcf of recovery assuming current technology. Should the operators establish commerciality in the shale play, the ICF assessment would likely increase substantially. Coalbed methane recovery has been assessed at approximately 3.9 Tcf. This assessment was based upon older public domain assessments as reviewed in the 2003 U.S. National Petroleum Council North American gas study.[17]

For Nova Scotia offshore, ICF's new field resource base is approximately 30 Tcf. Recently, ICF reviewed the Nova Scotia Play Fairway Analysis, which was a highly detailed 2011 evaluation of offshore potential funded by Nova Scotia. This study concluded that there is 120 Tcf of undiscovered gas in place in the Nova Scotia offshore, much of which is in the deep water. If one assumes a recovery factor of 60 %, this implies a recoverable resource of 72 Tcf, or 42 Tcf higher than the current ICF characterization in the model. However, these new resources are mostly in the deep offshore parts in the Scotian Slope and they will be more expensive to produce.

Opposition to hydraulic fracturing of gas and oil bearing shales appears to be considerable in Atlantic Canada. Nova Scotia has announced government will introduce legislation to "to prohibit high volume hydraulic fracturing for onshore shale gas."[18] Newfoundland has announced a moratorium on hydraulic fracturing onshore and offshore pending a study of the effects.[19] And the new Liberal government in New Brunswick has indicated it will institute a ban on hydraulic fracturing.[20] The general sense is that there will be little opportunity for exploiting the shale resources that are in these provinces in the immediate future.

In 2013, ICF prepared a report for the Nova Scotia Department of Energy, "The Future of Natural Gas Supply in Nova Scotia."[21] One of the conclusions of that report was that the SOEP is expected to decline in the face of challenging economics. The forecast decline is presented in Exhibit 2-17 below. The exhibit shows the initial decline of SOEP production from 2010 and the effect of new production from Deep Panuke coming online in 2014 and falling off dramatically thereafter. While this graph shows an asymptotic decline in production, it is more likely that production would be shut down at some point when producers decide that the project is no longer viable. Some have suggested that this could be as early as 2018 for SOEP.

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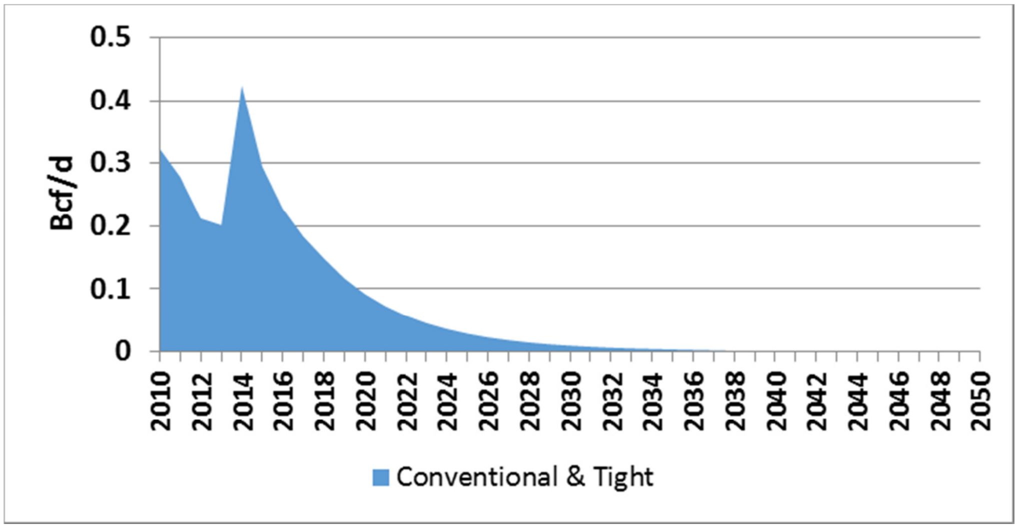
[17] National Petroleum Council, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," Washington, D.C., 2003. http://www.npc.org/reports/ng.html
[18] See http://novascotia.ca/news/release/?id=20140930002. Accessed October 19, 2014.
[19] See http://www.thetelegram.com/News/Local/2013-11-04/article-3465585/Moratorium-on-fracking-announced-by-Newfoundland-government/1. Accessed October 19, 2014.
[20] See http://globalnews.ca/news/1582187/fracking-moratorium-a-top-priority-promises-gallant/. Accessed October 19, 2014.
[21] See http://novascotia.ca/news/release/?id=20130731007. Accessed Sept. 9, 2014.

Exhibit 2-17: ICF Forecast Eastern Canada Production



Source: ICF International

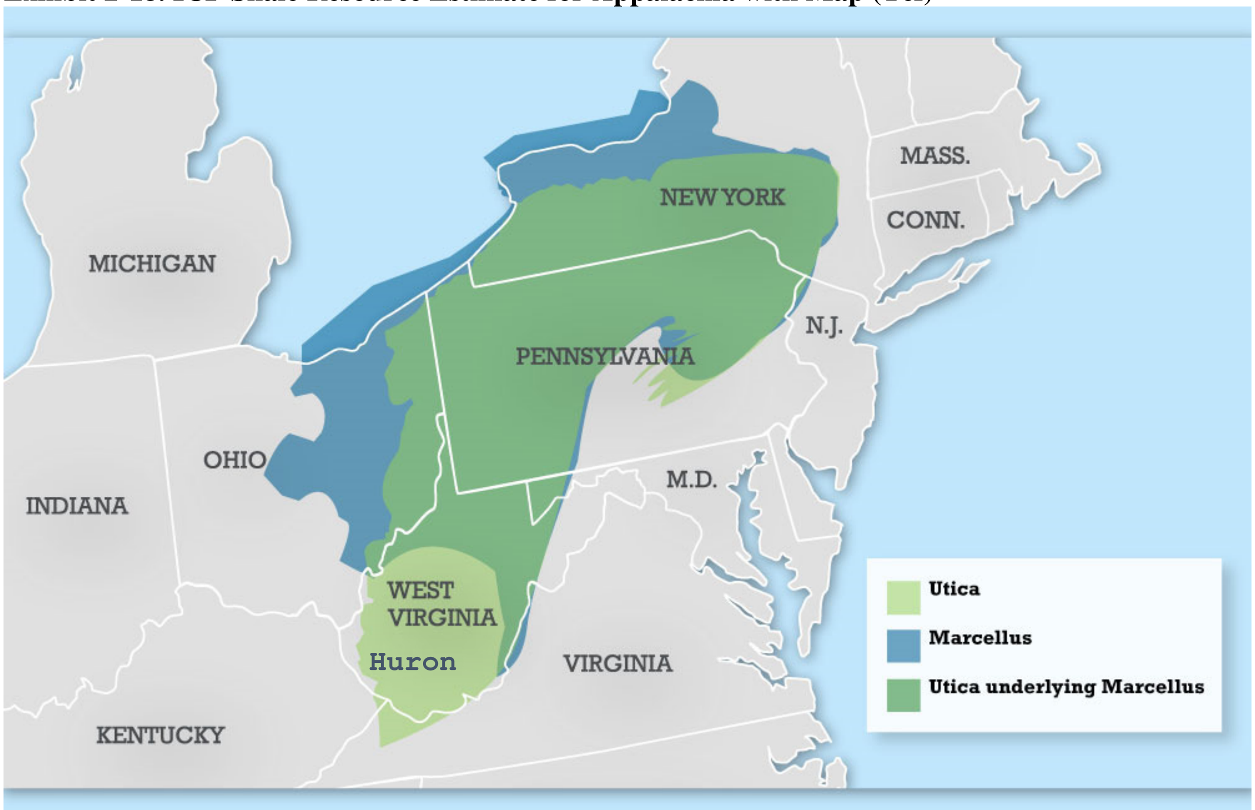
The challenge for Atlantic Canada producers is finding sufficient market to justify the investment in new production from the potential resources described above. The local market is small and the nearest large market, the Northeastern United States is supplied with low-cost shale gas from the Marcellus. At the prices that Marcellus gas can be delivered into the Northeast, producing gas for the same market from a challenging offshore environment and from the smaller onshore unconventional plays is difficult to justify economically. Thus, in ICF's report to the Nova Scotia Department of Energy, one recommendation was to evaluate options for bringing gas into Atlantic Canada via New England and the reversal of Maritimes and Northeast Pipeline.

2.3 United States Supply – Marcellus/Utica

The size of the Marcellus and Utica resource were shown above. Exhibit 2-18 provides additional detail on the organization of the resources. The Marcellus will continue to be the most dominant natural gas play in North America. Gas production from the area has grown from nothing in early 2007 to an average of nearly 15 Bcf/d in 2014, equaling roughly 20 % of the total gas production in the U.S. We project that the area's production will continue to grow at a robust rate of between 2 and 3 Bcf/d per year, equating to an annual growth rate of roughly 16 % over the next few years.

The Marcellus Shale formation is located close to market areas in the Northeast and is situated in the middle of existing pipeline corridors. Five major long haul interstate pipelines cross through the formation, and they can also supply gas to Atlantic Canada. All of these pipelines have access to premium price markets along the East Coast, and can potentially expand takeaway capacity to accommodate growing Marcellus Shale gas production.

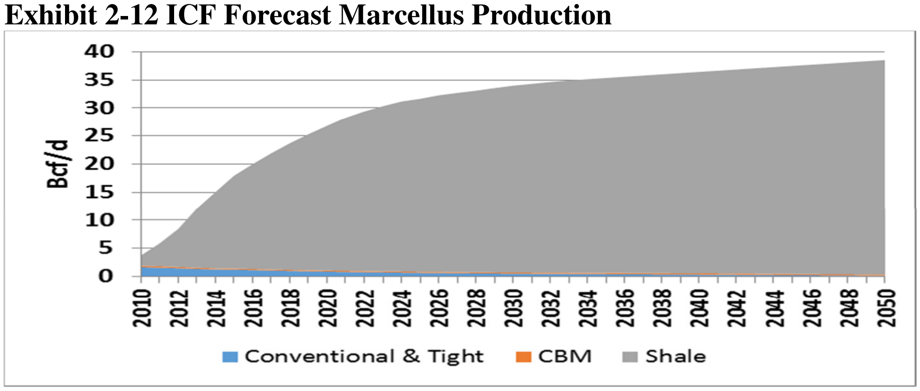
Exhibit 2-18. ICF Shale Resource Estimate for Appalachia with Map (Tcf)



Resources	Resource Estimate (Tcf)
Appalachian Vertical Low Pressure	15
Appalachian Marcellus	698
Appalachian Huron	35
Utica PA OH WV	266
NY Utica	56
Total	1,070

Source: ICF International. Map: http://marcelluscoalition.org

Exhibit 2-12 ICF Forecast Marcellus Production



Source: ICF International

2.4 Summary

The North American resource base has grown significantly in recent years thanks to advances in shale gas development. The overall resource base for North America, assuming current technology, is over 4,000 Tcf. A significant amount of this resource is in the U.S. Northeast, in the Marcellus and Utica basins of Appalachia.

Exhibit 2-19. Resources to Meet U.S. and Canadian Consumption Forecasts with and without AC LNG Inc. Export Project

Current Resources in Tcf		2014	2035	2050	2014	2035	2050
		Years of Supply w/o AC LNG			Years of Supply w/ AC LNG		
Total North American Resources	4,072	133	90	85	133	88	84
Total Canadian Resources	878	238	140	131	238	124	118

Source: ICF International

Note: Years of supply calculated by dividing current resources by forecast consumption, including exports of LNG and pipeline gas, in the years shown. No adjustments are made for resource appreciation.

The resource base in Eastern Canada is limited, and without significant new discoveries, production there is expected to decline below the requirements of local demand. However, the Middle Melford terminal stands to benefit from the vast low-cost resources of the Marcellus, as numerous pipeline projects come online to enable easy access to this resource. The WCSB and Eastern Canadian gas supplies may contribute a small portion of the terminal's gas needs. One way to assess the adequacy of the available resources is to compare the estimated life of the gas resource base with the current and projected future demand for gas with and without the LNG export project. Exhibit 2-19 shows that there is sufficient resource base to meet a large part of the Eastern U.S. and Eastern Canadian demand with Marcellus and Utica shale resources.

3. Supply/Demand Market Outlook

In the previous section we reviewed the resource base and production outlook for North America and the key basins relevant to the Middle Melford supply issue. In this section we present our analysis of the gas market outlook and supply demand balance.

AC LNG has indicated that it will seek to supply its LNG export project with Canadian supplies. At the same time, gas from the Marcellus shale will also be an option. Because the Canadian and U.S. gas markets are integrated into a single North American market, ICF's assessment of the "surplus gas" that is available for Canadian gas consumers include both Canadian and U.S sources. In this section, we begin with an overall assessment of the North American gas market and then analyze relevant regional gas supply and gas demand in both Canada and the United States. We also address the implications of the supply and demand balance for interregional gas pipeline flow. his approach will show how there is sufficient gas resource and production in the Marcellus to meet not only the expected demand for Eastern U.S. and Canadian gas consumers, but also the LNG export demand from Middle Melford LNG. We show that Canadian consumers, particularly in Nova Scotia, will benefit from having an anchor LNG export demand for gas in Nova Scotia.

3.1 Analytic Approach Outlook

ICF's supply and demand analysis is based on ICF's proprietary Gas Market Model (GMM®). The GMM® is a nationally recognized, comprehensive, detailed supply and demand equilibrium model of the North American gas market. The key features of the model are described below:

- The model has detailed representations of regional supply with data on production costs, ultimate recoverable reserves, per-well decline rates, and total production capabilities. The supply module also incorporates factor adjustments for technology improvements that tend to reduce the cost of production. Supply is made available to the model network solution at supply nodes that correspond to the geographic locations where supply is produced.
- The demand module represents the gas-consuming sectors (residential, commercial, industrial, and power). Each sector is characterised by price elasticity, alternative fuel costs, weather sensitivity, and technology trends that contribute to enhanced efficiencies. (The power sector is more detailed and incorporates input from ICF's Integrated Planning Model (IPM®) to represent the generation fleet and plant dispatch economics. Industrial demand incorporates heat and process uses as well as feedstock uses of gas.) Demand is represented at demand nodes corresponding to geographic market centers and that have the full cross-section of demand from the consuming sectors characteristic of those locations. Demand is represented monthly over the course of the year where weather is based on a 20 year "normal" pattern of heating degree days (HDD).
- The model contains a network of gas pipeline links that reflect pipeline capacity and costs of moving gas, including fuel costs. The costs of flow over the links increases with throughput. The links connect supply nodes with demand nodes.
- Storage is represented in the model on a regional basis, where during off peak periods gas is delivered into storage to be available in the on-peak (winter) periods. Storage use is an economic dispatch decision that depends in part on the price spread between injection volumes in the off peak period and withdrawal in the on-peak period.

- The model also includes LNG import and export facilities. Export volumes are based on estimates made outside the model of world demand and supply for LNG and the costs of North American LNG relative to other sources. LNG exports are stipulated in the model set-up.
- The model operates by equilibrating supply and demand across the pipeline network on a monthly basis for a forecast period. The model generates gas production and gas consumption forecasts, shows pipeline utilization and flows, and storage operations. The GMM® forecasts gas supply, consumption, and prices at over 120 supply and demand market nodes, including Henry Hub, Louisiana; AECO and Empress; Chicago; Dawn, and the major border hubs (e.g., Niagara, Waddington, Sumas, and Kingsgate). The model reports consumption by sector, by month. (A more detailed description of the GMM® is found in Appendix A.)
- The model operates through 2035. Beyond 2035, ICF has estimated demand, supply, and prices based on trends of the final years of the forecast and judgement on future potential developments.

The August 2014 Base Case incorporate the following key underlying assumptions:

- Historical U.S. GDP growth rates are based on the U.S. Bureau of Economic Analysis's (BEA) estimates. Economic growth rates for the balances of 2014 and 2015 are based on the Wall Street Journal's June 2014 Survey of Economists; for the balance of 2014 we assume 3.0% (annualized) growth, and for 2015 we assume 2.9% growth. From 2016 forward, we assume U.S. GDP grows at 2.6% per year. Historical Canadian GDP growth is based on estimates published by Statistics Canada; for the forecast, we assume we assume Canadian GDP grows at 2.5% per year from 2014 forward.
- Demographic trends are consistent with trends during the past 20 years. U.S. population growth averages about 1% per year. Canadian demographic trends are consistent with historical trends, and based on information from Statistics Canada.
- For power sector demand, ICF's Base Case reflects one plausible outcome of U.S. Environmental Protection Agency's (EPA) proposals for major rules that have been drawing the attention of the power industry – these include Mercury & Air Toxics Standards Rule (MATS), water intake structures (often referred to as 316(b)), and coal combustion residuals (CCR, or ash). It also includes a charge on CO_2 reflecting the continuing lack of consensus in Congress and the time it may take for direct regulation of CO_2 to be implemented. The case generally leads to retirement and replacement of some coal generating capacity with gas generating capacity. In Canada, power generation load growth is consistent with current trends. In Ontario, all the coal plants are already retired as of 2014, and future gas growth is consistent on overall electricity load growth and some nuclear retirements. The Canadian government has enacted legislation phasing out coal fired power plants ("Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations", SOR/2012-167 August 30, 2012) at the end of their normal lives).[22] For other provinces, coal capacity is yet to be retired, and ICF assumes coal capacity does retire gradually over time.
- In terms of power plant mix: we assume increased generation from renewables to meet state renewable portfolio standard (RPS) benchmarks, coal generation decreasing, and other forms of

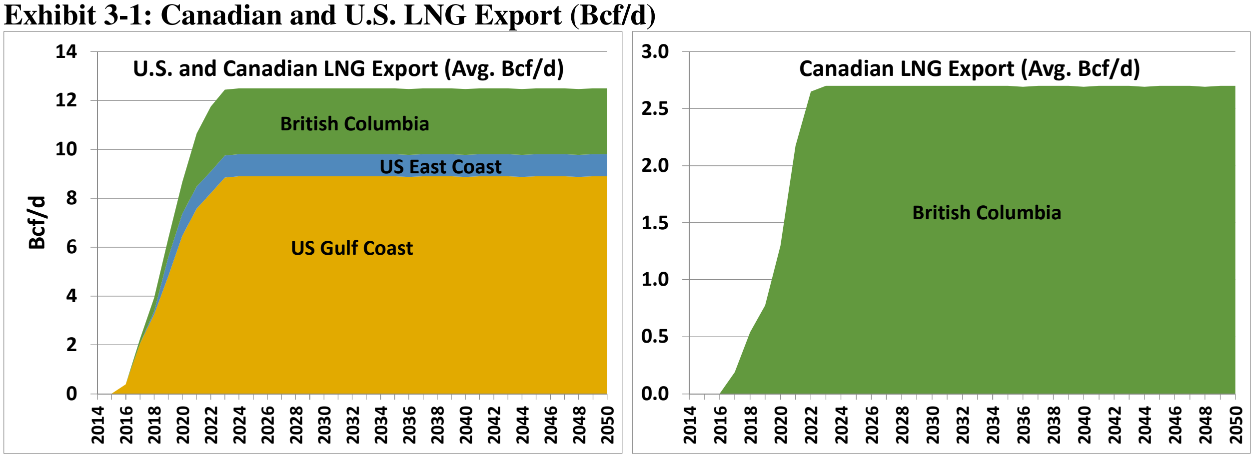
[22] www.gazette.gc.ca/rp-pr/p2/2012/2012-09-12/html/sor-dors167-eng.html. Accessed October 15, 2014.

non-gas generation remaining fairly flat. Gas generation grows to fill the gap between electric load and the total amount of generation from other sources.

