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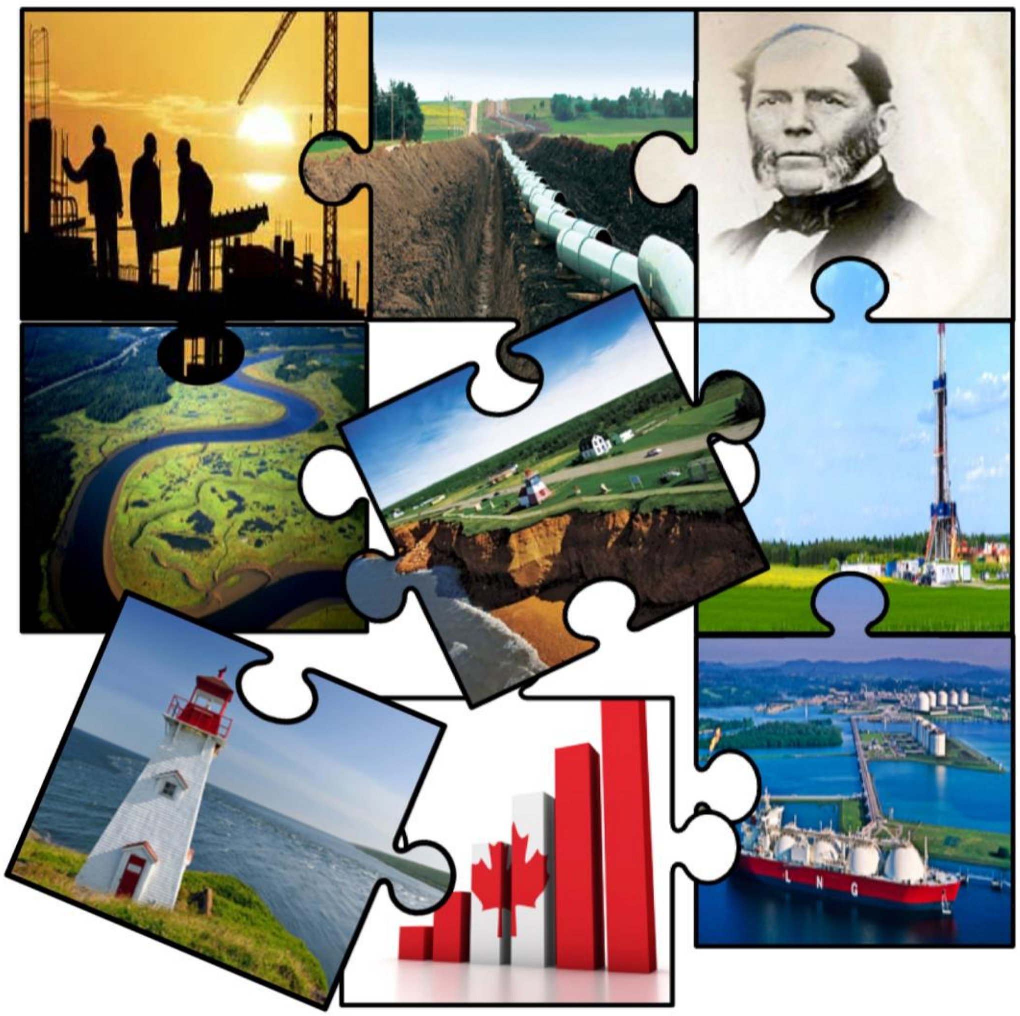
ECONOMIC POTENTIAL OF ONSHORE OIL AND GAS IN NEW BRUNSWICK AND NOVA SCOTIA



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ECONOMIC POTENTIAL OF ONSHORE OIL AND GAS IN NEW BRUNSWICK AND NOVA SCOTIA

Economic Potential of Onshore oil and Gas in
New Brunswick and Nova Scotia

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Acronyms and Abbreviations

AANDC	Aboriginal Affairs and Northern Development Canada
AAS	Aboriginal Affairs Secretariat (NB)
ACE	Atlantica Centre for Energy
AGT	Algonquin City-Gate
AGT +	AGT prices plus tolls
AGT -	AGT prices minus tolls
ANSMC	Assembly of Nova Scotia Mi’kmaq Chiefs
API	American Petroleum Institute
ARI	Advanced Resources International, Inc.
bbl	Barrels
BC	British Columbia
Bcf	Billion cubic feet
Bcfpd	Billion cubic feet per day
Bpd	Barrels per day
CAC	Criteria Air Contaminant
CAPP	Canadian Association of Petroleum Producers
CBM	Coalbed Methane
CCA	Council of Canadian Academies
CCME	Canadian Council of Ministers of the Environment
CEA	*Clear Environment Act* (NB)
CEAA, or CEA Agency	Canadian Environmental Assessment Agency
CEAA, 2012	*Canadian Environmental Assessment Act, 2012*
CEPA	Canadian Energy Pipeline Association
CERI	Canadian Energy Research Institute
CGE	Computable General Equilibrium
CGR	Cumulative Gross Revenue
CHF	Commission on Hydraulic Fracturing (NB)
CMOH	Chief Medical Officer of Health (NB)
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board

CO	Carbon monoxide
CO2	Carbon dioxide
COGOA	*Canada Oil and Gas Operations Act*
Corridor	Corridor Resources Inc.
CSUR	Canadian Society for Unconventional Resources
DAA	Department of Aboriginal Affairs (NB)
DELG	Department of Environment and Local Government (NB)
DEM	Department of Energy and Mines (NB)
DERD	Department of Energy and Resources Development (NB)
DOC	Direct Operating Costs
DOE	Department of Energy (NS)
DOH	Department of Health (NB)
DP	Depreciations
EA	*Environment Act* (NS)
EA	Environmental Assessment
E&P	Exploration and Production
ECCC	Environment and Climate Change Canada
EIA	Energy Information Administration (US)
EIA	Environmental Impact Assessment
EPA	Environment Protection Agency (US)
ER	Economic Rent
EUR	Estimated Ultimate Recovery
FBS	Frederick Brook Shale
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GLJ	GLJ Petroleum Consultants
GPA	Gas Processing Allowance
HBS	Horton Bluff Shale
HC	Health Canada
HIA	Health Impact Assessment
IEA	International Energy Agency

INAC	Indigenous and Northern Affairs Canada
I/O	Input/Output
IOGC	Indian Oil and Gas Canada
IP	Initial Production
IRPHF	Independent Review Panel on Hydraulic Fracturing (NS)
IRS	Indian Registry System
km	Kilometres
L	Litres
LNG	Liquefied Natural Gas
m3	Cubic metres
M&NP	Maritime & Northeast Pipeline
MBoe	Thousand barrels of oil equivalents
Mcf	Thousand cubic feet
Mcm	Million cubic metres
MEL	Ministry of Environment and Labour (NS)
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcfpd	Million cubic feet per day
MOU	Memorandum of Understanding
Mt	Million tons
MW	Megawatt
NB	New Brunswick
n.d.	Not dated
NEB	National Energy Board
NEBA	*National Energy Board Act* (Canada)
NILP	Non-Integer Linear Program
NORM	Naturally Occurring Radioactive Material
NOx	Nitrogen oxides
NRCan	Natural Resources Canada
NS	Nova Scotia
NSE	Nova Scotia Environment

OAA	Office of Aboriginal Affairs (NS)
OGC	Oil and Gas Commission (BC)
OHD	Overhead Allowance
ONGA	*Oil and Natural Gas Act (NB)*
2P Reserves	Proven and Probable Reserves
PCS	Potash Corporation of Saskatchewan Inc.
PM	Particulate Matter
PNGTS	Portland Natural Gas Transmission System
PSAC	Petroleum Services Association of Canada
psi	Pounds per square inch
Ro	Reflectance in Oil
SCC	Supreme Court of Canada
SCNS	Supreme Court of Nova Scotia
SIOT	Symmetrical Input/Output Table
SO2	Sulphur dioxide
SOEP	Sable Offshore Energy Project
SP	Selling Price
TC	Transport Cost
Tcf	Trillion cubic feet
TCPL	TransCanada Pipelines Limited
TMD	Total Measured Depth
TOC	Total Organic Carbon
TQM	Trans-Québec Maritimes
TVD	Total Vertical Depth
UBC	University of British Columbia
UCMRIO	CERI’s Multi-Regional Input/Output Model
UK, or U.K.	United Kingdom
US	United States
VOC	Volatile Organic Compound
WCSB	Western Canadian Sedimentary Basin
WP	Wellhead Price

Executive Summary

Natural gas is an important fuel in North America. And this is true for New Brunswick and Nova Scotia. Natural gas use in the two provinces has increased dramatically since 1999 — the completion of the Maritime & Northeast Pipeline (M&NP) delivering offshore Nova Scotia gas to these provinces and the US Northeast. With its many applications for various end-users, including residential, commercial, industrial and power generation, the demand for natural gas in both provinces is slated to increase over the next 20 years.

While both provinces are producers of natural gas, Nova Scotia's two offshore production assets are in natural decline, as is New Brunswick's McCully gas field. Not only are all three assets in decline, but the decline is rapid, with the region already looking to imports of gas in times of high local demand. Over the next few years that impending supply gap between domestic/regional natural gas production and regional demand for natural gas will likely grow.

Both provinces are without a doubt on the cusp of a fundamental change — a nexus point.

While Nova Scotia estimates its offshore resource potential at more than 8 billion barrels of oil and 120 trillion cubic feet (Tcf) of natural gas (CAPP 2017b), the region also has significant onshore oil and gas potential, largely stemming from unconventional resources, particularly shale gas. It is the three productive assets (McCully, Frederick Brook Shale and the Horton Bluff Shale) that are the focus of this study. Frederick Brook Shale (FBS) is estimated to contain 67.3 Tcf of shale gas in-place, while the estimates of the Horton Bluff Shale (HBS) range from 17 Tcf (ARI 2013) to 69 Tcf of gas in-place (NRCan 2016c).

While competitive with other nearby jurisdictions such as the Marcellus, the above-mentioned changes in technology could be a boon for the region's oil and gas sector and their economies, to utilize hydrocarbons for domestic purposes or to export them, there are also controversies, particularly regarding fracking. Whereas fracking is without doubt a game-changer for shale gas and tight oil, it is also a lightning rod for controversy, and is banned or has led to moratoriums in several jurisdictions, New Brunswick and Nova Scotia among them. On March 27, 2015, New Brunswick enacted an Act to amend the *Oil and Natural Gas Act*, prohibiting fracking in the province, while Nova Scotia banned fracking in the fall of 2014, following the Report of the Nova Scotia Independent Review Panel on Hydraulic Fracturing (NS IRPHF) (Corridor Resources Inc. 2016a; Gorman 2016).

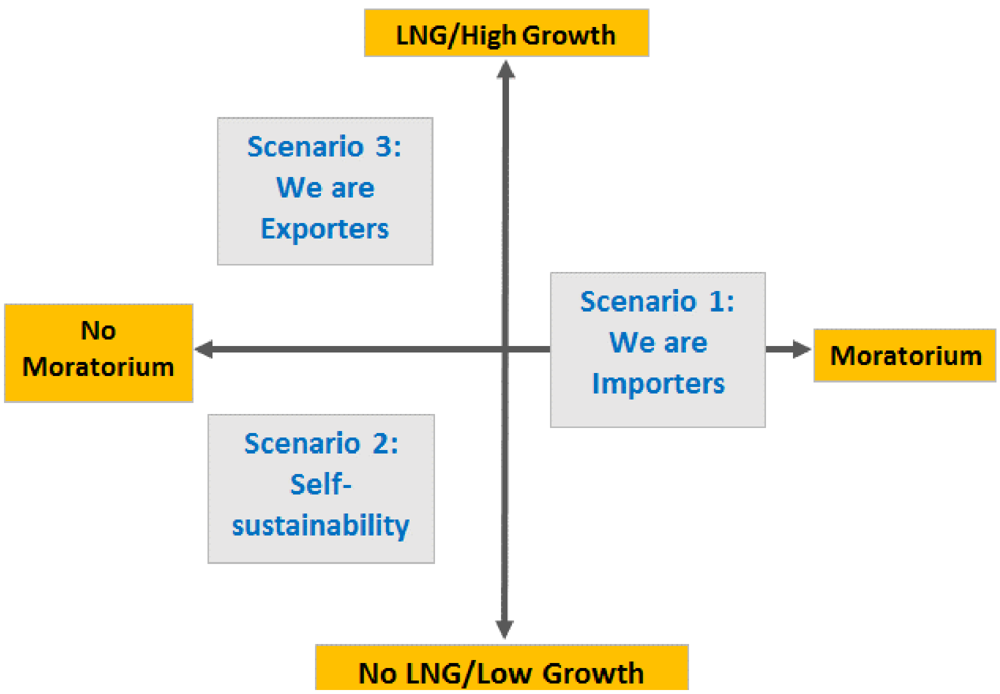
In addition to economic consideration, this study provides a review of potential environmental risks and Indigenous peoples' issues associated with oil and gas production in New Brunswick and Nova Scotia. There are five components in the former: surface and groundwater, greenhouse gas emissions, air quality, land impacts, and public health. The Aboriginal rights and Indigenous people's issues section reviews: the Indigenous peoples in New Brunswick and Nova Scotia, major legal cases clarifying the nature of Aboriginal rights and title, potential impacts on

Aboriginal rights, as well as highlights Aboriginal consultation and engagement issues and main approaches to address them.

While these issues are difficult to quantify, they must be weighed into the decision-making process.

There are an infinite amount of possibilities moving forward for New Brunswick and Nova Scotia from their nexus point. In this study, the Canadian Energy Research Institute (CERI) outlines three plausible scenarios, depicting the influence of high/low natural gas production and whether the current moratorium remains or is removed. These scenarios take into consideration onshore gas potential only, and excludes oil potential as it was found to be insignificant. Offshore potential is also excluded as it was out of scope of this study.

Figure E.1: Three Potential Scenarios of Shale Gas Development in New Brunswick and Nova Scotia



Source: CERI (2017)

Likewise, three scenarios yield different macroeconomic outcomes. Economic impacts under consideration include economy-wide impacts such as value-added gross domestic product (GDP), jobs created (given in person-years), as well as various forms of government revenue, including indirect, personal and corporate taxation revenues. Economic impacts are calculated for Canada, with Canadian impacts broken down to the provincial level. The results of developing gas in New Brunswick and Nova Scotia are presented for each scenario, to illustrate the impacts over the 21-year period (2017-2037).

The economic impacts for Scenario 1 are as follows (**for the period 2017-2037**):

- Total GDP impact in Canada is $166 million, of which $153 million is in New Brunswick, followed by $5 million in Ontario and $3 million in Quebec; the average GDP impact per year in New Brunswick is $7 million, or an increase in provincial GDP of 0.02 percent from 2015 GDP levels (measured in $2017).
- Total employment impact in Canada is 267 person years, of which 201 person years is in New Brunswick, followed by 27 person years in Ontario and 17 person years in Quebec; in other words, the total employment impact in Canada is 13 full-time annual jobs, on average over the life of the study, of which 10 full-time annual jobs, on average over the life of the study, are in New Brunswick.
- Total tax impacts in Canada (both federally and provincially) are $24 million, of which $22 million are in New Brunswick, followed by $1 million in both Ontario and Quebec.

The economic impacts for Scenario 2 are as follows (**for the period 2017-2037**):

- Total GDP impact in Canada is $14,634 million, of which $10,571 million is total operations and $4,063 million is total investment.
- Nova Scotia's total GDP impact is $6,923 million and New Brunswick's total GDP impact is $5,905 million, followed by Ontario and Quebec accounting for $825 million and $384 million, respectively. Alberta's GDP impact under Scenario 2 is $292 million.
- The average GDP impact per year in Nova Scotia is $330 million, or an increase in provincial GDP of 0.81 percent per year from 2015 GDP levels (measured in $2017) while the average GDP impact per year in New Brunswick is $281 million, or an increase in provincial GDP of 0.85 percent per year from 2015 GDP levels (measured in $2017).
- Total employment impact in Canada is 42,031 person years, of which 22,706 person years is from the investment phase and 19,325 person years is from the operations phase; in other words, total employment impact in Canada is 2,001 full-time annual jobs, on average over the life of the study, of which 1,081 full-time annual jobs, on average over the life of the study, are from the investment phase and 920 full-time annual jobs, on average over the life of the study, are from the operations phase.
- Nova Scotia's total employment impact is 19,032 person years and New Brunswick's total employment impact is 14,089 person years, followed by Ontario and Quebec accounting for 4,300 person years and 2,142 person years, respectively. Alberta's employment impact under Scenario 2 is 856 person years.
- In other words, Nova Scotia's total employment impact is 906 full-time annual jobs, on average over the life of the study, while New Brunswick's total employment impact is 671 full-time annual jobs, on average over the life of the study.
- Total tax impacts in Canada (both federally and provincially) are $2,262 million, of which $1,093 million is in Nova Scotia and $855 million are in New Brunswick. This is followed by $147 million in Ontario and $77 million in Quebec.

The economic impacts for Scenario 3 are as follows (**for the period 2017-2037**):

- Total GDP impact in Canada is $42,561 million, of which $25,524 million is total operations and $17,036 million is total investment.
- New Brunswick's total GDP impact is $18,855 million and Nova Scotia's total GDP impact is $17,715 million, followed by Ontario and Quebec accounting for $2,723 million and $1,300 million, respectively. Alberta's GDP impact under Scenario 3 is $967 million.
- The average GDP impact per year in New Brunswick is $898 million, or an increase in provincial GDP of 2.72 percent per year from 2015 GDP levels (measured in $2017) while the average GDP impact per year in Nova Scotia is $844 million, or an increase in provincial GDP per year of 2.07 percent per year from 2015 GDP levels (measured in $2017).
- Total employment impact in Canada is 141,242 person years, of which 95,269 person years is from the investment phase and 45,972 person years is from the operations phase; in other words, total employment impact in Canada is 6,726 full-time annual jobs, on average over the life of the study, of which 4,537 full-time annual jobs, on average over the life of the study, are from the investment phase and 2,189 full-time annual jobs, on average over the life of the study, are from the operations phase.
- Nova Scotia's total employment impact is 57,853 person years and New Brunswick's total employment impact is 53,666 person years, followed by Ontario and Quebec accounting for 14,232 person years and 7,280 person years, respectively. Alberta's employment impact under Scenario 3 is 2,843 person years.
- In other words, Nova Scotia's total employment impact is 2,755 full-time annual jobs, on average over the life of the study, while New Brunswick's total employment impact is 2,556 full-time annual jobs, on average over the life of the study.
- Total tax impacts in Canada (both federally and provincially) are $6,648 million, of which $2,838 million is in Nova Scotia and $2,766 million are in New Brunswick. This is followed by $486 million in Ontario and $262 million in Quebec.

With dwindling, offshore production and increasing local demand for natural gas, both jurisdictions will need to weigh the options moving forward, how and where local demand for natural gas will be met. The interesting irony is that Nova Scotia and New Brunswick have extensive histories in oil and gas exploration and production, New Brunswick dating back to 1859 – the same year as Pennsylvania's famous Drake well – and may yet become larger oil and gas players in the future. It was the unconventional resource, bituminous shale, that attracted Abraham Gesner in the mid-1800s. It is now another unconventional resource that may yet play a role in the Maritimes' future.

To what extent, to either satisfy their local needs or to become exporters, or perhaps just to import from the US Northeast or abroad, the decision has many variables and cannot be taken lightly.

Chapter 1: Introduction

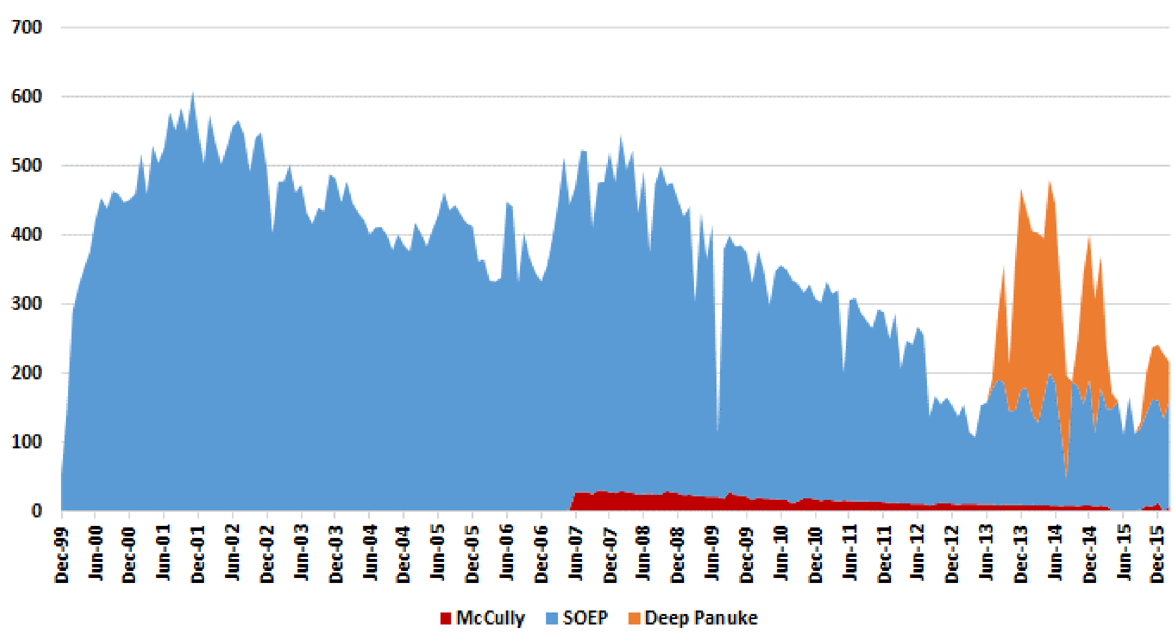
Setting the Stage

Nova Scotia and New Brunswick have extensive histories in oil and gas exploration and production. New Brunswick's oil and gas industry dates to 1859 while Nova Scotia's dates to the 1860s, ranking both jurisdictions as some of the oldest in North America, rivalling Pennsylvania's famous Drake Well, often regarded as the first commercial oil well in the world.

Both provinces are producers of natural gas, while New Brunswick is also currently an oil producer as well, with small amounts being produced at the historic Stoney Creek Oilfield, located near Hillsborough. Nova Scotia's production is entirely offshore, located approximately 250 kilometers off the coast of Nova Scotia, at Sable Offshore Energy Project (SOEP)[1] and Deep Panuke. The former is operated by a consortium, led by ExxonMobil, while the latter is operated by Encana Corporation. New Brunswick's gas production is onshore and is from the McCully Gas Field, located near Sussex in the southeastern part of the province. Corridor Resources holds an average of 75 percent, with its partner, Potash Corporation of Saskatchewan (PCS), holding the remaining natural gas lease (Corridor Resources Inc. n.d.).

Figure 1.1 illustrates natural gas production in Nova Scotia and New Brunswick.

Figure 1.1: Onshore New Brunswick and Offshore Nova Scotia Natural Gas Production (MMcfpd)



Data sources: (CNSOPB 2017b; NB DERD 2017c).

[1] SOEP is composed of six separate gas fields: Venture, South Venture, Thebaud, North Triumph, Glenelg and Alma.

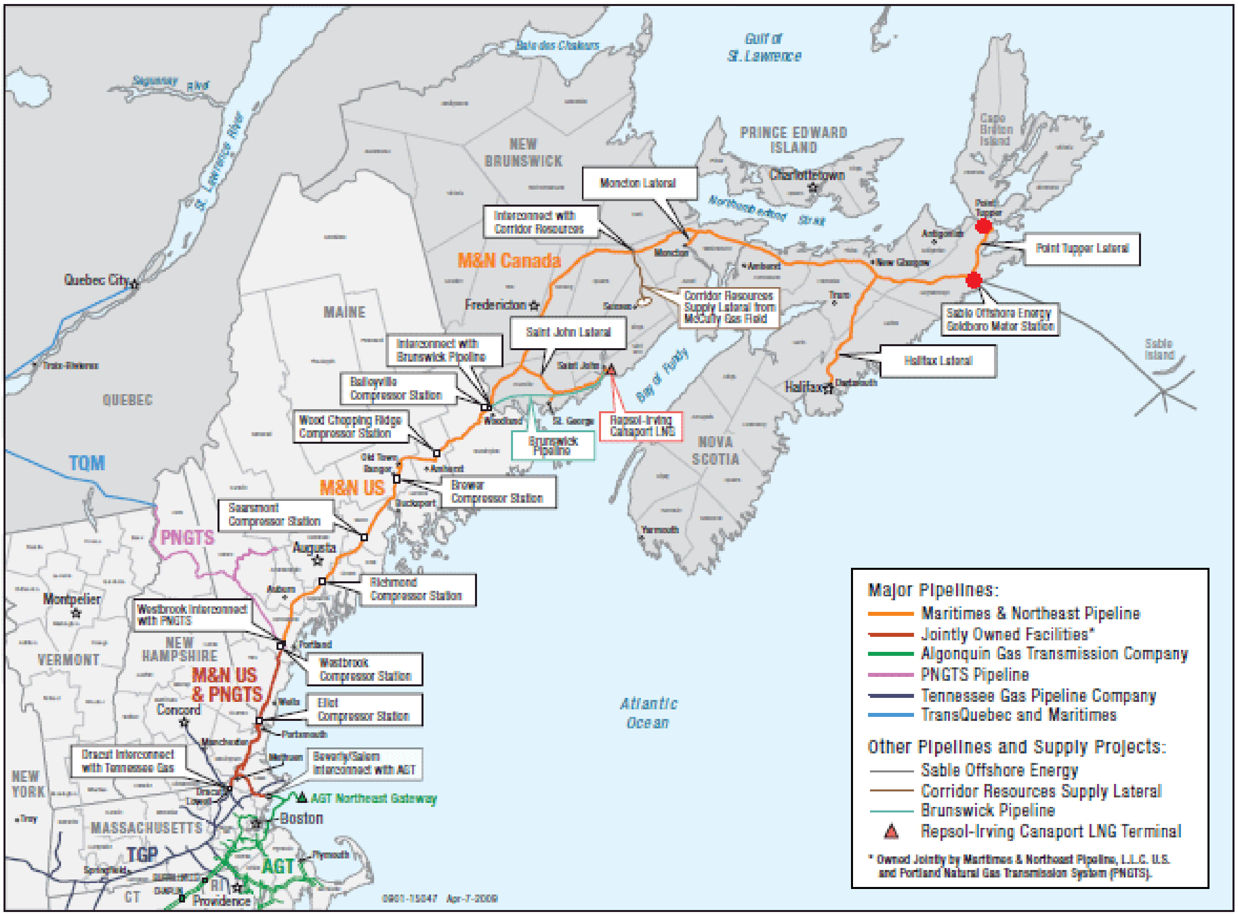
All three appear to be in natural decline. Beginning production in 1999, SOEP's life expectancy was expected to be 25 years, but this looks to be in doubt. With production peaking in the early 2000s, production dropped significantly thereafter, apart from a brief increase in early 2008 (NEB 2016b). Production decreased from a monthly peak of 518 million cubic metres (Mcm), or approximately 18.3 billion cubic feet (Bcf), in December 2001 to 105 Mcm, or approximately 3.7 Bcf, in November 2016. ExxonMobil announced in 2010 that Sable is being wound down, possibly as early as 2017 (Brooks Arenburg 2015; CBC News 2013a). Deep Panuke, on the other hand, began production in 2013 and was anticipated to have a 13-year production life (CNSOPB 2017a). Likewise, production of Deep Panuke has been reduced to seasonal in the fall of 2015, with production decreasing from 248 Mcm, or approximately 8.8 Bcf, in January 2014 to 47 Mcm, or approximately 1.7 Bcf, by November 2016 (CNSOPB 2014a, 2014b). Compared to SOEP and Deep Panuke, McCully' s gas production is moderate, producing 2,771 million cubic feet (MMcf) of natural gas in 2014,[2] compared to 117,048 MMcf in SOEP and Deep Panuke. Production at McCully is decreasing as well.

Beginning with SOEP, the energy landscape of both provinces changed with the onset of Nova Scotia's offshore production. It was accompanied by the construction of the 1,400-kilometer Maritimes & Northeast Pipeline (M&NP), transporting natural gas from the offshore projects to the New England markets, from Goldboro, Nova Scotia to Dracut, Massachusetts. Located approximately 250 kilometers off the coast of Nova Scotia, SOEP and Deep Panuke are connected to the Goldboro gas plant and Point Tupper Fractionation plant. The M&NP remains the Maritimes sole transmission line for natural gas.

Figure 1.2 illustrates the M&NP and the connectedness of the projects to nearby pipelines, as well as other energy-related infrastructure in the Maritimes and New England market. The figure also highlights New Brunswick's Canaport LNG facility — thus far, Canada's only liquefied natural gas (LNG) import or export facility — and the Emera Pipeline that delivers its natural gas from the regasification terminal in Saint John to St. Stephen where it connects with the M&NP. Emera owns the 145-kilometer pipeline while Repsol owns the regasification terminal.

[2] To illustrate the perspective, 2014 was used, due to Corridor shutting in natural gas production in part of 2015.

Figure 1.2: Energy Infrastructure in New Brunswick and Nova Scotia



Source: (Maritimes & Northeast Pipeline 2009)[3]

The M&NP with the capacity of 550 million cubic feet per day (MMcfpd) crosses into the US via St. Stephen and connects with the Portland Natural Gas Transmission System (PNGTS) at Westbrook which terminates in Dracut, Massachusetts. The M&NP is bi-directional, but the flow on the M&NP is traditionally north to south and terminates at Dracut, Massachusetts. However, this flow reversed in the spring of 2015, as the high demand in the Maritimes could not be met by Nova Scotia's offshore production.

At its southern point, the M&NP connects with a plethora of pipelines in the US Northeast, including the Algonquin Gas Transmission pipeline and the Tennessee Gas Transmission pipelines in the greater Boston area. The capacity of the US side of the M&NP is 830 MMcfpd (Spectra Energy 2017a). It is important to note that the PNGTS at Westbrook connects to Québec, via the Trans-Québec Maritimes Pipeline (TQM) at East Hereford, Québec, on the border with New Hampshire. The TQM pipeline's primary receipt point is with the TransCanada Pipeline (TCPL) Mainline, near Saint-Lazare, Québec, near the Ontario border and its main delivery points include

[3] Modified by CERI to show the locations of the proposed Goldboro LNG and Bear Head LNG (Pieridae LNG) facilities (depicted as red dots in Figure 1.2).

Montreal, Québec City and East Hereford (NEB 2017). The 572-kilometer pipeline has a capacity of 800 MMcfpd and is owned by TCPL (50 percent) and Gaz Metro (50 percent) (TransCanada 2017c). It is, however, important to note that the TQM connector from Montreal to East Hereford has a lower throughput capacity of 200 MMcfpd (NEB 2016c).

In addition, not only providing a critical piece of infrastructure, the M&NP features several laterals, serving local markets with natural gas as well. Following the construction of the M&NP, natural gas use in the Maritimes increased from 14,556 Terajoules in 2004 to 38,719 Terajoules in 2013, making it the fastest growing source of energy for the region (Jupia Consultants Inc. 2015). When the M&NP initially transported natural gas from SOEP in the early 2000s to the New England market, it delivered nearly 100 percent of the gas the project produced to the US market. At that time, there was virtually no natural gas market in Nova Scotia and New Brunswick (Jupia Consultants Inc. 2015). In 2012, the percentage of natural gas being transported, however, has decreased to approximately 18 percent, with larger amounts of gas being consumed in the Maritime Provinces (Jupia Consultants Inc. 2015).

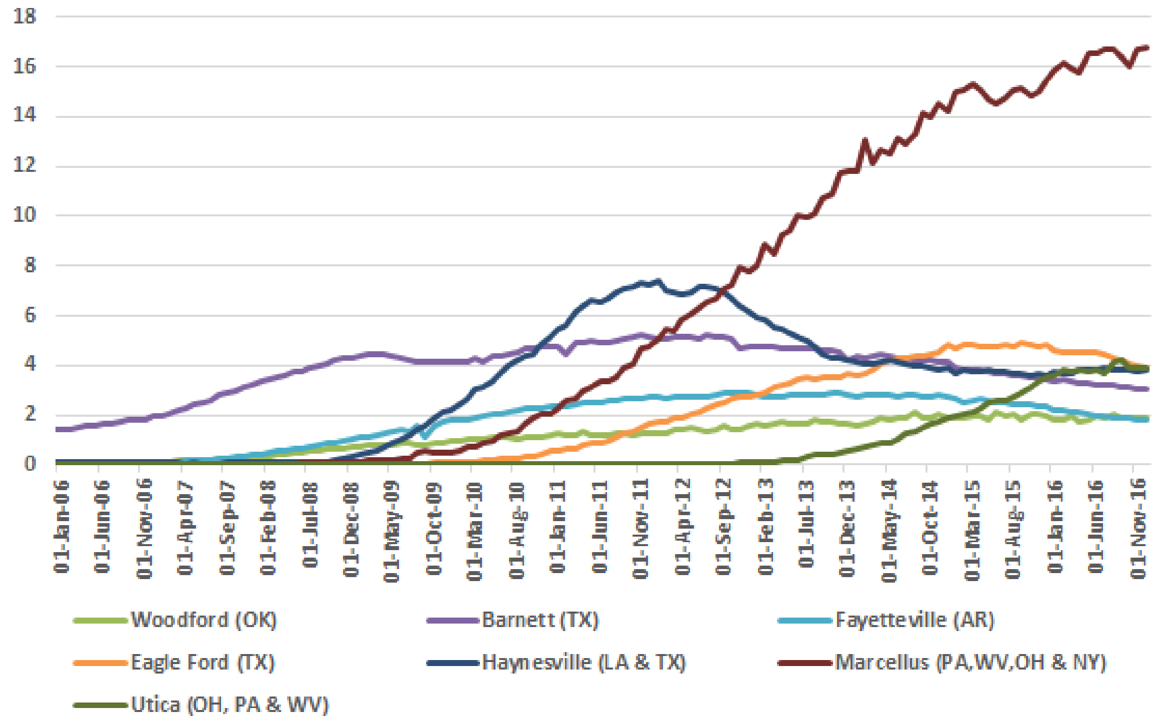
While still lagging behind other parts of Canada in terms of mid-size businesses and residential use, natural gas is mostly consumed by large industrial users and power generators. It is interesting to note that many homes utilize electricity in New Brunswick and predominantly fuel oil in Nova Scotia. Interestingly, while natural gas use in New England is also increasing, it is the part of the US that still also utilizes fuel oil at a higher percentage than other parts of the US.

The dramatic growth of the Marcellus and the Utica Shales in Pennsylvania, Ohio, West Virginia and New York are changing the role of natural gas in the US Northeast and have had a profound impact on the New England area, and will likely have an impact on Atlantic Canadian provinces as well.

Advances in horizontal drilling, 3-D seismic technology and hydraulic fracturing (fracking) are opening up new resources, previously determined as non-productive or not feasible to produce, particularly in the ability to economically recover natural gas and oil from shale rock.

Figure 1.3 illustrates US shale gas production, including the Marcellus Shale and the underlying Utica Shale. The figure also includes the Woodford, Haynesville, Eagle Ford, Barnett and Fayetteville.

Figure 1.3: Shale Gas Production in the US (Bcfpd)



Source: Energy Information Administration (US EIA 2017a)

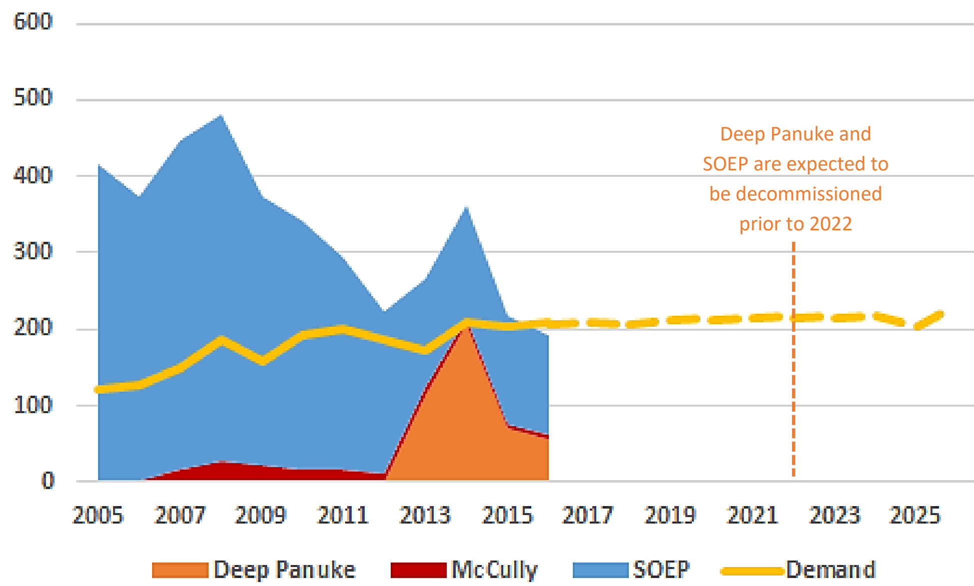
The impact of shale gas and tight oil cannot be overstated, and is truly global. Representing an increasingly large and growing share of the recoverable resource base, shale gas and tight oil is garnering a lot of interest, not only in the US, but is also having a profound impact for many jurisdictions across Canada. With the oil and gas resource in the two Maritime provinces' largely stemming from unconventional resources, please refer to Appendix A for additional information regarding shale gas.

While Nova Scotia estimates its offshore resource potential at more than 8 billion barrels of oil and 120 trillion cubic feet (Tcf) of natural gas (CAPP 2017b), the region also has significant onshore oil and gas potential, particularly for its unconventional resources. Frederick Brook Shale in New Brunswick and the Horton Bluff Shale in Nova Scotia are certainly garnering interest. These changes in technology could be a boon for the region's oil and gas sector and their economies, to export the hydrocarbons or to utilize them for domestic purposes, particularly in light of increasing regional demand combined with declining rates of natural gas production in SOEP and Deep Panuke.

This is illustrated in Figure 1.4, showing declines in Nova Scotia's offshore production in the backdrop of demand of natural gas in the two provinces. The figure illustrates the impending supply gap between domestic/regional natural gas production and regional demand for natural gas. The figure illustrates that Deep Panuke and SOEP are expected to be decommissioned by

2022. There is, however, speculation that offshore gas may be reduced before 2022. It is also important to note that the figure does not include the supply from Canaport LNG. The facilities' supply has been dwindling over the past several years, decreasing by more than half, from 27.86 Bcf in 2013 to 11.59 Bcf in 2016, and the facilities' use increasingly intermittent (NEB 2012).

Figure 1.4: New Brunswick and Nova Scotia Gas Production and Local Demand (MMcfpd)



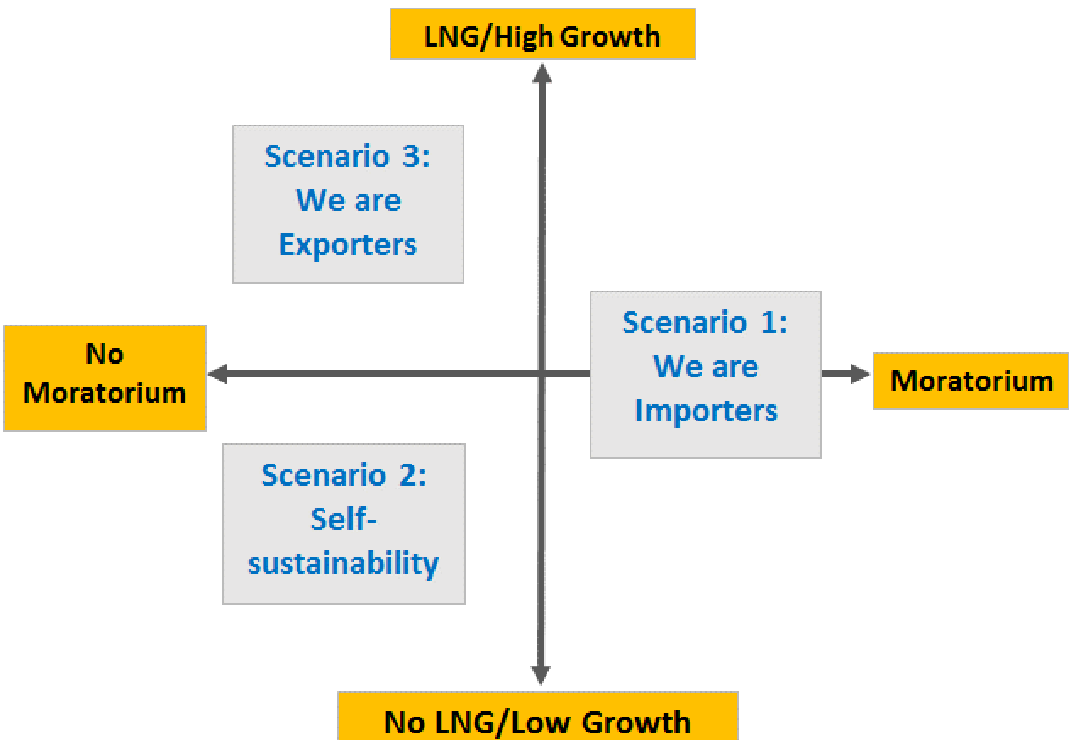
Data sources: (CNSOPB 2017b; NB DERD 2017c; NEB 2016a).

The techniques learned in East Texas' Barnett Shale that were soon utilized in other shale plays are, however, not without controversy. Hydraulic fracturing, in particular, draws concern from various stakeholders, across various jurisdictions, New Brunswick and Nova Scotia among them. On March 27, 2015, New Brunswick enacted an Act to amend the *Oil and Natural Gas Act*, prohibiting fracking in the province, while Nova Scotia banned fracking in the fall of 2014, following the Report of the Nova Scotia Independent Review Panel on Hydraulic Fracturing (NS IRPHF) (discussed in detail in Chapter 3) (Corridor Resources Inc. 2016a; Gorman 2016).

Both provinces are without a doubt on the cusp of a fundamental change — a nexus point.

While there is an infinite number of possible scenarios moving forward from the nexus point with regards to onshore gas development, CERI outlines three plausible scenarios for New Brunswick and Nova Scotia moving forward, depicting the influence of high/low natural gas production and whether the current moratorium remains or is removed. Despite the difference between moratorium and ban, the former is used in this document unless otherwise specified. These uncertainties are illustrated in Figure 1.5, with the X-axis showing whether both provinces keep the fracturing moratorium and the Y-axis showing LNG/high growth and no LNG/low growth production options. The decision to keep the moratorium denotes that exploration and production (E&Ps) operating in New Brunswick and Nova Scotia will not be permitted to frack, resulting in the fact that its shale gas resources will not be developed and no further development of McCully gas field takes place. The lifting of the moratorium results in the provinces developing their respective shale gas resources, as well as additional development at the McCully gas field. It is assumed that the decision to keep or remove the moratorium will be identical in Nova Scotia and New Brunswick (i.e., there is no scenario to measure the impacts if one or the other choose to remove or keep the moratorium, such as if New Brunswick allows fracking while Nova Scotia does not). This is assumed to simplify this exercise. The Y-axis, on the other hand, represents a low growth and high growth choice to develop regional resources. The low growth or no LNG option illustrates a development where an LNG facility is not required, while the high growth or LNG option includes the construction of an LNG export terminal for the export of locally-produced natural gas.

Figure 1.5: Three Potential Scenarios of Shale Gas Development in New Brunswick and Nova Scotia



Source: CERI (2017).

The following illustrates some of the underlying assumptions to the three scenarios.

Scenario 1 suggests that the moratorium remains in place in both provinces. As such, Frederick Brook Shale and Horton Bluff do not proceed and remain undeveloped. McCully, however, continues to produce at a continued lower production rate via existing wells. Due to the operators' inability to utilize fracking techniques in the gas field, no new wells are added in this scenario. Considering decreasing onshore and offshore production to satisfy local demand, both provinces become importers of natural gas, as the Deep Panuke is decommissioned in approximately 2022, but likely earlier. Recall, the only onshore production is occurring in New Brunswick.

The supply gap between the region's demand and supply can be satisfied in two ways. First, by reversing the flow of the M&NP, from south to north, delivering natural gas from the US Northeast, from the Marcellus and Utica Shales, through New England and into Atlantic Canada. As mentioned, this flow is already beginning to change in periods where local demand cannot be met by Nova Scotia's offshore production. Pipeline projects such as the recently approved Atlantic Bridge Project in the New England area facilitate Marcellus gas to flow northward. The second way for the region's demand to be satisfied is by importing LNG via the existing Canaport LNG, also connected to the M&NP.

There are currently two LNG proposed export facilities on Nova Scotia's east coast — Goldboro LNG and Bear Head LNG (Pieridae LNG). The locations of these facilities are depicted as red dots in the previously mentioned Figure 1.2. It is important to note that whether an LNG export facility is built on the east coast, both potentially sourcing US-produced natural gas, lies beyond the scope of this study.

Scenario 1 only includes the existing wells to produce McCully's 30.5 Bcf remaining proven and probable reserves (2P reserves). This estimate stems from Corridor Resources Inc. (Corridor) Quarterly Report, illustrating their summary of 2P reserves of 22.9 Bcf (Corridor Resources Inc. 2016b). It is important to note that this is for their estimated working interest of 75 percent. As such, the estimate was adjusted to reflect the estimated 25 percent working interest of Potash Corporation of Saskatchewan's size of reserves. Other potential reserves within the McCully gas field require fracking for development.

Scenario 2 suggests that the moratoriums are removed, allowing fracking in onshore resources in both provinces. As such, this scenario suggests that the Frederick Brook Shale and Horton Bluff are both developed. In addition, with the possibility of fracking, gas production at McCully also increases, as does the remaining proven and probable resources in that field. The latter's production increases due to the ability to frack the tight sand gas field. Development is, however, restricted to meet only local demand, with the objective that the two provinces become self-sustainable. In this scenario, no resources are exported.

Scenario 2 requires the development of three assets: a) McCully with 88 Bcf proven and probable reserves (includes the 30.5 Bcf of existing resources from the previous scenario), b) Frederick Brook Shale with a production constrained by 111.9 MMcfpd, and c) Horton Bluff Shale with a production constrained by 152.4 MMcfpd.

The McCully estimate stems from Corridor's Quarterly Report at end-2014, illustrating their summary of 2P reserves of 66 Bcf (Corridor Resources Inc. 2015b). This was prior to the write down of reserves due to the moratorium and ban of fracking. Similarly, this estimate is for their estimated working interest of 75 percent. As such, the estimate was adjusted to reflect the estimated 25 percent working interest of Potash Corporation of Saskatchewan's size of reserves.

The Frederick Brook Shale and Horton Bluff production constraints, on the other hand, represent the maximum demand in the respective provinces over the next 21-year period of this study, respectively. Recall, under the self-sustaining scenario, production must at least meet local demand. The natural gas demand for the two provinces is forecast by National Energy Board (NEB) Energy Futures (NEB 2016a).

Scenario 3 suggests that the moratoriums are removed, and New Brunswick and Nova Scotia pursue a higher growth path, exporting natural gas via an LNG option and/or by pipeline to the US. This scenario is characterized by the region becoming an exporter of natural gas. As such, it is assumed the region builds an LNG export terminal, including the need to expand the pipeline in Nova Scotia to a facility either in Goldboro or Point Tupper, Nova Scotia. Similar to Scenario 1, the costs and accompanying pipeline expansions are included in calculating supply costs, but the economic impacts of such a facility lies beyond the scope of this study.

In this scenario, however, the development of the Frederick Brook Shale and the Horton Bluff are assumed to be limited by the size of the M&NP's current capacity of 550 MMcfpd.

Scenario 3 requires the development of three assets: a) McCully with 88 Bcf proven and probable reserves (case identical to Scenario 2), b) Frederick Brook Shale with a production constrained by 550 MMcfpd, and c) Horton Bluff Shale with a production constrained by 550 MMcfpd.

Additional constraints and assumptions, as well as methodology, are discussed later in this study.

Recall, this study examines only onshore oil and gas resources for the two Atlantic Provinces, including several oil and gas plays, as well as Frederick Brook Shale and the Horton Bluff. The analogous plays are at the heart of the renewed interest.

Consistent with the work completed by CERI for Yukon and Quebec (Howard, Rozhon, and Kralovic 2015; Rozhon and Kralovic 2015), this project will examine production costs, and economic and environmental impacts of potential oil and gas development in New Brunswick and Nova Scotia. The objective of this project is to detail the size of the resource potential and the possible economic contribution it could make to the economy of those two provinces and to Canada.

As a follow-up to previous studies that CERI has undertaken on defining the economic and environmental impacts of hydrocarbon developments on a provincial or territorial basis, this study will attempt to define the potential economic benefits associated with potential oil and gas developments in Nova Scotia and New Brunswick.

This study will:

- Determine what onshore resources (crude oil and gas) could be economically developed to feed domestic demand using a 21-year scenario-based approach, including for export purposes.

- Determine the economic benefits of hydrocarbon development for the provinces of Nova Scotia and New Brunswick, as well as for Canada, utilizing CERI's proprietary Multi-Regional Input/Output (I/O) model.

- Provide a review of regulatory requirements and determine environmental and Indigenous peoples' issues associated with oil and gas production in New Brunswick and Nova Scotia.

Additional questions that will need to be considered include:

- Overall competitiveness of local oil and gas supply versus importing LNG and pipeline supply from the US.

Structure of the Report

Chapter 1 discusses the objective of the study and sets the stage, providing a backdrop to why this is a timely issue for New Brunswick and Nova Scotia.

Chapter 2 reviews briefly the oil and gas potential in New Brunswick and Nova Scotia. It is divided into three parts: Background, New Brunswick's Oil and Gas Potential, and Nova Scotia's Oil and Gas Potential. The first part provides a foundation of the various unconventional resources found in the Atlantic Provinces. The second part reviews the geology regarding oil and gas in New Brunswick. It is subsequently divided into two sections, the two main targets in the province — Hiram Brook Member and the Frederick Brook Member. The third part reviews the geology regarding oil and gas potential in Nova Scotia, focusing on the Horton Bluff Shale. While at its early stages of exploration and development, coalbed methane (CBM) is reviewed briefly, but is not included in this study. However, for additional information about CBM in Nova Scotia, refer to Appendix B.

Chapter 3 discusses the regulatory and environmental aspects of oil and gas activity in the two provinces. It is divided into three parts: regulatory requirements (federally and for both provinces) for oil and natural gas projects, potential environmental impacts associated with oil and gas development, and Aboriginal rights and Indigenous people's[4] issues influencing oil and gas development. Potential environmental impacts are subsequently divided into five parts: surface and groundwater issues, greenhouse gas emissions, air quality effects, land impacts and public health issues. The Aboriginal rights and Indigenous people's issues section reviews the Indigenous peoples in New Brunswick and Nova Scotia, major legal cases clarifying the nature of Aboriginal rights and title, potential impacts on Aboriginal rights, as well as Aboriginal consultation and engagement issues and main approaches to address them.

[4] The term Indigenous peoples is increasingly replacing Aboriginal peoples, since the *United Nations Declaration on Indigenous Peoples* (2007), even though the term Aboriginal peoples still prevails in Canadian legislation. The term Indigenous peoples is generally considered to be more inclusive and respectful. For the purposes of this report, CERI will use the terms "Aboriginal peoples" and "Indigenous peoples" interchangeably, dependent on provincial versus federal legislation.

Chapter 4 provides production outlooks and supply costs within the context of the three plausible scenarios for New Brunswick and Nova Scotia: *We Are Importers*, *We Are Self-sustainable* and *We Are Exporters*. Each scenario is divided into five parts: outline of the scenario, production outlook, supply costs, infrastructure costs and market dynamics. This chapter also reviews briefly the competitiveness of the shale gas from New Brunswick and Nova Scotia with shale gas from the Marcellus and gas from western Canada, as well as provides concluding thoughts.

Chapter 5 presents and reviews the economic impacts of gas development in the two Maritime Provinces. It is divided into two parts. The first is divided into three sections: 1) discusses the methodology of CERI's proprietary Input/Output (I/O) Model, 2) reviews various general assumptions and constraints of the I/O Model, and 3) examines in greater detail the three scenarios, including their assumptions regarding the relevant capital investments and operations. These inputs, determined by the production outlook and supply cost model in Chapter 4, are inputs in the I/O model. The second part presents and discusses the results of modelling the three scenarios. The results of developing gas in New Brunswick and Nova Scotia are presented for each scenario, to illustrate the impacts over the 21-year period (2017-2037).

Chapter 6 summaries several key conclusions of this study.

Chapter 2: Oil and Gas Potential in New Brunswick and Nova Scotia

This chapter reviews the oil and gas potential in New Brunswick and Nova Scotia. It is divided into two parts: New Brunswick's oil and gas potential and Nova Scotia's oil and gas potential.

The first part reviews the geology regarding oil and gas in New Brunswick. It is subsequently divided into two sections, the two main targets in the province — Hiram Brook Member and the Frederick Brook Member. The former has been the focus of the Province's oil and gas development and includes a review of Stoney Creek Oilfield and the McCully Gas Field, both producing oil and natural gas, respectively. The Frederick Brook, on the other hand, is the focus of E&Ps for its shale gas potential. Most of the 40 oil wells drilled and 40 natural gas wells drilling since 1990 are in these two geological regions (Somerville 2014).

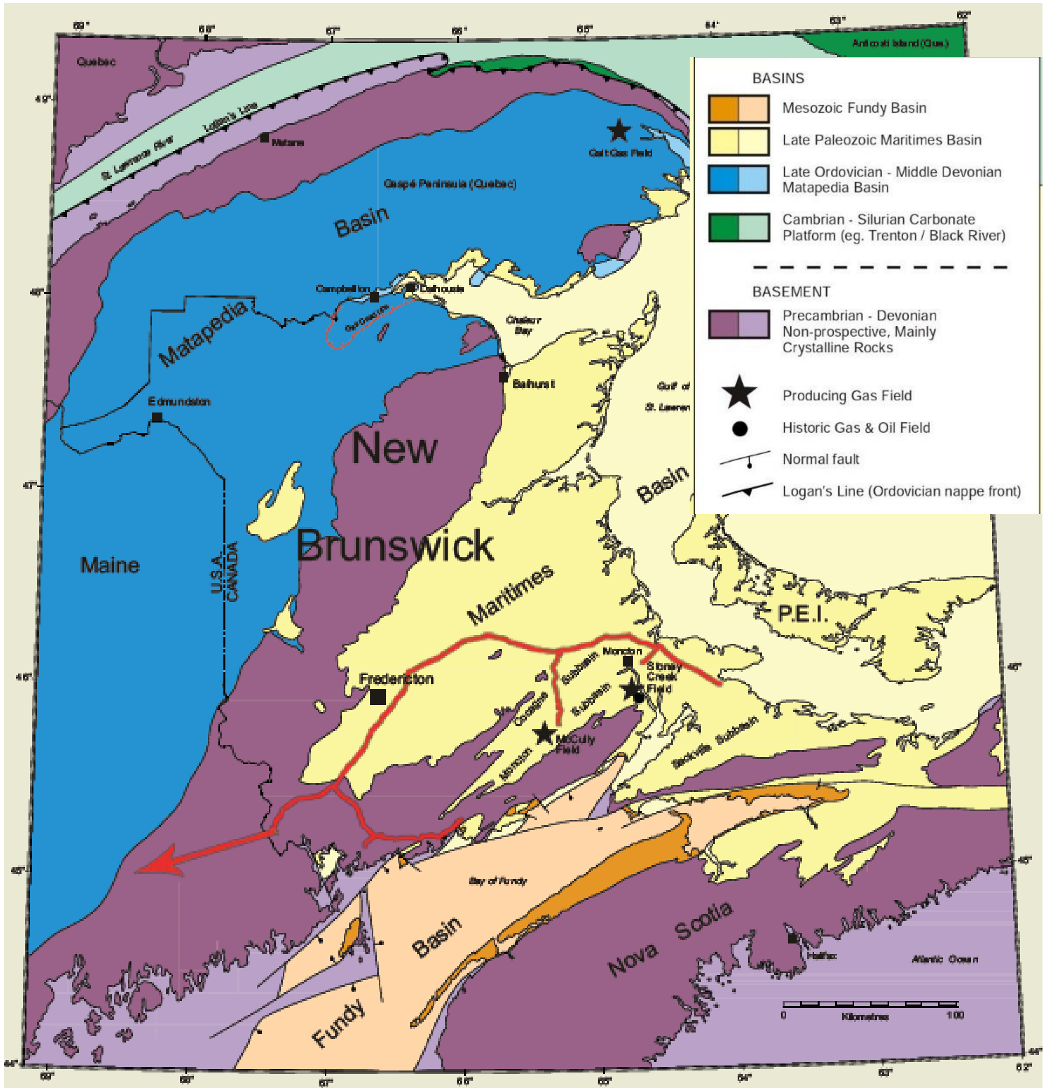
The second part reviews the geology regarding onshore gas potential in Nova Scotia and focusses on the Horton Bluff shale gas play. While coalbed methane (CBM) potential exists in Nova Scotia, its resource potential is undetermined. And while there is currently no production, there are several players, such as East Coast Energy that have production agreements that appear to be proceeding. However, further exploration, as well as more favourable economic conditions, is needed to develop this resource; as such it currently lies beyond the scope of this study. However, for more information regarding CBM in Nova Scotia, please refer to Appendix B.

New Brunswick's Oil and Gas Potential

Oil and gas activities in New Brunswick are focused in the rocks of the Maritimes Basin, formed during the Carboniferous period, approximately 359-299 million years ago (Saillant and Campbell 2014). Thus far, all the province's petroleum activities are located within this basin, including New Brunswick's two producing fields — the McCully Gas Field and Stoney Creek Oil Field — as well as the Frederick Brook Shale and the large oil shale deposits, located primarily at Albert Mines.

The Late Paleozoic Maritimes Basin is illustrated in Figure 2.1, along with the Late Ordovician – Middle Devonian Matapedia Basin and the Mesozoic Fundy Basin, as well as the Precambrian – Devonian Basement. Taking form during the Early to Middle Devonian Acadian Orogeny, the Maritimes Basin not only underlies the eastern part of New Brunswick but covers all of Prince Edward Island, parts of Nova Scotia, onshore Newfoundland, as well as the sea floor between the four Atlantic Provinces.