    - Assumes a maximum lifespan of 60 years for all nuclear units; this results in 15 GW of nuclear retirements between through 2035.

- Adoption of demand side management (DSM) programs and conservation and efficiency measures continues, consistent with recent history.
- Weather in forecast months (beginning April 2014) is assumed to be consistent with the 20-year average of heating and cooling degree days.
- Gas supply development is permitted to continue at recently observed activity levels – no significant restrictions on permitting and fracturing are introduced beyond current restrictions.
- No significant hurricane disruptions are forecasted to natural gas supply.
- No Arctic projects (specifically no Alaska and Mackenzie Valley gas pipelines) are included for gas to be marketed in North America.
- Near-term midstream infrastructure development is based on project announcements. Unplanned projects included when market signals need of capacity, and there are no significant delays in permitting and construction.
- LNG Exports: ICF's forecast for total U.S. and Canadian LNG exports rise to 12.5 Bcf/d by 2023. U.S. Gulf Coast exports are expected to reach 9 Bcf/d. U.S. East Coast LNG exports include Cove Point and Elba Island. Western Canadian LNG exports are expected to reach 2.7 Bcf/d by 2022. We hold these levels constant over the period of analysis. See Exhibit 3-1 below, and additional discussion of LNG exports is provided below.
- Mexican Exports: U.S. gas exports to Mexico are expected to grow, as new pipelines are added to serve growing power load south of the border. While recent legislation in Mexico opens this possibility of increased investment in their domestic oil and gas production, it is likely that Mexican demand growth will continue to outpace domestic production. Therefore, we exports from the U.S. to Mexico will increase to 1.8 Tcf per year (approximately 5 Bcf/d) by 2025.

Exhibit 3-1: Canadian and U.S. LNG Export (Bcf/d)



Source: ICF International

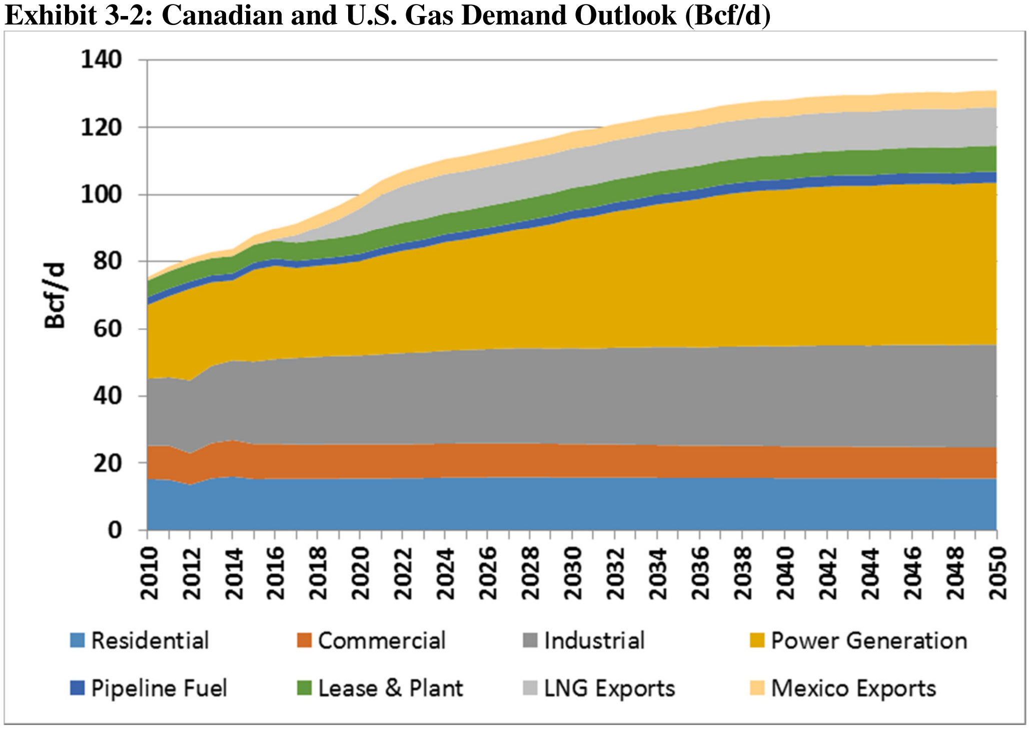
In the following subsections, we discuss ICF's demand projections first, as that is an input in our model, followed by a discussion of supply projections, which rely on price projections and production of gas based on the supply cost curves and transport costs. ICF's price projections are discussed next, and the price projections are a result of equilibrating the supply-demand balance at each node in the model. The resultant natural gas flows projected from the model are then discussed. Finally, we discuss the key pipeline infrastructure developments that are necessary to bring natural gas into Nova Scotia for export from the Middle Melford LNG facility.

3.2 Gas Demand Outlook

ICF forecasts gas demand by consuming sector by region. Gas demand in each sector is a function of the major drivers of demand. These include for the residential sector population growth, GDP, gas price, and weather, expressed in heating and cooling degree days for the region. Commercial demand is driven largely by GDP growth, price, and weather. Industrial demand forecasts also rely on GDP, but also incorporate economic fuel choice by industrial subsector (boiler fuel, process fuel, and feedstock). Power sector demand for gas is determined by the demand for electricity and the operation of the generation fleet to replicate generating fuel choice by plant type, plant heat rates, and fuel pricing decisions. Over the long term, the model adjusts the generating fleet mix in response to trends in new plant builds, retirements, and relicensing of nuclear plants. The GMM® solves for supply and demand simultaneously at the regional prices where the markets clear.

ICF's overall U.S. and Canadian gas demand outlook is presented in Exhibit 3-2. ICF forecasts substantial growth in gas consumption supported by a large resource base and production economics that will make gas a desirable fuel. By 2050, North American consumption is projected to increase by nearly 50 Tcf, an average growth rate of about 1.2 % per year. Driving the consumption growth will be the power sector, which grows to nearly 48 Bcf/d, based on expectations that gas will retain its current price, operating and environmental advantages relative to coal, and nuclear plant retirements will be replaced with gas.

Exhibit 3-2: Canadian and U.S. Gas Demand Outlook (Bcf/d)



Source: ICF August 2014 Base Case.

There are several important observations to make about this forecast.

- Residential and commercial demand will remain flat to declining under normal weather assumptions. This is due to DSM and general efficiencies in building envelope design.
- ICF projects strong industrial gas demand for petrochemical feedstock as well as for manufacturing. This demand will be centered in Alberta and the southern states (the traditional location of petrochemical manufacturing) but also in the Mid-Atlantic.
- Power demand will be the largest growth area in the North American market as coal generation declines and is replaced with natural gas. New environmental regulations in the United States will add to coal generation costs and lead to the retirement of many older coal units. Beyond 2035, gas will replace nuclear power plants with licences that will begin to expire after 2025. In addition, natural gas-fired generation will complement renewable energy by providing firming capability to renewables' intermittent generation profiles.
- We expect exports to Mexico will grow but level off by the 2030s and even decline thereafter as Mexican production begins to increase in response to reforms in the Mexican energy sector that could bring on more domestic Mexican gas.
- LNG Export forecasts are a major unknown. As mentioned above, our forecast is that U.S. LNG exports from the Gulf Coast and East Coast of the U.S. are also expected to increase to 9.8 Bcf/d by 2023. We forecast Canadian exports from the West Coast at 2.7 Bcf/d. The export volume included in our modeling is based on approved LNG projects that have publicly announced contracts with buyers, and ICF's judgement on upcoming projects. ICF has estimated that 2.7 Bcf/d of LNG exports, which is equivalent to four LNG trains, is the median value for LNG exports from the Canadian West Coast. Beyond that date and through the end of the forecast period we have not increased LNG exports from 2.7 Bcf/d, due to long term uncertainty about LNG demand and competition from other sources of LNG, particularly from Africa and continental sources of gas in Asia that can meet expected demand in China, India and elsewhere. The inclusion of Middle Melford could increase this forecast to 5.0 Bcf/d by 2024.

  ICF is aware that the NEB has approved a higher level of exports, and that the proposals in the United States are for much higher levels of exports. As of November 2014, approximately 24.4 Bcf/d of export authorizations have been made in Canada for West Coast projects (including two U.S. projects sourcing gas from Canada) and another 9.3 Bcf/d of export authorizations for non-FTA countries have been made in the United States.[23] (Appendix B lists all of the approved projects in Canada and the U.S., including both FTA and non-FTA approved projects.)

  However, ICF believes that many of the proposed projects, even those that have received regulatory approvals, will not become commercial.[24] Theoretically, there is sufficient gas supply

[23] This estimate consists of total authorizations of exports to non-Free Trade Agreement (non-FTA) countries granted by the U.S. Department of Energy.

[24] In neither the United States nor Canada does approval of an export permit provide any assurance that a project will come to fruition. Export permits are necessary but not sufficient to make a project successful. Commercial considerations such as securing long-term off-take contracts, project design, project costs, adequate feed gas, other permits (provincial/state and local), and financing must be resolved before a project can proceed.

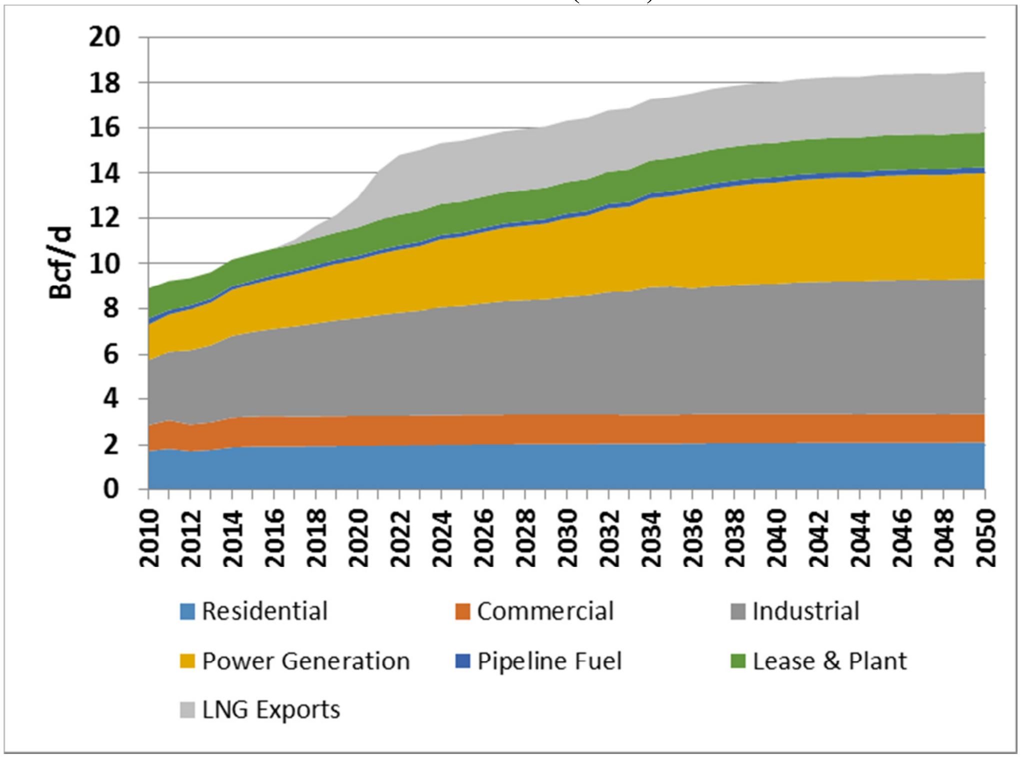
in Canada (and the United States) to support a large number of the approved LNG export projects. However, construction and operation of these projects is dependent on obtaining long term commercial contracts with LNG buyers and gas producers, approval of liquefaction facilities, obtaining pipeline capacity, and construction of new pipelines (especially in British Columbia), among other elements. Furthermore, total infrastructure costs for developing LNG exports in British Columbia (terminals plus pipeline costs) are high relative to U.S. Gulf Coast terminals.

If a large fraction of these projects do come to fruition, then gas prices would have to rise to support such levels of production, and on the demand side, LNG buyers need to be willing to pay higher prices.

Turning to Canadian demand, Exhibit 3-3 presents ICF's forecast of Canadian gas consumption through 2050. ICF forecasts a significant increase in Canadian consumption between now and 2050, including net LNG exports.

- Industrial demand will lead the expansion as more gas is expected to be used in the oil sands as well as in industrial applications in Alberta and to some extent in Ontario and Quebec, the latter made possible by access to low cost gas from the Marcellus. From a current level of 3.5 Bcf/d, industrial consumption could reach nearly 6 Bcf/d by 2050.
- Power consumption of gas will also grow substantially, mostly in Alberta and Ontario both due to the economy and the winding down of coal generation. From a current level in 2014 of 1.9 Bcf/d, by 2050 gas consumption will reach approximately 4.6 Bcf/d.
- Residential and commercial use will remain flat at approximately 2 Bcf/d as DSM programs and efficiency improvements take hold over time.
- ICF forecasts that British Columbia's LNG exports will increase to 2.7 Bcf/d over the forecast period, remaining at that level. Again, our reasoning is that the demand for LNG world-wide and competition from other sources will dampen export growth from North America.

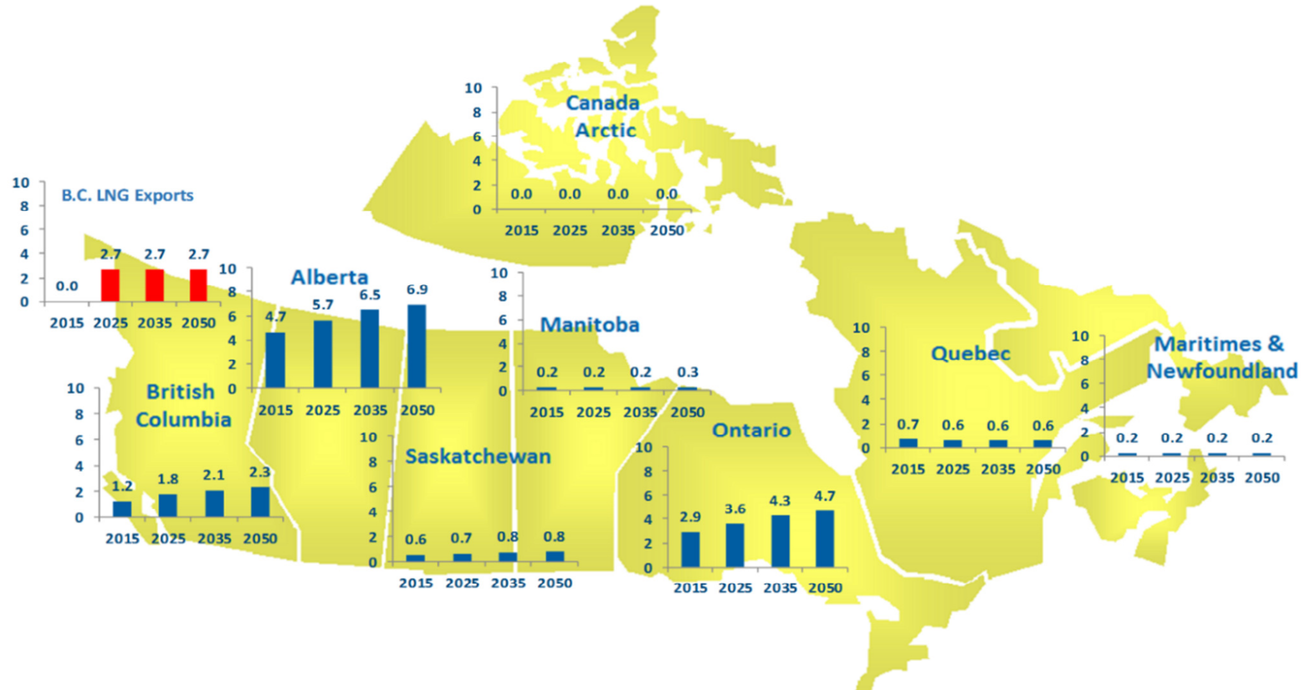
Exhibit 3-3: Canadian Gas Demand Outlook (Bcf/d)