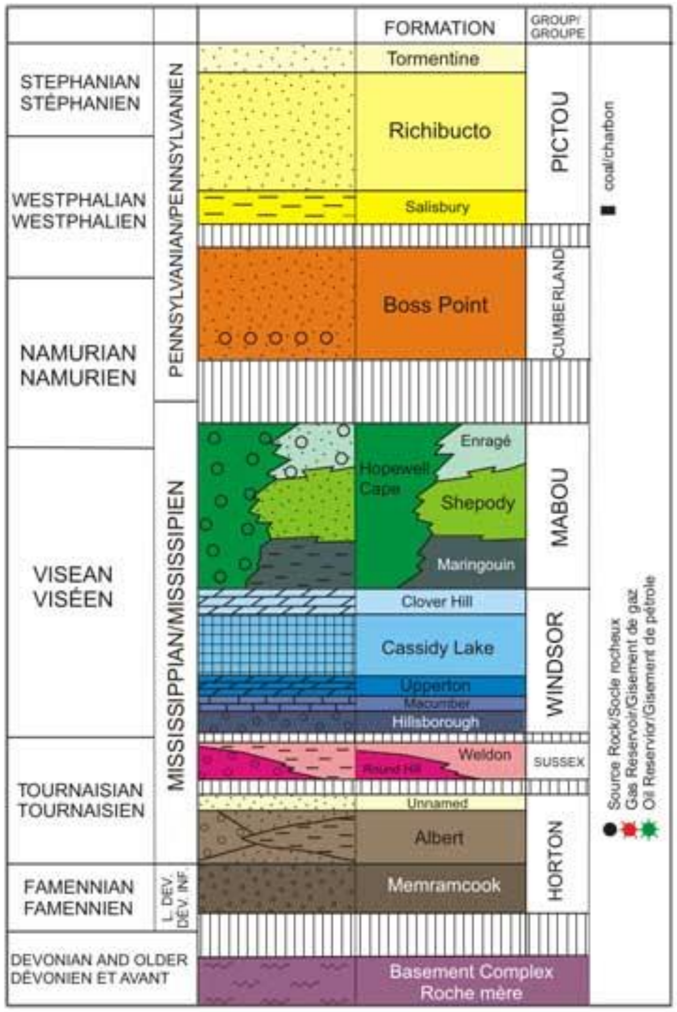
Figure 2.1: Basins in New Brunswick



Source: (Smith 2010). Modified by CERI.

Figure 2.2 illustrates the stratigraphy of the Maritimes Basin. The fill is separated by a Namurian unconformity, the thick layer shown by vertical lines. Above the unconformity, the fill comprises of the Cumberland Group and the Pictou Group, whereas below the line the fill comprises of the Mabou Group, Windsor Group, Sussex Group and the Horton Group (Government of NB 2017b). The latter is made of a basal alluvial-lacustrine succession and is the focus of much of the province's oil and gas exploration and activities. These petroleum resources are generally concentrated within the Mississippian-aged Albert Formation, within the lacustrine sandstones and mudstones, originating from the Albert Formation being deposited in a freshwater or brackish lake during the early Mississippian (lower Carboniferous) period (Government of NB 2017b). Unique in the make up in North American shale, only the Green River Basin (Wyoming, Utah) being of lacustrine origin shale.

Figure 2.2: Stratigraphy of the Maritimes Basin



Source: (Government of NB 2017b)

Located within the Horton Group, the Moncton Subbasin is the primary target of oil and gas activities, centered in the southeastern corner of New Brunswick. New Brunswick currently has 32 natural gas wells and 18 oil wells producing — all of which are within the Albert Formation and the Horton Group (NRCan 2016b; NB DERD 2017b, 2017c). It is important to note that Horton Bluff in Nova Scotia is also located within the Horton Group, indicating the similar age and other geological characteristics of the two neighbouring shales.

The Albert Formation typically contains three conformable members: Hiram Brook Member, Frederick Brook Member and the Dawson Settlement Member. All three members contain kerogenous sandstone, mudstone and shale, with the Hiram Brook being the shallowest and the Dawson Settlement being the deepest.

The following section focuses on the members attracting the most attention from E&Ps and geologists: Hiram Brook and the Frederick Brook. The former also reviews the historic Stoney

Creek Oilfield and the McCully Gas Field, while the latter reviews the shale gas potential in the Frederick Brook Shale. The Dawson Settlement Member likely contains oil and gas as well but is less explored.

Hiram Brook Member

The Hiram Brook Member typically is the main exploration and development target for conventional oil and gas, dating back to the first oil and gas drilling in New Brunswick in the late 1800s at Dover, near Moncton. Records are incomplete; however, some gas was encountered during drilling of the old Dover Field and a limited amount of shallow oil was produced during the late 1800s and early 1900s (C. St. Peter 2000). Targeting the lacustrine sandstone of the Albert Formation, this discovery proved to be valuable in that it attracted additional exploration in the Albert Formation.

Along the same trend as the Dover Natural Gas Field, natural gas and oil were discovered at the Stoney Creek Oil and Gas Field, approximately 15 kilometers south of Moncton. At present, there is no natural gas produced, it is now simply called the Stoney Creek Field. The field contains mostly tight sand zones containing oil and gas, deposited in a delta along an ancient lake (Saillant and Campbell 2014). This lake is sometimes referred to as the Windsor Sea which covered southern New Brunswick and large parts of Nova Scotia during the Visean period (Saillant and Campbell 2014). The Stoney Creek Field is located within the Lower Carboniferous Albert Formation, and is sandwiched between the mostly red bed sequences of the underlying Memramcook Formation (Horton Group) and the overlying Weldon Formation (Sussex Group) (C. St. Peter 2000). While the area is complex geologically, the Stoney Creek area source and reservoir rocks of the Albert Formation comprises of grey mudstones and siltstones, interbedded with kerogenous mudstones, oil shales and coarse sandstones (C. St. Peter 2000).

The following data is from the Government of New Brunswick's Monthly Production Statistics (NB DERD 2016). Between 1909 and 1991, Stoney Creek produced approximately 800,000 barrels of oil and approximately 30 Bcf of natural gas. In this period, natural gas annual production peaked at 856.3 MMcf in 1913. Annual production exceeded the 575 MMcf level between 1916 and 1945, but subsequently decreased until the field was shut-in in 1991. Interestingly, annual production never exceeded the 200 MMcf level after 1952. While annual oil production peaked at 30,373 barrels (bbls) in 1945 and remained above the 20,000 bbls between 1937 and 1948, annual production did not exceed the 10,000 bbls after 1962, declining to only 2,309 bbls in 1988, the last year of production before the field was shut-in. The oil produced at Stoney Creek is waxy. Originally thought to be paraffinic in nature, its oil is rather naphthalene in nature (Bacon, Romero-Zerón, and Chong 2010). Prior to the suspending of the project, 168 wells were drilled, 71 percent of which produced hydrocarbons (Marsh 2004).

High oil prices in the 2000s likely led to a revival of the Stoney Creek Oilfield in 2005. In 2007, Contact Exploration Inc. began to produce oil again from two horizontal wells drilled in 2006. As various directional wells were drilled in 2008 and several re-entered, past-producing wells are now in operation. Between 2007 and the end of 2015, approximately 150,000 barrels of oil have been produced at Stoney Creek, peaking at approximately 32,500 barrels in 2011, but dropping dramatically to 12,621 barrels of oil in 2015 (NB DERD 2016). There are currently 16 oil wells currently producing approximately 30 barrels per day (bpd) (NB DERD 2016).

Contact Exploration was purchased by Kicking Horse Exploration in 2010 and later Kicking Horse Energy was bought by ORLEN, a large producer head-quartered in Poland with offices in Alberta and New Brunswick. ORLEN's project plans for the small project are unclear and the project is not currently discussed on its website or its annual reports. The highlight of the C$356 million acquisition of Kicking Horse is likely the companies East Kakwa properties in BC's Montney Formation.

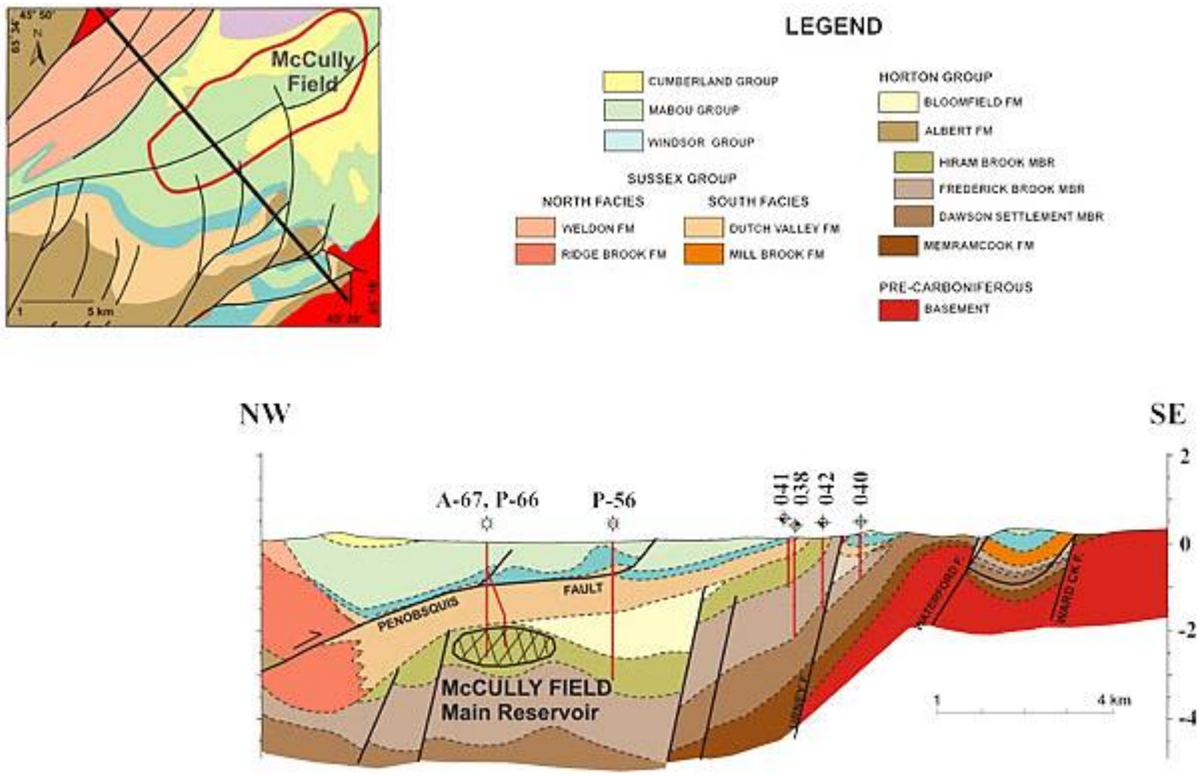
The New Brunswick Government suggest that the region is estimated to contain proven and probable reserves of 1.3 million barrels of oil and 7.9 Bcf of natural gas (Government of NB n.d.). The predecessor to ORLEN suggested that its Stoney Creek and Hopewell properties were estimated at 1,756 thousand barrels of oil equivalent (MBoe) (Kicking Horse Energy Inc. 2015); the estimate was conducted by Calgary-based GLJ Petroleum Consultants (GLJ). The reserves were, however, reduced due to the fracturing moratorium announced in 2014, delaying project development and affected the amount of proven and probable reserves on their books (Kicking Horse Energy Inc. 2015). Kicking Horse's total proven and probable reserves subsequently decreased from 2,192 MBoe at the end of March 2013 (Contact Exploration Inc. 2014).

Other lease holders in the area include M Pharmaceutical Ltd. (formerly PetroWorth Resource) and Irving Oil — one of the previous acreage holders of the Stoney Creek area (Marsh 2004). The former lease holder PetroWorth made a natural gas discovery in 2007 in the area while the latter is a major energy player in New Brunswick, operating the nearby Irving Oil Refinery — Canada's largest refinery (Smith 2010).

The McCully Field, located near Sussex, houses a tight sand zone. In the fall of 2000, shortly after the opening of the M&NP, transporting natural gas from the SOEP via Goldboro, Nova Scotia, Corridor Resources Inc. and Potash Corporation of Saskatchewan Inc. made a major discovery of natural gas in lacustrine and fluvial sandstones of the Albert Formation. Also located in the Moncton Subbasin, the McCully is a part of the Horton Group in the late Devonian-Carboniferous Maritimes Basin.

Figure 2.3 illustrates the surface geology of the McCully Gas Field as well as a cross-section schematic of the area. An important fact to note is that the depth to the producing Hiram Brook is between 1,700 and 2,200 meters and varies between 40 and 850 meters thick (The Maritimes Energy Association 2017).

Figure 2.3: Cross-section of McCully Gas Field



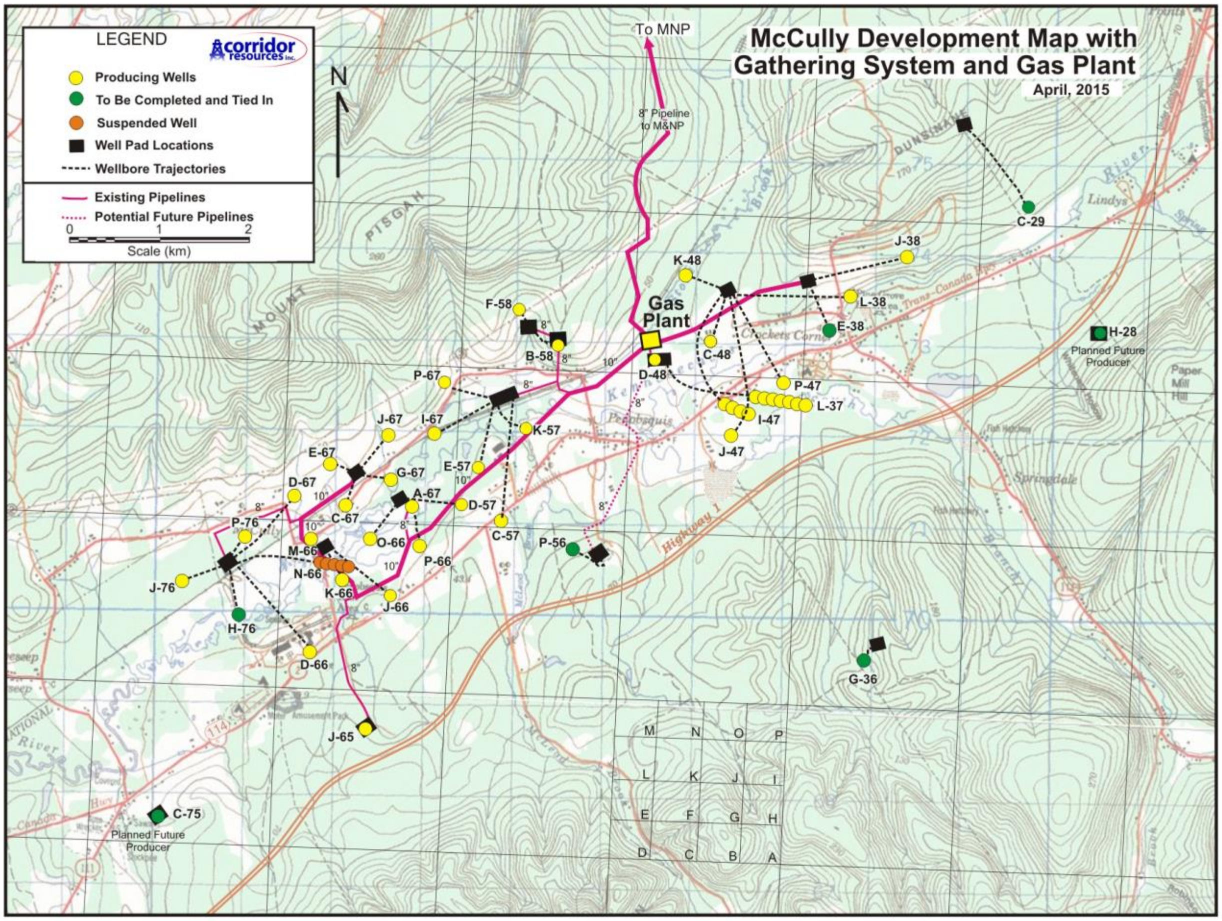
Source: (NB DERD 2017a)

Corridor Resources drilled a discovery well in September 2000 in partnership with PCS, developing the field in April 2003, producing enough sales gas from two wells to meet a daily potash mill demand of about 2 MMcfpd. Corridor has working interest of 75 percent of the McCully Field, approximately 61,000 net acres (Corridor Resources Inc. 2016a). The remaining working interest is owned by PCS.

In June 2007, Corridor completed the construction of a field gathering system, a gas plant, and a 50-kilometer pipeline lateral connecting the McCully field to regional (Canadian and US) markets through the existing M&NP (NRCan 2016b). The gas plants processing capacity is 35 MMcfpd while the length of the gathering system is approximately 15 kilometers (Corridor Resources Inc. 2016d).

Figure 2.4 illustrates the McCully development map with the producing wells, suspended wells, wellbore trajectories, as well as the gathering system and the gas plant, as of April 2015. With the fracturing moratorium, no wells have been drilled since 2014.

Figure 2.4: McCully Development Map

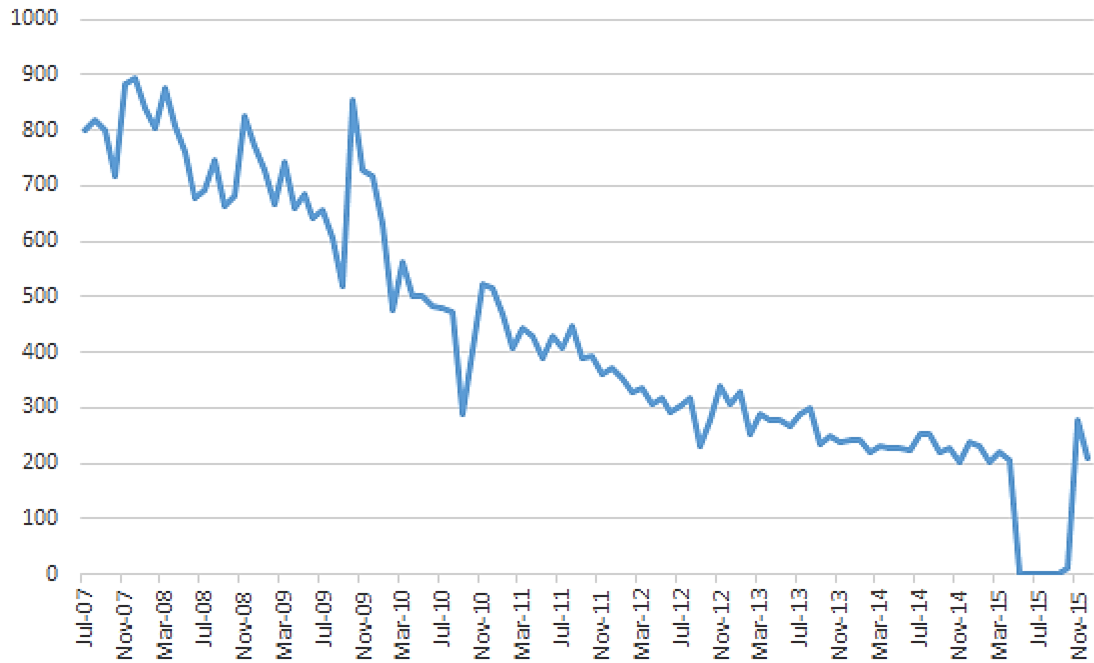


Source: (Corridor Resources Inc. 2015c)

Figure 2.5 illustrates the natural gas production levels from the McCully natural gas field, from the time of commissioning of the natural gas gathering facilities, plant, and pipeline lateral in 2007, until end-2015. It is important to note that this represents the amount of natural gas produced from the Hiram Brook sands in the McCully Field. The decline is likely a combination of natural decline of existing wells and few new wells drilled since 2007. There are 28 producing wells from 11 well pads (Corridor Resources Inc. 2016d). As of September 30, 2016, current production capacity is approximately 5.1 MMcfpd (Corridor Resources Inc. 2016c).

To date, nearly 55 Bcf has been produced up to the end of 2016 from the tight sandstone reservoir.

Figure 2.5: Monthly Natural Gas Production in New Brunswick (MMcf)



Data source: (Statistics Canada 2016a).

The average natural gas price at Algonquin City-Gate (AGT) in Q1 2016 was $US3.29 per million British thermal units (MMBtu) as compared to $US11.41 per MMBtu in Q1 2015. In response to this trend in natural gas prices, and to take advantage of the expected significant differential in the sale price of natural gas at AGT for the summer of 2015 relative to the winter of 2015/2016, management shut-in most of Corridor's producing natural gas wells in the McCully Field in New Brunswick from May 1, 2015 to October 29, 2015, which resulted in a decrease in natural gas production during this period (Statistics Canada 2016a). Average natural gas price for the three-months ending September 30, 2016 was C$3.98 per thousand cubic feet (Mcf); this is down from an average natural gas price of C$6.10 per Mcf (Statistics Canada 2016a).

Despite spending approximately C$50 million, drilling 13 wells with fracture stimulation between 2008 and 2011, production in the McCully has been decreasing. Following the moratorium on hydraulic fracturing, Corridor wrote down their undeveloped (non-drilled) reserves, from 98.3 Bcf at end-2014 to 66 Bcf at March 31, 2015 (Corridor Resources Inc. 2015b). As of end-June 2016, the revised proved and probable reserves are at 22.9 Bcf (Corridor Resources Inc. 2016b).

By the end of 2010, Corridor Resources had drilled 39 wells, all of which encountered natural gas and most of which were completed and producing through the company’s gas gathering system and gas plant (Corridor Resources Inc. 2011). In the summer of 2014, Corridor Resources completed a five well hydraulic fracturing operation, exploiting both tight gas sands and shale targets (NRCan 2016b).

SWN Resources Canada, a subsidiary of Houston-based Southwestern Energy, is the largest player in terms of net acreage in New Brunswick. In 2010, the company acquired 32 exploration licenses covering 1.1 million hectares (Southwestern Energy 2015). SWN Resources Canada completed two geophysical surveys in 2013, additional to seismic surveys undertaken in 2010 and 2011 (NRCan 2016b). Through December 31, 2014, the company had invested approximately C$45 million in its New Brunswick exploration program (Southwestern Energy 2015). SWN's plans to drill exploration wells is suspended and the company has closed its Moncton office, primarily due to New Brunswick's legislation imposing a moratorium on all types of hydraulic fracturing in the province (Jupia Consultants Inc. 2015).

Frederick Brook Member

The most promising source of natural gas in New Brunswick is the Frederick Brook Shale (FBS), lying beneath the Hiram Brook Member. Like the Hiram Brook Member, the grey brown shale of the FBS is a member of the Albert Formation. Like the Hiram Brook Member, the Frederick Brook Member shale has a long history of development dating back to 1849, when a solid bitumen vein of "Albertite" was discovered within a thick oil shale sequence near the town of Albert Mines. Throughout the late 1800s and early 1900s, various companies sold the Albertite and oil shale derivatives to prospective local and US markets (Hume 1932).

The Frederick Brook Shale is the source rock for the Hiram Brook sands and extends northeast from the Sussex region. It is comprised of siltstone, dolomitic marlstone, limestone and ironstone layers (Saillant and Campbell 2014). These layers were deposited in the center or deepest portions of the freshwater lake or brackish lake 300 to 360 million years ago during the Lower Carboniferous period (Alexander et al. 2011). It is for this reason that the shale is lacustrine in origin, quite unique among North American shales which are primarily marine-deltaic in nature, such as East Texas' Barnett Shale and the prolific Marcellus Shale.

Table 2.1 illustrates the various geological characteristics of the Frederick Brook Shale in comparison to other shale plays in North America, including BC's Montney Shale and the Horn River Basin.

Table 2.1: Frederick Brook Shale Comparisons to Other Shale Plays in North America

	Fredrick Brook	Montney	Horn River	Barnett	Eagle Ford	Marcellus	Haynesville	Utica
Age	Mississippian	Triassic	Devonian	Mississippian	Late Cretaceous	Devonian	Jurassic	Ordovician
Estimated Basin area (mi2)	180	10,038	4,900	5,000	4,700	23,400	9,000	40,300 - 58,440
Depth (ft)	5,000-15,000	6,500 - 11,000	5,900 - 9,800	6,500 - 8,500	5,500 - 14,400	3,300 - 8,000	10,000 - 14,000	2,000 - 14,000
Net Thickness (ft)	3,500	450 - 525	50 - 350	100 - 600	3 - 326	45 - 384	200 - 300	150 - 700
OGIP (TCF)	67	4,274	145 - 600	330	-	1,500	717	3,192
Technically Recoverable Resources (TCF)	-	449	29 - 120	72	-	141	251	890
Gas In Place BCF/Mi^{2*}	100 - 625	426	30 - 122	66	-	64	80	55 - 79
Porosity (%)	3 - 8	2.5 - 8	3.6 - 6.2	4 - 5	3 - 12	3 - 13	8 - 14	2.2 - 3.7
Permeability (nD)	65 - 311	250 - 450	-	70 - 5000	100 - 700	200 - 900	500 - 0.4 mD	<100 to 335
TOC (%)	1 - 2.5	1.0 - 5.0	1 - 8	2.4 - 5.1	0.3 - 5.4	2.0 - 8.0	0.5 - 4.0	1 - 3
Clay Content (%)	6 - 55	10 - 20	20 - 40	10 - 30	-	20 - 35	25 - 35	8 - 40
Vitrinite Reflectance (Ro)	1.2++	2.2 - 3.8	2.2 - 2.8	0.6 - 1.6	1.5	1.25	1.0-5.0	1.1 - 4.0
Liquids Yield (bbl/mmcf)	1 - 6	0 - 100+	Dry	0 - 50	-	-	-	0 to Oil
Pressure (psi)	3,000 - 6,000	3,500 - 6,400	4,100 - 7,700	3,000 - 5,000	4,300 - 10,900	2,000 - 5,100	7,000 - 10,000	up to 7,000
Pressure Gradient (psi/ft)	0.53 - 0.6	0.6 - 0.75	0.49 - 0.75	0.45 - 0.5	-	0.45 - 0.60	-	0.4 - 0.9
Recovery Factor *	-	10.5%	20.0%	21.8%	-	9.4%	35.0%	27.9%

* Gas in place per square mile and recovery factor are calculated
\- Unknown or Unavailable

Sources:

	Fredrick Brook	Montney	Horn River	Barnett	Eagle Ford	Marcellus	Haynesville	Utica
Age	Mississippian	Triassic	Devonian	Mississippian	Late Cretaceous	Devonian	Jurassic	Ordovician
Estimated Basin area (mi2)	(1)	(10)	(11)	(16)	(16)	(16)	(16)	(7)
Depth (ft)	(1)	(8)	(11)	(16)	(16)	(16)	(16)	(13)
Net Thickness (ft)	(1)	(8)	(11)	(16)	(16)	(16)	(16)	(7)
OGIP (TCF)	(2)	(5)	(11)	(11)		(11)	(11)	(12)
Technically Recoverable Resources (TCF)		(5)	(11)	(6)		(17)	(11)	(12)
Gas In Place BCF/Mi2	(1)							
Porosity (%)	(1)	(5)	(11)	(16)	(16)	(16)	(16)	(11)
Permeability (nD)	(1)	(8)		(16)	(16)	(16)	(16)	(14)
TOC (%)	(1)	(8)	(11)	(16)	(16)	(16)	(16)	(7)
Clay Content (%)	(1)	(9)	(11)	(11)		(11)	(11)	(11)
Vitrinite Reflectance (Ro)	(1)	(8)	(11)	(16)	(16)	(16)	(16)	(11)
Liquids Yield (bbl/mmcf)	(1)	(9)	(10)	(11)				(7)
Pressure (psi)	(1)	(9)	(10)	(16)	(16)	(16)	(16)	(15)
Pressure Gradient (psi/ft)	(1)	(9)	(10)	(11)		(8)		(12)
Recovery Factor		(18)	(18)	(18)		(18)	(18)	(18)

1 Data determined by Corridor Resources and third party vendors
2 GLJ estimate of gross discovered resources, 2010
5 NEB et al, "The Ultimate Potential For Unconventional Petroleum From the Montney Formationof BC and Alberta", November 2013
6 EIA/ARI World Shale Gas and Shale Oil Resource Assesment, June 2013
7 USGS, "Assesment of Undiscovered Oil and Gas Resources of the Ordovician Utica Shale of the Appiliacian Province", 2012
8 www.sanleonenergy.com/operations-and-assets/baltic-basin.aspx
9 BC Oil &Gas Commision "Montney Formation Play Atlas" October 2012, Data taken from Maps
10 BC Oil &Gas Commision "Horn River Basin Unconventional Shale Gas Play Atlas", June 2014, Data may be taken from Maps
11 PTEC and SCEK "The Modern Practices of Hydraulic Facturing: A Focus on Cnadian Resources", Rev November 2012
12 Utica Shale Appalachian Basin Exploration Consortium (West Virginia University) "A Geologic Play Book for Utica Shale Appalachian Basin Exploration", rev July 1, 2015
13 King, Hobart, Geology.com, "Utica Shale - The Natural Gas Giant Below the Marcellus", retreived August 2015
14 Ness etal, "Horn River Shales…Boring or Black", GeoCanada 2010
15 ITG, "Utica Shale: A Glimpse into the Future", Nov 2013
16 Z. Dong et al, SPE167768, "Probailistic Assessment of World Recoverable Shale Gas Resources, 2014
17 US DOE/EIA "Annual Energy Outlook", June 2012
18 Calculated from data stated within this table

Source: Table created by Corridor Resources (Corridor Resources Inc. 2015a). Used with permission.

While all shale plays are unique in their geology, there are several unique characteristics regarding the Frederick Brook Shale. First, while the true area of the basin is yet unknown, the estimated basin area is only 180 square miles, by far one of the smallest basins in North America. This is compared to the Devonian-aged Marcellus at 23,400 square miles or the Utica Shale at between 40,300 and 58,440 square miles. Second, while geographically small, the Frederick Brook Shale is considered quite thick. The net thickness of the shale is 3,500 feet, or approximately 1,068 meters. The depth of the Frederick Brook Shale ranges between 5,250 to 13,123 feet, or between 1,600 to 4,000 meters (Corridor Resources Inc. 2016d).

As such, its gas in-place (Bcf/square mile) is high, between 100 and 625 Bcf/square mile. This is compared to the Montney at 426 Bcf/square mile, followed by Horn River Basin (30-122 Bcf/square mile), Haynesville (80 Bcf/square mile) and the Utica (55-79 Bcf/square mile) (see Table 2.1).

There are several plays that can be considered analogs for the Frederick Brook Shale, including the Montney and the Horn River Basin. The former is interesting for a number of characteristics, among them being a higher clay content in portions of the basin.

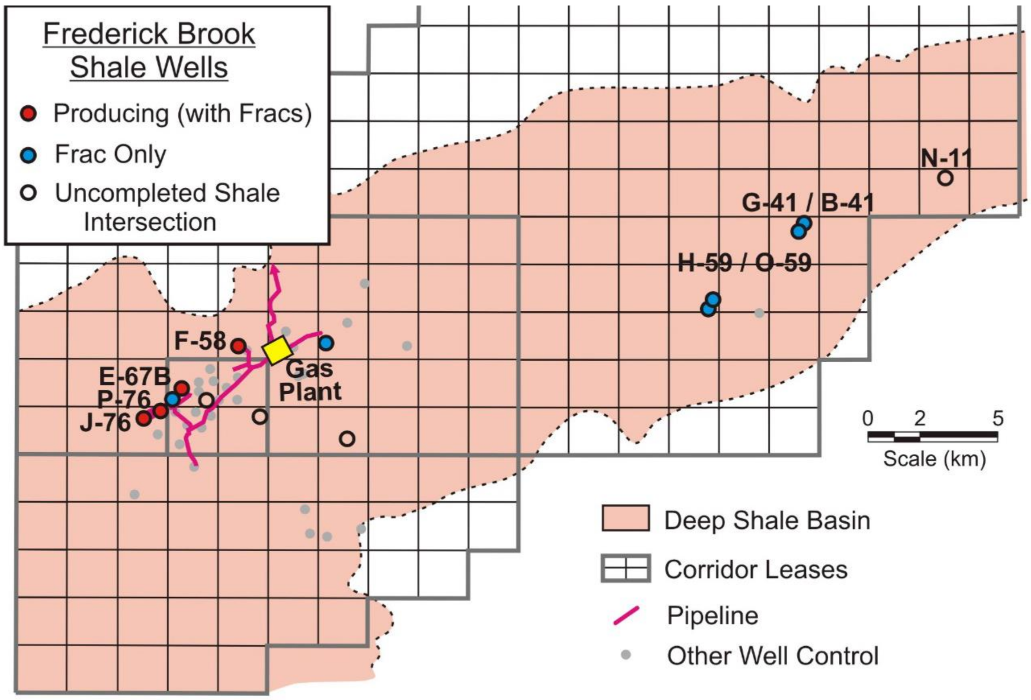
In-place resource estimates under Corridor's acreage suggest that there are an estimated 67.3 Tcf of shale gas in-place; estimates were conducted by GLJ & Associates, within the Sussex and Elgin sub-basins (Corridor Resources Inc. 2009). The Frederick Brook was divided into two intervals: upper and lower. The former is characterized by higher clay content (up to 67 percent) and silica (up to 25 percent), while the latter is characterized by lower clay content and more dolomite and albite (GLJ Petroleum Consultants 2009). The upper interval is estimated to contain 43.2 Tcf of discovered gas in-place and the lower interval is estimated to contain 24.1 Tcf of discovered gas in-place (GLJ Petroleum Consultants 2009). It is important to note that a technical recovery factor must be attached to the gas in-place estimate, which estimated the total quantity of gas contained in the reservoir.

The New Brunswick Department of Energy and Resource Development (NB DERD) suggests there could be as much as 80 Tcf of gas in-place in the Frederick Brook Shale. The latter, however, includes an estimated 10.9 Tcf of natural gas resources at Hillsborough, near the existing Stoney Creek Oil Field. This estimate, however, could not be substantiated and is not included in our resource estimation utilized within this study.

Much of the data compiled thus far is from Corridor Resources. While most of Corridor's gas development occurs in the McCully Gas Field, the company has drilled thirteen wells into the Frederick Brook Shale, including one long-term producing vertical well (Corridor Resources Inc. n.d.). The McCully F-58 drilled in 2008, is currently producing approximately 316 Mcfpd over the past seven years, in a very flat production curve (NB DERD 2017c). The well was fracture stimulated with water, although the volume of water was small compared to recent techniques for completion (Corridor Resources Inc. n.d.). Other producing wells include the E-67B and the J-76, all of which were single fracks. The E-67B well was drilled in October 2014 and operated for seven months (NB DERD 2017c).

Figure 2.6 illustrates Corridor's Frederick Brook Shale wells, including producing wells, fracks only and uncompleted shale intersections. The figure also shows the location of the 35 MMcfpd gas processing plant, used primarily for its McCully tight sand gas production and its pipeline that links up with the M&NP.

Figure 2.6: Corridor's Frederick Brook Shale Wells



Source: (Corridor Resources Inc. 2016d)

The wells drilled in the Elgin sub-basin are noteworthy for two reasons. First, G-41 (Green Road well) was drilled and completed in 2009. The well has two intervals completed with small fracks. The lower interval tested at 0.4 MMcfpd while the upper interval tested at 4 MMcfpd, with a peak rate of 11.7 MMcfpd (Corridor Resources Inc. 2014). Second, Corridor entered a joint venture with Apache Corporation. The latter drilled two horizontal wells in 2010 — the B-41 and G-59 (H-59) (Corridor Resources Inc. 2010). The 18-month drilling program ended in June 2011, with neither well indicating economic production (Apache Canada 2010).

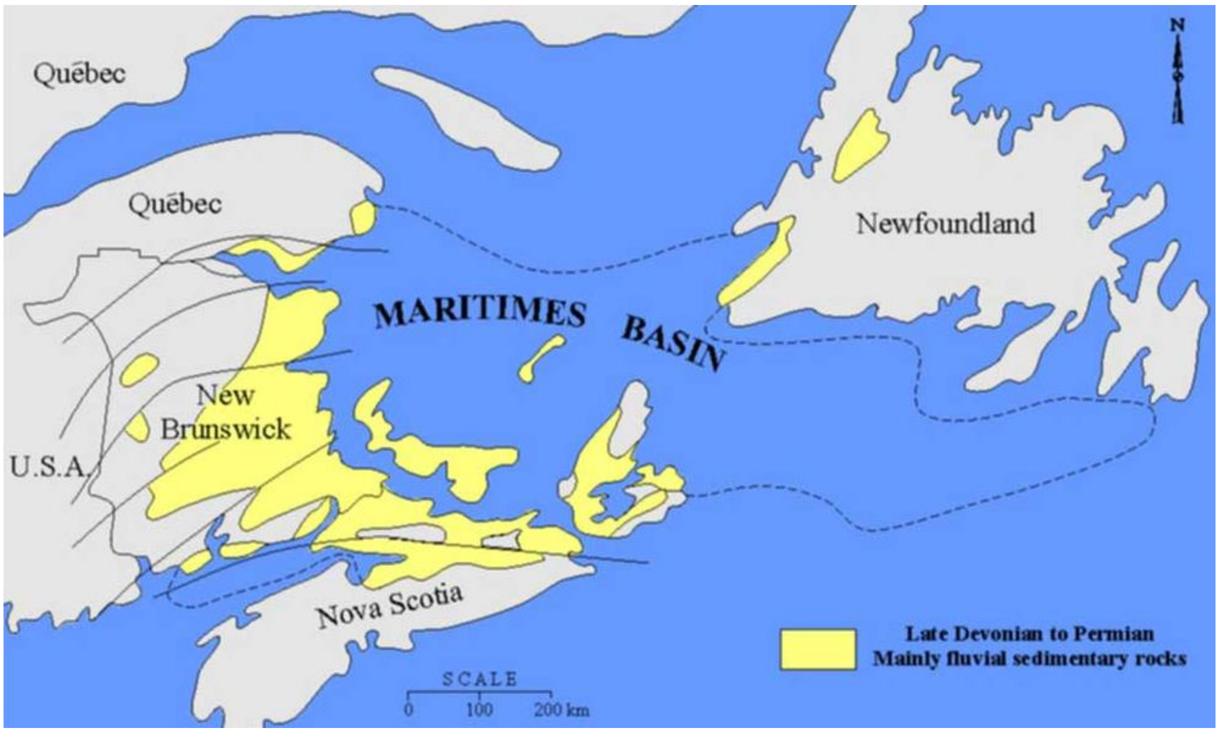
Like the McCully Gas Field, the Frederick Brook Shale's proximity to the M&NP is also a benefit. As previously mentioned, the pipeline was originally built to deliver offshore Nova Scotia gas to the New England market. It can be easily utilized to transport Frederick Brook Shale gas to domestic or US markets, as offshore Nova Scotian gas production dwindles over the next few years.

Nova Scotia's Oil and Gas Potential

This section reviews Nova Scotia's onshore resource potential, focusing on the Horton Bluff Shale. Nova Scotia also has coalbed methane (CBM) potential but its size of the resources and development are uncertain at this time and are not included in this study. Additional work to assess the size of resource potential needs to occur to get a better and more accurate understanding of CBM potential. However, for more information regarding CBM in Nova Scotia, please refer to Appendix B.

There are a couple of similarities for Nova Scotia with its Maritime neighbor. First, onshore oil and gas exploration is among the oldest in North America. In the case of Nova Scotia, the industry dates to the 1860s in Cape Breton. Second, the majority of oil and gas activities are also centered on the Maritimes Basin. The rocks of the Late Paleozoic Maritimes Basin in particular are of interest. Recall, the Maritimes Basin not only underlies the eastern part of New Brunswick but covers all of Prince Edward Island, parts of Nova Scotia, onshore Newfoundland, as well as the sea floor between the four Atlantic Provinces. This is illustrated in Figure 2.7.

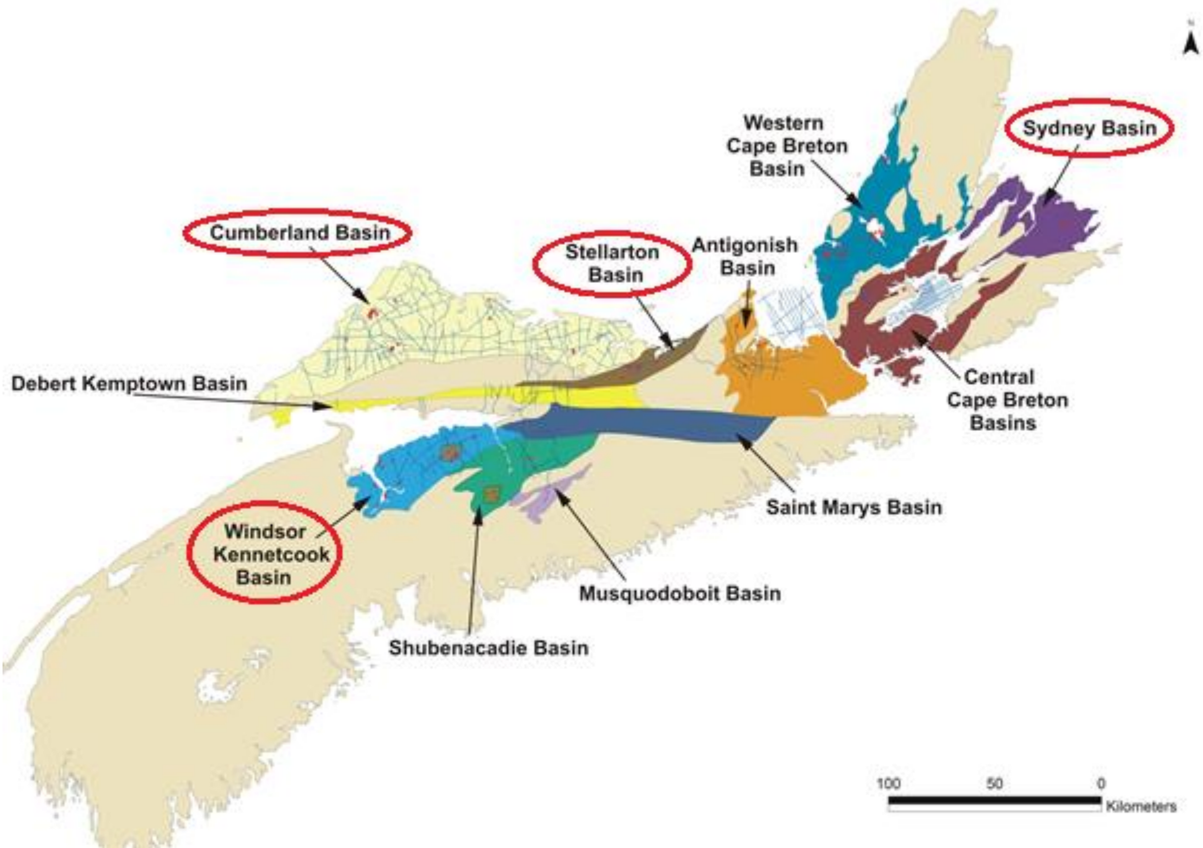
Figure 2.7: Distribution of Late Devonian-Permian Rocks in the Maritimes Basin



Source: (NB DERD n.d.)

Most of the northern half of Nova Scotia is covered by sedimentary rock, making up roughly a third of Nova Scotia's surface area (NRCan 2016c). These areas correlate to oil and gas exploration in the province, whether shale gas or CBM. Parts of Nova Scotia rich with petroleum resources are illustrated in Figure 2.8. The map shows the basins and group geology of the province's onshore oil and gas basins. Areas circled in red show the Horton Bluff shale gas play (Windsor-Kennetcook Basin), as well as the CBM targets (Stellarton Basin, Cumberland Basin and the Sydney Basin).

Figure 2.8: Basins of Nova Scotia



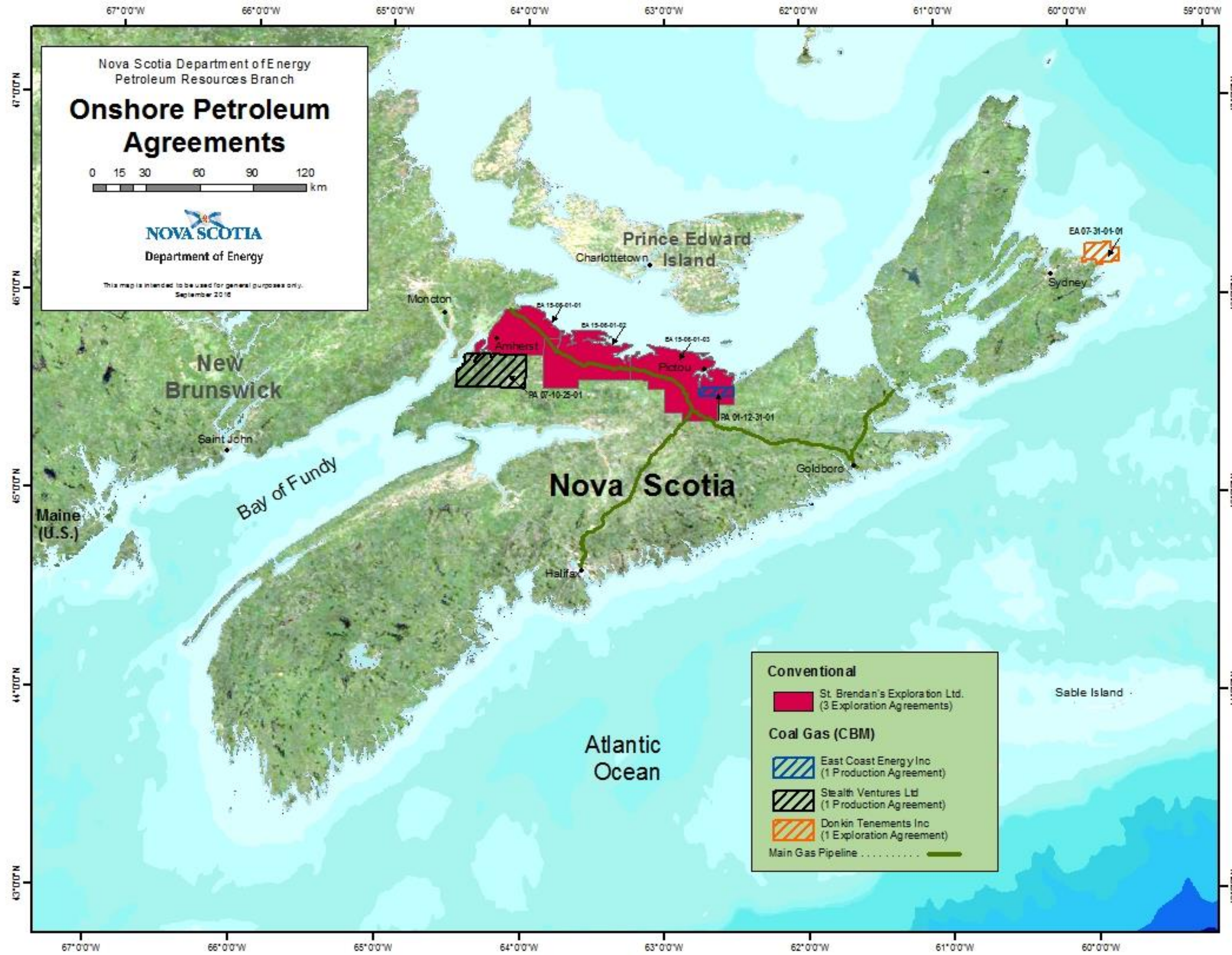
Source: (Cen 2012)[1]

Thus far, more than 125 exploration wells have been drilled in Nova Scotia, with approximately a third resulting in small amounts of petroleum discovered (CAPP 2017b). It is interesting to note that historically the majority of wells have been drilled in the Western Cape Breton Basin, followed by the Cumberland Basin and Windsor-Kennetcook Basin (Cen 2012). The former was the target for exploration activities prior to 1985, while the Cumberland Basin and Windsor-Kennetcook Basin dominate petroleum wells drilled after 1985 (Cen 2012). Not surprisingly, the latter two were also popular targets for seismic programs after 1985.

While there are no commercially producing onshore oil and gas activities in the province, there are, however, four companies that have six petroleum agreements. Figure 2.9 illustrates onshore petroleum agreements in Nova Scotia, including both conventional resources and CBM. Interestingly, shale gas is categorized as conventional.

[1] Modified by CERI to show the CBM targets (circled in red in Figure 2.8).

Figure 2.9: Onshore Petroleum Land Rights in Nova Scotia



Source: Nova Scotia Department of Energy (NS DOE 2016)

The province has three conventional gas exploration agreements with St. Brendan's Exploration Ltd., located in the Cumberland and Stellarton Basins' region. These are illustrated by red in Figure 2.9. East Coast Energy and Stealth Ventures have production agreements for CBM while Donkin Tenements has an exploration agreement for CBM. The latter is in Cape Breton, in the Sydney Basin.

It is interesting to note the number of agreements and companies has decreased over the past couple of years. Eastrock Resources (two exploratory agreements) and Elmworth Energy Corporation (one production agreement) no longer have agreements with the Nova Scotia Government. Elmworth (a subsidiary of Triangle Petroleum Corporation) leased the acreage on the Windsor Block, but on June 29, 2016, Triangle USA Petroleum Corporation and its subsidiaries filed for Chapter 11 of the United States Bankruptcy Code (Triangle Petroleum Corporation 2016). As such, there is currently no exploration in the Windsor-Kennetcook Basin.

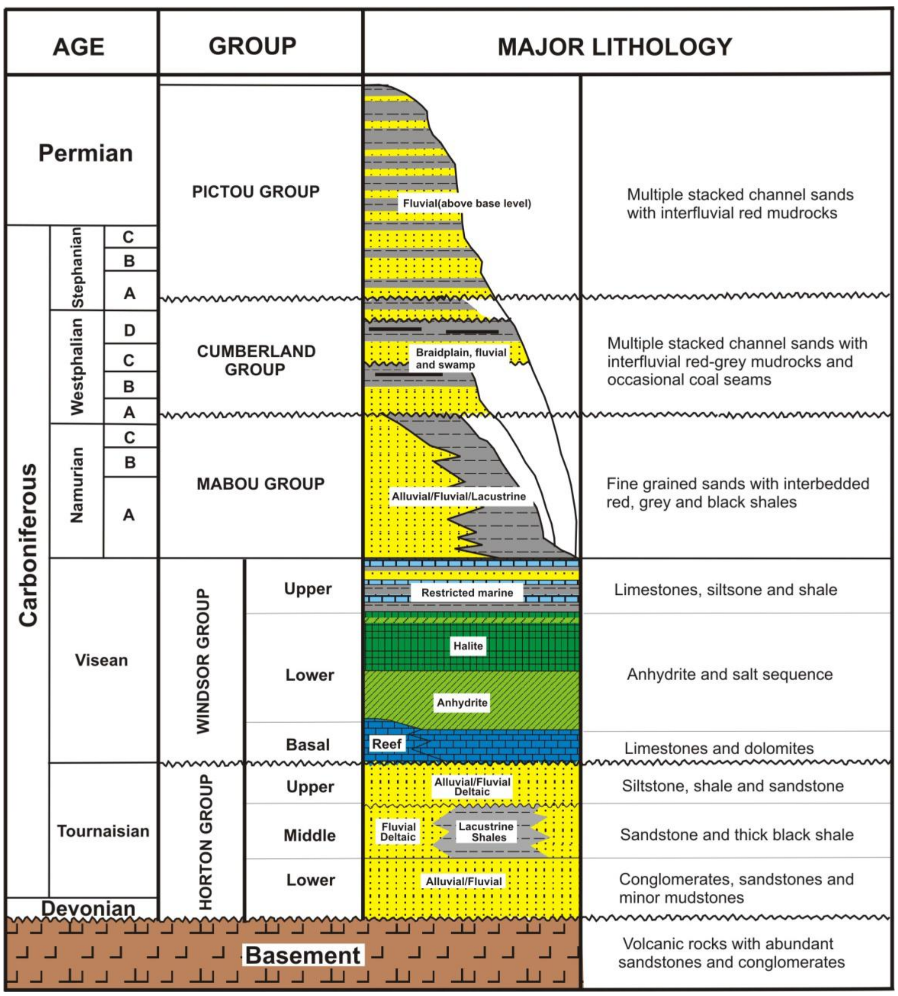
It is important to note that the Nova Scotia Department of Energy is moving forward to establish their in-house resource assessment, to get a better understanding of their province's complex geology. The project is called Onshore Petroleum Atlas, and aims to compile geological, geophysical and geochemical data, to establish Nova Scotia's hydrocarbon potential (Cen 2012). The project is scheduled to be completed in 2017.

Horton Bluff Formation

Though smaller compared to the Frederick Brook Shale, the Horton Bluff is a significant source of natural gas for Nova Scotia. Thus far, the focus of attention has been on the Windsor land block in the northern part of the province.

Figure 2.10 illustrates the stratigraphy of the Windsor Basin and the Horton Group. The two shales are considered by many to be analogous to each other. Both, for example, are of the Early Carboniferous Period, from the Tournaisian Age.

Figure 2.10: Stratigraphy of the Windsor and Horton Group

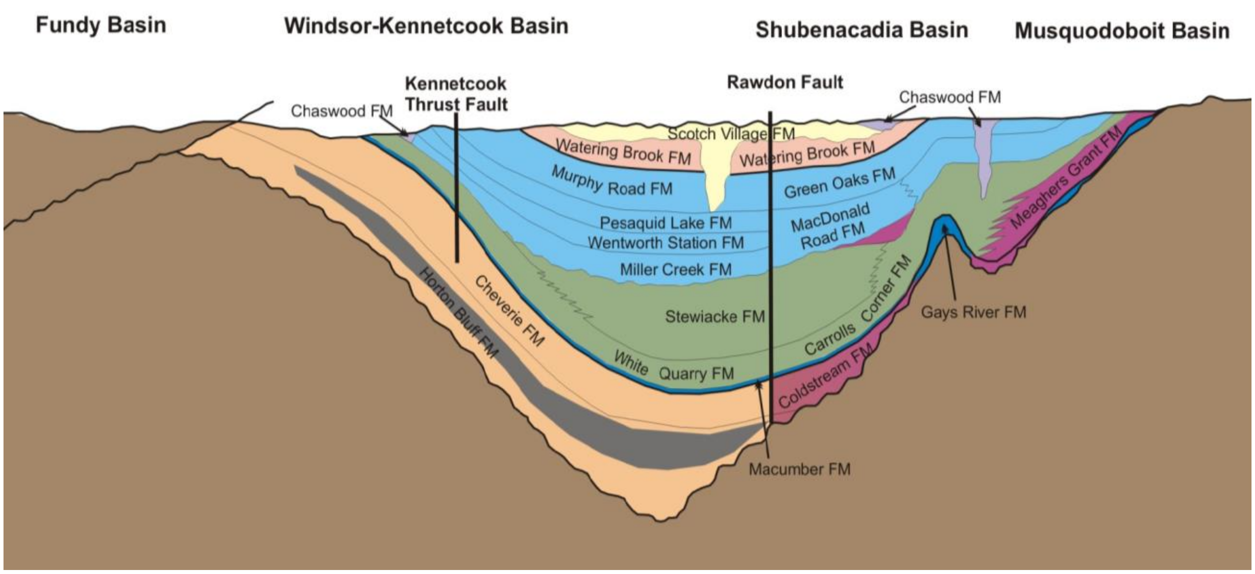


Source: (Cen 2012)

The Windsor Group is comprised of limestone, gypsum, and hydrite and considered a marine deposit. The Horton Group and the main target for petroleum activities, on the other hand, is comprised of clastic sediments and fluvial-lacustrine. The Horton Group is divided into three parts: Upper, Middle and Lower. The shallowest is comprised of siltstone, shale and sandstone, and its lithography is of alluvial/fluvial deltaic. Middle Horton Group is comprised of sandstone and thick black shale and is a combination of fluvial deltaic and lacustrine shales. The Lower Horton Group is made up of conglomerates, sandstones and minor mudstone, and is of alluvial/fluvial succession.

Figure 2.11 illustrates the stratigraphy of the Windsor-Kennetcook Basin, including the Kennetcook Thrust Fault and the Rawdon Fault. Similar to the Frederick Brook Shale, these layers were deposited in the center or deepest portions of the freshwater lake or brackish lake 300 to 360 million years ago, during the Lower Carboniferous period (Alexander et al. 2011). It is for this reason that the shale is lacustrine in origin, but there are also indications of a marginal marine origin as well. The figure illustrates the geological complexity of the area.

Figure 2.11: Stratigraphy of the Windsor-Kennetcook Basin



Source: (Cen 2012)

The thick organic shales of the Horton Bluff are a target for E&Ps over the past decade in this area, particularly for two small operators — Elmworth Energy and Forent Energy. As previously mentioned, however, both companies are not currently involved in the Windsor-Kennetcook Basin. The former, however, explored the basin between 2007 and 2009, spending over C$30 million and drilled five exploratory wells (Elmworth Energy Corporation 2014). The wells included Kennetcook #1, Kennetcook #2 and the N-14A. Test wells failed to produce commercially, but did result in better estimating the potential resource itself (Hayes and Ritcey 2014). Much of the data stems from the exploratory of those efforts.

There have been several notable estimates for the Horton Bluff. Ryder-Scott Consultants estimated the resource potential, utilizing Elmworth's test well data, as 69 Tcf of gas in-place within the Horton Bluff (NRCan 2016c). Other data suggested that the total organic carbon (TOC) values exceed 5.5 percent and the thermal maturity (reflectance in oil, Ro) is 1.6 percent (MacDonald 2011; C. J. St. Peter and Johnson 2009). In addition, parts of the shale play are greater than 500 meters thick (C. J. St. Peter and Johnson 2009). The second is an estimate provided by EIA and Advanced Resources International (ARI). Their estimate for gas in-place at the Horton Bluff is 17 Tcf, with a risked recoverable of 3.4 Tcf (ARI 2013).

Table 2.2 illustrates the shale gas reservoir characteristics of the Horton Bluff, as well as Québec's Utica Shale.