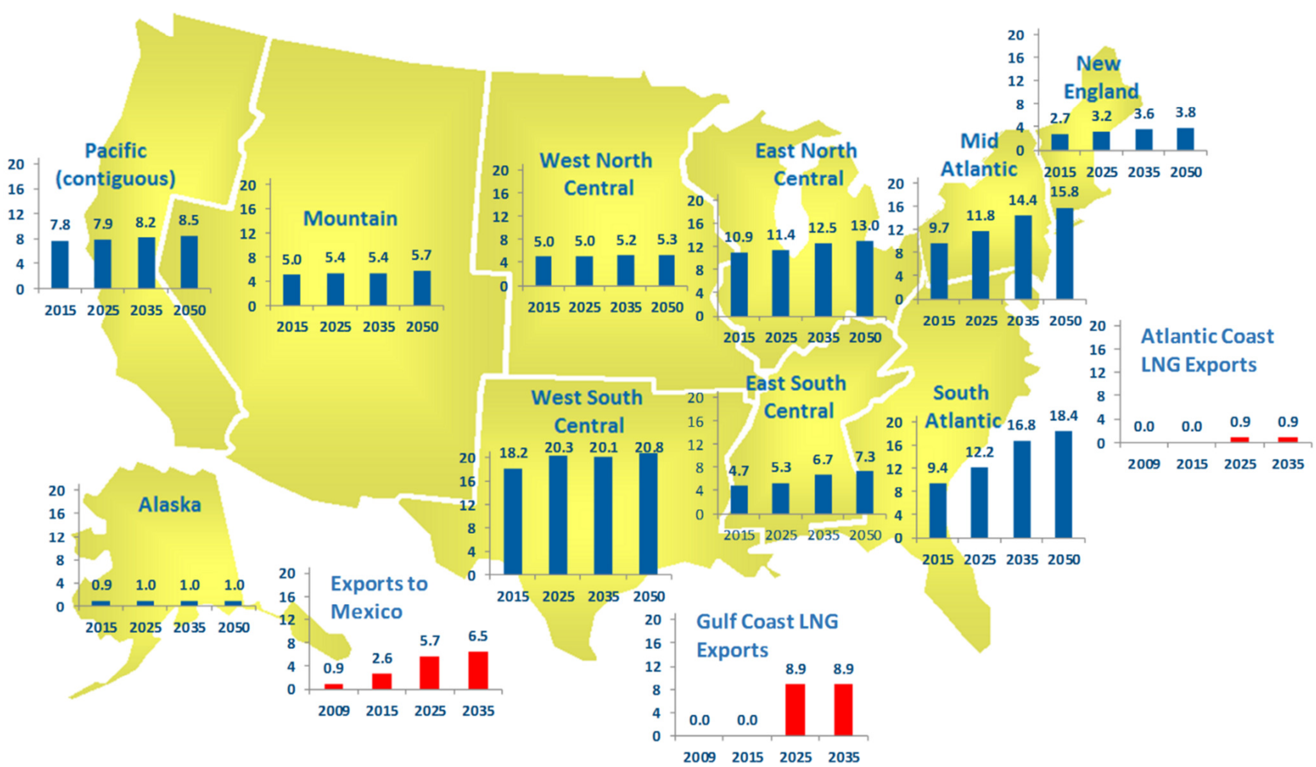


Source: ICF International

A regional view of the gas consumption is shown in Exhibit 3-4. The largest increases occur across the U.S. south, driven by both power and industrial demands. Significant growth will also occur in the Mid-Atlantic and East North Central, mostly driven by power sector growth. ICF also forecasts growing markets for natural gas in Canada, with the strongest growth occurring in Alberta and British Columbia, driven by the oil sands developments and the retirements of coal-fired power generation. Ontario consumption, reaching 4.3 Bcf/d by 2035, is primarily driven by growing gas use to replace retired coal generating units. Ontario consumption is expected to rise to 4.7 Bcf/d by 2050. Note that the regional gas demand forecasts shown in Exhibit 3-4 are for domestic North American demand, and does not include LNG exports. LNG exports are separately shown in the exhibit.

Exhibit 3-4: Regional Canadian and U.S. Gas Demand in the U.S. to 2050 (Bcf/d)

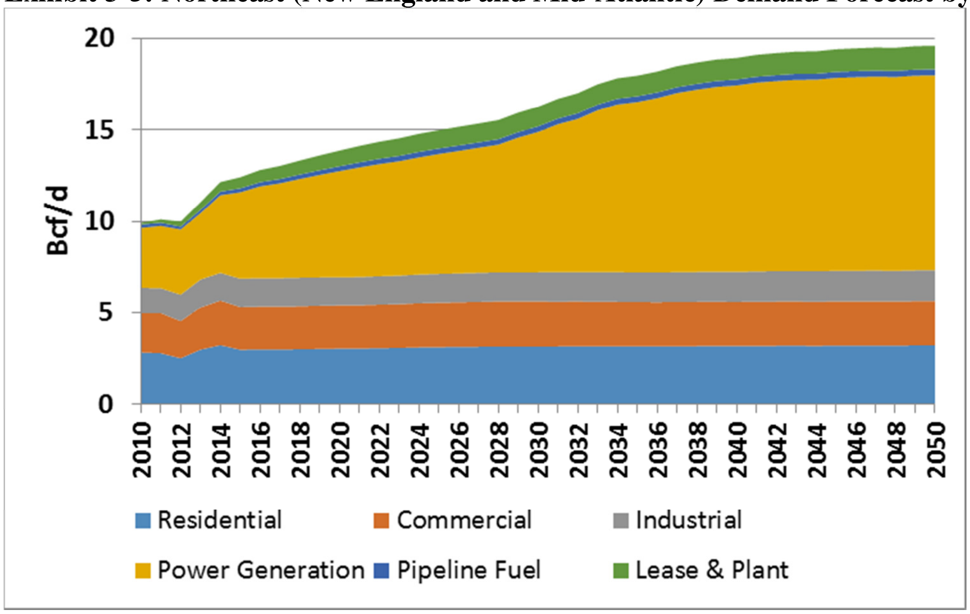




Source: ICF August 2014 Base Case

Because of the interest in Marcellus as a source of supply for Middle Melford and the logistics of moving gas into Atlantic Canada, we have included a forecast of northeastern U.S. and Atlantic Canadian demand. ICF expects most of the gas demand growth in the U.S. Northeast to come from power generation (see Exhibit 3-5). The U.S. Northeast is assumed to include New England and Mid-Atlantic regions, and the power generation demand in this region is expected to grow an average of 3.2 % on an annual basis through 2050 due to coal plant retirements in the region. Other sectors experience a small growth over the period. Total U.S. Northeast gas consumption is expected to reach 18 Bcf/d by 2035 and 19.6 Bcf/d by 2050.

Exhibit 3-5: Northeast (New England and Mid-Atlantic) Demand Forecast by Sector (Bcf/d)



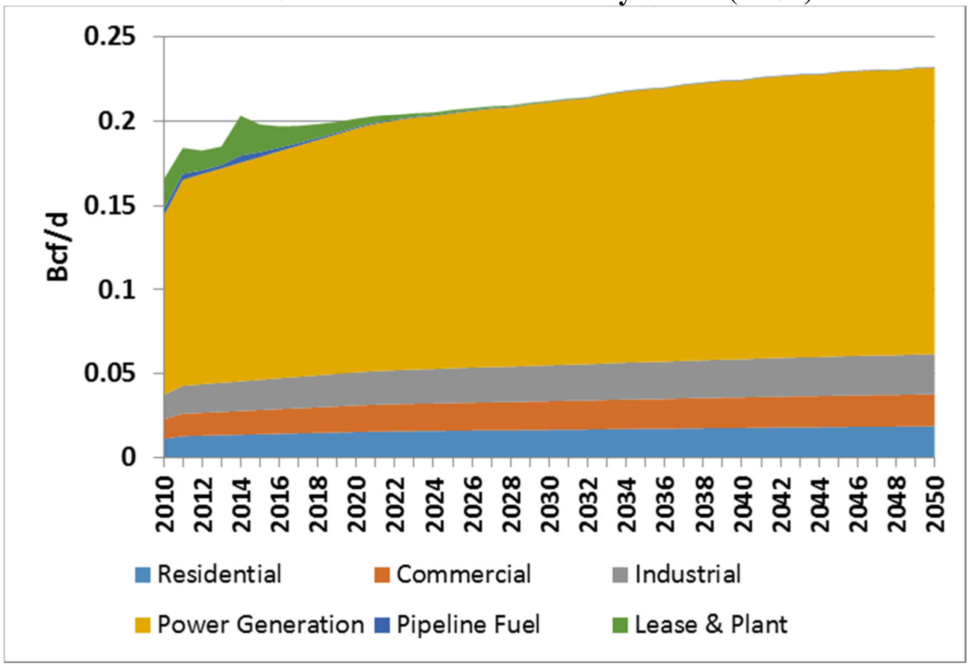
Source: ICF August 2014 Base Case

In contrast to the U.S. Northeast, the gas consumption in Atlantic Canada is expected to show much more modest growth, mostly from increasing gas consumption in the power generation sector. Nova Scotia has some coal plants that could be retired in the future and replaced with gas fired generation. The growth in the natural gas demand in the residential, commercial and industrial sectors is not likely to be significant over the forecast period (see Exhibit 3-6). The demand estimate shown below does not include the Middle Melford LNG demand. Note that in the forecast below a noticeable amount of gas consumption is for lease and plant. This use is associated with the SOEP and will decline as this production declines.

An obvious question about Atlantic Canada consumption going forward is the source of gas. Ultimately, New Brunswick and Nova Scotia will import natural gas from the United States with the gas flowing over Maritimes and Northeast Pipeline (M&NP).[25]

[25] See ICF's report for the Nova Scotia Department of Energy, "The Future of Natural Gas Supply for Nova Scotia," March 28, 2013 which can be accessed at http://novascotia.ca/news/release/?id=20130731007 .

Exhibit 3-6: Atlantic Canada Demand Forecast by Sector (Bcf/d)



Source: ICF International

3.3 Gas Supply Outlook

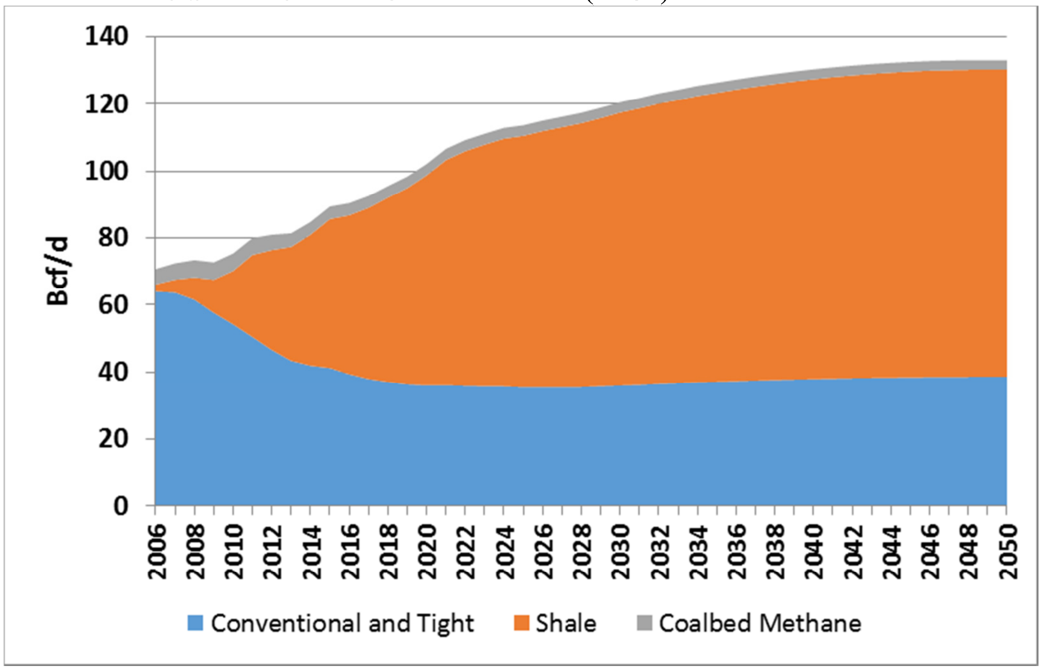
Exhibit 3-7 shows ICF's forecast of production based on the assumed resource base, cost of supply curves, and the outlook for demand and prices. Gas production from conventional wells, historically and currently the major source of natural gas is shown at the bottom of the graph; the unconventional sources of gas are arrayed at the top of the graph.[26] North America in 2014 produces just over 85 Bcf/d from all sources, up from just over 75 Bcf/d in 2010. ICF expects total gas production to reach 100 Bcf/d by 2020 and grow to nearly 133 Bcf/d by 2050, keeping up the demand projections discussed earlier.

Virtually all of the growth will come from shale and other unconventional sources, which is expanding from virtually nothing in 2005, to about 40 Bcf/d in 2014, 80 Bcf/d in 2030, and 92 Bcf/d by 2050. This production is dominated by shale gas production in the Appalachia, Texas/Louisiana, and the Bakken.

Consistent with recent trends, ICF forecasts a continuing decline in production from conventional gas wells. Conventional production will continue to be displaced by cheaper and higher producing shale production. Conventional and tight gas production falls from 42 Bcf/d in 2014 to 39 Bcf/d in 2050. Conventional production is expected to decrease over time, while tight gas, which also requires hydraulic fracturing, is also expected to slowly expand in production over the period. CBM will see a slight decline, while offshore production will increase slightly between 2014 and 2050.

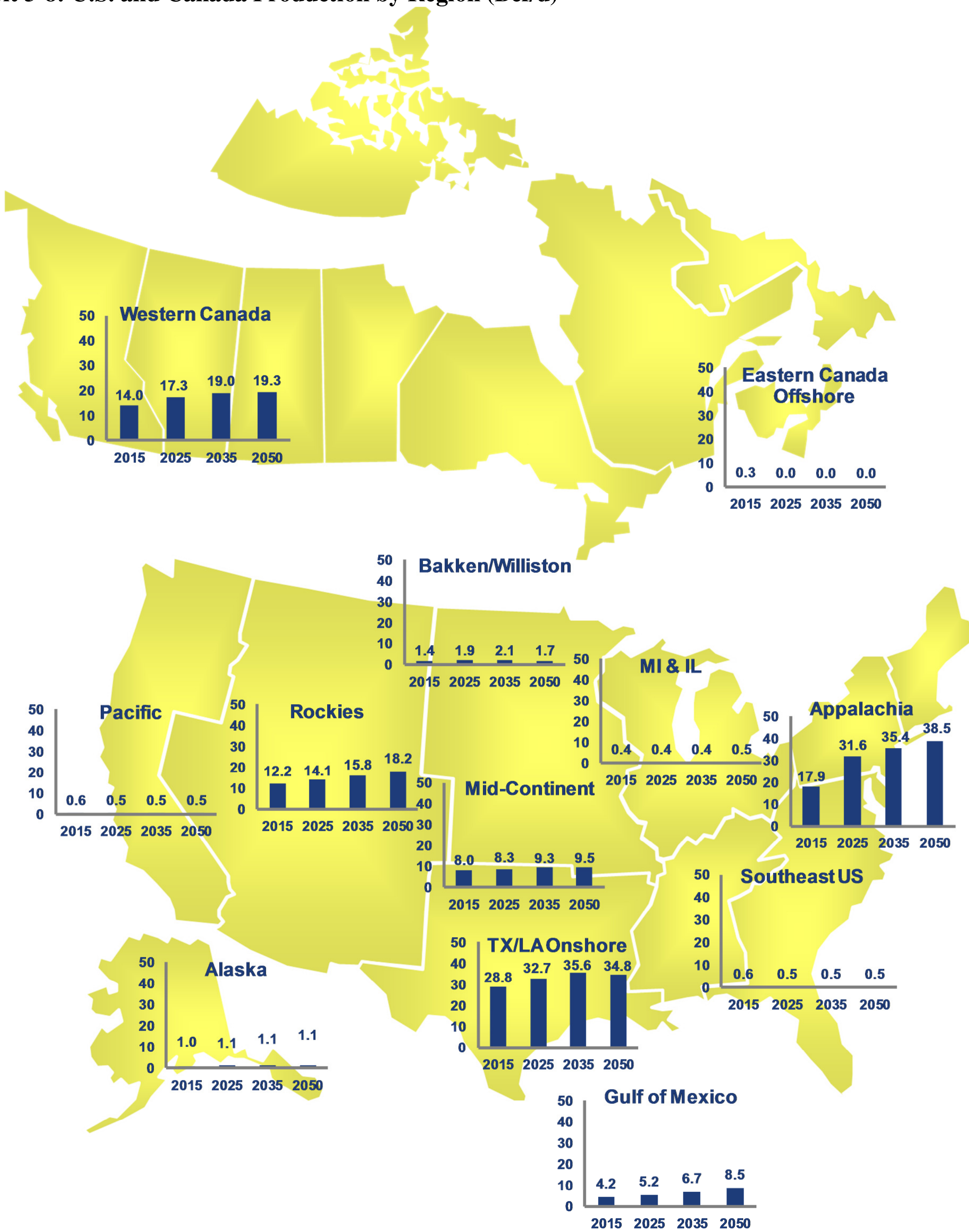
[26] Unconventional sources are those that require some additional stimulation for the wells to produce natural gas or oil, such as hydraulic fracturing necessary for production from "tight" or shale resources. Conventional sources refers to wells that do not require additional work to induce flows into the well bore.

Exhibit 3-7: U.S. and Canada Gas Production (Bcf/d)



Source: ICF August 2014 Base Case

Exhibit 3-8: U.S. and Canada Production by Region (Bcf/d)



Source: ICF August 2014 Base Case

At a regional level, ICF projects increasing gas production in all U.S. producing regions, as shown in Exhibit 3-8. Areas with the greatest growth in U.S. production are the West South Central (WSC) and the

Mid Atlantic. The production growth in in WSC is driven by the robust resource base in the Eagle Ford, Haynesville, Barnett, and Fayetteville shales. Driving much of the production growth is drilling for natural gas liquids (NGLs) and oil, especially in the Permian basin of west Texas. Much of this production will meet growing demand in the WSC and across the southeastern United States.

Significant production growth in the Mid-Atlantic is due to increased production from the Marcellus and Utica shales, with annual production reaching 31 Bcf/d in 2025 and 38 Bcf/d by the end of our forecast in 2050. Marcellus gas displaces supplies that traditionally were transported from the Gulf Coast to the Northeast. ICF expects that all new gas demand in the northeast will be met by Marcellus/Utica gas. The primary reason for this is the relatively low cost of Marcellus gas compared to the gas that is produced in the Gulf Coast and transported to the Northeast.

For Canada, most production growth takes place in British Columbia with robust shale gas production. Total Western Canada production will reach 19.3 Bcf/d by 2050. Conventional and tight production in Western Canada is expected to fall to 4.8 Bcf/d in 2035 and 3.1 Bcf/d in 2050, leading to increasing displacement of gas demand in Ontario, Quebec, and Atlantic Canada by Marcellus gas. However, shale gas production will more than triple from current levels, reaching 13.9 Bcf/d by 2035 and 15.9 Bcf/d by 2050. Shale gas production is mainly driven by growing LNG exports from British Columbia.

In summary, ICF believes that the North American production outlook is robust and can be produced at prices that are consistent with supporting both U.S. and Canadian demand, as well as the demand for LNG exports to international markets.

We present below more detailed production forecasts for the Marcellus, WCSB, and Eastern Canada, since these production forecasts are relevant to the Middle Melford LNG Terminal. However, as noted earlier, the focus of Middle Melford LNG is gas from Marcellus.

3.3.1 Marcellus/Utica Production Forecast

Gas production from the Marcellus and Utica area is approximately 15 Bcf/d in 2014, equaling roughly 20 %t of the total U.S. gas production. ICF projects Marcellus/Utica production to continue to grow at a robust rate of between 2 and 3 Bcf/d per year, equating to an annual growth rate of roughly 16 % over the next few years (see Exhibit 3-9). Beyond 2020, Marcellus production growth rate is expected to slow down, but the total production will reach over 31 Bcf/d by 2025 and 38 Bcf/d by 2050.

Access to Marcellus/Utica supply is especially attractive to the regions of the U.S. Northeast and Eastern Canada: New England, Mid-Atlantic, East North Central, Ontario, Quebec, and Atlantic Canada. Marcellus/Utica offers a low cost supply option due to its proximity to these markets and the prices in the Marcellus relative to other basins. The total 2050 gas demand in these regions is expected to be 38 Bcf/d, and the production of Marcellus gas in 2035 is 38 Bcf/d (see Exhibit 3-9). This implies that Marcellus/Utica production by itself can meet all of the demand in this area. With the addition of gas production from other regions in U.S. and Canada, there is sufficient gas to meet any Canadian demand for Marcellus gas, as well as Middle Melford exports (which amount to a total of only 2.1 Bcf/d). Furthermore, Marcellus gas is also expected move further south and west with the reversal of several existing gas pipelines that connect the Northeast with the U.S. Gulf Coast.

Exhibit 3-9: Production Forecast for Marcellus/Utica (Bcf/d)

	Conventional & Tight	CBM	Shale	Total
2010	1.68	0.24	1.82	3.74
2015	1.23	0.19	16.50	17.93
2020	0.89	0.19	25.71	26.79
2025	0.67	0.19	30.79	31.65
2030	0.53	0.19	33.26	33.99
2035	0.44	0.21	34.71	35.35
2040	0.35	0.22	35.87	36.43
2045	0.26	0.21	37.03	37.50
2050	0.17	0.18	38.19	38.54

Source: ICF August 2014 Base Case

3.3.2 Western Canadian Sedimentary Basin

Although gas produced from the WCSB is not expected to play a major role in the Middle Melford LNG gas supplies, we include ICF's outlook for WCSB production as shown in the exhibit below since the WCSB will continue to be a major source of supply into Ontario and Quebec. Overall, production from the WCSB is expected to grow from about 15.5 Bcf/d in 2010 to 17.3 Bcf/d by 2025 and 19.3 Bcf/d by 2050. These increases are based on the sharp growth projected from British Columbia and northwestern Alberta shale reserves, as can be seen in Exhibit 3-10. Conventional gas, coal bed methane, and tight gas account for a decreasing portion of WCSB production, declining from just under 14.5 Bcf/d in 2010 to 3 Bcf/d by 2050. During the same period, shale gas more than makes up for the reduction in conventional output, growing to just under 16 Bcf/d by 2050.

Exhibit 3-10: Production Forecast for WCSB (Bcf/d)

	Conventional & Tight	CBM	Shale	Total
2010	13.59	0.87	1.05	15.52
2015	8.96	0.69	4.35	14.00
2020	6.59	0.52	8.29	15.40
2025	5.58	0.40	11.33	17.30
2030	5.13	0.32	12.59	18.04
2035	4.75	0.27	13.93	18.95
2040	4.31	0.24	15.06	19.61
2045	3.77	0.22	15.73	19.72
2050	3.14	0.21	15.92	19.26

Source: ICF August 2014 Base Case

ICF believes that shale gas producers in the Horn River and Montney plays of WCSB will seek to export through the various LNG terminals proposed for the Pacific Coast in order to maximize their net-back value of gas. ICF forecasts approximately 2.7 Bcf/d of exports from these projects, a volume far below what has been proposed and authorized by the NEB. The ICF Base Case represents a conservative projection of the potential LNG exports. In the last year, several major milestones have been reached, and new projects with strong financial backing have been proposed that, if developed, would result in LNG exports above the levels included in the ICF Base Case. As of January, 2015, the NEB had granted approval for 10 LNG facilities located on the British Columbia coast with total approved export volumes of 21 Bcf/d. The NEB has also approved natural exports for two projects on the Oregon coast that would source gas at least in part from western Canada.

Most of the projected demand growth in the WCSB is in oil sands demand, with some for power generation. Development of Alberta's oil sands will mean significant consumption of natural gas fuels. While significant development uncertainties persist, ICF expects oil sand production in Alberta to exceed 1.5 billion annual barrels by 2025, which would require nearly 1.1 Tcf in gas consumption. This represents an increase of about 0.6 Tcf, or 1.6 Bcf/d of natural gas demand between 2013 and 2025. The remaining supply will be exported from Alberta to eastern Canada over TransCanada Pipelines (TCPL) and into the United States over the Alliance, Northern Border, GTN, and Spectra/Westcoast pipelines.

3.3.3 Atlantic and Eastern Canada

The locally available production near Middle Melford from offshore Nova Scotia is expected to decrease significantly. ICF's outlook for Eastern Canada declines over time from 0.42 Bcf/d in 2014 to a negligible amount by 2035 (see Exhibit 3-11). Aside from a modest amount of on-shore gas production, most of Atlantic Canada's current gas supplies come from conventional SOEP gas. Originally brought online in 1999, SOEP gas production has been uneven over the past 5 years, ranging from a high of 570 MMcfd in December 2001 to a low of 81 MMcfd in August 2009. ICF projects that SOEP production will continue to decline throughout the forecast. Another offshore field, Deep Panuke, came online towards the end of 2013, and peak production is expected to be around 300 MMcfd by 2014-15. New Brunswick also has onshore shale gas resources in the Frederick Brook Shale. However, based on current cost assessments for Frederick Brook versus other shale plays, ICF's Base Case projects no significant development of the Frederick Brook Shale in the forecast period. ICF's current production outlook for Eastern Canada is consistent with the Base Case analysis that ICF conducted for the Department of Energy in Nova Scotia for the "The Future of Natural Gas Supply in Nova Scotia" report.[27]

[27] http://0-fs01.cito.gov.ns.ca.legcat.gov.ns.ca/deposit/b10664245.pdf

Exhibit 3-11: Production forecast for Eastern Canada (Bcf/d)

	Conventional & Tight	CBM	Shale	Total
2010	0.32	-	-	0.32
2015	0.29	-	-	0.29
2020	0.09	-	-	0.09
2025	0.03	-	-	0.03
2030	0.01	-	-	0.01
2035	0.00	-	-	0.00
2040	None			
2045				
2050				

Source: ICF August 2014 Base Case

3.4 Natural Gas Supply Demand Balance

Below in Exhibit 3-12, ICF presents our forecast of the North American and Canadian natural gas supply demand balance. This table highlights the integration of the North American gas market, especially in terms of cross-border flows between Canada and the United States, where over time, less Canadian gas will flow to the United States from the current level of about 4.2 Bcf/d but more flows from the United States into Canada.

Exhibit 3-12 North American and Canadian Supply Demand Balance (Bcf/d)

	2014	2020	2025	2035	2050
North America					
Total Production	84.8	102.1	113.7	126.3	133.0
LNG Imports	0.4	0.1	0.1	0.1	0.2
Total Supply	**85.2**	**102.2**	**113.8**	**126.4**	**133.2**
Exports of LNG	0.0	8.7	12.5	12.5	12.5
Exports to Mexico	2.1	4.2	4.5	4.9	5.0
Consumption	81.6	88.2	95.4	107.7	114.5
Total Exports and Consumption	**83.7**	**101.1**	**112.4**	**125.1**	**132.0**
Balancing Item	1.5	1.1	1.4	1.3	1.2
Canada					
Production	14.4	15.5	17.3	18.9	19.3
LNG Imports	0.1	0.1	0.1	0.1	0.2
Imports-Pipeline from US	2.5	4.0	4.3	4.4	4.5
Total Supply	**17.0**	**19.6**	**21.7**	**23.4**	**24.0**
Exports-LNG	0.0	1.3	2.7	2.7	2.7
Exports-Pipeline to US	6.8	6.6	6.1	5.8	4.5
Consumption	10.2	11.6	12.7	14.7	15.8
Total Exports and Consumption	**17.0**	**19.5**	**21.5**	**23.2**	**23.0**
Balancing Item	0.1	0.1	0.2	0.2	1.0

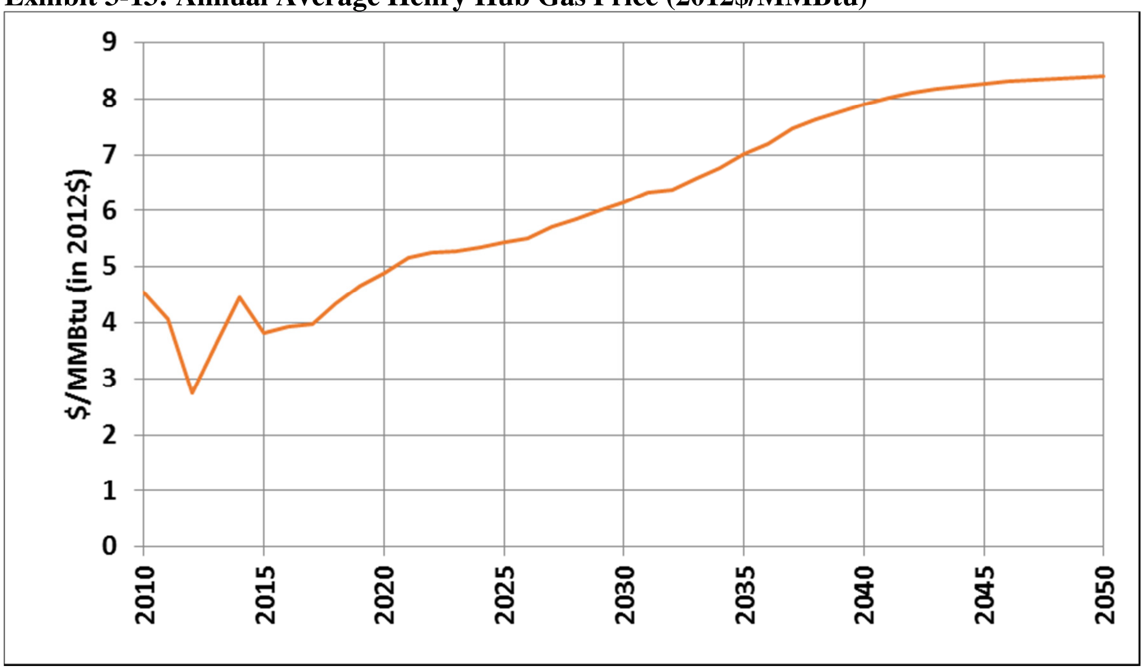
Source: ICF International

The market balance in Exhibit 3-12 represents the ICF Base Case outlook. To support additional exports of LNG, both from Canada and the United States, additional production would be forthcoming from the resource base described in Section 2. The additional production would be made possible by increased prices of gas as described in the subsection below.

3.5 Market Price Forecast and Impact of Exports on Natural Gas Prices

The supply-demand balance at each of the GMM® nodes is used to derive the gas price forecast in ICF's model. The price forecast (in real 2012$) for the Henry Hub is shown in Exhibit 3-13. Over the long term, we expect Henry Hub gas prices to trend upwards, reaching $7/MMBtu (in 2012$) by 2035. By 2050, gas prices could reach between $8/MMBtu and $9/MMBtu. The lower prices before 2025 and 2030 support rising demand for gas-fired power generation and industrial use, including LNG and Mexican exports. This demand growth moderately outpaces production growth, such that market prices rise gradually from 2020 to 2030. After 2030, with the retirement of nuclear generating capacity, demand for gas will increase and push prices further upward. After 2035, prices increase as more gas production at higher cost is brought on-line to meet demand.

Exhibit 3-13: Annual Average Henry Hub Gas Price (2012$/MMBtu)



Source: ICF August 2014 Base Case

ICF's annual price forecasts at four key trading points relevant to Middle Melford LNG, as well as the Henry Hub price, which is the U.S. national reference price, are in Exhibit 3-14. The four key hubs are: Average of Leidy, Dominion South, Columbia Gas, and TGP Zone 4 hubs, a proxy for Marcellus Shale gas; Dawn, Ontario, a benchmark for Canadian supply delivered from the WCSB priced in Ontario: average of New York and AGT hub prices; a benchmark for New England prices; and AECO, a proxy for WCSB supply priced in Alberta

The changes in the location of natural gas supply and demand are projected to have a fundamental impact on the price relationships between the available sources of natural gas for Ontario and Quebec consumers. The rapid growth in Marcellus/Utica supply is turning the Northeastern U.S. into a major supply center, and pushing down gas prices at major Northeast supply centers, including Dominion South Point; Columbia Appalachia; Clarington, Ohio; and other regional market points.

The growth in LNG and Mexican exports from the Gulf of Mexico is changing the Gulf Coast into a gas demand region that will be purchasing natural gas from the Marcellus basin over time. As flows from the Gulf Coast into the Midwest and Northeast markets decline, prices in the Gulf Coast are expected to increase relative to prices in the Northeast producing regions. In the WCSB, the decline in conventional natural gas production, combined with growth in natural gas demand for oil sands production and LNG exports is expected to lead to increasing prices relative to Northeastern markets.

Exhibit 3-14: Base Case Price Forecast (2012$/MMBtu)

Year	Henry Hub	AECO	Dawn	New England	Marcellus
2010	4.55	4.04	4.93	5.64	4.75
2015	3.82	3.39	4.92	5.87	3.66
2020	4.89	4.29	5.14	6.10	4.57
2025	5.43	4.81	5.60	5.97	4.78
2030	6.19	5.48	6.35	6.74	5.47
2035	6.77	6.07	6.91	7.37	6.06
2040	7.27	6.53	7.45	7.91	6.53
2045	7.50	6.75	7.69	8.20	6.77
2050	7.58	6.82	7.79	8.31	6.84

Source: ICF August 2014 Base Case

Note: Marcellus prices represent the average of four hubs relevant to the Marcellus (Dominion South, Columbia Gas, TGP Zone 4, and Leidy). New England prices represent the average of New York and New England nodes in the GMM.

Exhibit 3-15: Gas Basis Spreads to Henry Hub from Various Supply Sources (2012$/MMBtu)

Year	AECO	Dawn	New England	Marcellus
2010	-0.51	0.38	1.09	0.20
2015	-0.43	1.10	2.05	-0.16
2020	-0.61	0.24	1.21	-0.33
2025	-0.62	0.17	0.53	-0.65
2030	-0.71	0.16	0.55	-0.72
2035	-0.70	0.13	0.60	-0.72
2040	-0.74	0.18	0.64	-0.74
2045	-0.75	0.19	0.70	-0.73
2050	-0.76	0.21	0.74	-0.73

Source: ICF August 2014 Base Case

The changes in prices of natural gas from these three producing regions and Dawn is reflected in the basis from the producing regions to Henry Hub over time, shown in Exhibit 3-15. Historically, New England basis spreads have been the highest since New England has been the farthest from supply sources. With the growth of Marcellus production and expansions of pipeline capacity into New England, the basis begins to narrow over the forecast period, declining to $0.60/MMBtu by 2035 and $0.74/MMBtu by 2050. AECO and Marcellus see continuing and larger discounts to Henry Hub, with AECO trading at $0.76/MMBtu below Henry Hub in 2050 and Marcellus trading at $0.73/MMBtu below Henry Hub by 2050. What is most significant however relative to Henry Hub is that Marcellus basis moves from a positive basis to Henry Hub to a strong negative basis that is close to the AECO basis. Dawn basis spread to Henry Hub remains positive but also shows a decreasing trend. The strong negative basis for Marcellus relative to AECO and Dawn suggest that WCSB supply will face challenges competing with Marcellus supply in the Northeastern markets and that Marcellus supply will increasingly be attracted to the Ontario and Quebec market via Dawn.

Impact of LNG Exports on Natural Gas Prices

The economic impact of incremental LNG exports is of interest to both Canadian and the United States policy makers. Incremental exports will require additional drilling and production to meet the incremental demand of exports. The price forecasts above represent an expected level of LNG exports equal to 12.5 Bcf/d in 2025, and remaining at that level through 2050. The question is what would be the effect on these prices if exports were to be higher than assumed in the ICF Base Case? Additional exports would have effects on pricing in several ways.

- **Resource depletion price effect:** Accounts for the fact that increased depletion of natural gas to accommodate exports moves production up on the long-run supply curve, increasing long-run marginal cost.
- **Drilling activity price effect:** Accounts for higher prices needed to accommodate short-term factor cost increases that usually accompany increased drilling activity and the price effects of the delay between when price signals change due to higher demand and when drilling activity and wellhead deliverability respond to accommodate that demand.
- **Demand response:** The theoretical price increase that is avoided because some demand for natural gas declines as prices increase.

In 2013, ICF prepared a report for the American Petroleum Institute (API) that quantified economic and pricing effects of LNG exports, U.S. LNG Exports: Impact on Energy Markets and the Economy (May 15, 2013).[28] In that report, ICF estimated that for each incremental export of 1 Bcf/d gas prices could increase by up to $0.10/MMBtu, based on the then estimated ultimate recovery (EUR) per well and well completion costs. Since that report, the EURs per well have increased and the efficiencies of wells have improved such that the supply elasticity to price increases appears to be higher than the 2013 study estimated. ICF has updated the long term price impact to approximately $0.07 per Bcf/d of exports. ICF provides our estimate of the gas price impacts of Middle Melford exports below in Exhibit 3-16. The calculations accept that exports will be 0.46 Bcf/d by 2019, 0.92 Bcf/d by 2021 and 2.1 Bcf/d by 2025. This table also assumes that the basis spreads between the pricing points remain unchanged from what is shown in Exhibit 3-15. The prices shown in Exhibit 3-16 should be compared to the price forecasts in Exhibit 3-14. In 2022, the prices at all hubs are about $0.11/MMBtu higher than the Base Case; from 2025 onward, the prices are $0.15/MMBtu higher than the Base Case.