Table 2.2: Shale Gas Reservoir Characteristics of the Horton Bluff and Québec's Utica Shale

Basic Data	Basin/Gross Area		Appalachian Fold Belt ($3,500\ mi^2$)	Windsor ($650\ mi^2$)
	Shale Formation		Utica	Horton Bluff
	Geologic Age		Ordovician	Mississippian
	Depositional Environment		Marine	Marine
Physical Extent	Prospective Area (mi^2)		2,900	520
	Thickness (ft)	Organically Rich	1,000	500
		Net	400	300
	Depth (ft)	Interval	4,000 - 11,000	3,000 - 5,000
		Average	8,000	4,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Normal
	Average TOC (wt. %)		2.0%	5.0%
	Thermal Maturity (% Ro)		2.00%	2.00%
	Clay Content		Low	Unknown
Resource	Gas Phase		Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		133.9	81.7
	Risked GIP (Tcf)		155.3	17.0
	Risked Recoverable (Tcf)		31.1	3.4

Source: (ARI 2013)

Similar to the Frederick Brook Shale, the Mississippian-aged Horton Bluff area is relatively small, with the prospective area being only 520 square miles. It is, however, larger than the Frederick Brook Shale, at only 180 square miles. While the average thickness is less than the Frederick Brook Shale, one of the benefits to E&Ps is its depth ranges between 3,000 and 5,000 feet, roughly between 915 and 1,525 meters. This will reflect in lower drilling costs. Recall, the depth of the Frederick Brook Shale ranges between 1,600 to 4,000 meters (MacDonald 2011). As a general description, the Horton Bluff represents about 20% of the opportunity of the Quebec's Utica Shale.

Chapter 3: Environmental and Indigenous Peoples Issues Associated with Oil and Gas Development in New Brunswick and Nova Scotia

This chapter is divided into three parts. The first outlines the regulatory requirements of oil and natural gas projects and the current regulatory status of unconventional gas and oil development in New Brunswick and Nova Scotia. The second part reviews potential environmental impacts associated with oil and gas development, including surface and groundwater issues, greenhouse gas emissions, air quality effects, land impacts and public health issues. The third part reviews Aboriginal rights and Indigenous people's issues influencing oil and gas development.

Regulatory Requirements and the Current Regulatory Status of Unconventional Gas and Oil Development in New Brunswick and Nova Scotia

Legislative and regulatory requirements are fundamental to the efficient regulation of oil and natural gas development. Government agencies and associated organizations, and their respective legislative documents and regulatory frameworks related to the effective governance of the oil and gas industry are discussed below.

According to Canada's Constitution, the ownership of onshore energy resources (including oil and gas resources) within the provincial borders, as well as primary regulation of energy resources development rests with provinces. Provincial regulations for oil and gas development differ. Provincial regulatory bodies include numerous departments and organizations that are constantly updating their legislative framework to reflect the changes in oil and natural gas resource development (NRCan 2016d). The provincial regulatory frameworks can overlap with federal legislation to some degree, however, there are some legislative documents and authorities specific and unique for each province.

Detailed information regarding federal regulatory requirements, followed by provincial regulatory requirements for New Brunswick and Nova Scotia is presented in Appendix C. The Appendix includes a list of federal and the respective provincial departments that are pertinent to oil and gas development, and provides an overview of relevant federal and provincial acts, regulations, guidelines, policies and best management practices. Regulatory frameworks for federal and provincial environmental assessment (EA) processes and types of environmental assessments that can be conducted for various oil and natural projects are also discussed in Appendix C.

In December 2014, the Government of New Brunswick introduced the Prohibition Against Hydraulic Fracturing Regulation under the provincial *Oil and Natural Gas Act* (NB ONGA) that imposed an open-ended moratorium on hydraulic fracturing in the Province. The Regulation was voted into law and came into effect in June 2015 (Government of NB 2014, 2015). In May 2016, the Province indefinitely extended the moratorium in response to the report prepared by the New Brunswick Commission on Hydraulic Fracturing (NB CHF) (McHardie 2016), however, as discussed later in this chapter, the report itself did not propose a moratorium or any other political device. As stated by the provincial government, there are five conditions that must be met for the moratorium to be lifted (Government of NB 2014; NB CHF 2016b):

- A social license in place;
- Clear and credible information about the impacts of hydraulic fracturing on human health, environment and water, allowing to develop a country-leading regulatory regime with sufficient enforcement capabilities;
- A plan that mitigates the impacts on the public infrastructure and that addresses issues such as wastewater disposal;
- A process in place to respect the obligations under the duty to consult with First Nations;
- A mechanism in place to ensure that benefits are maximized for New Brunswickers, including the development of a proper royalty structure.

In 2012, the Government of Nova Scotia imposed a moratorium on all forms of hydraulic fracturing in the province, and in September 2014 introduced amendments to the provincial *Petroleum Resources Act* (NS PRA) to ban the practice of high-volume hydraulic fracturing for onshore oil and gas development (Government of NS 2014). To reconsider the ban, social, economic, health, environmental and regulatory effectiveness, as well as scientific and technical considerations must be taken into account (Government of NS 2014). Before implementing the ban, only 11 wells have been hydraulically fractured in Nova Scotia, eight for CBM production evaluation and three for exploring shale gas potential (Wheeler et al. 2014).

Key Environmental Concerns Associated with Oil and Gas Development

As discussed earlier, potential oil and natural gas development in New Brunswick and Nova Scotia is mostly associated with unconventional resources, including shale gas. One of the key conditions to reconsider currently imposed moratoria on hydraulic fracturing in these two Maritime provinces is to provide reliable information on the impacts of hydraulic fracturing on environment and human health (Government of NB 2014; Government of NS 2014). Consequently, this section focuses on reviewing the potential environmental impacts of unconventional gas and oil development associated with practices of hydraulic fracturing.

CERI attempts to review existing concerns and potential impacts related to environment when unconventional resources are developed. Examples of existing regulatory or mitigation measures taken by the industry, or a level of the development of technology are provided, as well as a difference between potential impacts from conventional and unconventional gas developments is made where possible. However, these examples cannot and should not be treated as a comprehensive body of information of such kind. The subject of potential environmental impacts of the unconventional gas and oil development in a specific location (provincial, geographical and geological settings) is a theme for separate research or formal Environmental Impact Assessment processes for a particular project.

Environmental Concerns: Context and State of Knowledge

Extensive research to examine environmental impacts of unconventional gas and oil development has been completed in the last few years both on federal and provincial levels. The most comprehensive studies to date include the following:

- *Environmental Impacts of Shale Gas Extraction in Canada* (CCA 2014a). The report was commissioned by Environment Canada (now Environment and Climate Change Canada [ECCC]) and prepared by the Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction (the Expert Panel) at the Council of Canadian Academies (CCA);

- *Report of the New Brunswick Commission on Hydraulic Fracturing*, released in three volumes (NB CHF 2016a, 2016b). The New Brunswick Commission on Hydraulic Fracturing (NB CHF) was appointed by the Premier of New Brunswick to study the issue of hydraulic fracturing in New Brunswick;

- *Report of the Nova Scotia Independent Review Panel on Hydraulic Fracturing* (NS IRPHF) (Wheeler et al. 2014). The review was commissioned by the Province of Nova Scotia and the NS DOE, and prepared by an independent panel of experts assembled by the Verschuren Centre for Sustainability in Energy and the Environment at Cape Breton University.

This section provides an overview of the current state of knowledge on potential environmental issues arising from unconventional resources development, drawing on the above reports, as well as a review of recent peer-reviewed literature and documents from government, industry and international organizations.

As it has been demonstrated in the reviewed sources, even though a very large number of unconventional wells have been drilled across North America over the last twenty years, data on the environmental impacts of shale gas and oil development are still limited, and often are not publicly available. Interpretations about some of these available data can also differ (CCA 2014a, 2014b; NB CHF 2016a; Wheeler et al. 2014). In addition, most peer-reviewed articles on environmental impacts of hydraulic fracturing are based on US studies. The reasons behind these challenges include (CCA 2014a; R. B. Jackson et al. 2014; Wheeler et al. 2014):

- the relatively young age of the large-scale shale industry (that has been established in Canada for approximately 10 years now);

- the proprietary nature of some industrial information;

- the lack of regulations for many of the chemical additives used in hydraulic fracturing, and, thus, inability to monitor their impact properly;

- the confidentiality regarding settlement of damage claims with the industry;

- the lack of sufficient environmental baseline data that makes identification and assessment of potential impacts more difficult;

- the possibility of long-term environmental and health effects of unconventional resources development that may become evident after many years or even decades.

The potential environmental impacts associated with unconventional oil and gas development may differ between regions, since practices that are appropriate in one region may be unacceptable in another. Accordingly, concerns expressed by stakeholders may vary regionally, however, the majority are widely shared (CCA 2014a). The potential environmental concerns frequently raised in public discussions regarding unconventional gas and oil development in Canada include the following (Pembina Institute 2012):

- water use and water contamination from methane and fracturing fluid;
- waste treatment and disposal;
- local air quality;
- land use and biodiversity;
- induced seismicity;
- greenhouse gas emissions;
- cumulative environmental effects.

For the Province of New Brunswick, the main environmental concerns, based on comments made at the nine shale gas public consultations at the request of the provincial government and subsequent presentations, included government integrity, potential water contamination, well integrity, chemicals and health risks, and security of fresh water supply (LaPierre 2012).

A summary of environmental concerns expressed by stakeholders in Nova Scotia, based on 238 public submissions to the NS IRPHF, included water contamination and water massive usage; waste and clean up (wastewater disposal/storage); climate change (methane leaks/greenhouse gas contributions); land impacts (habitat fragmentation, soil contamination, earthquake concerns); and human health (Mauro et al. 2014; Wheeler et al. 2014). The identified issues will be discussed in detail below.

Potential Impacts on Water

Potential impacts on water resources are usually considered by stakeholders as the top issue associated with unconventional resources development, and most experts share this opinion (CCA 2014a; NB CHF 2016a, 2016b; Wheeler et al. 2014). However, as stated in the CCA's report, the extent of this risk to water resources "cannot be assessed because of a lack of scientific data and understanding" (CCA 2014a).

Overview of Potential Groundwater Impacts

Regional groundwater contamination has been among the main concerns for residents of the two Maritime provinces (CCA 2014b; LaPierre 2012; Mauro et al. 2014; NB CHF 2016b). Nevertheless, the analysis of publicly available sources shows that impacts of upstream oil and gas development on groundwater have been researched to a much lesser extent than impacts of downstream development, including pipeline incidents (CCA 2014a; Wheeler et al. 2014). As noted in the CCA's report, a common statement in the non-peer reviewed literature is that no direct impacts from shale gas on groundwater have been proven or verified. The report further emphasizes that peer-reviewed sources are more cautious about this general statement pointing out "the limitations of relying on absence of evidence" to support it (CCA 2014a).

A risk of potable groundwater contamination arises from the potential upward migration of natural gas and the saline flowback water through several pathways including: a) well casing leakage, b) natural fractures in the rock and permeable faults, and c) old abandoned wells (CCA 2014a). Possible pathways of groundwater contamination are illustrated in Figure 3.1. Migration of gases and possibly saline waters through the pathways may continue for a long time and may potentially lead to substantial cumulative effects on aquifer water quality that are difficult to predict (CCA 2014a).

One of the main threats to groundwater is gas leakage from wells, therefore maintaining well integrity should be stated as the highest priority to prevent contamination (CCA 2014b; U.K. Royal Society and Royal Academy of Engineering 2012). This risk of improper cementing or cementing impairment over time is not exclusive or a specific property to shale gas wells but rather a risk inherent to any oil or gas wells.

Proper well cementing can minimize the risk of groundwater contamination. It is noteworthy to mention that both provinces heavily regulate casing design in order to mitigate the potential issues. For example, the requirements for well casing and cementing are established in the Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick: Rules for Industry and in the Well Construction Regulations made under the Nova Scotia *Environment Act* (NS EA) (see Appendix C for details). Modern well cementing and completion techniques for unconventional gas and oil development contribute to generally good wellbore performance, however, it is impossible to reach complete success in avoiding any future well impairment (Wheeler et al. 2014).

Natural fractures in the rock and permeable faults can also serve as a pathway for shale gas and injected water upwards. While conventional completion of a cased gas well (not-fracked) also implies perforating of the casing and wellbore, the distance of the penetration into the productive zone is small compared to fractures produced by fracking. As such, fracking of shale gas reservoirs has a higher chance of hydraulic fractures connecting with natural fractures and permeable faults which may be connected to an aquifer.

Likewise, shale gas and injected water may find pathways to groundwater through nearby decommissioned wells if fractures from a fractured well reach a decommissioned well, and the latter is not sealed properly. The numbers of leaking decommissioned wells and the rates of leakage are not well-understood. This amount can vary depending on many factors, including geographical region, geological setting, age of well, quality of cement, nature and rate of cement deterioration, etc. (CCA 2014a; Wheeler et al. 2014).

The impacts of leaking wells are not being systematically monitored; in addition, knowledge on the mobility and fate of hydraulic fracturing chemicals and wastewater in the subsurface water is also still insufficient (CCA 2014b; Wheeler et al. 2014).

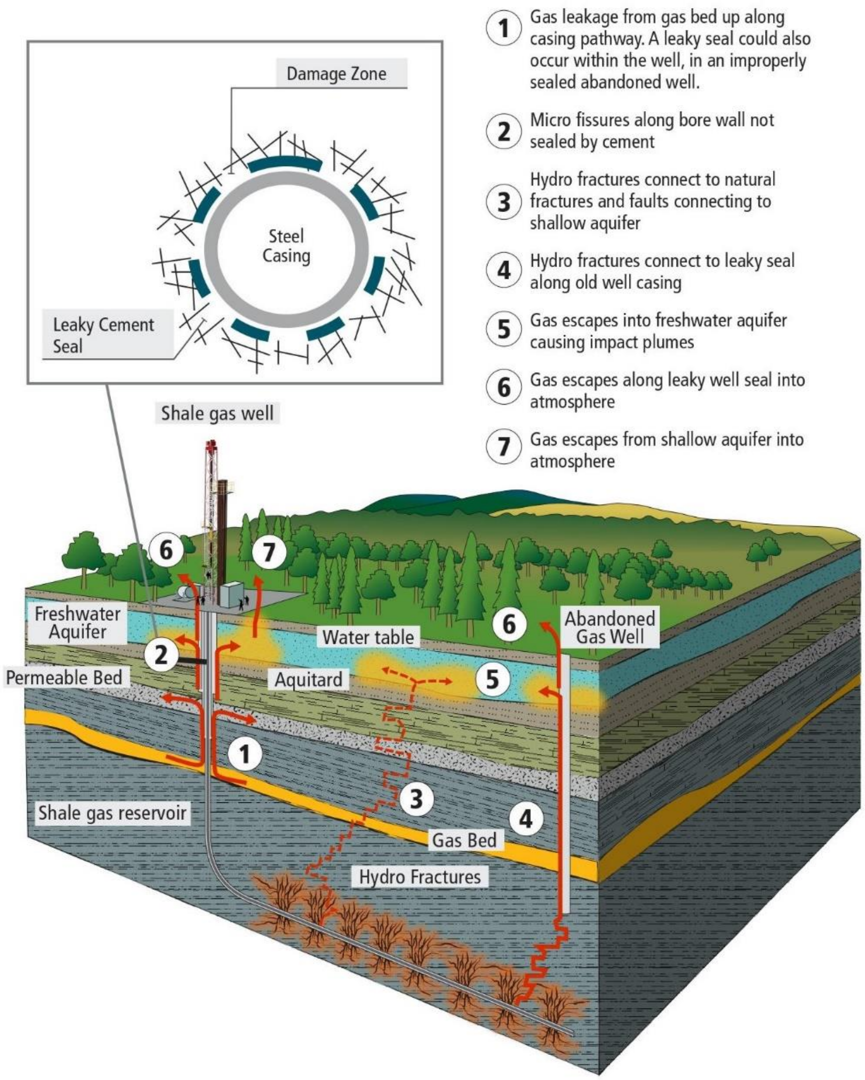
It should be noted that gas leakage from wells into aquifers will not always cause significant impacts on groundwater, since the groundwater zone has certain capacity to purify the water from contaminants, known as the assimilation capacity. Strong assimilation capacity can prevent degradation of groundwater resources due to leakage from unconventional gas wells, however, the resilience of fresh groundwater systems to gas migration still needs to be studied (CCA 2014a, 2014b).

It is worthwhile to mention that methane can be a naturally occurring component of shallow groundwater, and its presence in water wells is not necessarily a result of oil and gas extraction (NB CHF 2016a). For example, detectable levels of methane have been found in approximately 12 percent of the water wells surveyed in Sussex, New Brunswick, and 21 percent of the wells tested in northeastern Nova Scotia (T. A. Al, Leblanc, and Phillips 2013; Drage and Kennedy 2013). However, it has also been reported as a possible contaminant from the hydraulic fracturing process in some jurisdictions in the US. A study conducted in Pennsylvania has detected methane in 82 percent of drinking water samples from 141 drinking water wells with average concentrations six times higher in homes less than 1 km away from natural gas wells, in comparison to homes more than 1 km away (R. B. Jackson et al. 2013). This highlights the importance of collecting baseline water samples, with another study underscoring the need for thorough analyses of data, pre-drill testing, and long term monitoring for well water contamination near unconventional gas extraction (Alawattegama et al. 2015). The lack of scientific baseline groundwater data makes it difficult to address the issues of unconventional gas and oil development on shallow groundwater (R. E. Jackson et al. 2013).

A recent study in northeastern Pennsylvania by Siegel et al. was based on a much larger sampling size (Chesapeake Energy's baseline data sets of > 11,300 dissolved methane analyses) and was intended to address the limitations of the previous studies. The study found that "there is no significant correlation between dissolved methane concentrations in groundwater and proximity to nearby oil/gas wells" (Siegel et al., 2015a).[1]

[1] It should be noted that the correction to this article published later acknowledged the lead author was funded privately by Chesapeake Energy Corporation for this work, and for the other authors, funding by Chesapeake was provided through their organizations of employment (Siegel et al., 2015b).

Figure 3.1: Groundwater Contamination Pathways



Source: G360 Centre for Applied Groundwater Research, University of Guelph, as referred to in (CCA 2014a).

Subsurface and Surface Water Concerns

In the Maritime provinces, due to location of unconventional gas resources, the drilling of gas wells can often occur in the proximity to water wells used as sources of drinking water by rural residents. However, the available information indicates that the risk to surface water quality arising from unconventional gas and oil development is more related to operational practices (e.g., chemical handling or waste management), rather than the hydraulic fracturing process (CCA 2014a; Wheeler et al. 2014).

Main pathways for chemicals used for hydraulic fracturing (mostly in the case of slickwater stimulations) to interact with shallow groundwater and surface water include the following (CCA 2014a; R. B. Jackson et al. 2014; Kuwayama, Olmstead, and Krupnick 2015; NB CHF 2016a):

- accidental spills or release of chemicals during their transportation, storage at shale gas pads or use;
- spills or inadequate storage/treatment of flowback water/wastewater that returns to the surface during or after hydraulic fracturing;
- leaks and spills from well pads, storage tanks and wastewater holding ponds;
- creation of impervious surfaces for well pads and related infrastructure such as access roads.

As summarized in the CCA's report, other concerns associated with unconventional gas and oil development and related to surface water include but are not limited to (CCA 2014a):

- the extraction of water from surface water sources for shale gas production;
- impacts on hydrology from changes to the land;
- loss of buffer strips;
- habitat discontinuities and fragmentation associated with temporary road and culvert placement;
- the potential consequences of dams or other structures associated with water collection or impoundments;
- increased sedimentation, etc.

Chemicals Used in Hydraulic Fracturing

The unconventional gas and oil industry has been criticized for being non-transparent about disclosure of the chemical additives used in hydraulic fracturing (CCA 2014a). Now regulators in many jurisdictions have required hydraulic fracturing companies to provide full or substantial disclosure and registration of chemical additives that may be used during operations. As an example, the FracFocus registry website has been designed to provide similar information, and has already been adopted by Alberta, British Columbia and the Northwest Territories (Wheeler et al. 2014). Current New Brunswick regulations require shale gas producers to fully disclose to the Department of Environment and Local Government (NB DELG) all chemicals to be used in hydraulic fracturing, and to list the chemicals on the FracFocus website once fracturing is completed (NB CHF 2016a).

The mixtures of chemical additives used in hydraulic fracturing can be complex and are not standardized (Wheeler et al. 2014). For example, a report prepared for Health Canada refers to 750 chemicals in more than 2,500 hydraulic fracturing products reported by 14 oil and gas companies in the US between 2005 and 2009 (Carrier 2012; Waxman, Markey, and DeGette 2011).

In addition to full disclosure of the chemical additives and the chemical composition of flowback water, information on potentially hazardous chemicals produced by chemical interactions under high temperature and pressure is also required for the assessment of the environmental risks associated with hydraulic fracturing. This includes data on concentration, mobility, persistence in groundwater and surface water, and bio-accumulation properties, for both individual chemicals and their mixture (CCA 2014a). Since groundwater flow is slow, it can take a long time after unconventional development to recognize the issues of its contamination with fracturing chemicals (Wheeler et al. 2014).

The CCA's report also draws attention to the fact that potential effects of the fracturing chemicals on human and environmental health are unknown. According to the report, there is "only minimal reference literature and no peer-reviewed literature that assess the potential for the various chemicals in hydraulic fracturing fluids to persist, migrate, and impact the various types of subsurface systems or to discharge to surface waters" (CCA 2014a).

Water Use

Generally, hydraulic fracturing operations consume more water than do conventional natural gas operations, however, they are less water-intensive than average conventional oil production (Kuwayama, Olmstead, and Krupnick 2015). The amount of water required for hydraulic fracturing depends on the length and orientation of the well bore, the well depth and the geological setting for different unconventional gas and oil plays (Hansen, Mulvaney, and Betcher 2013; Mauro et al. 2014; Rahm and Riha 2014; Wheeler et al. 2014). The amount of water needed for unconventional gas and oil development can be a concern in some regions. It is a lesser issue in Canada, where the hydrological resources are significant in comparison with the absolute volume of water required for hydraulic fracturing, however, the timing of water withdrawal is important (CCA 2014b). Large volumes of water may be required over short periods of time that could stress available water resources depending on their location, season (e.g., during low-flow summer conditions) and pre-existing use (CCA 2014a; NB CHF 2016a). Re-fracturing of wells to extend their production life can also lead to the increased water consumption by the shale gas industry (R. B. Jackson et al. 2014). Cumulative effects of a large number of wells concentrated in just a few watersheds has also been mentioned as a concern (NB CHF 2016a).

In Nova Scotia, approximately two thirds of water consumption are for residential purposes. Water resources in the Province support many other industries too, so any new industrial activity, such as unconventional oil and gas development, would need to align with the available water resources. The NS IRPHF's report underlines that NS Environment needs to develop more data to confirm water availability for specific watersheds in the Province (Wheeler et al. 2014).

Estimates of future water demands vary for different unconventional gas and oil plays. It is stated that an average water use per well for the major shale plays in North America is about 15,000 to 20,000 cubic metres (m3) (C. Rivard et al. 2012). The United States average water use is estimated to be approximately 19,000 m3 per well (CCA 2014a). Corridor Resources estimates that its water use for future wells in the Fredrick Brook Shale would be between 10,000 and 20,000 m3 per well (Corridor Resources Inc. 2015d; NB CHF 2016a). Another estimate of future water demand for wells in New Brunswick is 20,000 to 60,000 m3 per well (T. Al et al. 2012). The CCA's report further identifies that the average water use per unconventional gas and oil well would vary from 2,000 to 20,000 m3 in New Brunswick and between 5,900 and 6,800 m3 in Nova Scotia (based on data for the two wells fracked to date) (CCA 2014a; C. Rivard et al. 2012; Wheeler et al. 2014).

It should be noted that various approaches could be used by the unconventional gas and oil industry to mitigate water use issues. They include using of recycled water or saline water from deep saline aquifers, reusing produced water, storing water on-site, and even replacing water used in hydraulic fracturing with gas (CCA 2014a; Christine Rivard et al. 2014). However, freshwater remains the main source of the water used in hydraulic fracturing.

Wastewater Management and Wastewater Disposal

Wastewater generated because of unconventional gas and oil activities typically includes two main types (NB CHF 2016a; Wheeler et al. 2014):

- flowback water, which is injected hydraulic fracturing fluids that return to the surface after fracturing operations; and
- produced water that is wastewater produced as a co-product during the productive life of the well.

The composition of flowback water varies from pad to pad and from area to area due to geological conditions and company practices (CCA 2014a; Haluszczak, Rose, and Kump 2013; NB CHF 2016a). Generally, flowback water has a higher flow rate on the short-term scale, in comparison with produced water, but has lower salinity and lower levels of naturally occurring radioactive material (NORM) (Jiang, Hendrickson, and VanBriesen 2014; NB CHF 2016a). In practice, wastewater is a mixture of flowback water with formation water that naturally occurs in the pores of rocks and comes to the surface along with the gas. Formation water has high salinity due to naturally occurring salts and contains metals, petroleum hydrocarbons and NORM (CCA 2014a; NB CHF 2016a).

Estimates of the total volume of wastewater generated from major shale gas plays in the US range from 4,000 to 12,400 m3 per well during the first four years of gas production; these amounts can increase over the life of the well (R. B. Jackson et al. 2014). A preliminary study by Atlantica Centre for Energy (ACE) based on production from the McCully gas field to date, estimates 9,000 m3 per day of flowback water and 25 m3 per day of produced water based on an assumption of 100,000 MMcfd of gas production (ACE 2015).

Typically, it is expected that approximately 30 percent of the injected water will be recovered, though this amount depends on the shale formation and technologies used (C. Rivard et al. 2012). According to other estimates, between 25 percent and 50 percent of the water returns up the well to the surface after stimulation as flowback water (CCA 2014a). The flowback fluid can be treated and re-used in the next stage. In many jurisdictions, the flowback fluids are not treated, they are re-used in multiple operations and when drilling is completed, they are disposed either at a treatment facility or by injecting into designated deep wastewater wells (CCA 2014a; NB CHF 2016a; Wheeler et al. 2014).

Deep-well injection is the industry's commonly preferred option when the geology is suitable (e.g., in Alberta and British Columbia). Unlike the Western provinces, geological conditions in the Maritime provinces are not favorable for the construction of such wells (Keighley and Maher 2015; NSE 2008). The Maritimes Basin is mostly comprised of low permeability rocks and generally do not have thick permeable saline aquifers that would permit deep wastewater disposal (T. Al et al. 2012; CCA 2014a; NB CHF 2016a). It is unlikely that deep wastewater disposal would ever be used in New Brunswick or Nova Scotia, and it is currently not permitted (NB CHF 2016a; NSE 2008; Wheeler et al. 2014). Thus, wastewater treatment and recycling become the most viable options and the potential long-term solutions for both provinces (CCA 2014a; NB CHF 2016a).

Before treatment, reuse or disposal, the flowback water and produced water are typically stored in tanks or in lined surface ponds on site (CCA 2014a; Holloway and Rudd 2013; Speight 2013; Wheeler et al. 2014). The main concern with wastewater storage in clay-lined ponds is the potential of its leakage into the local groundwater due to increase in the liner permeability caused by the saline flowback water (Folkes 1982; Wheeler et al. 2014).

The Province of New Brunswick does not allow storage of the flowback and produced water in ponds (Government of NB 2013). The Province of Nova Scotia did not have regulations in place for the flowback water disposal or treatment when exploratory hydraulic fracturing waste water containment ponds in Kennetcook, NS, had leaked. Waste byproduct (mostly saline water with some NORM), totaling 14,000 m3 of the flowback water, has remained on site since the operator and the provincial government have not agreed on the disposal options for the wastewater (CCA 2014a; Mauro et al. 2014). As summarized in the CCA's report, "this stalemate has become a symbol of the difficulties of wastewater disposal associated with shale gas development in eastern Canada" (CCA 2014a).

Treatment and recycling of flowback water in wastewater treatment facilities can be challenging due to the variable composition of the flowback water, the possible presence of NORM (including uranium and thorium, that decay into radium 226 and radium 228, respectively) and the high costs of treatment (CCA 2014a; Irvin 1996; as cited by Wheeler et al. 2014).

The composition of the wastewater obtained from unconventional gas and oil development differs significantly from the water typically processed in a municipal wastewater treatment plant. This flowback/processed water is a potentially hazardous waste since it contains hydraulic fracturing chemicals, petroleum hydrocarbons (including benzene and other aromatic compounds), metals and metalloids, NORM that have leached from the shale, and has increased salinity (CCA 2014a; Haluszczak, Rose, and Kump 2013; Wheeler et al. 2014). Thus, flowback water cannot be treated in a typical municipal wastewater treatment plant, since its salinity adversely affects microbial activity in the activated sludge process for normal waste. In addition, NORM components may flow through the treatment plant and be released into the municipal water system or the environment (CCA 2014a; Wheeler et al. 2014).

In addition, not enough is known about the fate, transformation and toxicity of the chemicals in the flowback water to understand potential impacts to human health and the environment (CCA 2014a). It can be related to the fact that even if the complete chemical composition of the hydraulic fracturing substances is known, the chemical composition of the flowback water will still be different. The flowback water includes a mixture of injection fluids and shale water that both have undergone the high temperatures and pressures in shale formation (CCA 2014a).