[28] See API: http://www.api.org/policy-and-issues/policy-items/lng-exports/us-lng-exports-impacts-on-energy-markets-and-economy

Exhibit 3-16: Estimated Price with AC LNG Exports (2012$/MMBtu)

Year	Henry Hub	AECO	Dawn	New England	Marcellus
2020	$4.95	$4.35	$5.20	$6.16	$4.63
2022	$5.00	$4.40	$5.25	$6.21	$4.68
2025	$5.58	$4.96	$5.75	$6.12	$4.93
2030	$6.34	$5.63	$6.50	$6.89	$5.62
2035	$6.92	$6.22	$7.06	$7.52	$6.21
2040	$7.42	$6.68	$7.60	$8.06	$6.68
2045	$7.65	$6.90	$7.84	$8.35	$6.92
2050	$7.73	$6.97	$7.94	$8.46	$6.99

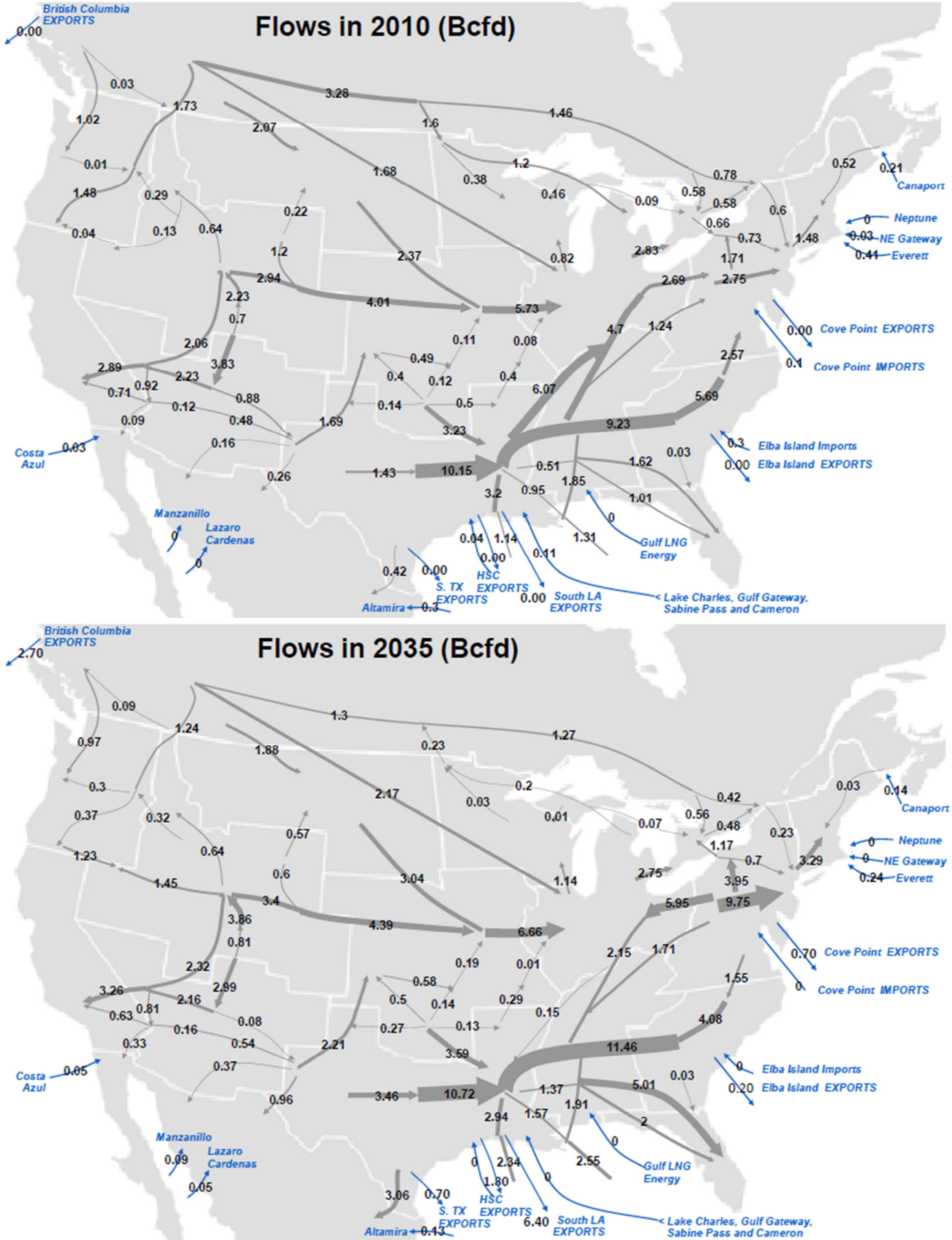
Source: ICF International

3.6 Pipeline Flows Forecasts

Exhibit 3-17 shows a map of gas pipeline flows as of 2010 and 2035 from the ICF Base Case. The upper map illustrates the pipeline system flows prior to the full emergence of the Marcellus as a major production center. In 2010, volumes of gas flow over TCPL from the WCSB remain strong albeit less robust than in 2000. Similarly, flows from the Gulf Coast and Texas and the Rocky Mountains into the east and northeast are large and dominate the supply for the northeastern quadrant of North America. The upending of this pattern is seen in the lower map. Gas flows on the TCPL Mainline decline dramatically as does gas supply moving northward from the U.S. Coast and easterly from the Rockies.

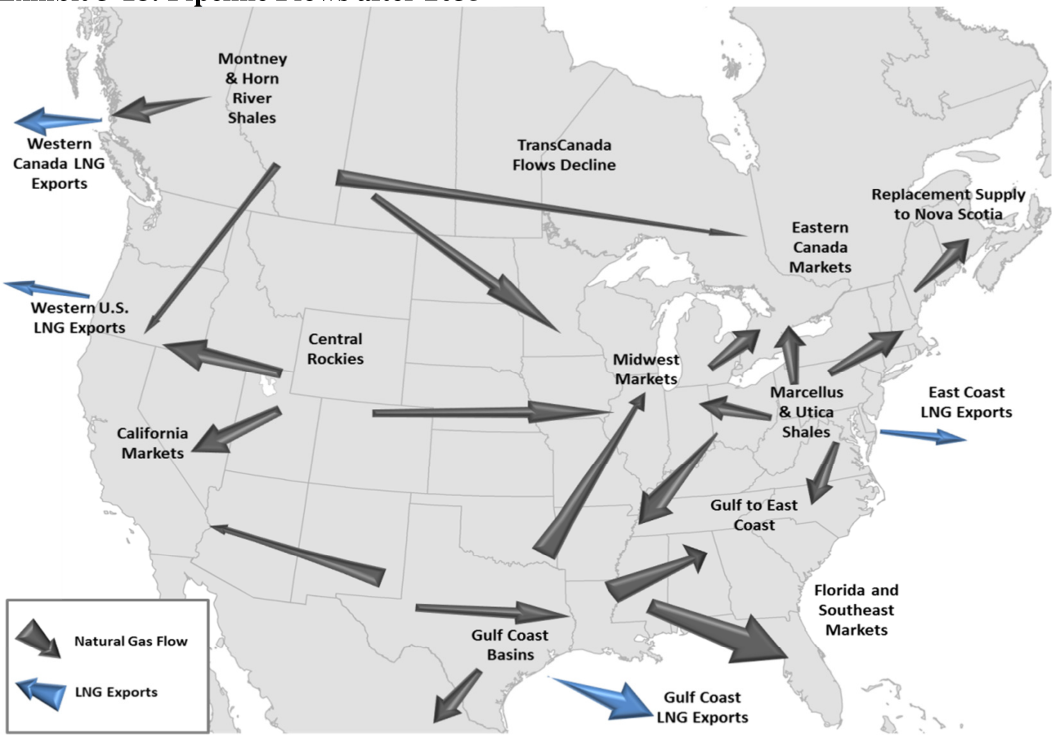
Exhibit 3-18 illustrates natural gas flows along major flow corridors based on ICF's forecast estimates of demand and supply after 2035. In our view, gas flows over TCPL may fall slightly after. The main driver of this is more gas entering Ontario from Marcellus production. Marcellus gas will flow westward into the Chicago markets and southward to feed the petrochemical complex in the Gulf States. Gulf Coast gas will serve the LNG export market, Mexico, and growing demand across the southeastern quadrant of the United States. British Columbia productions will primarily serve LNG exports but also supply gas into Alberta and the Pacific Northwest. Notably, Atlantic Canada will be supplied from the United States.

Exhibit 3-17: Schematic of Pipeline Flow Changes from 2010 and 2035



Source: ICF August 2014 Base Case

Exhibit 3-18: Pipeline Flows after 2035



In sum, the changing flows over the North American gas network reflect the changes in the locations and sources of the major producing and consuming regions. The Northeast is now the dominant gas resource in North America and because it is so close to the consuming markets, Marcellus is changing the flows across the entire pipeline network. Continuing developments in Alberta and British Columbia will result in less pipeline exports out of the region and greater exports of LNG. The flow patterns changes create opportunities for expanded gas supply into New England and into Atlantic Canada.

3.7 The Impact of Higher Canadian Demand on ICF's Assessment

ICF has considered the impact of higher gas demand in Canada on the conclusions of this analysis by increasing gas demand in Canada by 20% by the year 2035, and remaining at that higher level through 2050. ICF implemented this scenario by increasing demand proportionately across the provinces, thus much of the increase occurs in Ontario and Alberta. We then re-ran the GMM® to see how the solution changed. The resource base is adequate for meeting higher demand in Canada. The new gas supply/demand balance with the higher demand in Canada is shown in Exhibit 3-20.

Exhibit 3-19: Supply Demand Balance with 20% Higher Canadian Demand (Bcf/d)

	2014	2020	2025	2035	2050
North America					
Total Production	84.8	102.9	115.1	129.2	136.0
LNG Imports	0.4	0.1	0.1	0.1	0.2
Total Supply	**85.2**	**103.0**	**115.2**	**129.3**	**136.2**
Exports of LNG	0.0	8.7	12.5	12.5	12.5
Exports to Mexico	2.1	4.2	4.5	4.9	5.0
Consumption	81.6	89.0	96.9	110.6	117.6
Total Exports and Consumption	**83.7**	**101.8**	**113.9**	**128.0**	**135.1**
Balancing Item	1.4	1.1	1.3	1.2	1.1
Canada					
Production	14.4	15.6	17.6	19.5	20.0
LNG Imports	0.1	0.1	0.1	0.2	0.3
Imports-Pipeline from US	2.5	4.2	4.6	4.9	5.1
Total Supply	**17.0**	**20.0**	**22.4**	**24.6**	**25.3**
Exports-LNG	0.0	1.3	2.7	2.7	2.7
Exports-Pipeline to US	6.8	6.1	5.3	4.1	3.2
Consumption	10.2	12.4	14.3	17.6	19.0
Total Exports and Consumption	**17.0**	**19.9**	**22.2**	**24.5**	**24.9**
Balancing Item	0.0	0.1	0.1	0.1	0.5
Canada consumption change	0%	7%	12%	20%	20%

Source: ICF International

Gas price impacts vary. With higher demand, gas prices in AECO increase by \$0.35/MMBtu, a 6 % increase over the Base Case in 2035. Dawn prices increase by 4% over the Base Case, or \$0.27/MMBtu by 2035. (See Exhibit 3-20.)

Exhibit 3-20: Gas Prices with 20% Higher Canadian Demand by 2035 (2102$/MMBtu)

Year	Henry Hub	AECO	Dawn	New England	Marcellus
2010	4.55	4.04	4.93	5.64	4.75
2015	3.84	3.44	4.96	5.89	3.68
2020	4.97	4.48	5.22	6.17	4.66
2025	5.49	5.09	5.70	6.09	4.87
2030	6.24	5.87	6.53	6.98	5.60
2035	6.82	6.42	7.18	7.69	6.17
2040	7.33	7.07	7.72	8.31	6.64
2045	7.55	7.28	7.95	8.57	6.87
2050	7.63	7.35	8.05	8.66	6.94
Change from the Base Case					
2010	--	--	--	--	--
2015	0.02	0.05	0.04	0.02	0.02
2020	0.08	0.19	0.08	0.07	0.09
2025	0.06	0.28	0.10	0.12	0.09
2030	0.05	0.39	0.18	0.24	0.13
2035	0.05	0.35	0.27	0.32	0.11
2040	0.06	0.54	0.27	0.40	0.11
2045	0.05	0.53	0.26	0.37	0.10
2050	0.05	0.53	0.26	0.35	0.10

Source: ICF International

3.8 Impact of Higher Exports on ICF's Assessment

ICF has noted elsewhere in this document that exports of LNG from western Canada are unlikely to exceed approximately 2.7 Bcf/d. Given that the NEB has approved export projects capable of exporting the equivalent of 24.4 Bcf/d, ICF was asked to evaluate the implications of exporting this amount of gas on our Base Case forecast. For this evaluation, we have increased LNG exports gradually to the full 24.4 Bcf/d by 2050. The impact of the increase on supply and demand are shown in Exhibit 3-21. The price impacts are estimated in Exhibit 3-22.

The higher exports can be accommodated by the reserves ICF has identified previously. There would have to be a much more intensive drilling program in the WCSB, particularly the Montney and Horn River basins to accommodate this level of exports. In addition, there would have to be extensive new pipeline construction to deliver the volumes of gas to the export terminals on the west coast. As table 3-21 shows, production would be expanded in Canada to accommodate the exports.

Exhibit 3-21: North American and Canadian Supply Demand Balance with Higher Exports (Bcf/d)

	2014	2020	2025	2035	2050
North America					
Total Production	84.8	105.6	120.8	136.9	150.0
LNG Imports	0.4	0.1	0.1	0.1	0.2
Total Supply	**85.2**	**105.7**	**120.9**	**137.0**	**150.2**
Exports of LNG	0.0	13.4	22.0	26.7	34.2
Exports to Mexico	2.1	4.2	4.5	4.9	5
Consumption	81.6	87.0	93.0	104.2	109.8
Total Exports and Consumption	**83.7**	**104.6**	**119.5**	**135.7**	**149.0**
Balancing Item	1.5	1.1	1.4	1.3	1.2
Canada					
Production	14.4	19.0	24.4	29.5	36.3
LNG Imports	0.1	0.1	0.1	0.1	0.2
Imports-Pipeline from US	2.5	4	4.3	4.4	4.5
Total Supply	**17.0**	**23.1**	**28.8**	**34.0**	**41.0**
Exports-LNG	0.0	6.0	12.2	16.9	24.4
Exports-Pipeline to US	6.8	6.6	6.1	5.8	4.5
Consumption	10.2	10.4	10.3	11.2	11.1
Total Exports and Consumption	**17.0**	**23.0**	**28.6**	**33.8**	**40.0**
Balancing Item	0.0	0.1	0.2	0.2	1.0

Source: ICF International

The major effect will be the higher prices for natural gas across the entire market as it adjusts to the higher level of exports. With higher prices, ICF forecasts that consumption would decline, with most of the reductions occurring in the industrial sector.

The exhibit below shows natural gas price increases at various North American hubs due to LNG exports totaling 24.4 Bcf/d by 2050. Again, using an incremental price increase of $0.07 per MMBtu per 1 Bcf/d in LNG exports the price increases reflect the full expansion of Canadian LNG exports by an additional 24.4 Bcf/d. We have estimated natural gas price increase of $1.52/MMBtu by 2050 due to the incremental increase in LNG exports of 21.7 Bcf/d. This results in a natural gas price at the AECO hub of $8.34/MMBtu in 2050 (in real dollars).

Exhibit 3-22: Natural Gas Price Forecast with Higher Exports (2012$/MMBtu)

Year	Henry Hub	AECO	Dawn	New England	Marcellus	Increase Over Base Case
2010	$4.55	$4.04	$4.93	$5.64	$4.75	$0.00
2020	$5.22	$4.62	$5.47	$6.43	$4.90	$0.33
2025	$6.09	$5.47	$6.26	$6.63	$5.44	$0.66
2035	$7.76	$7.06	$7.90	$8.36	$7.05	$0.99
2050	$9.10	$8.34	$9.31	$9.83	$8.36	$1.52

Source: ICF International

(Note: Marcellus prices represent the average of four hubs relevant to the Marcellus (Dominion South, Columbia Gas, TGP Zone 4, and Leidy). New England prices represent the average of New York and New England nodes in the GMM.)

Again, ICF does not believe that this level of exports is likely and may not be economically or commercially feasible.

3.9 Caveats to the Forecast and Outlook

Market developments that may have some effect on ICF's forecast or the outlook for LNG from Nova Scotia include:

- **Economic activity**: Economic growth has a direct impact on gas demand growth, particularly in the industrial and power sectors. Lower growth in power demand will reduce the amount of gas-fired generation needed in the future.
- **Oil prices**: Lower oil prices would stimulate the economy but also reduce the incentives to drill in liquids rich plays that would yield both oil and gas (e.g., Bakken, Eagle Ford, Permian basins). This would tend to reduce gas supply and increase gas prices in North America. Lower oil prices could also affect the pricing of LNG since in the Pacific basin LNG is priced by a formula tied to crude oil prices and against fuel oil in Europe. These effects tend to work on prices in opposing directions.
- **Government Policies on Climate Change:** These policies may change over time. ICF assumes a moderate policy that effectively restricts coal-fired generation to reduce CO_2 emissions. Such policies support additional gas use. Policies on methane emissions could restrict gas use or increase gas costs.
- **Pipeline expansion**: Significant uncertainties remain in the midstream infrastructure space. The quantity and timing of pipeline projects coming online in the Northeast impacts the supply and demand balance and prices of various markets. This applies both to United States and Canadian expansions.
- **Energy Efficiency and Renewable Energy:** Power demand may also be affected by improved energy efficiency and demand side management as well as by more renewable energy. While intermittent power (wind, solar) often relies on gas-fired generation as a back-up, the total amount of gas consumption for such uses tends to be small.
- **Hydraulic fracturing regulations**: ICF's Base Case assumes a modest increase in production costs due to anticipated U.S. Federal regulations on hydraulic fracturing and wastewater disposal. More stringent Federal, state/provincial, or local regulations could increase production costs or

limit access to shale resources. This will be the case in Atlantic Canada, as recent governments have set moratoria on hydraulic fracturing.

- **Technology improvements:** The shale revolution has been made possible by technology. While ICF's forecasts incorporate assumptions about incremental technological improvements that reduce costs and improve outcomes of existing exploration and production processes, we do not forecast revolutionary changes. Over the time horizon of this study it is quite possible that methane hydrates could become commercial. It is also possible that dramatic changes in power generation could obviate the need for fossil fuels. Such outcomes are not anticipated in this forecast.

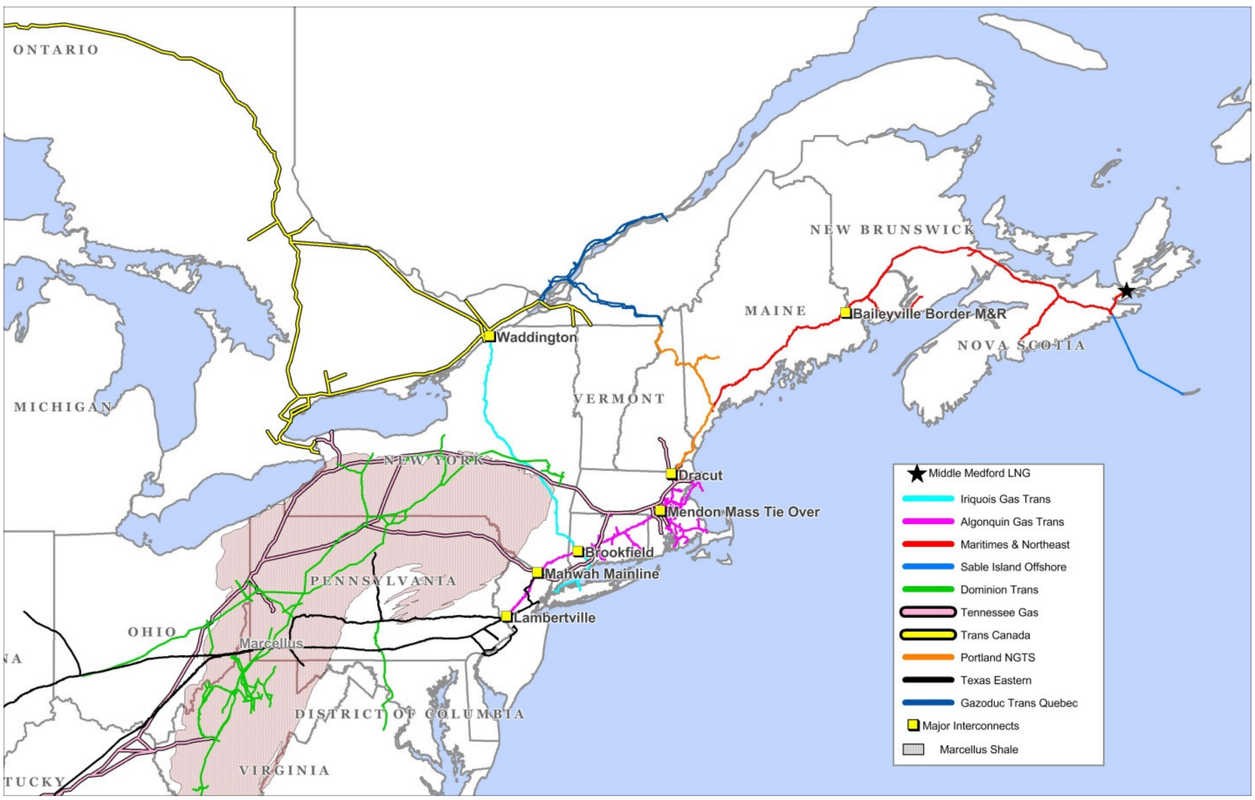
4. Pipeline Infrastructure Developments in the Northeast

This section addresses pipeline infrastructure issues especially relevant to the Middle Melford LNG export facility. Access to Middle Melford will require expansion of the pipeline network in New England and reversal of M&NP. At present, a number of pipeline expansion proposals have been announced. These are described below.

4.1 Northeast Pipeline Expansions

Over many decades, pipeline operators in New England have steadily developed an expansive network of interstate pipelines that serve large areas of the region (Exhibit 4-1). These systems are interconnected with a network of interprovincial pipelines in Eastern Canada. These pipeline systems link New England, Ontario, Quebec and Atlantic Canada gas buyers with gas reserves in every major North American basins, including the Gulf of Mexico, Western Canada, the U.S. Rockies, and Appalachia.

Exhibit 4-1 New England Natural Gas Pipelines



Source: Ventyx, ICF

The pipelines serving New England with access to Marcellus and WCSB production include the following, along with their capacities.

Exhibit 4-2 Pipelines Serving New England from the West and South

Pipeline	Capacity in Bcf/d
Algonquin Gas Transmission	1.087
Iroquois Gas Transmission System	0.220
Tennessee Gas Pipeline	1.261
Portland Natural Gas Transmission System	0.168
Total	2.736

Source: ICF International

The growth in Marcellus production has been accompanied by aggressive midstream infrastructure development over the past few years, a trend that is likely to continue into the future. There have been many gas pipeline projects completed to debottleneck Marcellus gas supplies, and there are many pipeline projects still under development. While there are a large number of small localized projects aimed at making incremental production accessible to the existing pipeline network, there are a number of larger gas pipeline projects that are much broader in geographic reach. Some of these projects are aimed at reversing transport on lines that have historically transported gas from the Gulf Coast toward the Mid-Atlantic States. There are also projects aimed at increasing gas supply into New England and Atlantic Canada. These projects are much more expansive in scope and reach, requiring significant enhancements to existing lines (i.e., substantial changes to compression and a significant amount of looping of existing lines).

Exhibit 4-3 lists recent pipeline projects that have been announced in the Northeast U.S. markets associated with expanding the supply of Marcellus gas into New England and Canada. Several of these projects sponsored by Tennessee Gas Pipeline (TGP), Algonquin Gas Transmission (AGT), Portland Natural Gas Transmission System (PNGTS), and M&NP are directly relevant to Middle Melford LNG.

Exhibit 4-3 U.S. Gas Pipeline Expansions in the Northeast

Project Name	Company	Route	Capacity (MMcfd)	Planed In-Service Date	Status
TEAM 2014	Texas Eastern	OH, WV, PA Looping & Compression	600	Nov-14	Under Construction
Northeast Connector/Rockaway Lateral	Williams Transcontinental Gas Pipeline	St195 SE PA to Rockaway Deliv Lateral - National Grid NYC	100/647*	Nov-14	Under Construction
Wright Interconnect Project	Iroquois Gas Transmission	Expand Wright Interconnect to accommodate Constitution Pipeline	650	Mar-15	Filed with FERC
Constitution Pipeline	Williams/Cabot Oil/Piedmont Natural Gas	Susquehanna PA to Schoharie NY	650	May-15	Filed with FERC
East Side Express	Columbia Gas Transmission	Increased receipt capacity in NY from Millennium and NJ from Tennessee	310	Dec-15	Under Construction
AIM Project	Algonquin (Spectra)	Algonquin looping and compression	342	Nov-16	Filed with FERC
TGP 200 Line Looping	Tennessee Gas Pipeline (Kinder Morgan)	Loops on 200 Line between Wright NY and Mendon MA	500-1000	2016-18	Announced
Continent to Coast (C2C) Project	Portland Natural Gas Transmission	Increased throughput from upstream compression on TQM.	~140	Nov-16	Announced
Atlantic Bridge	Algonquin & Maritimes and Northeast Pipeline (Spectra)	New Jersey to New England and Atlantic Canada	1000	Nov-17	Announced
Northeast Energy Direct (NED)	Tennessee Gas Pipeline	Wright NY to Dracut MA	1200	2017-18	Announced

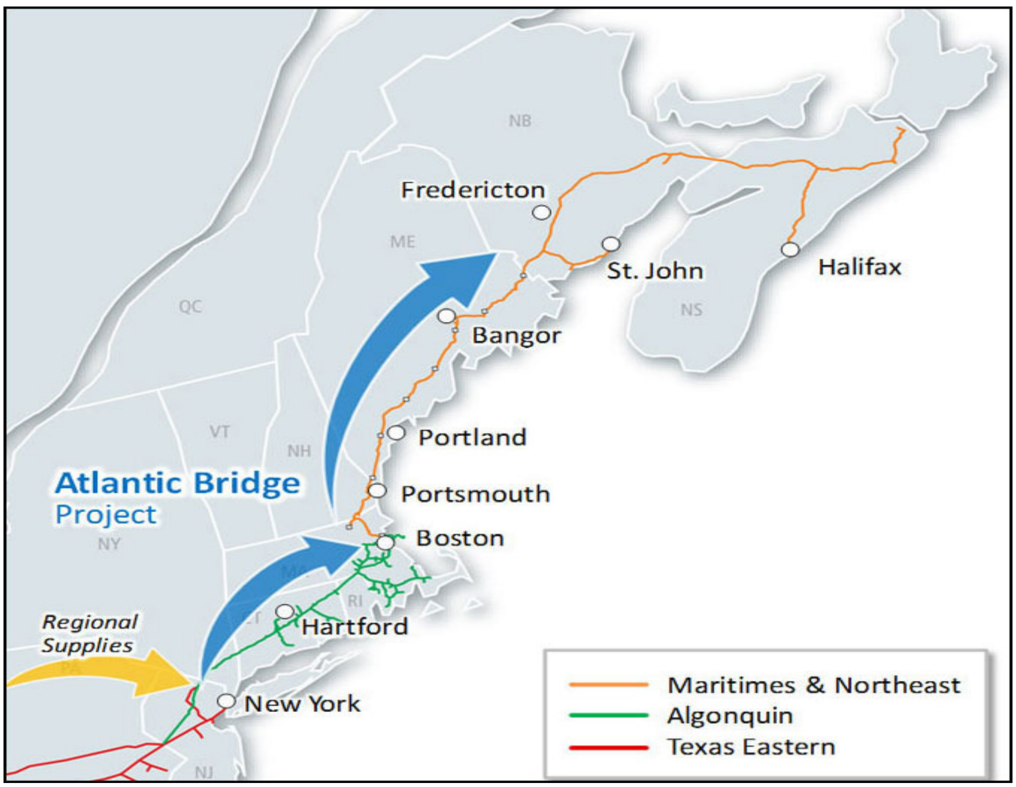
Source: Compiled by ICF from various sources.

Below are summarized particulars of new pipeline projects that could support Middle Melford LNG.

- Atlantic Bridge Project (AGT and M&NP)
- Algonquin Incremental Market (AIM) (AGT)
- Northeast Energy Direct (TGP)
- C2C Expansion (PNGTS)

AGT and M&NP also are proposing the **Atlantic Bridge Project**, which will expand capacity on the existing AGT and M&N Pipelines to serve New England and Maritime markets. Atlantic Bridge recently completed an open season in February 2014 with Unitil Corporation as an anchor shipper. The project's capacity is uncertain, ranging between 100 and 600 MMcfd as market interest dictates. The project is projected to come online in November 2017. This expanded capacity of Atlantic Bridge into New England is separate from, and in addition to, that of the AIM expansion (see below).

Exhibit 4-4 Atlantic Bridge Project



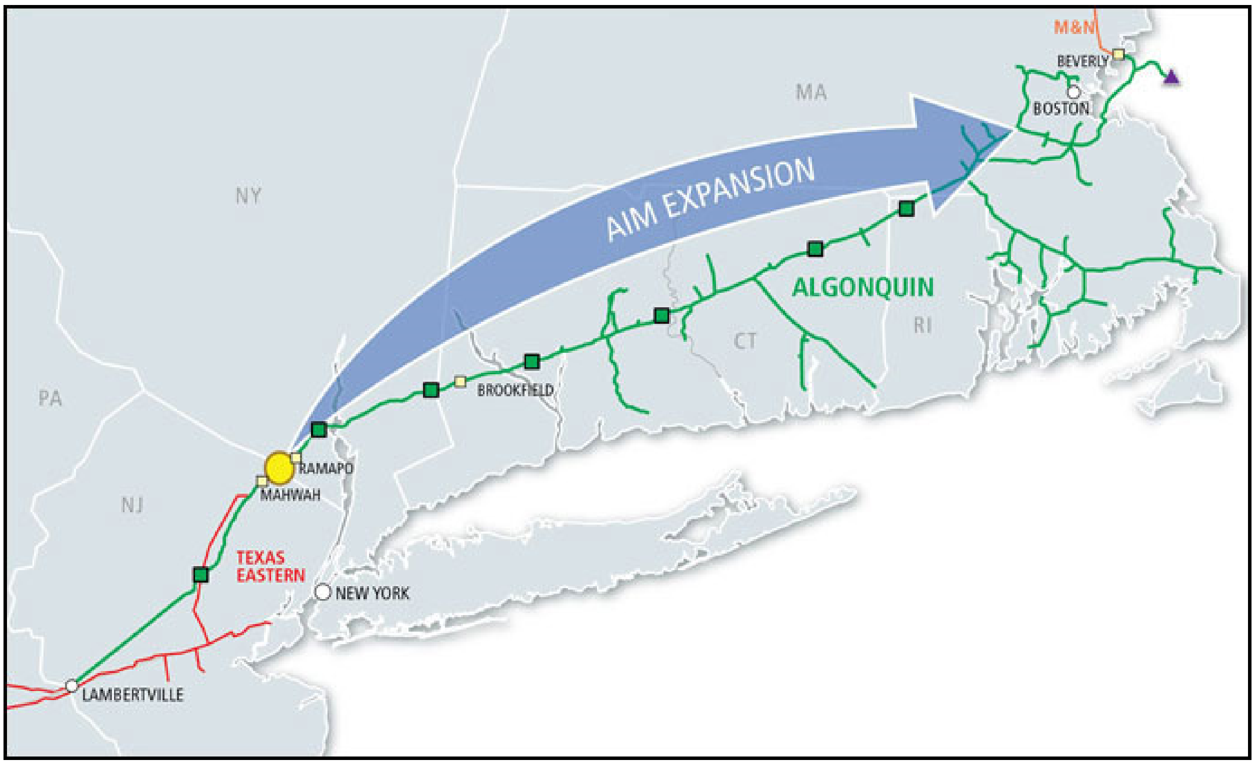
Source: Spectra Energy

A key part of the Atlantic Bridge project will be the reversal of the M&NP. There have been times in the past when the Sable Offshore Energy Project has reduced flows over M&NP. To some extent, this has resulted in gas being supplied by line-pack (i.e., the compressed gas that is effectively stored in the pipeline itself) but it has also resulted in flows northward from M&NP-US into Canada. Reversing flow on M&NP-US would involve different levels of investment depending on the amount of northward flow. Full reversal of the existing pipeline would easily support the first liquefaction train at Middle Melford

LNG and also meet the demand in Maine and Atlantic Canada. No new pipe would be required,[29] and ICF expects the costs of reversing flow to be modest. In order to supply gas to additional trains at Middle Melford LNG, new pipeline infrastructure will need to be added beyond the Atlantic Bridge project.

AGT's **Algonquin Incremental Market (AIM)** expansion is a Spectra Energy project created to expand capacity into New England markets. An open season to secure requests for firm service was held in the fall of 2012. No announcement has been made as to how many shippers signed up or the ultimate capacity of the line, but the open season notice indicated that a binding precedent agreement had been completed with an un-named anchor shipper. The project could include expansions of the AGT interconnection with M&NP. Spectra investor documents list the company as planning to spend over $2 billion on this project, suggesting a major looping or parallel line for AGT. AIM would link New England to an array of upstream supplies and pipeline interconnections. .

Exhibit 4-5 Algonquin Incremental Market Expansion



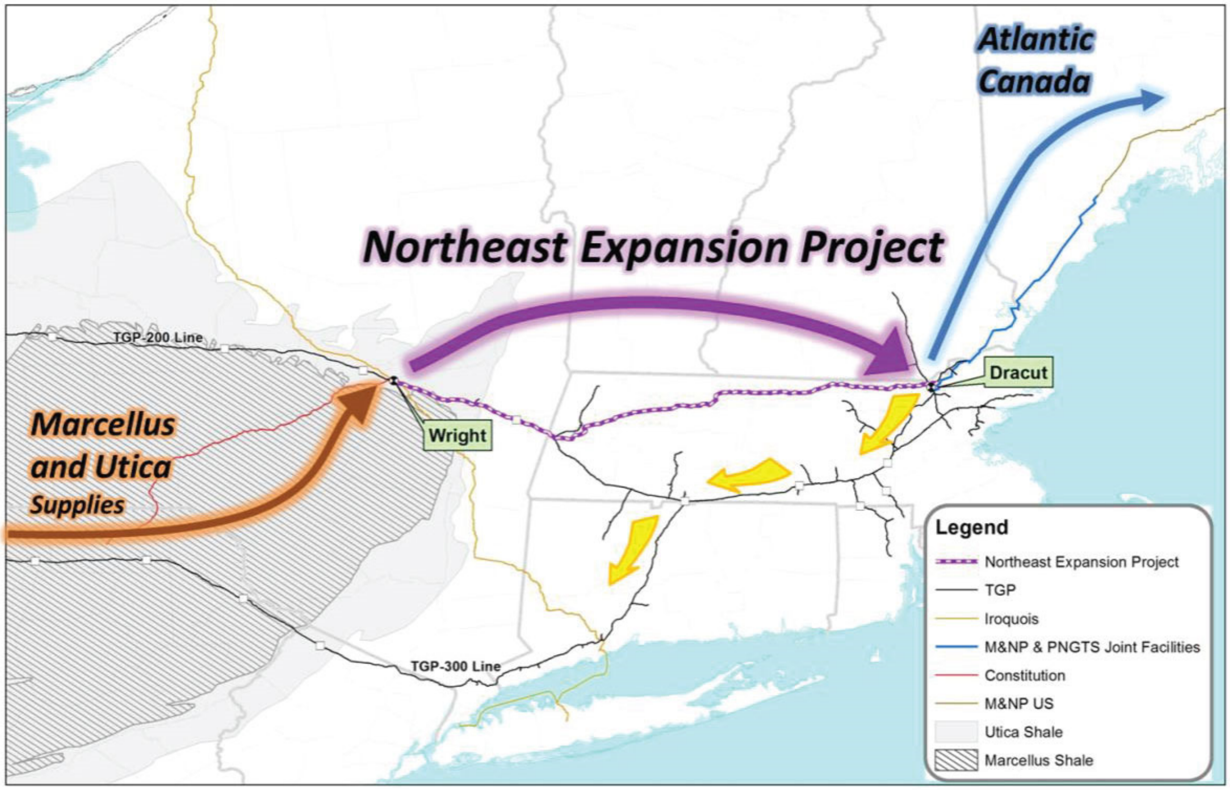
Source: Spectra Energy

TGP is proposing the **Northeast Energy Direct** project as part of its Northeast Expansion to bring Marcellus gas into New England. This line would consist of new, greenfield pipe from Wright, New York to Dracut, Massachusetts and looping of the existing 317 line to Wright. Its capacity is expected to be between 0.8 and 1.4 Bcf/d. From Wright, New York interconnections TGP shippers can procure supplies

[29] The original two compressors at Baileyville and Richmond were designed to be fully reversible. The five additional compressors installed for the last expansion of the pipeline to accommodate Canaport imports can be reversed by installing new valves.

from a diverse set of U.S. and Canadian sources. TGP's expansion is expected to enter service in November 2018.