It should be noted that shale gas wastewater treatment and disposal is currently being studied by several institutions in North America, and technologies to deal with wastewater do exist. Some examples of water technologies that are generally used in the natural gas industry and might be applied to treat wastewater from hydraulic fracturing activities include thermal desalination, reverse osmosis and forward osmosis, solids filtration, electrocoagulation, activated carbon treatment and biological treatment (ACE 2015; CCA 2014a; Gregory, Vidic, and Dzombak 2011; NB CHF 2016a; Wheeler et al. 2014). However, the wastewater treatment processes can be costly (in order to achieve environmental and human health standards), highly energy-intensive, and may require a combination of treatment technologies (ACE 2015; Gregory, Vidic, and Dzombak 2011; CCA 2014a). In addition, the challenges discussed above (including the specific chemical composition of wastewater, high concentrations of total dissolved solids, and potential radioactivity) should be considered while selecting the most effective treatment options before disposal the wastewater to the environment.

As outlined in the NB CHF's report, the next step will be to determine what options can be implemented in New Brunswick should the provincial government decide to proceed with hydraulic fracturing (NB CHF 2016b). A wastewater management plan is required before shale gas activities begin that describes how and where wastewater will be managed, transported, treated or disposed of (Government of NB 2013). It should also be noted that any new wastewater treatment facility would likely trigger an environmental impact assessment (EIA) according to the Environmental Impact Assessment Regulation under the New Brunswick *Clean Environment Act* (NB CEA) (NB CHF 2016a).

As stated in the NS IRPHF report, pathways and technologies for wastewater treatment and well pad clean up must be determined in consultation with all relevant stakeholders prior to any potential commercial development of unconventional gas and oil activities in Nova Scotia (Wheeler et al. 2014). Those consultations represent a possibility of linking advancements in technology to reducing knowledge gaps, operating costs and increased economic potential.

Greenhouse Gas Emissions

The risk of increased greenhouse gas (GHG) emissions (including fugitive methane emissions during and after operations) is one of the primary concerns regarding unconventional gas and oil development (CCA 2014a; Pembina Institute 2012). Estimates of GHG emissions from unconventional gas production as compared to emissions from conventional production vary between different sources (O'Sullivan and Paltsev 2012). Some studies of GHG emissions from shale plays and conventional production in the US showed little difference between them (CCA 2014a). On the other hand, Burnham et al. suggested that in many cases, estimated emissions from shale gas production are on average six percent lower than emissions for conventional gas production (Burnham et al. 2012). However, the authors notice there is a statistical uncertainty whether shale gas life-cycle emissions are lower than conventional natural gas, since the range in values for conventional and unconventional gas overlap (Burnham et al. 2012).

GHG emissions for all types of natural gas development include (CCA 2014a; Johnson, Covington, and Clark 2015; NB CHF 2016a):

- methane and carbon dioxide (CO2) emissions during drilling and well completion, mostly due to venting and flaring;
- emissions from plays where the gas contains significant proportions of carbon dioxide that must be removed before the gas can be brought to market;
- methane emissions from fugitive emissions during production, processing, and transport to market (e.g., defects in well casing and cementing; escape from production equipment such as compressors, pneumatic devices, valves and storage tank vents); and
- methane emissions from well leakage after abandonment.

It is well known that methane is a more potent greenhouse gas than CO2, since it is more efficient at trapping heat than CO2. Methane's lifetime in the atmosphere is much shorter than carbon dioxide, however, the comparative impact of methane on climate change is about 34 times greater than CO2 over a 100-year period (NB CHF 2016a; U.K. Task Force on Shale Gas 2015). Methane leakage (known as fugitive emissions) can reduce the GHG advantage of natural gas used as a substitute for coal or oil for electricity generation (Allen 2014; CCA 2014a). It is currently acknowledged that methane leakage is poorly understood and may be largely underestimated in both the US and Canada (Brandt et al. 2014).

The most important way to prevent methane leakage and protect the environment is to ensure well integrity that can be negatively impacted by the following issues (CCA 2014a, 2014b):

- problems encountered during cementation, such as poor well centralization, inadequate mud displacement, and an irregular well hole;
- improperly placed cement seals and inadequate sealing;
- degradation over time of both casing and the cement sheath;
- damage from repeated fracturing treatments.

The most common long-term well integrity issue after abandonment is slow leakage of methane around the external casing (NB CHF 2016a; Wheeler et al. 2014). In addition, there is no understanding of the long-term (over 100 years) effectiveness of well decommissioning (CCA 2014a; Wheeler et al. 2014).

The CCA's report emphasizes that information about the current state of GHG and fugitive methane emissions from unconventional gas and oil development is mostly based on the data obtained in US studies. However, the situation can be slightly different in Canada, since Canadian regulations and best management practices are generally more stringent, with requirements of fully cemented production casing, less venting, etc. (CCA 2014a). For example, the requirements for well casing and cementing are established in the Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick: Rules for Industry, and in the Well Construction Regulations made under the NS EA (see Appendix C for more details). In Canada, it is estimated that methane emissions can be reduced by almost half (45 percent), which is equal to 27 million tons (Mt) CO_2e or 56 Bcf of methane, with existing technologies, and these technologies (applicable to both unconventional and conventional oil and gas developments) will also reduce emissions of volatile organic compounds (VOCs) and hazardous air pollutants (ICF International 2015; NB CHF 2016a).

As discussed earlier, both provinces have their Climate Change Action Plans in place to establish provincial GHG emissions reduction targets (Government of NB 2016; NSE 2009). New Brunswick's Rules for Industry currently require companies to submit a GHG reduction plan and report annually on GHG emissions, and contain provisions for addressing wellbore integrity and air quality impacts (NB CHF 2016a; Government of NB 2013).

Air Quality Effects

The atmosphere is an important pathway of contaminants transportation to freshwater, marine, terrestrial and human environments. Air quality impacts of unconventional gas and oil activities although known in general still need to be explored further. Reasons behind that include the short time unconventional gas technologies have been used by industry; focusing the majority of the research efforts on water quality issues; significant differences in air emissions and concentrations; limited air quality monitoring networks, etc. (Carlton et al. 2014; Field, Soltis, and Murphy 2014; Moore et al. 2014; NB CHF 2016a).

As established in a number of studies mostly conducted in the US, substances emitted to the air during unconventional oil and gas activities may include: VOCs (e.g., alkanes, benzene, formaldehyde, xylene, ethane, toluene, propane, butane, pentane, and methylene chloride), polycyclic aromatic hydrocarbons, nitrogen oxides (NO_x), sulphur oxides (SO_x), CO, ozone, hydrogen sulfide, and particulate matter (e.g., $PM_{2.5}$ – respirable, PM_{10} – inhalable), including silica dust (CCA 2014a; Colborn et al. 2014; Gilman et al. 2013; NB CHF 2016a). SO_2, NO_x, PM_{10}, $PM_{2.5}$, CO are collectively referred to as criteria air contaminants (CACs) (Gilman et al. 2013). Typically, the air emissions associated with unconventional gas and oil development come from the same sources as those associated with conventional activities. Nevertheless, these sources may be produced more intensively in unconventional resources development (e.g., due to a higher well density, more sustained drilling, larger holding ponds, more trucks being used, etc.)

(CCA 2014a; R. B. Jackson et al. 2014), although in fewer locations as a consequence of using horizontal wells and multiple wells drilled from a single surface location.

Short- and long-term sources of air emissions from unconventional gas development may include drill rigs, hydraulic pump engines, vehicles, compressors, dust from sand used as a proppant, venting during flowback, flaring, fumes and flashing emissions tanks, etc. (CCA 2014a; Colborn et al. 2014; NB CHF 2016a). Many of the potential air quality impacts are not unique to unconventional oil and gas development, but accompany a wide variety of resource development undertakings including conventional oil and gas, mining, forestry and non-resource industrial developments. Air emissions can vary at different oil and gas facilities, and at different stages of well development. It has been shown that the drilling, flaring and finishing, and gas production stages produced higher intensity exposures to PM2.5 and VOC than the hydraulic fracturing stage (Brown, Lewis, and Weinberger 2015).

Some of the above substances can potentially impact human health. An increase in VOCs and CACs locally, as well as generation of ozone have been reported as potential health threats (CCA 2014a; Colborn et al. 2014; R. B. Jackson et al. 2014; NB CHF 2016a).

Even though air emissions may have a greater intensity and duration in unconventional oil and gas development in comparison to conventional, switching from coal to natural gas for electricity generation will reduce air pollution with sulfur, nitrogen, mercury, and particulate matter (CCA 2014a; R. B. Jackson et al. 2014).

It should also be noted that air emissions from unconventional gas and oil activities can be reduced with the implementation and maintaining of best management practices, for example, those established in the Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick: Rules for Industry (Government of NB 2013). Such practices are built upon existing regulations, including the Air Quality Regulations made under the *NB CEA* and the *NS EA*, and the Canadian Ambient Air Quality Standards made under the federal *Canadian Environmental Protection Act*.

Impacts on Land, Wildlife and Wildlife Habitat, and Induced Seismicity

Land impacts related to unconventional gas and oil activities arise from the construction and operation of well pads, and associated ancillary facilities and infrastructure (water storage infrastructure, access roads, etc.). Development of unconventional gas and oil resources also involves the construction of associated processing plants and transmission pipelines that will contribute to the land disturbance and potential cumulative effects in the region.

It should be noted that with improvements in the technology of horizontal drilling, the industry's footprint and the land disturbance will be reduced. Modern technologies allow placing more wells on an individual pad, thus reducing the number of associated facilities and ancillary sites, and potential conflicts with other land uses. In case the area of unconventional development has more than one zone at depth, multiple stacked wells can be drilled on the same pad to reach a secondary layer (CCA 2014a; Wheeler et al. 2014). According to some estimates, a pad with four horizontal wells would have approximately one tenth of the land disturbance compared to sixteen vertical wells that produce the same volume of shale gas (Spellman 2013; as cited by Wheeler et al. 2014).

Nevertheless, since unconventional wells are often productive for a relatively short period, and new ones are often added to secure stable productivity (Hughes 2013), unconventional gas and oil development can have substantial impacts on land (CCA 2014a; Wheeler et al. 2014). Taking into consideration potential density of horizontal wells in the future, unconventional oil and gas development may have greater long-term impacts than conventional development (CCA 2014a). This is especially true in terms of the cumulative effects of the large number of wells and associated infrastructure that can cause substantial environmental impacts (CCA 2014b; Wheeler et al. 2014). Therefore, any environmental assessment of the effects of unconventional gas and oil development cannot focus on a single well or well pad, but eventually must address cumulative environmental effects on the regional scale (CCA 2014b; NB CHF 2016b).

Potential impacts to land from unconventional gas and oil activities can include deforestation and fragmentation of forested lands, associated with loss or alteration of habitat, and adverse effects on existing land uses, such as agriculture (CCA 2014a, 2014b; NB CHF 2016a; Racicot et al. 2014; Wheeler et al. 2014), as is the case with conventional oil and gas development, forestry, mining, etc.

As specified in the CCA's report, forests cover about 85 percent of New Brunswick's land base and about 75 percent of Nova Scotia's base (CCA 2014a). Some regions of Nova Scotia are also known to contain old growth Acadian forest (B. J. Stewart et al. 2003). Unconventional gas and oil activities can be expected to affect forested land, wildlife and wildlife habitat in several ways, including (CCA 2014a; NB CHF 2016a; Racicot et al. 2014; Wheeler et al. 2014):

- fragmentation of forested lands, associated habitat fragmentation or alteration and creating edge effects between disturbed and undisturbed habitats;
- loss or alteration of native vegetation, plant species and/or vegetation communities of concern;
- loss or alteration of wetland functions;
- changes in habitat availability for wildlife resulting from loss or alteration of habitat;
- changes in wildlife movement, disrupted migration patterns, and increased wildlife mortality risk;
- changes in hydrological regimes, increased sedimentation, and loss of aquatic habitat.

As summarized by the NB CHF, fish and fish habitat can be affected by unconventional gas and oil development via hydrological (water withdrawals), chemical (contamination by fracturing fluids and wastewater) or physical (sedimentation and suspended solids) pathways (NB CHF 2016a). A recent study demonstrated that fracking fluids and wastewater from unconventional wells could harm fish even at low concentrations, if a spill or a leak of those fluids happened near a water body. Some chemicals in the process water could cause an oxidative stress to fish leading to premature aging in their livers and gills, and also to endocrine-disrupting effects (Blewett et al. 2017; He et al. 2017). To ensure that the risks of spills or leaks are minimized or mitigated, several regulations, policies or best management practices regarding fluid transport, handling, storage and disposal currently exists. An example of this would be CAPP's *Hydraulic Fracturing Operating Practices* (2012) (see Appendix C for details).

Both New Brunswick and Nova Scotia have a rural population higher than the average in Canada, therefore risk of adverse effects from unconventional gas and oil activities on existing land use such as agriculture can be higher than in the Western provinces (CCA 2014a). Potential impacts to agriculture as a result of unconventional development include, but are not limited to (NB CHF 2016a):

- surface water and groundwater contamination;
- loss or fragmentation of agricultural land;
- impacts on soil fertility and soil structure;
- soil contamination due to leaks and spills;
- soil contamination due to onsite waste disposal;
- impacts on livestock health, etc.

Seismic events could be induced or triggered at two points in the unconventional gas and oil development process: during hydraulic fracturing (well stimulation), and during wastewater injection (liquid wastes disposal) (CCA 2014a). Most experts are of the view that the risk of seismic events triggered by hydraulic fracturing is low, and the risk of induced seismicity posed by deep wastewater injection is greater but still low (CCA 2014b; Ellsworth 2013). None of the earthquakes induced by hydraulic fracturing of thousands of wells in the midcontinent US in recent years had a magnitude greater than 4.0 which is not enough to pose a serious risk (Ellsworth 2013; R. B. Jackson et al. 2014). However, the earthquakes associated with wastewater injection in the Central and Eastern US could reach maximum magnitudes sometimes exceeding 5 (up to 5.6-5.8) which is sufficient to pose risk of damaging buildings and injuring people (Ellsworth 2013; R. B. Jackson et al. 2014; McGarr 2014; Yeck et al. 2017). The risks can be minimized by micro-seismic monitoring during operations, reducing injection volumes, and through careful site selection, monitoring, and management (CCA 2014b; Yeck et al. 2017). In addition, considerable effort is being made by operators, service companies, regulators and universities to understand what geological and reservoir characteristics lead to increased local susceptibility to induced seismicity.

A recent study indicated that most injection-induced earthquakes in Western Canada have been triggered by hydraulic fracturing, unlike those in the Midwestern US, where deep-well wastewater injection has been considered as the key triggering mechanism (Bao and Eaton 2016). According to the study, instantaneous earthquakes in Western Canada were concentrated near hydraulic fracturing sites and resulted from increases in underground pressure along fault lines caused by the ongoing fracturing operations, with the largest event (maximum magnitude 3.9) occurring several weeks after injection (Bao and Eaton 2016). In contrast, earthquakes that continued to occur months after drilling operations were attributed to the long-term presence of fracking fluids underground, that have caused pressure changes in the rock formations (Bao and Eaton 2016; Maclean 2016; B. Stewart 2016).

While the East Coast is generally considered as a tectonically stable area, the causes of earthquakes in Eastern Canada are not well understood (CCA 2014a; NRCan 2016a; Wheeler et al. 2014). Though earthquake potential from hydraulic fracturing is considered to be low, the long-term consequences of deep-well wastewater disposal in the Maritime provinces are not well understood, so there may be a delayed reaction associated with these activities (Ellsworth 2013; CCA 2014a; NB CHF 2016a; Wheeler et al. 2014). Potential for hydraulic fracturing in New Brunswick and Nova Scotia to cause induced seismic events will depend on a number of factors that include the geological characteristics of shale plays and the location of hydraulic fracturing in relation to existing faults, and the volume and pressure of injected hydraulic fracturing fluid (NB CHF 2016a; Wheeler et al. 2014).

Public Health Issues

While many risks to human health arising from unconventional gas and oil development are similar to those of other large-scale resource developments, some of them are specific to the unconventional gas and oil activities (CCA 2014b). Potential health issues associated with these relatively young technologies can be attributed to the proximity of the extraction sites to human habitation, potential cumulative impacts of a large numbers of wells, the potential toxicity of chemical additives used for hydraulic fracturing, potential degradation of water quality, etc. (Slizovskiy et al. 2015; Wheeler et al. 2014). Some of the potential health issues such as proximity of the development sites to human habitation and potential cumulative impacts are not specific to unconventional oil and gas development, but may accompany high density conventional development as well.

The known health risks from unconventional gas and oil development (based on experience from other jurisdictions, a review of the available scientific publications and subject matter expert opinions) include, but are not limited to (Carrier 2012; CCA 2014a, 2014b; NB CHF 2016a; NB DOH 2012; Rich and Crosby 2013; Wheeler et al. 2014):

- risk of releases of the chemical additives present in hydraulic fracturing fluids as a potential impact to the physical environment;
- waste management as an environmental and health issue;
- potential health risks due to air pollution (by CACs, as described earlier), noise, vibration, continuous illumination and physical hazards due to extensive heavy truck traffic;
- potential health risks due to exposure to the chemicals and by-products of the fracturing process;

- potential health risks due to possible agricultural lands and crops contamination with potentially harmful radioisotopes, as a result of run-off or evaporation from wastewater ponds or flowback pits;

- possible social and community health risk of the "Boomtown Effect" that can arise during economic development. While the risk to human health from the "Boomtown Effect" is not specific for shale gas development, and can be attributed to many other large-scale resource developments, this phenomenon should not be underestimated (Christopherson and Rightor 2012; Jacquet 2014; Weber, Geigle, and Barkdull 2014);

- potential mental health issues, specifically, depression, anxiety and stress to rural residents from unconventional gas and oil development in their communities, associated with the ongoing social and community changes resulting from the unconventional activities;

- risks of long-term global environmental and human health issues associated with potential methane leaks from decommissioned wells and their possible impact on climate change.

Operators and regulators are increasingly aware of these risks and for many of them, regulations, guidelines and best management practices are in place or are being developed to minimize or mitigate any potential impacts. Others, like the "Boomtown Effect", and potential mental health issues associated with development and community changes, have been known for a long time and are not unique to unconventional resource development. However, they are real and need to be reflected in resource development planning at a policy level.

It is well-known that the main direct pathways of human exposure to potentially hazardous chemicals include contamination of drinking water supplies and air pollution. In addition, there are some indirect impact pathways that are associated with the drilling and fracturing process (Wheeler et al. 2014).

A recent US Environmental Protection Agency (EPA) report issued in December 2016 has reviewed approximately 1,200 cited sources of data and information regarding impacts from the hydraulic fracturing water cycle on drinking water resources in the United States. The report concluded that hydraulic fracturing poses a risk to drinking water in some circumstances, but a lack of information precludes a definitive statement on how severe the risk is (Daly 2016; US EPA 2016). This final report excluded an earlier finding from a draft EPA report indicating that the process of hydraulic fracturing has not caused "widespread, systemic" harm to drinking water in the United States (Daly 2016; US EPA 2016). Notwithstanding that the US EPA report is based on the data and information specific to the US, it can be applicable to a great extent to the Canadian situation. As concluded in a report prepared for Health Canada, "it is reasonable to anticipate that the risks of water contamination and the related health hazards reported in the US may be similar in Canada if the practices (e.g., method of extraction) are comparable" (Carrier 2012).

Potential human exposure to air pollutants associated with oil and gas development can occur through direct contact (e.g., to eyes, skin) or through inhalation (e.g., respiratory tract or gastrointestinal tract) (Colborn et al. 2011). It has been shown that exposure to air contaminants arising from unconventional development may lead to a small increase in the risk of cancer and other diseases (e.g., neurological and respiratory effects) for residents of communities in close proximity to a well (CCA 2014a).

Comprehensive recommendations by the New Brunswick Chief Medical Officer of Health (CMOH) concerning shale gas development in New Brunswick (2012) identify both the known health issues that should be addressed and the key knowledge gaps that should be investigated further (NB DOH 2012). As outlined in the document, the major information gaps related to impacts of shale gas development on public health include a lack of the following (NB DOH 2012):

- standard methods for preventing and mitigating social impacts;
- health status studies before and during gas development;
- systematic health impact assessments;
- the toxicological characteristics of industry products and wastes;
- knowledge about the extent, locations and rate of development which makes it difficult to assess the potential cumulative effects over time;
- studies that consider the overall potential impacts on health and the physical and social environments over the entire lifetime of the industry.

The analysis of some other recent publications confirms the findings of the NB CMOH’s report regarding the need for short- and long-term studies of the potential effects of unconventional gas and oil development on human health (Bamberger and Oswald 2015; R. B. Jackson et al. 2014). There is a potential for long-term effects of even low doses of environmental toxicants and for the cumulative impact of exposures of multiple chemicals by multiple routes of exposure, so obtaining detailed epidemiological data on the long-term health effects from unconventional energy extraction is important (Bamberger and Oswald 2015).

The New Brunswick CMOH’s report has provided the numerous recommendations aimed to protect public health from impacts of shale gas development. As stated in the report, the existing information gaps should be filled through research and ongoing monitoring, and through adopting of the health impact assessment (HIA) process in New Brunswick (NB DOH 2012; NB CHF 2016b). In Nova Scotia, specific recommendations on the development and application of the HIA process in the context of hydraulic fracturing have also been made (Wheeler et al. 2014). Implementing HIAs into the regulatory process would provide regulators with a possibility to assess cumulative impacts since its intent and scope is broader than a traditional EIA (NB CHF 2016a).

It should be noted that similar work on identifying, exploring and assessing concerns regarding human health risks related to oil and gas activities has already been conducted in British Columbia. The *Human Health Risk Assessment of Oil and Gas Activities in Northeastern British Columbia*, led by the BC Ministry of Health, was a three-phase project that began in 2012 and is now complete. The *Progress Report* released in June 2016 provides 14 recommendations and outlines the steps the BC Government and provincial agencies need to implement to address the human health issues identified in the recommendations report (BC Ministry of Health 2016, 2017).

Environmental Perspectives of Unconventional Gas and Oil Development in New Brunswick and Nova Scotia

As demonstrated by numerous studies and summarized in the comprehensive reports (CCA 2014a, 2014b; NB CHF 2016a; Wheeler et al. 2014), the unconventional gas industry has made some considerable improvements over the past decade to mitigate potential environmental impacts, including:

- drilling multiple wells from one surface location to reduce land use and disturbance;
- drilling longer laterals resulting in fewer pads and roads needed;
- reducing water use for hydraulic fracturing (in some cases, using propane to fracture the well);
- reducing the volume and toxicity of chemical additives for hydraulic fracturing;
- recycling of flowback water;
- regulating distances from fractured wells to other wells to prevent damage to the latter;
- relying on tanks rather than lined ponds for wastewater storage;
- improving ponds design and safety;
- reducing methane emissions by improving well sealing;
- in some cases, switching from diesel fuel to natural gas in on-site engines;
- in Western Canada (Alberta and British Columbia), in areas where anomalous induced seismicity is a concern, increased monitoring has been implemented and regulatory thresholds and operating protocols are in place that lead to curtailment or shut down of operations in the event of anomalous seismic activity.

However, unconventional gas and oil development is still at its early stage in Canada. Currently, significant challenges exist that do not allow accurate estimating or predicting risks and benefits of unconventional gas and oil development for people and the environment in New Brunswick and Nova Scotia. Consequently, additional data collection, further research and monitoring of environmental and health impacts, and integrating of multidisciplinary expertise will be required to fill the current knowledge gaps (CCA 2014a; NB CHF 2016a; Wheeler et al. 2014).

Based on the analysis described in their expert reports, both the NB CHF and NS IRPHF concur with the findings in the CCA report that data about potential environmental impacts "are currently neither sufficient, nor conclusive", and strongly advocate a precautionary and "go slow" approach to unconventional gas and oil development in the two Maritime provinces (CCA 2014a;

NB CHF 2016a; Wheeler et al. 2014). As suggested in the NB CHF's report, "the Government has time to design, resource and implement a regulatory system, including a robust research and monitoring process, and industry has time to engage in a substantive way with local communities" (NB CHF 2016b). The NS IRPHF echoes the latter and states that "a significant period of learning and dialogue is now required at both provincial and community levels" (Wheeler et al. 2014).

Both the NB CHF and NS IRPHF conclude that, at the present time, fully informed decisions either for or against the development of unconventional gas and oil resources by hydraulic fracturing in New Brunswick and Nova Scotia cannot be made (NB CHF 2016a, 2016b; Wheeler et al. 2014). However, as emphasized in the reports, they are neither proposing a moratorium or any other political device (such as a referendum) in the two provinces, nor determining the fate of the existing hydraulic fracturing moratoria (NB CHF 2016a, 2016b; Wheeler et al. 2014). Rather, they support a science-based, adaptive, and outcomes-based regulatory approach which "is more likely to be effective than a prescriptive approach, and is more likely to result in an increase in public trust" (CCA 2014a).

Nevertheless, the dilemma of unconventional oil and gas development in New Brunswick and Nova Scotia extends beyond the issue of potential adverse impacts on the environment and human health. The possibility of future unconventional resource developments in the two provinces strongly depends on the level of trust the provincial residents have in all levels of government and the industry; clarifying major questions regarding acceptable levels of risk and ways of sharing risk and benefits; and a community involvement in the decision-making process (NB CHF 2016a, 2016b; Wheeler et al. 2014). As emphasized in the CCA's report, "Science alone […] will not address all the relevant concerns because the actual (as opposed to potential) impacts of shale gas development will likely depend to a great extent on the manner in which resource development is managed and regulated" (CCA 2014a).

Aboriginal Rights and Indigenous Peoples Issues Influencing Oil and Gas Development

Indigenous Peoples in New Brunswick and Nova Scotia

The Indigenous, or Aboriginal peoples, are the descendants of the original inhabitants of North America. Section 35 of the *Constitution Act* (1982) recognizes three groups of Aboriginal peoples: First Nations people (previously known as Indians),[2] Métis and Inuit. These are three distinct peoples with unique heritages, languages, cultural practices, and spiritual beliefs.

There are 15 First Nations in the Province of New Brunswick that belong to two distinct Indigenous cultures – the Mi'kmaq (nine First Nation communities) and the Maliseet, also known

[2] For the purposes of this report, CERI will use the term "First Nation(s)", unless referring to a document or event where the term "Indian" was used.

as the Wolastoqiyik[3] (six First Nation communities). In total, there are 27 reserve locations for both the Mi'kmaq and the Maliseet communities across the Province (NB DAA 2016). Based on the 2011 census, it is estimated that there were 22,620 people of Aboriginal identity living in New Brunswick. The term "Aboriginal identity" included persons who reported being an Aboriginal person (First Nations/North American Indian, Métis or Inuit) and/or those who reported Registered or Treaty Indian status (Statistics Canada 2013a). According to the Indian Register System (IRS) from Indigenous and Northern Affairs Canada (INAC), as of December 31, 2015, there were approximately 15,506 First Nations people in New Brunswick, with 9,501 (61.3 percent) of them living on reserve and 6,005 (38.7 percent) living off reserve (NB DAA 2016). With a total 2015 population in New Brunswick of 753,900, First Nations represented 2.1 percent of the total population. Figure 3.2 provides detailed information on the First Nation community locations throughout the Province of New Brunswick.

In the Province of Nova Scotia, the Mi'kmaq is the founding nation of Nova Scotia and the predominant Aboriginal group that includes 13 First Nations with 42 reserve locations across the Province (NS OAA 2014, 2015a). Based on the 2011 census, there were 33,845 people of Aboriginal identity living in Nova Scotia (Statistics Canada 2013b). According to the INAC IRS, as of December 31, 2014, there were approximately 16,245 First Nations people with a Registered Indian status in Nova Scotia, with 10,368 (63.8 percent) of them living on reserve and 5,877 (36.2 percent) living off reserve (NS OAA 2015a). With a total 2014 population in Nova Scotia of 943,294, First Nations represented 1.7 percent of the total population. Figure 3.3 provides detailed information on the First Nation community locations throughout the Province of Nova Scotia.

[3] Although the term "Maliseet" is the one generally used for the First Nations of the St. John River Valley, "Wolastoqiyik" is becoming more common as it is the term the Aboriginal groups use for themselves (NB DAA 2017).

Figure 3.2: Mi'kmaq and Maliseet First Nations in New Brunswick

Source: (Province of NB n.d.)

Figure 3.3: Mi'kmaq First Nations in Nova Scotia

Source: (NS OAA 2013)

History of Treaties in New Brunswick and Nova Scotia

Peace and Friendship Treaties signed with Mi'kmaq and Maliseet First Nations of the East Coast prior to 1779 differ from any other historic treaties in Canada, since they did not involve First Nations ceding or surrendering their rights to the traditional lands and resources in exchange for a variety of benefits (a situation common for later treaties signed in other parts of Canada) (INAC 2013, 2015). Treaty rights stated in the *Treaty or Articles of Peace and Friendship Renewed 1752* and the *Treaty of Peace and Friendship 1760*, have been recognized by the Supreme Court of Canada (SCC) and confirmed in a number of landmark decisions, including the *Simon* and the *Marshall* cases (see Appendix D) (INAC 2010a, 2015, SCC 1985, 1999). Nowadays, the Mi'kmaq and Maliseet First Nations maintain that in accordance with the signed treaties, they continue to hold both treaty rights, and Aboriginal rights[4] and title through their traditional territory (INAC 2013; MacIntosh 2014).