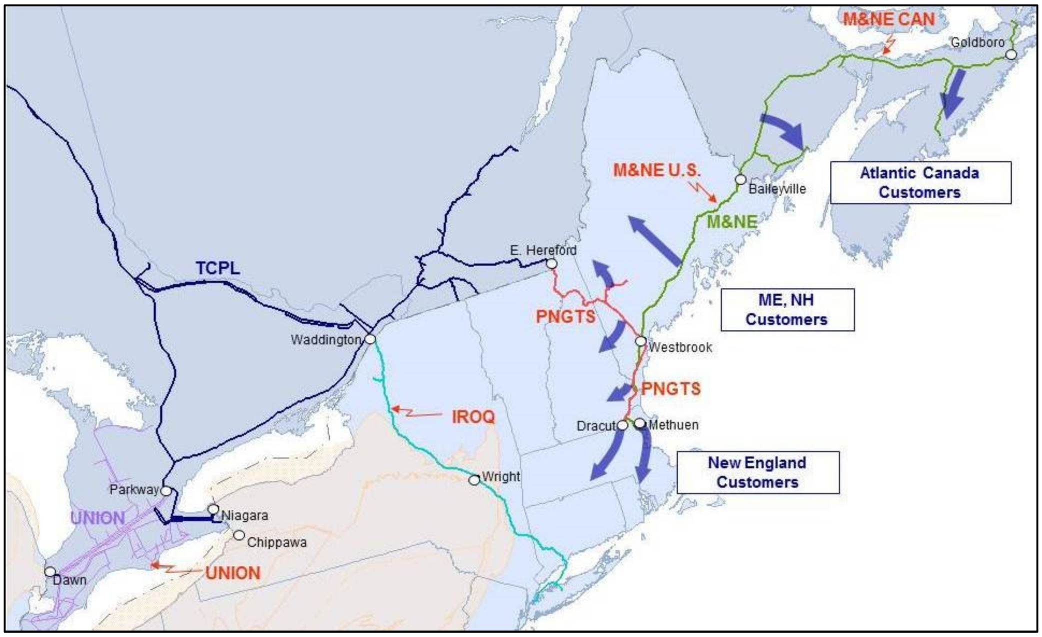
Exhibit 4-6 Northeast Energy Direct Expansion



Source: Kinder Morgan via Nashoba Conservation Trust http://nashobatrust.org/what-is-it/

PNGTS, which connects the Trans Quebec and Maritimes Pipeline (TQM) with M&NP-US at Westbrook, Maine and has announced a new PNGTS C2C Expansion that would combine available unused capacity on its pipeline with new capacity from compression investments. The project would raise system capacity by nearly 60 MMcfd to 300 MMcfd, and make up to 140 MMcfd available to interested shippers. The PNGTS expansion may also be paired with upstream expansions on TQM and TCPL that expand shipper supply choices.

Exhibit 4-7 Portland Natural Gas Transmission System C2C Expansion



Source: PNGTS

The total proposed pipeline expansions into New England capable of serving Atlantic Canada is approximately 2.68 Bcf/d. ICF makes no prognosis on which of these pipeline projects will go forward or the total amount of new capacity available to shippers in New England and in Atlantic Canada. This will depend on the number of shippers who will agree to contract for long term pipeline capacity.

4.2 Middle Melford LNG and Nova Scotia Gas Demand

In 2013, the Department of Energy released a report entitled "The Future of Natural Gas Supply for Nova Scotia", written by ICF International. The report forecast that Nova Scotia's "gas demand will exceed domestic gas production regularly within the next ten years," and that rapid growth of shale gas production will make Atlantic Canada production less economic. Our conclusion in the report spoke to this issue:

> *Given the need for external supply, ICF believes there is a strong argument for Maritimes Canada consumers to contract for firm pipeline capacity on one of the proposed pipeline expansions into New England that would allow shippers to buy gas at one of the Marcellus basin hubs to an interconnection with M&NP.*[30]

In our view, Middle Melford LNG can act as an anchor shipper in order to support the delivery of gas into Nova Scotia. With such an anchor demand, Nova Scotia and New Brunswick would be more likely to attract investors to develop pipeline infrastructure to meet the growing shortfall in supply. Gas storage at the proposed Alton storage facility could also be beneficial for the region, and as such Middle Melford LNG will also help support the investment in the storage project. Thus, as an anchor shipper, Middle

[30] ICF Consulting Canada, The Future of Natural Gas Supply in Nova Scotia. March 2013, p. 6.

Melford LNG could play a critical role in supporting infrastructure build-outs that could benefit all gas consumers in Atlantic Canada.

5. Summary & Conclusions

Based on this review, ICF believes the gas resources are adequate for meeting Middle Melford LNG's export requirements and that pipeline capacity will be available to supply the project. ICF's concluding observations are as follows.

- The U.S. and Canadian gas markets are highly developed relative to the rest of the world. ICF assumes normal functioning of the gas market to continue. This implies that the market will respond to the demand for LNG exports and for domestic consumption in such a way that both can be served, with minimal market disruptions. The restrictions on LNG exports will not be from the market or the lack of resource base, but in the form of commercial viability of individual projects.
- North America's gas resources are very large, with shale resources accounting for over half of the remaining, economically recoverable gas. ICF estimates over 4,000 Tcf of gas is producible with today's technology at a cost of production of $14/MMBtu or less. (More resources could be produced at higher cost.) At this level of resources, the market can support 133 years of total North American consumption with Middle Melford. Using Canadian resources alone and Canadian consumption, the multiple is 238 years. In reality, as more wells are drilled, more resources will be discovered (resource appreciation), technology will improve exploration and production efficiencies, and costs of production will decline, even as more costly resources are tapped. Thus, ICF believes that the natural gas resources are more than adequate to meet domestic demand and exports from Middle Melford.
- This large resource base has been a key driver underlying the general decline in gas prices since the early 2000s and the growth of gas demand for power, industrial use, and exports. ICF forecasts that by 2050, the domestic market for natural gas in North America will be at 130 Bcf/d. This translates to approximately 47.5 Tcf per year. ICF's resource supply curve shows approximately 1,500 Tcf are available at prices at or below $5.00/MMBtu. Thus, there are substantial resources available at moderate prices.
- This report notes that the Canadian resources available in Atlantic Canada are modest relative to the rest of the continent, approximately 100 Tcf of remaining and unproved resources out of the 4,072 Tcf total for North America. Development of the resources from Sable Island took place when gas prices were much higher and expectations were for a declining resource base in North America. With the advent of shale gas, the economics of the Atlantic Canada gas production have changed and ICF forecasts declining production, mainly for lack of market. ICF is aware that AC LNG has met with Atlantic Canada producers and may acquire some portion of their gas from local production. Nevertheless, we believe the major source of supply will be the United States, mainly the Marcellus production. WCSB supply can also be a source for the Middle Melford facility. In both cases, there is adequate supply from these basins to support the incremental exports from Middle Melford.
- The proposed LNG export volumes from Middle Melford would begin in 2019 at 0.46 Bcf/d, approximately 1.3% of ICF's forecast for production from North American domestic sources. By 2030, when the exports from Middle Melford reach 2.1 Bcf/d, the quantity represents less than 2% of North American production.
- LNG exports will lead to greater demand for gas than would be the case otherwise and requiring additional drilling and production to meet the incremental export requirements. This will lead to

higher costs. ICF's gas price forecasts include already include the effects of 12.5 Bcf/d of exports from Canadian and U.S. ports. Our estimates of the incremental cost of exports over the long run are about $0.07 per Bcf/d of export expansion. At 2.1 Bcf/d, Middle Melford could have a price impact of approximately $0.15/MMBtu on North American gas prices above those prices forecast by ICF for this report.

- Were Canadian demand to be higher than forecast in this report, gas prices would increase throughout North America. ICF estimated a case where Canadian domestic demand increased by 20% by the year 2035. The results show that the resource base is adequate to meet that contingency, with price impacts greatest in AECO where gas prices could increase by 6% and at Dawn where gas prices would increase by 4%. Under this scenario there is higher gas production in the WCSB relative to the Base Case and more imports from Marcellus to Ontario and Quebec than in the Base Case.
- In the unlikely case that all of the LNG export projects approved by the NEB were to become operational, the impact on prices could be considerably more substantial. We estimate that by 2050, the gas price could be $1.52/MMBtu higher in real terms (2012$) than in the Base Case.
- The major barrier to supplying the Middle Melford project will be adequate pipeline capacity from the supply sources into Nova Scotia. Pipeline capacity is being developed to support growth in production from Marcellus, including expansions into New England and Atlantic Canada to meet demand growth. ICF is aware that AC LNG has been in discussions with some of these pipeline companies.

Thus, ICF sees substantial movement in providing the infrastructure to support expanded consumption in Atlantic Canada and the Middle Melford export facility.

Appendix A – ICF Gas Market Model

ICF's Gas Market Model (GMM®) a nationally recognized modeling and market analysis system for the North American gas market will be used to forecast gas prices and avoided costs for this project. GMM© was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. Subsequently, GMM has been used to complete strategic planning studies including:

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

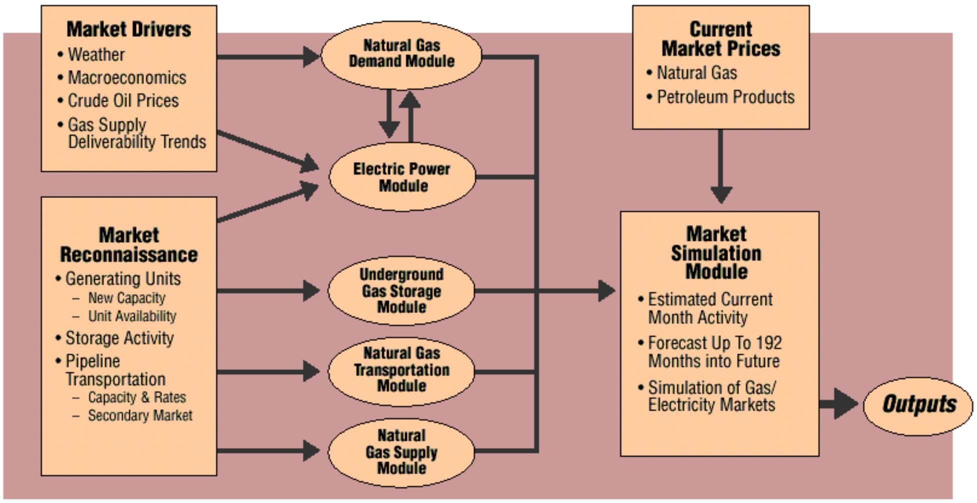
In addition to its use for strategic planning studies, the GMM has been widely used by a number of institutional clients and advisory councils, including INGAA, which relied on the model for the 30 Tcf market analysis completed in 1998 and again in 2004. The model was also the primary tool used to complete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

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

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

There are nine different components of the GMM, as shown in Exhibit A-1. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Exhibit A-1: GMM Structure



The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Exhibit A-2 and the nodes are identified by name in Exhibit A-7. The gas supply component of the model solves for node-level natural gas deliverability or supply capability. The Hydrocarbon Supply Model (HSM) may be integrated with the GMM® to solve for deliverability. The supply module also creates LNG supply curves that are used by the model to solve for LNG imports. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, Markets, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module. A few other charts that summarize input/output and regional breakout for the GMM are shown as Exhibits A-3 through A-6.

Exhibit A-2: GMM Transmission Network

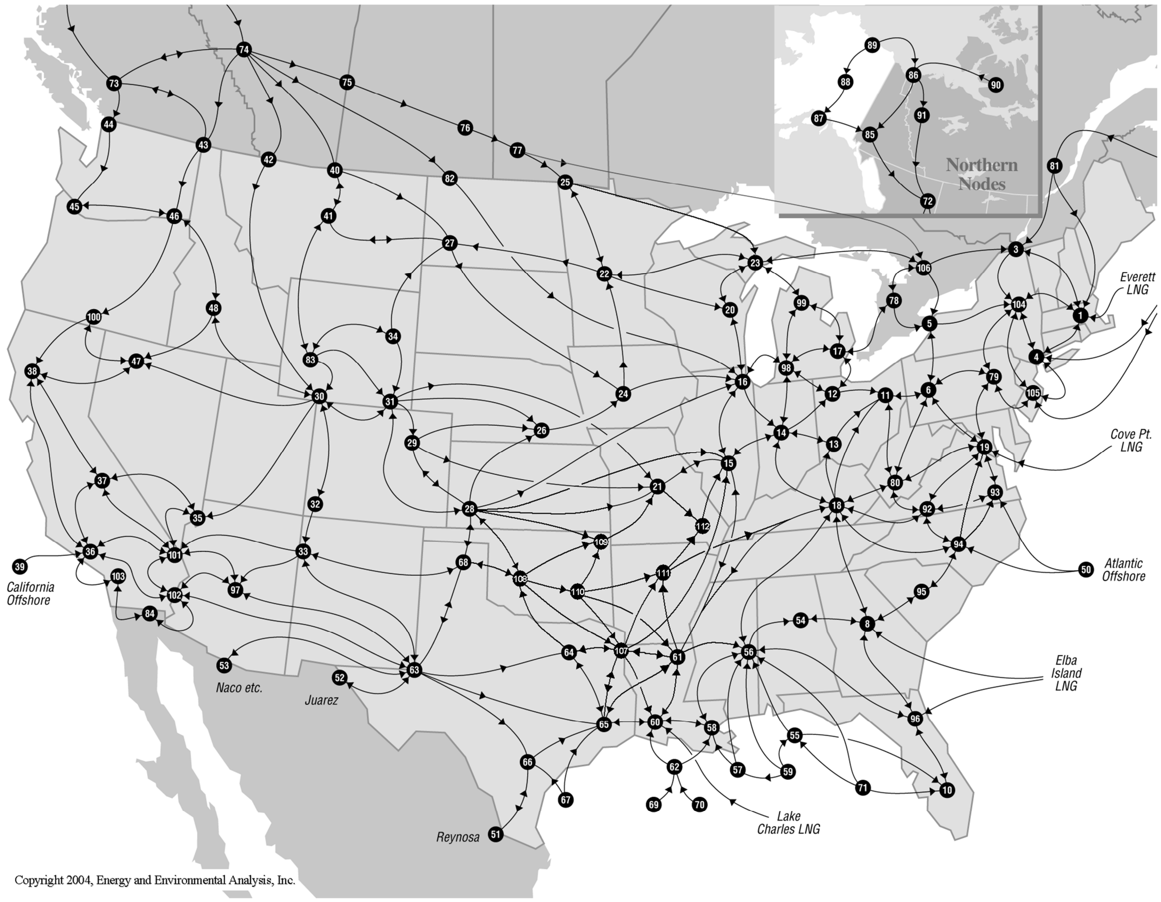


Exhibit A-3: Model Input and Output

Model Drivers And Output

R/C/I Natural Gas Demand

DRIVERS	OUTPUT
• **Heating Degree Days** • **Economic Activity** • **Gas & Petroleum Prices**	► ***Residential, Commercial, & Industrial Gas Demand***

Gas Supply

DRIVERS	OUTPUT
• **Base Deliverability Trends** • **Gas Prices** • **LNG Supply**	► ***Natural Gas Production*** ► ***Wellhead and Gathering System Deliverability***

Gas Transportation

DRIVERS	OUTPUT
• **Pipeline Capacity** – *Existing Capacity* – *Capacity Expansions* – *Operating Conditions* • **Transportation Rates** – *FERC Tariffs* – *Discounted Rates* – *Brokered Capacity Prices*	► ***Flow on pipeline corridors*** ► ***Value of gas transmission, i.e. forecast rates based on corridor load factors.***

Electric Utility Gas Demand

DRIVERS	OUTPUT
• **Total Electricity Generation** • **Non-fossil Generation** • **Unit Availability** – *New Capacity On-Line* – *Scheduled Downtime* – *Maintenance & Availability Conditions* • **Fuel Prices** • **Heating & Cooling Degree Days** • **Economic Activity**	► ***Gas Consumed by Power Generators***

Gas Storage

DRIVERS	OUTPUT
• **Storage Capacity** • **Deliverability**	► ***Storage Inventory***
• **Withdrawal Season:** – *Market Demand* – *Usage Patterns* – *Cycling Requirements*	► ***Net Storage Injections/Withdrawals***
• **Injection Season:** – *Inventory Targets* – *Refill Patterns* – *Spot/Futures Price Spread*	► ***Net Storage Injections/Withdrawals***

Exhibit A-4: Model Input and Output

Outputs of the Forecasting System

MONTHLY DATA	*DATA CONTENT*	*GEOGRAPHIC DETAIL OF DATA*
Gas Pricing	Delivered to Pipeline and Citygate Prices	112 Points
Pipeline Transportation	Inter-Regional Capacity Tariffs Caps Market Value of Capacity	327 Network Corridors
Gas Storage	Working Gas Capacity Inventories Injection/Withdrawal Activity	26 Storage Regions
Natural Gas Demand	By Sector (R/C/I)	34 U.S. and 7 Canada/Alaska Regions
Natural Gas Supply	Deliverability Dry Production Gas Imports/Exports Supplemental Fuels	62 U.S. and 13 Canada/Alaska Regions
Electricity Markets (U.S. Only With Explicity Imports)	Natural Gas Demand Electricity Demand Power Generation Balance Gas-fired Generation	13 "NERC" Regions