Currently, Canada is in a negotiation process with the provincial governments and the Mi'kmaq and Maliseet First Nations in New Brunswick and Nova Scotia to address outstanding issues regarding Aboriginal and treaty rights (INAC 2013).

In 2011, the Mi'kmaq (Mi'gmag) and Wolastoqiyik (Maliseet) of New Brunswick, the Province of New Brunswick and Canada signed a tripartite Umbrella Agreement designed to guide discussions among the Parties with the aim of concluding a Framework Agreement on inter-governmental relationships, Aboriginal and treaty rights, and the self-government of the Mi'gmag and Wolastoqiyik in New Brunswick (Mi'gmag and Wolastoqiyik of New Brunswick, Province of New Brunswick, and Government of Canada 2011).

The Mi'kmaq of Nova Scotia, the Province of Nova Scotia and Canada has established a tripartite Made-in-Nova Scotia Process to promote efficient and effective negotiations towards a resolution of issues regarding Mi'kmaq rights and title. Under this process, the Parties have signed several agreements, including an Umbrella Agreement in 2002, a Framework Agreement in 2007, and the Terms of Reference for a Mi'kmaq-Nova Scotia-Canada Consultation Process in 2010. Currently, the Parties are negotiating an Agreement-in-Principle, with discussions on lands, governance, wildlife and fish issues in progress (INAC 2013; Mi'kmaq of Nova Scotia, Province of Nova Scotia, and Government of Canada 2002, 2007).

Canadian Aboriginal Law and Major Legal Cases Clarifying the Nature of Aboriginal and Treaty Rights and Aboriginal Title

Canadian aboriginal law is closely related to Canadian history and the settlement of Canada. Indigenous peoples struggled for recognition of their rights and fair treatment in their relations with European settlers long before establishing Canadian Confederation in 1867. Canadian aboriginal law has developed as a response to the actions of government and/or as a tool used by Indigenous peoples in their struggle.

Major legal cases clarifying the nature of Aboriginal and treaty rights and Aboriginal title are discussed in detail in Appendix D. Important principles that clarify the nature of Aboriginal rights and title established by the SCC in these landmark judgments are consistent with international legal instruments including the United Nations Declaration on the Rights of Indigenous Peoples which was endorsed by Canada in 2010.

[4] It is important to understand that treaty rights differ from Aboriginal rights. Aboriginal rights are not clearly defined, and must be established on a case-by-case basis, whereas treaty rights are negotiated, and can be exhaustively set out and described in detail.

Potential Impacts on Aboriginal Interests, Aboriginal and Treaty Rights

As set out in Section 5(1)(c) of the *Canadian Environmental Assessment Act, 2012* (CEAA 2012), the effects that are to be considered in relation to a designated project include, with respect to Indigenous peoples, an effect to the environment on:

a) health and socio-economic conditions;
b) physical and cultural heritage;
c) the current use of lands and resources for traditional purposes;
d) any structure, site or thing that is of historical, archeological, paleontological or architectural significance.

These protected activities could be affected by oil and gas development, either directly or indirectly. Thus, both direct and indirect potential adverse impacts on Mi'kmaq and Maliseet's Aboriginal and treaty rights could arise if the oil and gas activities resulted in alteration or loss of site-specific traditional land use, depletion of resources within Aboriginal traditional territories, or alteration of traditional subsistence activities, such as hunting, fishing, gathering and trapping.

There has been a discussion on possible consequences if the proposed oil and gas development (including unconventional oil and gas that require hydraulic fracturing activities) is located on the First Nations traditional territories where the potential Aboriginal title rights can be claimed (MacIntosh 2014; Wheeler et al. 2014). As concluded in the NS IRPHF's report, the established or asserted Aboriginal title rights would need to be addressed in any provincial decision-making and regulatory processes related to hydraulic fracturing (Wheeler et al. 2014).

If potential oil and gas resources are located on the designated reserve lands, a regulatory process can be even more complex. First Nations reserve lands are under federal jurisdiction, so a federal decision to consider the exploitation of oil and gas and authorizing hydraulic fracturing on reserve lands will automatically trigger a federal environmental assessment process under CEAA 2012 (Canada 1994; Wheeler et al. 2014). In addition, specific protocols for hydraulic fracturing have been developed by Indian Oil and Gas Canada (IOGC) to protect First Nations citizens from adverse effects of oil and gas activities on reserve lands (IOGC 2013).

The Crown's Duty to Consult with Indigenous People and the Role of Project Proponents

In accordance with Section 35 of the *Constitution Act,* 1982, the Crown is legally obligated to consult on and, if necessary, accommodate asserted or established Aboriginal rights including Aboriginal title or treaty rights that may be impacted by government decisions. The duty to consult also stems from Canadian common law as expressed in court decisions (including the landmark SCC's decisions in the *Delgamuukw, Haida, Taku, Mikisew* and *Little Salmon/Carmacks* cases, as discussed in Appendix D) and is based on a legal interpretation of the obligations of the Crown regarding established or asserted rights of the Indigenous peoples (AANDC and NS OAA 2010). In addition, First Nations in New Brunswick and Nova Scotia assert they can claim

Aboriginal title to the land itself, since they did not surrender their lands to the Crown under the Peace and Friendship Treaties (NB AAS 2011).

Both New Brunswick and New Scotia have developed a number of policies and guidelines to provide directions to the provincial governments on consultation with the Mi'gmag (Mi'kmaq) and Wolastoqiyik (Maliseet) First Nations when a provincial action or decision may infringe upon proven or asserted Aboriginal and treaty rights. The goal of the Duty to Consult Policy (NB) is to facilitate and maintain mutually beneficial relationships between the Government of New Brunswick, First Nations and industry (NB AAS 2011). First Nations engagement is also one of the key objectives outlined in the New Brunswick Oil and Natural Gas Blueprint (NB DEM 2013). In 2010, Canada and the Province of Nova Scotia signed a Memorandum of Understanding (MOU) on Cooperation Regarding Duty to Consult to facilitate effective and efficient Aboriginal consultation and accommodation among the Province, Canada and the Mi'kmaq First Nations (AANDC and NS OAA 2010). In addition, the Governments of Nova Scotia and Canada, and the Mi'kmaq have agreed to follow a Consultation Terms of Reference that clearly lays out a process for Crown consultation with the Mi'kmaq (NS OAA 2012, 2015b). Another document, the Policy and Guidelines: Consultation with the Mi'kmaq of Nova Scotia provide detailed direction to the provincial government and outlines why and when consultation may be required, how to proceed with consultation, and which parties should be involved (Government of NS 2015).

The government's approach to consultation with Indigenous people is very similar for both provinces and is based on the principles of integrity and good faith, respect, transparency, accountability and timeliness (NB AAS 2011; Government of NS 2015). Both NB and NS policies also specifically refer to a reciprocal responsibility of Indigenous groups to participate in consultation with good faith, and stipulate that the Governments retain final decision-making authority, while First Nations do not have veto over government decisions (NB AAS 2011; Government of NS 2015). Six main steps in the consultation process, as established by the Government of Nova Scotia, include consultation screening, initiating consultation, identification of Mi'kmaq concerns, accommodation (avoidance, mitigation or compensation), the government's decision and follow-up/monitoring (Government of NS 2015). The Government of New Brunswick's Policy does not identify specific steps in the consultation process with First Nations.

While the main responsibility for adequate and appropriate consultation and accommodation with Indigenous peoples rests with the provincial and/or federal Crown, and the Crown cannot delegate the duty to consult to a third party, the procedural aspects of consultation may be delegated to proponents or third parties (NS OAA 2012). There are six steps for proponents to follow when engaging the Mi'kmaq of Nova Scotia outlined in the provincial Proponent's Guide. They include: notifying the Mi'kmaq First Nations as early as possible in the development process; providing as much project information as possible; meeting with potentially impacted Mi'kmaq communities; completing an Ecological Knowledge Study; addressing potential project-specific impacts; and documenting the engagement process (NS OAA 2012).

Aboriginal Consultation and Engagement Issues and Key Approaches to Address Them

The effect that resistance or support of Indigenous people can have on future oil and gas development in the Provinces of New Brunswick and Nova Scotia cannot be underestimated. For example, in 2013, the Maliseet First Nations and local residents held several public demonstrations and protests in front of the provincial legislature to oppose the Government of New Brunswick's plans to encourage the shale gas exploration (CBC News 2013b). Protests at a potential shale gas fracking site near Rexton, New Brunswick, in October 2013 (that later resulted in a violent clash) brought up an issue about the duty to consult and accommodate Indigenous people when resource development is considered on their traditional lands (Schwartz and Gollom 2013). Another example of Aboriginal resistance to the governmental decisions includes successful protests against exploratory oil and gas drilling on the shore of Lake Ainslie in Cape Breton, Nova Scotia, organized by the Mi'kmaq First Nations in September 2012. The Mi'kmaq communities have been clear in their opposition to exploratory drilling around the watershed emphasizing the importance of water resources for Indigenous peoples (Peters and Sichel 2012).

Although many leaders of First Nations in New Brunswick are not opposed to development on traditional lands (some Aboriginal groups already have resource agreements with companies), it will be much more difficult to obtain First Nation's consent for fracking on their land due to ongoing Aboriginal concerns about water contamination (Schwartz and Gollom 2013). In early 2014, the Assembly of Nova Scotia Mi'kmaq Chiefs (ANSMC) that represents the highest level of decision making for the Mi'kmaq of Nova Scotia made it clear that it is the expectation of the ANSMC to have full and meaningful consultation prior to any decisions being made by the Province of Nova Scotia on hydraulic fracturing (MacIntosh 2014). In June 2014, the Native Council of Nova Scotia that represents the organized communities of Mi'kmaq and Aboriginal people who live off reserves have announced official opposition to hydraulic fracturing and all activities associated with this practice on their traditional lands, and have requested that this statement be included in the official report by the Independent Panel on Hydraulic Fracturing (MacIntosh 2014; Ross 2014).

In January 2016, the Government of Nova Scotia issued permits for the Alton Natural Gas Storage LP for the construction of underground salt caverns to store natural gas that can be used for energy supply (NSE 2016). An EA approval for the project was granted in 2007, subject to a number of conditions, including those for fish, fish habitat and groundwater protection (NS MEL 2007). However, in September 2016, protesters from the Mi'kmaq First Nations blocked access to the construction site, stating the proposed project threatens the tidal Shubenacadie River that traverses their traditional lands, and stressing the Crown's responsibility to protect Mi'kmaq fishing rights in the area (Tutton 2016). In January 2017, the Supreme Court of Nova Scotia (SCNS) ruled for the First Nation in the *Sipekne'katik v. Nova Scotia (Minister of Environment) and Alton Natural Gas Storage* case, and concluded the previous decision of the Nova Scotia Minister of Environment should be quashed since it was not procedurally fair. However, the SCNS' decision did not halt work on the project, and it also did not respond on the adequacy of consultation issue (SCNS 2017).

To avoid or mitigate possible issues, the engagement of Indigenous Peoples by proponents needs to start as early as possible. The Crown's duty to consult and accommodate relates to avoiding or mitigating impacts on Aboriginal rights or title, and does not imply an obligation to enter into any form of economic benefits agreement with Indigenous groups. Nevertheless, signing such agreements can build effective relations with Indigenous groups potentially affected by a proposed project. It is important to remember that by entering into impact benefit agreements, Indigenous groups are not waiving their right to review, comment and approve or not, any environmental studies, permit applications or environmental monitoring regimes related to the project.

There are currently no impact benefit agreements related to oil and natural gas development in New Brunswick and Nova Scotia. As outlined in the New Brunswick Oil and Natural Gas Blueprint, expansion of the oil and natural gas industry in the province can provide economic and social opportunities for New Brunswick Indigenous people. The document states that the Province is committed to a development of a First Nations Economic Opportunities Plan that should include capacity building initiatives and a framework for collaborative industry-First Nations economic development (NB DEM 2013). In June 2016, an Impact Benefits Agreement was signed between the Assembly of Nova Scotia Mi’kmaq Chiefs that represents 13 Mi’kmaq First Nations, and Kameron Coal Management Ltd. for the Donkin Mine Project in Cape Breton, NS. Although not for oil and gas development, this was the first time that a royalty agreement for natural resources development has been reached with Nova Scotia’s Mi’kmaq people. The Assembly was satisfied with the Agreement as an acknowledgement that the Mi’kmaq First Nations have partial ownership over the province’s land and resources, and referred to it as a “really great example of a mutually beneficial outcome of the consultation process” (Gunn 2016).

Chapter 4: Production, Supply Costs and Market Dynamics

Description

This chapter provides production outlooks and supply costs within the context of the three plausible scenarios for New Brunswick and Nova Scotia: *We are Importers*, *We are Self-sustaining* and *We are Exporters*. As previously mentioned in Chapter 1, the three scenarios explored in this analysis are illustrated in Figure 1.5, depicting the influence of high/low natural gas production and whether the current moratorium remains or is removed. While there is an infinite variation of possible scenarios, the three chosen provide reasonable paths that the two Maritime provinces could take moving forward.

This chapter is divided into four sections. The first three sections are illustrated by the particular scenario (i.e., Scenario 1, Scenario 2 and Scenario 3). The structure of the first three sections are identical, each divided into five parts: outline of the scenario, production outlook, supply costs, infrastructure costs and market dynamics. The first component outlines the scenario and reviews key assumptions, including assets, production flow constraints, new pipelines and capacity. Subsequent sections review production outlooks, supply costs, infrastructure costs (pipelines) and market dynamics for the various assets within that particular scenario. The market dynamics section includes flows and prices, important components in analyzing that particular scenario. Regarding the market dynamics section within each scenario, it is important to establish flows of gas and prices to come up with revenues for the I/O model. This last section provides the explanation on the destination of modeled produced gas flows per scenario and prices assumed. As mentioned previously, until recently, the main direction of gas flows in the Maritimes has been southward, from Goldboro, Nova Scotia, to local customers and to US customers. As a result, the pricing of gas in two provinces was dictated by the major market where gas flowed to, the AGT hub near Boston, Massachusetts. Thus, the producers in the Maritimes could enjoy prices at AGT minus tolls (AGT -), paid to the M&NP US and M&NP Canada, irrespective of where the gas is sold – in the US or Canada. However, while generally moving southward, the bi-directional pipeline has already started switching directions, supplying natural gas to the Atlantic Provinces, initially in times of high demand (such as winter 2013), but has become more common as Nova Scotia's offshore production declines.

The fourth section reviews competitiveness of the shale gas from New Brunswick and Nova Scotia with shale gas from the Marcellus and gas from western Canada. All priced in the two Maritime Provinces, except for gas from western Canada. This section provides a summary as well as concluding thoughts.

It is essential to note that the results from these models forecasting gas production volumes, capital expenditure, and revenues under the three scenarios are subsequently used as inputs, or injections, into CERI's Multi-Regional Input/Output Model. These inputs, in turn, calculate the various economic impacts associated with the level of activity stemming from the outlook models over a 21-year period (2017-2037). As such, field development planning and supply costs for the period of 21 years is considered.

Additional general assumptions regarding the production outlook and supply costs are discussed below with regards to calculating supply costs and production profiles.

Methodology and Assumptions for Supply Costs

To gauge the competitiveness of oil and gas development in New Brunswick and Nova Scotia, it is important to estimate the supply costs associated with the two commodities. The supply cost is derived as the price (in 2017 Canadian dollars) of gas required to recover all capital expenditures, operating costs, royalties, taxes, and a specified return on investment for each well.

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

The net cash flow is discounted back over the lifetime of the well (on average 32 years) to the first time period (2017) using a specified discount rate of 10 percent (real), thereby allowing the price of gas to vary and solve for the supply cost. The supply cost is gas price per Mcf that sets the Net Present Value of the cash flow to zero.

Companies may evaluate individual projects and investments using higher or lower discount rates than those used in this analysis. This would result in higher or lower supply costs than those presented here.

The analysis has been undertaken for three areas: McCully gas field in New Brunswick (conventional tight gas), Frederick Brook Shale play in New Brunswick (shale gas), and Horton Bluff Shale play in Nova Scotia (shale gas). The results represent the supply cost for a “typical new well” located in each area.

General assumptions applied to all scenarios for supply costs modelling:

1) Exchange rate of CAD to USD – $0.76.

2) Inflation rate for operating costs – 1.8 percent, as an average for 1996-2016. Capital costs are incurred in the first year of operations.

3) Transportation costs from the AGT hub in Boston to New Brunswick/Nova Scotia via M&NP – $1.4 per Mcf ($0.7 for AGT to the border – M&NP US side, and $0.7 for M&NP Canadian side). The cost was calculated as the average toll paid to transmit gas from New Brunswick to AGT for 2014-2016. The M&NP uses a “postage stamp” tolling model in which the toll is the same for all paths on the system regardless of the distance travelled (NEB 2017). The same system is assumed to be applied further.

4) Gas price growth rate – 2.16 percent annually, based on US EIA Outlook 2017 price growth rate for 2017-2037 in Henry Hub (US EIA 2017b).

5) AGT prices are based on the Henry Hub price forecast in the US EIA Outlook 2017, rebased to 2017 Canadian dollars (US EIA 2017b).

6) Henry Hub to AGT differential – $1.9 per Mcf, based on the average for 2010-2017.

7) Federal corporate tax – 15 percent, New Brunswick provincial corporate tax – 14 percent, Nova Scotia provincial corporate tax – 16 percent.

8) Processing loss factor for gas of 10 percent. While this assumption is likely a bit high, this accounts for many unknown variables to the authors, including reservoir pressure. It is conservative but recall, this is not a conventional resource and is highlighted by permeability issues and lower pressures in general. Contract deliverability is also likely high on the M&NP (between 550 and 1,450 pounds per square inch [psi]). This means that only 90 percent of production modelled in a production subsection for each scenario is further used for revenue calculations and I/O model.

9) Discount rate (minimum rate of return for investors) – 10 percent.

10) In the scenarios which imply well fracturing, water treatment and disposal are not included in supply costs as predominant means of treatment and disposal are not yet identified for New Brunswick and Nova Scotia.

Royalties and tax calculations are determined according to the current provincial royalty structure, and provincial and federal corporate tax rates. The section discusses the royalty regimes in the two provinces.

Royalty Regime in New Brunswick

To produce royalties, the Licence to Search and Lease Regulation (NB Reg 2001-66) under the *NB ONGA* was used (Government of NB 2001).

According to the Regulation, the royalty payable on natural gas consists of:

a) a basic royalty component, and
b) an economic rent royalty component.

A basic royalty component is whichever is greater:

- 4 percent of the product of the wellhead price for natural gas produced in the month and the units of natural gas produced in that year, and

- 2 percent of a licensee's or lessee's monthly gross revenue from sales of natural gas from all of its wells.

Wellhead prices (WP), according to the regulations, is calculated as:

$$WP = SP - TC - GPA, \text{ where}$$

- SP (Selling Price) is the weighted average selling price per unit for the month, in Canadian dollars, received by a licensee or lessee for its natural gas in the market place (per unit);
- TC (Transport Cost) is the transportation costs from the processing facility to market for the month, consisting of the per unit transport fee charged by a third party[1] (per unit);
- GPA (Gas Processing Allowance) is the gas processing allowance per unit sold for the month, as determined by the following formula:

$$GPA = (DOC + OHD + DP + RC)/U, \text{ where}$$

- DOC (Direct Operating Costs) is the direct operating costs for the month of a licensee or lessee that are used directly in the gathering, processing and transportation of its New Brunswick natural gas subject to a royalty;
- OHD (Overhead Allowance) is an overhead allowance calculated as 10 percent of DOC;
- DP (Depreciations) is straight line depreciation over 20 years of the licensee's or lessee's capital assets for the month that are used directly in New Brunswick in the gathering, processing and transportation of its New Brunswick natural gas;
- RC (Undepreciated Balance of Assets) is a 15 percent annual return on the average monthly undepreciated balance of capital assets in New Brunswick related to the gathering, processing and transportation of the licensee's or lessee's natural gas produced in New Brunswick;
- U (Units) is the number of units of natural gas sold for the month from all of the licensee's or lessee's New Brunswick wells.

An economic rent (ER) royalty component is calculated using the following formula:

$$ER = 25\% \times [CGR - (E + CF)], \text{ where}$$

- CGR (Cumulative Gross Revenue) is a licensee's or lessee's cumulative gross revenue from all of its natural gas operations in New Brunswick;

[1] Note: A simplifying assumption was applied that gas is sold at the site gate after processing marking TC equal zero for the WP calculation.

- E is an amount equal to the sum of all licensee's or lessee's capital expenditures and all operating costs that are associated with its natural gas operations in New Brunswick, including the expenses, depreciation expenses or corporate income taxes; and
- CF is an amount equal to the sum of any capital expenditures, operating costs and interest referred to in Subsection (11).

Subsection (11): Any expenditures and costs that could not be deducted under Subsection (10) may be carried forward and an annual interest rate equal to the daily average Government of Canada Benchmark Bond Yield: Long-Term Rate for the calendar year shall be applied to those expenditures and costs. Bond Yield for the study is assumed to be 2.5 percent (according to the Bank of Canada's current rate) (Bank of Canada 2017).

It is important to note that since supply costs is calculated for a single typical well for two different cases in New Brunswick, it is assumed for economic royalty calculations that "natural gas operations in New Brunswick" consist of this single well.

Royalty Regime in Nova Scotia

According to Petroleum Resources Regulations (NS Reg 178/85, amended to NS Reg 145/2015) under the *NS PRA* (Government of NS 1985):

1. All petroleum produced under the authority of a lease is subject to a royalty of ten percent (10 percent) of the petroleum that is produced in each month;
2. Royalty shall be based on the fair market value of petroleum at the wellhead;
3. In determining the royalty to be paid on any petroleum other than oil, there shall be deducted an allowance for the cost of processing or separation as determined in any particular case by the Minister;
4. No royalty shall be calculated or paid with respect to any oil or gas that is produced from the first lease that is granted with respect to lands subject to an exploration agreement for a period of two years from the date of commencement of the lease.

Since royalty scheme in the act is not a straightforward formula, the following formula was used for Nova Scotia royalty calculations to arrive for "fair market value of petroleum at the wellhead" and royalty:

$$\text{Royalty} = 10\% \times (\text{Wellhead Price x Number of Units}), \text{ where}$$

- Wellhead Price = Gas Sales Price – (Operational Costs for the period – Overhead Costs for the period) / Number of Units.
- Overhead Costs for the period are assumed to be 10 percent of Operational Costs for the period.

Methodology and Assumptions for Production Modelling

As previously mentioned, the field development planning period of 21 years is considered in this study, from 2017 to 2037. In order to generate an outlook for production, several models and methods were developed and utilized by CERI. Beyond general assumptions, specific assumptions and methods are discussed in the various production sections.

To satisfy the production outlooks for the three scenarios, six production profiles are required. Table 4.1 shows the different assets to be produced in each scenario, recoverable remaining resources and production flow constraints.

Table 4.1: Six Production Cases within the Three Scenarios of Shale Gas Development[2]

<table>
<tr><th></th><th>No Fracking/ Moratorium</th><th>Fracking/No Moratorium</th></tr>
<tr><td>LNG/High Growth</td><td rowspan="2">1) McCully – 30.5 Bcf</td><td>2) McCully – 88 Bcf
3) FBS (13.4 Tcf recoverable resources) – constrain production by 550 MMcfpd
4) HBS (7 Tcf recoverable resources) – constrain production by 550 MMcfpd</td></tr>
<tr><td>No LNG/ Low Growth</td><td>2) McCully – 88 Bcf (same as case two above)
5) FBS (13.4 Tcf recoverable resources) – constrain production by 112 MMcfpd
6) HBS (7 Tcf recoverable resources) – constrain production by 152 MMcfpd</td></tr>
</table>

The cases are only numbered here to illustrate their different assumptions in production volume. They are not numbered but rather discussed in the particular scenario in which they reside.

Before discussing the models utilized in this exercise, it is important to review several assumptions regarding the geological basins in the study. Recall from Chapter 2, the gas in-place in the Frederick Brook Shale is estimated to be 67 Tcf, with an estimated recovery factor of 20 percent. On the other hand, this study assumes the gas in-place in Horton Bluff Shale to be 35 Tcf, a reasonable number between the EIA's estimate of 13 Tcf and Ryder-Scott's estimate of 69 Tcf. It is important to note that the size of the resource is not critical in the sense that the Horton Bluff resource, as well as the Frederick Brook Shale, will not be fully developed under any of the three scenarios over the next 21-year period of study. Also, like the Frederick Brook Shale, a recovery factor of 20 percent is assumed and both shale plays are considered analogous to each other. The recovery factor of 20 percent is moderate and is assumed by the NEB (NEB 2009).

The Montney Shale was identified to be geologically analogous to the Frederick Brook Shale and the Horton Bluff Shale. While there are differences, there are parts of the Montney that also

[2] All numbers are recoverable remaining reserves, not the gas in-place.

contain similar clay content, comparable to the shales in New Brunswick and Nova Scotia. CERI analyzed production data that covered all Montney wells in British Columbia and sorted the data in a “virtual” format, where the monthly data is expressed as virtual time (time 0 [MTH 1] is the first month of production and each subsequent production month is MTH 2, 3, 4 etc.). CERI used analogue data, more specifically, and determined an average initial production (IP) and monthly decline rates in the Montney Shale within a four-year period. In addition, CERI isolated a certain portion of the play, a more moderate portion of the Montney shale play, with higher rates of clay content similar to those of both plays in the Maritimes.

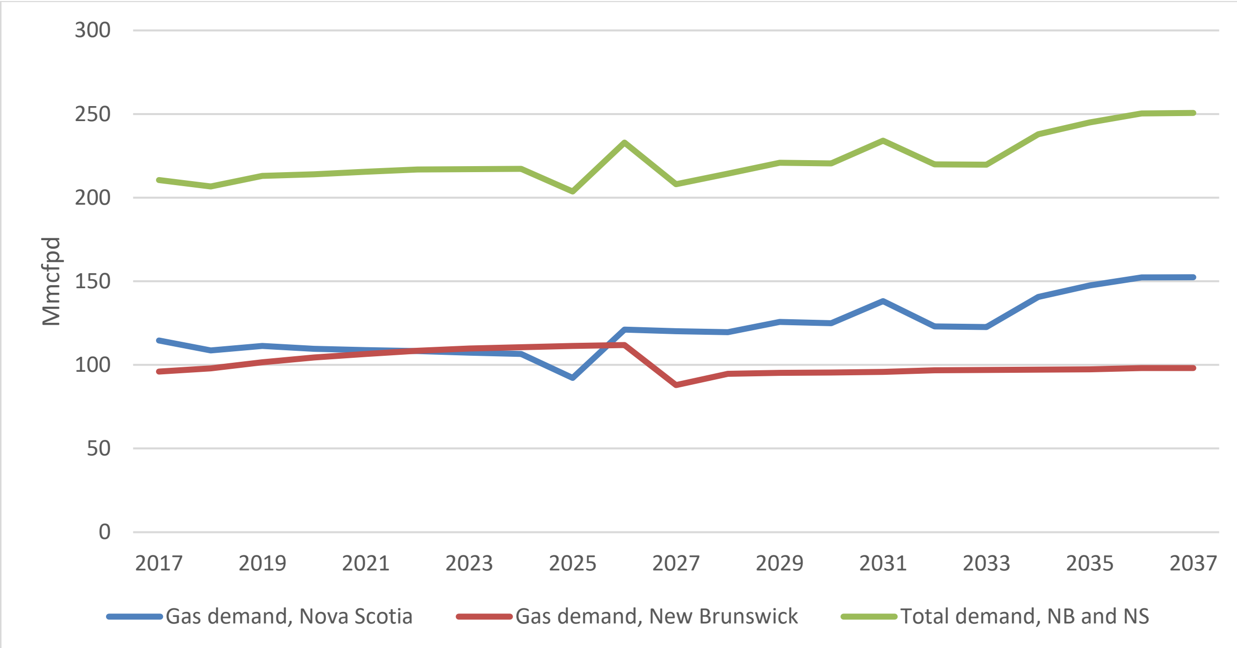
These IP rates and decline data were used to forecast the Frederick Brook Shale and Horton Bluff Shale production. The IP and monthly decline rates determined by CERI are: 4.13 MMcfpd, with a 75 percent decline rate in year 1, with hyperbolic decline factor of 1.21. In the second year, we applied a monthly decline factor of 15 percent and 10 percent decline factor in the subsequent years, and minimum gas production decline of 1.0 MMcfpd after 4 years. This assumption affects both Scenario 2 and Scenario 3.

With regards to the Frederick Brook Shale and the Horton Bluff Shale in the following self-sustaining scenario and the exporters’ scenario, it is important to note that currently there is no significant production from the former and no commercial production at all from the latter. Most of the wells drilled into the Frederick Brook Shale have been exploratory wells, and were tested to estimate the Frederick Brook Shale potential. While additional exploration needs to occur to find the ‘sweet spots’, Nova Scotia’s Horton Bluff Shale needs further exploration to better define the extent of the resource.