Exhibit A-5: Demand Regions

Exhibit A-6: Production Regions

Exhibit A-7: GMM Network Node List

Node	Name	Node	Name
1	New England	57	East Louisiana Shelf
2	Everett LNG	58	Eastern Louisiana Hub
3	Quebec	59	Viosca Knoll/Desoto/Miss Canyon
4	New York City	60	Henry Hub
5	Niagara	61	North Louisiana Hub
6	Leidy	62	Central and West Louisiana Shelf
7	Cove Point LNG	63	Southwest Texas
8	Georgia	64	Dallas/Ft Worth
9	Elba Island LNG	65	East Texas (Katy)
10	South Florida	66	South Texas
11	East Ohio	67	Offshore Texas
12	Maumee/Defiance	68	Northwest Texas
13	Lebanon	69	Garden Banks
14	Indiana	70	Green Canyon
15	South Illinois	71	Eastern Gulf
16	North Illinois	72	North British Columbia
17	Southeast Michigan	73	South British Columbia
18	Tennessee/Kentucky	74	Caroline
19	MD/DC/Northern VA	75	Empress
20	Wisconsin	76	Saskatchewan
21	Northern Missouri	77	Manitoba
22	Minnesota	78	Dawn
23	Crystal Falls	79	Philadelphia
24	Ventura	80	West Virginia
25	Emerson Imports	81	Eastern Canada Demand
26	Nebraska	82	Alliance Border Crossing
27	Great Plains	83	Wind River Basin
28	Kansas	84	California Mexican Exports
29	East Colorado	85	Whitehorse
30	Opal	86	MacKenzie Delta
31	Cheyenne	87	South Alaska
32	San Juan Basin	88	Central Alaska
33	EPNG/TW	89	North Alaska
34	North Wyoming	90	Arctic
35	South Nevada	91	Norman Wells
36	SOCAL Area	92	Southwest Virginia
37	Enhanced Oil Recovery Region	93	Southeast Virginia
38	PGE Area	94	North Carolina
39	Pacific Offshore	95	South Carolina
40	Monchy Imports	96	North Florida
41	Montana/North Dakota	97	Arizona
42	Wild Horse Imports	98	Southwest Michigan
43	Kingsgate Imports	99	Northern Michigan
44	Huntingdon Imports	100	Malin Interchange
45	Pacific Northwest	101	Topock Interchange
46	NPC/PGT Hub	102	Ehrenberg Interchange
47	North Nevada	103	SDG&E Demand
48	Idaho	104	Eastern New York
49	Eastern Canada Offshore	105	New Jersey
50	Atlantic Offshore	106	Toronto
51	Reynosa Imp/Exp	107	Carthage
52	Juarez Imp/Exp	108	Southwest Oklahoma
53	Naco Imp/Exp	109	Northeast Oklahoma
54	North Alabama	110	Southeastern Oklahoma
55	Alabama Offshore	111	Northern Arkansas
56	Mississippi/South Alabama	112	Southeast Missouri

Appendix B – Approved LNG Export Projects (US & Canada)

Exhibit B-1 Canada: NEB Approved Projects

Company	NEB Application Status	Term Length	Licence Issued	Capacity (Bcf/d)
KM LNG	Approved	20 years	Yes	1.28
BC LNG	Approved	20 years	Yes	0.23
LNG Canada	Approved	25 years	Yes	3.23
Pacific Northwest LNG	Approved	25 years	Yes	2.70
WCC LNG	Approved	25 years	Yes	4.11
Prince Rupert LNG	Approved	25 years	Yes	2.96
Woodfibre LNG	Approved	25 years	Yes	0.29
Jordan Cove LNG	Approved	25 years	No	1.55
Triton LNG	Approved	25 years	Yes	0.3
Aurora LNG	Approved	25 years	Yes	3.7
Oregon LNG	Approved	25 years	No	1.3
Woodside LNG	Approved	25 years	N/A	2.8
CANADA TOTAL	**12**		**9**	**24.4 Bcf/d**

Source: National Energy Board: *http://www.neb-one.gc.ca/pplctnflng/mjrpp/lngxprtlcnc/index-eng.html*

Exhibit B-2: U.S. DOE Approved Projects

Project	Location	Year In-Service	Quantity (Bcf/d)	FTA Approval	Non-FTA Approval	FERC Approval
Sabine Pass Liquefaction, LLC	Sabine, LA	2015	2.2	Y	Y	Y (2.76 Bcf/d)
Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC	Freeport, TX	2017	1.4	Y	Y	Y (1.8 Bcf/d)
Lake Charles Exports, LLC	Lake Charles, LA	2018	2	Y	Y	N
Carib Energy (USA) LLC	N/A	Unknown	0.03	Y	Y	N
Dominion Cove Point LNG, LP	Cove Point, MD	2017	1	Y	Y	Y (0.82 Bcf/d)
Jordan Cove Energy Project, L.P.	Coos Bay, OR	2018	1.2	Y	Y	N
Cameron LNG, LLC	Hackberry, LA	2017	1.7	Y	Y	Y (1.7 Bcf/d)
Freeport LNG Expansion, L.P. and FLNG Liquefaction,	Freeport, TX	2017	1.4	Y	Y	N
Gulf Coast LNG Export, LLC (i)	Brownsville, TX	Unknown	2.8	Y	N	N
Gulf LNG Liquefaction	Pascagoula, MS	2018	1.5	Y	N	N
Oregon LNG	Astoria, OR	2018	1.25	Y	N	N
SB Power Solutions Inc.	N/A	Unknown	0.07	Y	N	N
Southern LNG Company, L.L.C.	Elba Island, GA	2016	0.5	Y	N	N
Excelerate Liquefaction Solutions I, LLC	Lavaca Bay, TX	2018	1.38	Y	N	N
Golden Pass Products LLC	Sabine Pass, TX	2018	2.6	Y	N	N
Cheniere Marketing	Corpus Christi, TX	2018	2.1	Y	N	N
Main Pass Energy Hub, LLC	Offshore LA	2018	3.22	Y	N	N
CE FLNG, LLC	Plaquemines Parish, LA	2018	1.07	Y	N	N
Waller LNG Services, LLC	Cameron Parish, LA	Unknown	0.16	Y	N	N
Pangea LNG (North America) Holdings, LLC	Corpus Christi, TX	2017	1.09	Y	N	N

Magnolia LNG, LLC	Lake Charles, LA	2018	0.54	Y	N	N
Trunkline LNG Export, LLC (same facility as Lake Charles)	Lake Charles, LA	2018	2	Y	N	N
Gasfin Development USA, LLC	Cameron Parish, LA	Unknown	0.2	Y	N	N
Freeport-McMoRan Energy LLC (same facility as Main Pass)	Offshore LA	2018	3.22	Y	N	N
Sabine Pass Liquefaction, LLC	Sabine Pass, LA	2018	0.28	Y	N	N
Sabine Pass Liquefaction, LLC	Sabine Pass, LA	2018	0.24	Y	N	N
Venture Global LNG, LLC	Cameron Parish, LA	Unknown	0.67	Y	N	N
Advanced Energy Solutions	Baltimore, MD	Unknown	0.02	Y	N	N
Argent Marine Management			0.003	Y	N	N
Eos LNG LLC	Brownsville, TX	Unknown	1.6	Y	N	N
Barca LNG LLC	Brownsville, TX	2016	1.6	Y	N	N
Sabine Pass Liquefaction, LLC	Sabine, LA	2015	0.86	Y	N	N
Delfin LNG	Offshore GOM	2017	1.8	Y	N	N
Magnolia LNG, LLC	Lake Charles, LA	2018	1.08	Y	N	N
Annova LNG	Brownsville, TX	2019	0.94	Y	N	N
Texas LNG	Brownsville, TX	2018	0.27	Y	N	N
Louisiana LNG Energy LLC	Plaquemines Parish, LA	2017	0.28	Y	N	N
TOTAL			**44.3 Bcf/d**	**37**	**9**	**4**
Approved Non-FTA Total			**9.3 Bcf/d**			
FERC Approved Total			**7.1 Bcf/d**			

Sources: U.S. DOE:
http://energy.gov/sites/prod/files/2014/10/f18/Summary%20of%20LNG%20Export%20Applications_0.pdf
FERC: http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf

Appendix C – Key ICF August 2014 Base Case Projections

Exhibit C-1: WCSB Gas Production (Bcf/d)

Year	Conventional & Tight	CBM	Shale	Total
2010	13.59	0.87	1.05	15.52
2015	8.96	0.69	4.35	14.00
2020	6.59	0.52	8.29	15.40
2025	5.58	0.40	11.33	17.30
2030	5.13	0.32	12.59	18.04
2035	4.75	0.27	13.93	18.95
2040	4.31	0.24	15.06	19.61
2045	3.77	0.22	15.73	19.72
2050	3.14	0.21	15.92	19.26

Exhibit C-2: Eastern. Canada Gas Production (Bcf/d)

Year	Conventional & Tight	CBM	Shale	Total
2010	0.32	-	-	0.32
2015	0.29	-	-	0.29
2020	0.09	-	-	0.09
2025	0.03	-	-	0.03
2030	0.01	-	-	0.01
2035	0.00	-	-	0.00
2040	-	-	-	-
2045	-	-	-	-
2050	-	-	-	-

Exhibit C-3: US & Canada Demand (Bcf/d)

Sector	2010	2015	2020	2025	2030	2035	2040	2045	2050
Residential	15.34	15.32	15.50	15.76	15.78	15.67	15.59	15.57	15.51
Commercial	9.81	10.33	10.11	10.07	9.90	9.59	9.39	9.29	9.19
Industrial	20.04	24.56	26.43	27.84	28.52	29.32	29.74	30.29	30.61
Power Generation	22.01	27.37	28.13	32.97	38.57	43.30	46.70	47.84	48.16
Pipeline Fuel	2.34	2.09	2.17	2.38	2.56	2.86	3.06	3.19	3.30
Lease & Plant	4.85	5.33	5.85	6.39	6.69	6.95	7.20	7.47	7.71
LNG Net Exports	(0.36)	(0.17)	7.65	11.50	11.47	11.46	11.41	11.44	11.44
Mexico Exports	0.93	2.75	4.20	4.52	4.98	4.94	4.93	4.95	4.95
TOTAL	74.99	87.58	100.04	111.43	118.47	124.09	128.02	130.02	130.87

Exhibit C-4: Canada Demand (Bcf/d)

Sector	2010	2015	2020	2025	2030	2035	2040	2045	2050
Residential	1.72	1.92	1.96	2.00	2.03	2.04	2.07	2.09	2.10
Commercial	1.14	1.32	1.30	1.30	1.29	1.27	1.26	1.25	1.24
Industrial	2.88	3.74	4.33	4.82	5.22	5.68	5.79	5.93	6.00
Power Generation	1.56	2.13	2.59	3.06	3.46	3.98	4.47	4.61	4.67
Pipeline Fuel	0.27	0.15	0.18	0.19	0.20	0.22	0.24	0.25	0.26
Lease & Plant	1.34	1.18	1.24	1.37	1.42	1.48	1.51	1.53	1.53
LNG Net Exports	(0.21)	(0.10)	1.18	2.60	2.57	2.56	2.54	2.54	2.54
TOTAL	8.70	10.34	12.77	15.34	16.18	17.24	17.88	18.20	18.33

Exhibit C-5: Regional Canadian Total Consumption (including LNG Exports) Bcf/d)

Canadian Regions	2010	2015	2020	2025	2030	2035	2040	2045	2050
Maritimes	0.17	0.20	0.20	0.21	0.21	0.22	0.22	0.23	0.23
Quebec	0.59	0.68	0.66	0.63	0.57	0.58	0.58	0.59	0.59
Ontario	2.36	2.88	3.21	3.58	3.83	4.30	4.55	4.65	4.69
Manitoba	0.21	0.22	0.22	0.23	0.23	0.25	0.26	0.26	0.27
Saskatchewan	0.58	0.57	0.61	0.67	0.71	0.75	0.77	0.79	0.80
Alberta	4.04	4.66	5.18	5.66	6.17	6.47	6.70	6.84	6.89
British Columbia	0.96	1.23	1.51	1.77	1.90	2.13	2.26	2.31	2.33
LNG Net Exports	-0.21	-0.10	1.18	2.60	2.57	2.56	2.54	2.54	2.54
Canada Total	8.70	10.34	12.77	15.34	16.18	17.24	17.88	18.20	18.33

Exhibit C-6: US & Canada Gas Production (Bcf/d)

Year	Conventional & Tight	CBM	Shale	Total
2010	54.18	15.98	5.22	75.37
2015	41.19	44.47	3.75	89.41
2020	35.97	62.79	3.35	102.11
2025	35.40	75.07	3.17	113.65
2030	35.95	81.48	3.06	120.49
2035	37.10	86.23	3.00	126.33
2040	37.91	89.49	2.95	130.35
2045	38.41	91.29	2.88	132.58
2050	38.58	91.65	2.80	133.02

Exhibit C-7: Marcellus Region Gas Production (Bcf/d)

Year	Conventional & Tight	CBM	Shale	Total
2010	1.68	0.24	1.82	3.74
2015	1.23	0.19	16.50	17.93
2020	0.89	0.19	25.71	26.79
2025	0.67	0.19	30.79	31.65
2030	0.53	0.19	33.26	33.99
2035	0.44	0.21	34.71	35.35
2040	0.35	0.22	35.87	36.43
2045	0.26	0.21	37.03	37.50
2050	0.17	0.18	38.19	38.54

Appendix-D. Planned Annual Export Volumes and Tolerance

Project Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Anticipated Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Natural Gas Feed Volume to LNG facility																									
Annual Quantity (10^9 m3)	5.3	5.3	10.6	10.6	10.6	10.6	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
Annual Quantity (Bcf)	186.6	186.6	373.2	373.2	373.2	373.2	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7	839.7
Cumulative Quantity (10^9 m3)	5.3	10.6	21.1	31.7	42.3	52.9	76.6	100.4	124.2	148.0	171.8	195.6	219.4	243.2	267.0	290.7	314.5	338.3	362.1	385.9	409.7	433.5	457.3	481.0	504.8
Cumulative Quantity (Bcf)	187	373	746	1,120	1,493	1,866	2,706	3,546	4,385	5,225	6,065	6,904	7,744	8,584	9,424	10,263	11,103	11,943	12,783	13,622	14,462	15,302	16,142	16,981	17,821
Daily Quantity (10^6 m3)	14.5	14.5	29.0	29.0	29.0	29.0	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2	65.2
Daily Quantity (Bcf)	0.51	0.51	1.02	1.02	1.02	1.02	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
LNG Export Licence (Exclusive of tolerance)																									
Annual Quantity (MT)	3.0	3.0	6.0	6.0	6.0	6.0	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Annual Quantity (10^9 m3)	4.1	4.1	8.3	8.3	8.3	8.3	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6	18.6
Annual Quantity (Bcf)	146.0	146.0	292.1	292.1	292.1	292.1	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2	657.2
Cumulative Quantity (MT)	3	6	12	18	24	30	44	57	71	84	98	111	125	138	152	165	179	192	206	219	233	246	260	273	287
Cumulative Quantity (10^9 m3)	4.1	8.3	16.5	24.8	33.1	41.4	60.0	78.6	97.2	115.8	134.5	153.1	171.7	190.3	208.9	227.5	246.2	264.8	283.4	302.0	320.6	339.2	357.9	376.5	395.1
Cumulative Quantity (Bcf)	146	292	584	876	1168	1460	2118	2775	3432	4089	4746	5403	6060	6718	7375	8032	8689	9346	10003	10661	11318	11975	12632	13289	13946
Daily Quantity (10^6 m3)	11.3	11.3	22.7	22.7	22.7	22.7	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
Daily Quantity (Bcf)	0.40	0.40	0.80	0.80	0.80	0.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
LNG Export Licence (inclusive of tolerance)																									
Annual Quantity (MT)	3.5	3.5	6.9	6.9	6.9	6.9	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Annual Quantity (10^9 m3)	4.8	4.8	9.5	9.5	9.5	9.5	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Annual Quantity (Bcf)	167.9	167.9	335.9	335.9	335.9	335.9	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7	755.7
Cumulative Quantity (MT)	3	7	14	21	28	35	50	66	81	97	112	128	143	159	174	190	205	221	236	252	267	283	298	314	329
Cumulative Quantity (10^9 m3)	4.8	9.5	19.0	28.5	38.1	47.6	69.0	90.4	111.8	133.2	154.6	176.0	197.4	218.8	240.3	261.7	283.1	304.5	325.9	347.3	368.7	390.1	411.5	432.9	454.3
Cumulative Quantity (Bcf)	168	336	672	1008	1344	1679	2435	3191	3947	4702	5458	6214	6970	7725	8481	9237	9993	10748	11504	12260	13015	13771	14527	15283	16038
Daily Quantity (10^6 m3)	13.0	13.0	26.1	26.1	26.1	26.1	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7	58.7
Daily Quantity (Bcf)	0.46	0.46	0.92	0.92	0.92	0.92	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07	2.07

Assumptions

Pipeline/Facility losses and consumption	10%

Conversion Factors

1.0 Tonnes (t) LNG	1,379.549 Cubic metres (m^3) natural gas
1.0 Cubic metres (m^3) natural gas	35.301 Cubic feet (cf) natural gas

Notes

1. A foundation project of three (3) LNG trains with first train commercial operations on January 1, 2019.
2. First train starts production from Year 2019 equivalent to 3.0 mtpa LNG export capacity, second train from year 2021 equivalent to 3.0 mtpa and third train from year 2025 equivalent to 7.5 mtpa.
3. Term of 25 years commences at the export of the first cargo from Train 1 .
4. Output of each train is 100% of nameplate capacity at time of commissioning .
6. Import volumes are calculated based on the LNG Export Licence quantities that are inclusive of the tolerance and the 10 percent pipeline/facility losses and consumption factor.

Natural Gas Feed volume to LNG facility				
Annual Quantity	*23.8*	*10^9 m^3*		
Term Quantity	*505*	*10^9 m^3*		
Daily Quantity	*2.3*	*Bcf*		
Export Licence Metrics				
Exclusive of Tolerance				
Annual Quantity	*13.5*	*MT*	*18.6*	*10^9 m^3*
Term Quantity	*287*	*MT*	*395*	*10^9 m^3*
Daily Quantity	*1.8*	*Bcf*		
Inclusive of Tolerance				
Annual Quantity	*15.5*	*MT*	*21.4*	*10^9 m^3*
Term Quantity	*329*	*MT*	*454*	*10^9 m^3*
Daily Quantity	*2.1*	*Bcf*		