For this reason, the Frederick Brook Shale is assumed to enter production in 2021, whereas the Horton Brook Shale is assumed to begin production in 2023. It is also important to note that the Frederick Brook Shale and Horton Bluff Shale development is identical, separated only by the year of development.

For the self-sufficiency scenario (Scenario 2), the flows are constrained by local demand for gas, with supply being restricted by demand. The future demand for gas is derived from the NEB’s Energy Future to 2037 and is illustrated in Figure 4.1 (NEB 2016a).

Figure 4.1: Future Gas Demand in New Brunswick and Nova Scotia



Source: (NEB 2016a)

In planning the production development for the remaining reserves in the various fields under various constraints and assumptions, CERI developed the in-house Hyperbolic-Exponential Hybrid Decline Model to forecast production. In addition, CERI developed a Non-Integer Linear Program (NILP) to generate the required number of wells using the production realizations from the Hyperbolic-Exponential Hybrid Decline Model, including the declines curves. The expected annual flow in each year was then calculated by simple multiplication of the number of wells generated and the associated production rate.

It is important to note that the case of the McCully gas field is different, not only in terms of geology, being a tight sand play, but it is also a producing field. Recall there are 28 wells in total currently producing gas. Thus far, these wells have produced nearly 55 Bcf since 2003. The assumptions regarding the McCully (No Fracking case) and the McCully (Fracking case) are discussed in their respective parts in this chapter.

Further assumptions are discussed with the production outlook by scenario sections below.

Scenario 1: We are Importers

Outline of the Scenario

Scenario 1 suggests that the moratorium remains in place in both provinces. As a result, the McCully is the only asset to be developed within this scenario, using only existing wells. No new investments are incurred under this scenario, as other resources in both provinces require fracking to enhance hydrocarbon recovery. This includes the McCully which will need fracking to tap resources that were written off in 2016 by the operator.

In light of decreasing offshore Nova Scotia natural gas production, this scenario requires the import of gas to both provinces to meet local demand requirements. This supply gap is likely satisfied in two ways, by pipeline from the US Northeast (via AGT using the M&NP) or by vessel (importing LNG from Repsol's Canaport LNG facility in Saint John, New Brunswick). In the case of the former, the M&NP will be reversed, delivering gas from the Marcellus Shale, through New England into Atlantic Canada. As previously mentioned, this is already beginning to happen in times of high natural gas demand in the Maritimes and improving pipeline infrastructure in the US Northeast, with projects such as the Atlantic Bridge that will facilitate this northward flow of gas into the Maritimes.

All assets and additional infrastructure are described in Table 4.2. As specified, the only asset is the existing wells in the McCully gas field. The 28 wells are assumed to produce the remaining recoverable reserves of 30.5 Bcf (2P reserves). This estimate stems from Corridor's Quarterly Report, illustrating their summary of 2P reserves of 22.9 Bcf (Corridor Resources Inc. 2016b). Indicated in the table is the working interest of both owners — Corridor Resources and Potash Corporation of Saskatchewan. As such, the estimate was adjusted to reflect the 25 percent working interest of Potash Corporation of Saskatchewan's size of reserves. Also shown is the production flow constraint, the 35 MMcfpd capacity of the lateral pipeline, connecting the gas processing facility to the M&NP pipeline.

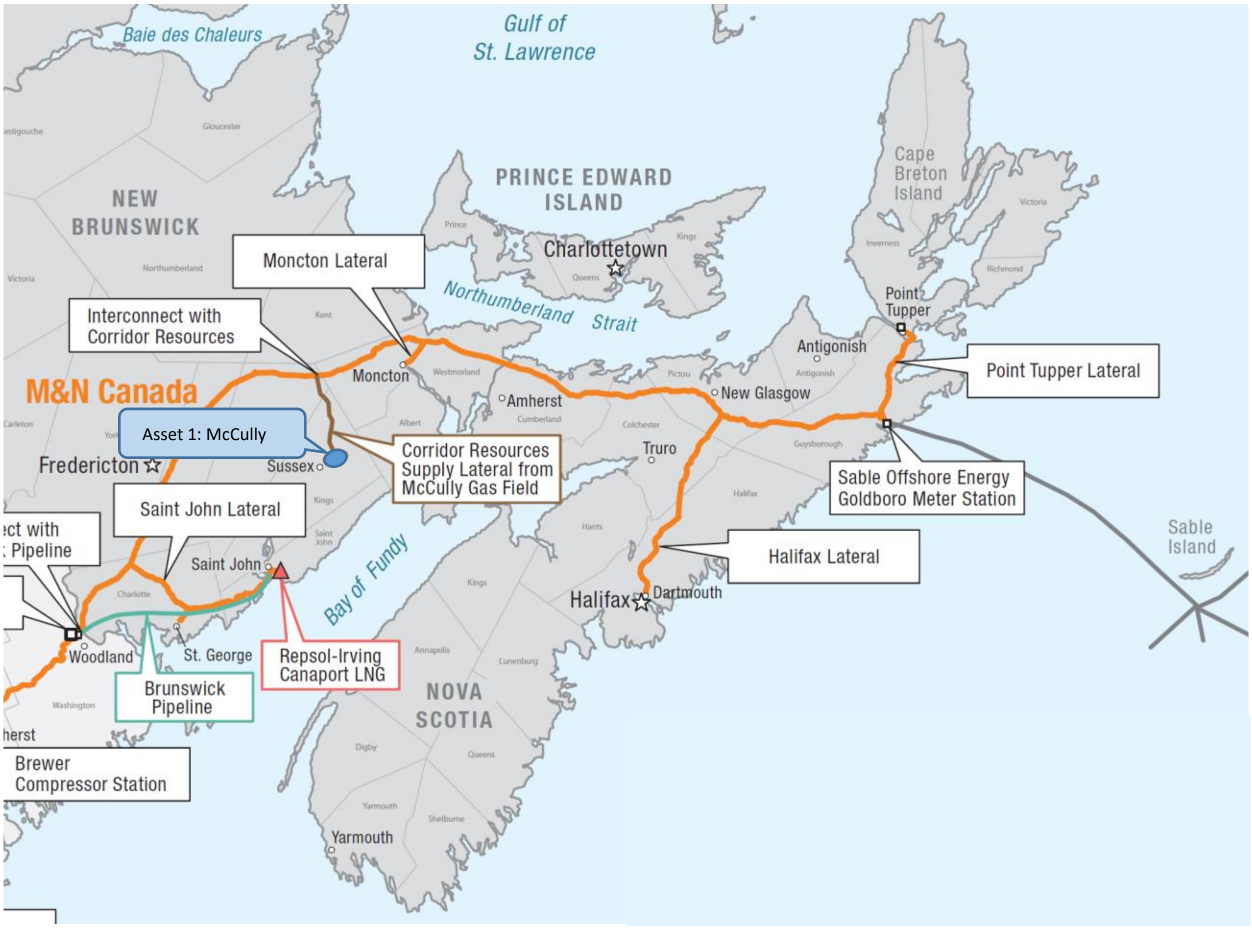
Table 4.2: Produced Assets under Scenario 1

No	Asset	Province	Recoverable remaining reserves	Production flow constraints for modelling	Additional infrastructure
1	McCully field, tight gas	New Brunswick	2P, 30.5 Bcf* Corridor Resources: 22.9 Bcf Potash Corporation: 7.6 Bcf	Capacity of the pipeline (35 MMcfpd)	None required

*Provided fracking is not allowed

Figure 4.2 illustrates the Scenario 1 assets (McCully field) and routes of pipelines, as well as the entire Canadian side of the M&NP and the various energy-related facilities in the area.

Figure 4.2: Scenario 1 Assets and Infrastructure



Source: (Maritimes & Northeast Pipeline 2009), map modified by CERI.

Production Outlook

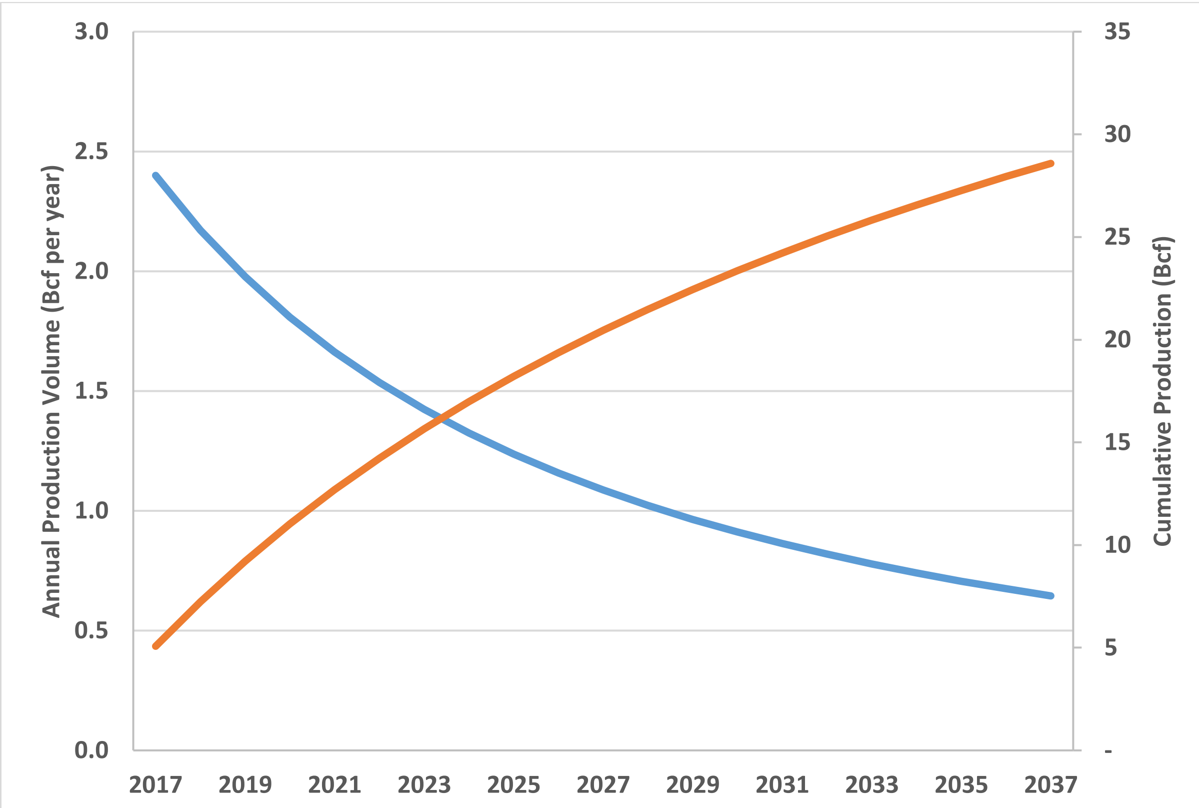
As this scenario is defined by no fracking in an environment where fracking restricts further development, it is unique from the other production cases in the sense that it also requires no new wells to be drilled to develop the remaining reserves of 30.5 Bcf. With the moratorium remaining, the remaining gas reserves are likely to be depleted with the existing wells.

As a result, CERI's in-house Hyperbolic-Exponential Hybrid Model to forecast production and NILP, used to generate the required number of wells using the production realization from the former, are not applied. Instead, CERI's production forecast relied on historical data.

The 28 wells have developed 54.8 Bcf since 2003, as of end-2016. Using annual production between 2008 and 2014, CERI established a production profile over a 21-year period.

Figure 4.3 illustrates McCully's production forecast under the no fracking case. By 2037, CERI anticipates that the remaining reserves of the McCully gas field are depleted.

Figure 4.3: McCully Production Forecast for the No Fracking Case



Supply Costs

Supply costs are not calculated for this case as no new wells are drilled. Based on Corridor Resource's information the latest field operating netback estimate was $3.55 per Mcf; this reflects actual results to December 31, 2016 and revised natural gas prices from January 1, 2017 to March 30, 2017 (Corridor Resources Inc. 2017b).

Infrastructure Costs

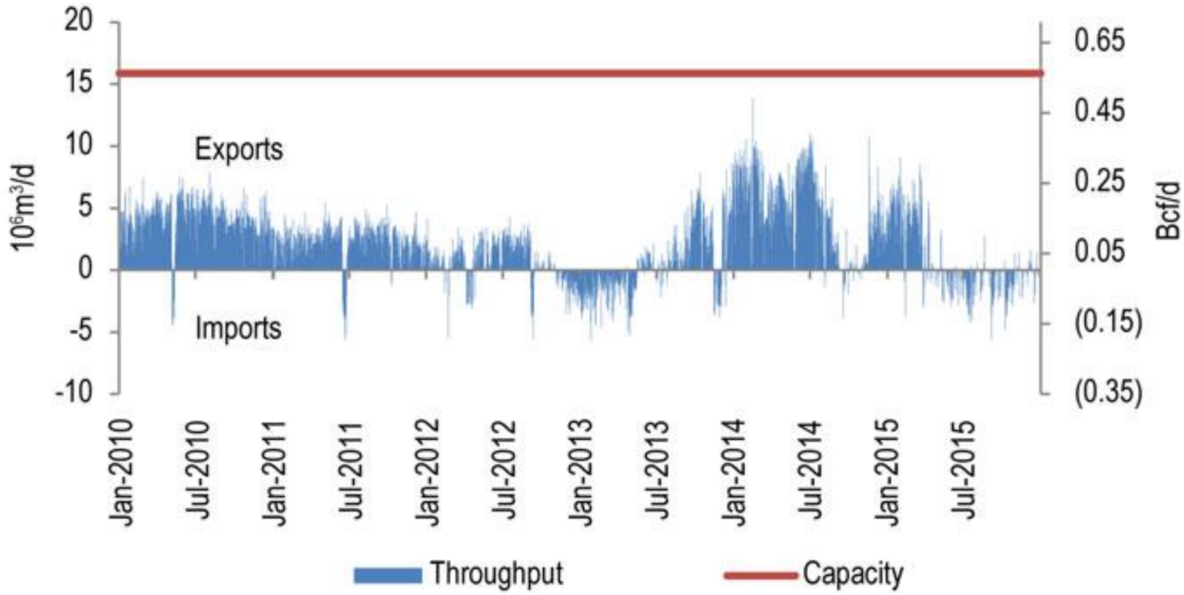
No additional infrastructure is needed with Scenario 1, as such, no infrastructure costs are calculated.

Market Dynamics

As previously mentioned, in this scenario, further decline of offshore production in Nova Scotia will result in increased volume of imports of gas to both provinces to meet local demand. These imports will occur by the M&NP pipeline or by LNG imports, via the Canaport LNG. It is assumed for modelling purposes that both offshore Nova Scotia projects will be decommissioned by 2022. The M&NP pipeline, possibly as early as 2019, could entirely start moving natural gas northward, in the "import-to-Canada" mode.

Figure 4.4 illustrates the throughput from the perspective of St. Stephen, showing the relationship between exports and imports through the border point. While generally moving southward, the bi-directional pipeline has already started switching directions, supplying natural gas to the Atlantic Provinces in times of high demand (i.e., winter 2013), as shown in Figure 4.4.

Figure 4.4: M&NP Daily Throughput at St. Stephen

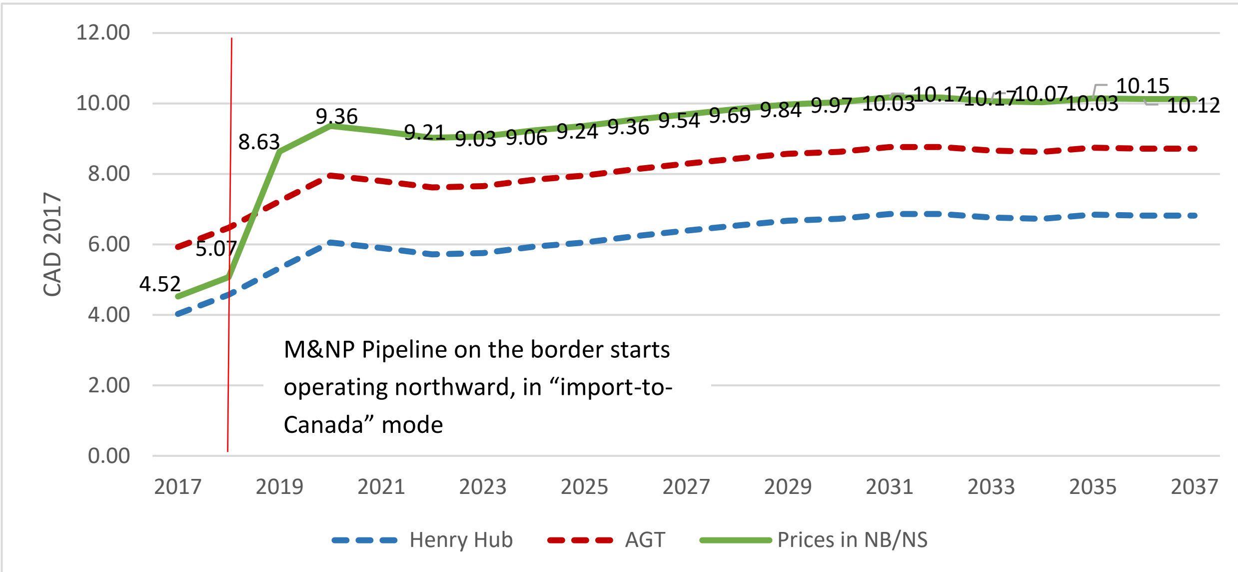


Source: (NEB 2017)

However, as of mid-late 2015, there is already more importing of gas to the Maritimes. As a result, the pricing model for local users in the Maritimes changes from AGT minus tolls (AGT -) to AGT price plus tolls (AGT +) for both M&NP parts of the pipeline, the Canadian and the US-sides of the pipeline. Tolls include both M&NP parts of the pipeline. AGT market prices are modeled based on US EIA Outlook 2017 (US EIA 2017b). Recall, the Henry Hub to AGT differential is assumed to be fixed at $1.90, based on the average for 2010-2017.

Figure 4.5 illustrates that dynamic. Recall that the M&NP pipeline, possibly as early as 2019, could start moving natural gas northward, in the “import-to-Canada” mode (indicated by the red line), given the production declines of the SOEP and the Deep Panuke in offshore Nova Scotia.

Figure 4.5: Pricing Forecast for Scenario 1 ($CAD 2017)



For 2017-2018, netback prices for the producer, specifically for the McCully asset which is modeled, are lower than AGT. However, after 2019, the producers of McCully will be getting a higher price than AGT, but the degree of which is uncertain. However, with Henry Hub price growth from $4.00 in 2017 to $6.00 in 2020, as well as the change in pricing scheme, the local price for gas may grow from $4.52 in 2017 to $9.36 in 2020.

Scenario 2: We are Self-sustaining

Outline of Scenario

Scenario 2 assumes that the moratoriums are removed as early as 2017. Assuming the lifting of the bans in both provinces in 2017 allows to estimate the economic impacts as early as they could happen, provided there is time allocated for exploration and development of perspective fields. It is important to note that assuming the year 2017 is not based on information from either Atlantic province, it is simply chosen to easier illustrate the potential outcomes of the three scenarios. If the reader assumes that the bans are lifted in a later year (i.e., 2020), the impacts calculated below can be simply deferred for several years added to 2017 (i.e., 2020).

Fracking allows E&Ps to develop additional reserves in the two provinces, increasing the proven and probable reserves (2P). As such, the Frederick Brook and Horton Bluff are both developed. In addition, with the possibility of fracking, gas production at McCully also increases, as do the remaining proven and probable resources in that field. Corridor's estimated reserves at end-2014 was 66 Bcf, for their estimated 75 percent working interest. As such, the estimate was adjusted to reflect the estimated 25 percent working interest of Potash Corporation of Saskatchewan's size of reserves. Per se, the total 2P resources are estimated at 88 Bcf under the 'We are Self-sustaining' scenario.

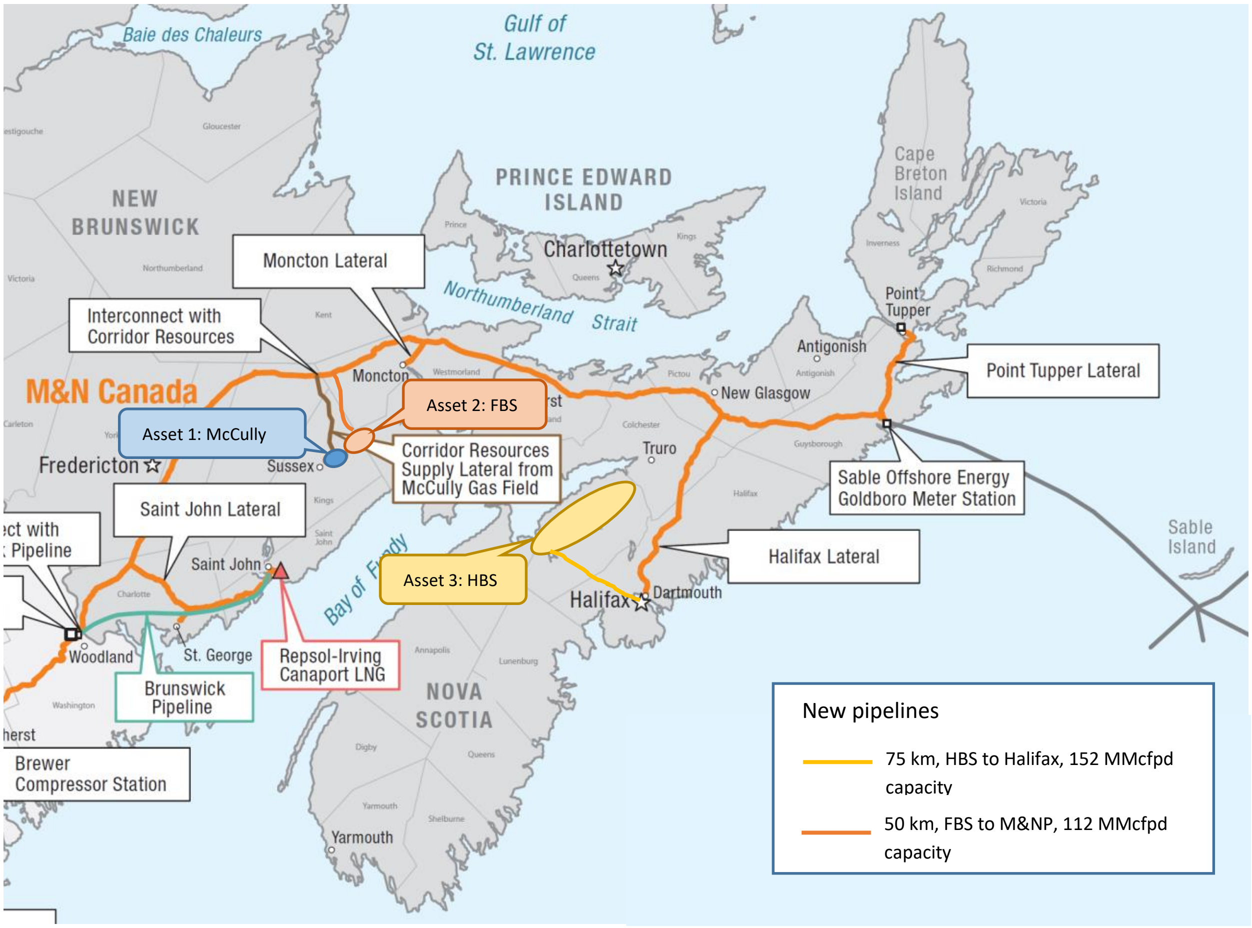
Scenario 2 assumes the development of three assets: a) McCully, b) Frederick Brook Shale in New Brunswick, and c) Horton Bluff Shale in Nova Scotia. Resources are developed more moderately, with the objective that the two provinces can meet local demand, to become self-sustainable. Thus, development of resources is restricted by local demand levels forecast. The Frederick Brook Shale and Horton Bluff production constraints represent the maximum demand over the next 21 years, respectively.

All assets and additional infrastructure are described in Table 4.3 and illustrated in Figure 4.6. Shapes of assets in Figure 4.6 and the routes of pipelines are illustrated in simplified form.

Table 4.3: Produced Assets under Scenario 2

No	Asset	Province	Recoverable remaining reserves	Production flow constraints	Additional infrastructure
1	McCully	New Brunswick	2P, 30.5 Bcf – existing wells Corridor Resources: 22.9 Bcf Potash Corporation: 7.6 Bcf 2P, 57.5 Bcf – new wells Corridor Resources: 43.1 Bcf Potash Corporation: 14.4 Bcf	Capacity of the pipeline (35 MMcfpd)	None required
2	Frederick Brook Shale	New Brunswick	13.4 Tcf	112 MMcfpd, maximum NB demand for study period	50 km pipeline from the site to M&NP, capacity 112 MMcfpd
3	Horton Bluff Shale	Nova Scotia	7 Tcf	152 MMcfpd, maximum NS demand for study period	75 km pipeline from the site to Halifax, capacity 152 MMcfpd

Figure 4.6: Scenario 2 Assets and Infrastructure



Source: (Maritimes & Northeast Pipeline 2009), map modified by CERI.

In this scenario, it is assumed that the pipeline from the Frederick Brook Shale to the M&NP (indicated in orange) will provide up to 112 MMcfpd capacity to the main pipeline, where gas is further transported via M&NP and the various distribution pipelines to end-customers. On the other hand, the Horton Bluff Shale to Halifax pipeline, illustrated in yellow, will provide up to 152 MMcfpd capacity to the capital city in Nova Scotia. The portion which will not be consumed in the Halifax area, is assumed to be transmitted through existing infrastructure to the rest of the province, including via the Halifax Lateral part of the M&NP.

Production Outlook

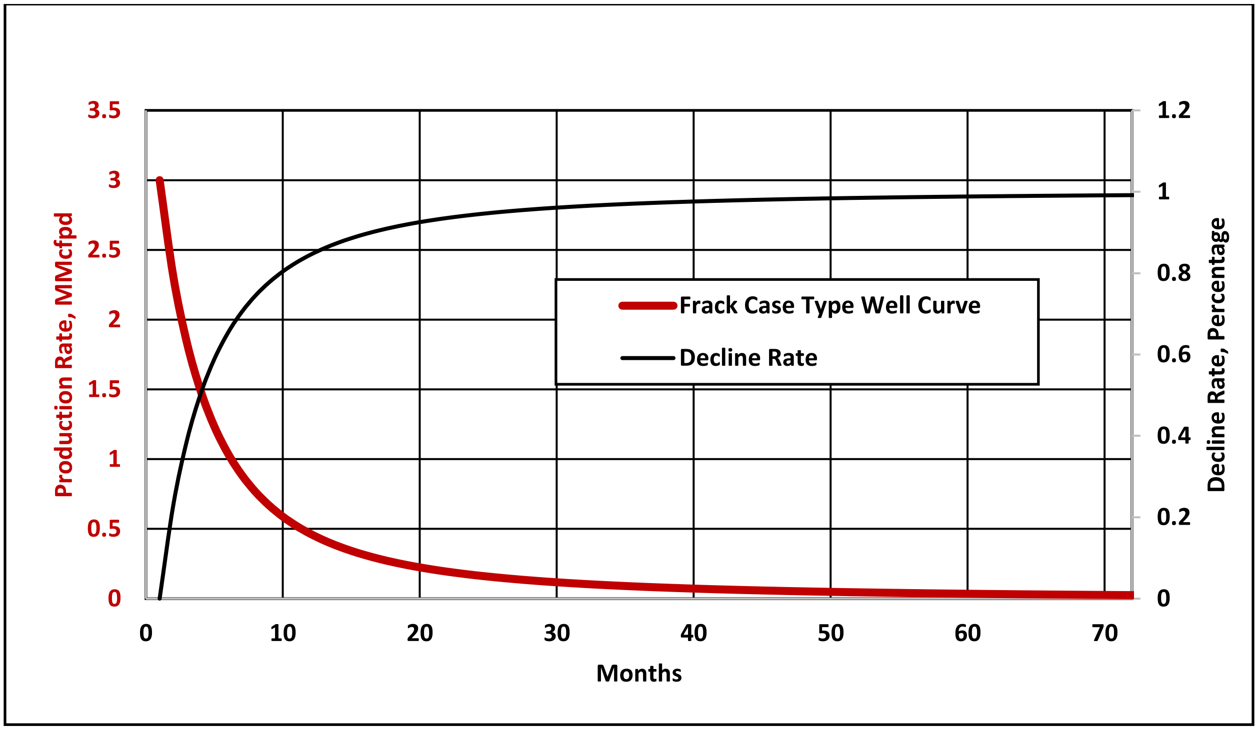
As previously mentioned, this section discusses the production profiles of three assets: McCully (fracking case), Frederick Brook Shale and the Horton Bluff Shale.

The first asset includes the McCully where fracking is permitted. As previously mentioned, this increases the number of proven and probable reserves to 88 Bcf from 30.5 Bcf in which no fracking is permitted. This case is constrained by the pipeline with a capacity of 35 MMcfpd delivering natural gas from the gas processing facility to the M&NP.

The production and decline percent profiles are indicated in Figure 4.7. For the McCully production forecast, the following IP rate and monthly decline rates are used: 3.0 MMcfpd and 0.28 percent per month in the first year, with a hyperbolic factor of 0.5 percent. It is important to note that the constants were calculated from Corridor Resources' existing well K-66.

These curves are indicated in Figure 4.7.

Figure 4.7: McCully Production Forecast and Decline Profile for Fracking Case

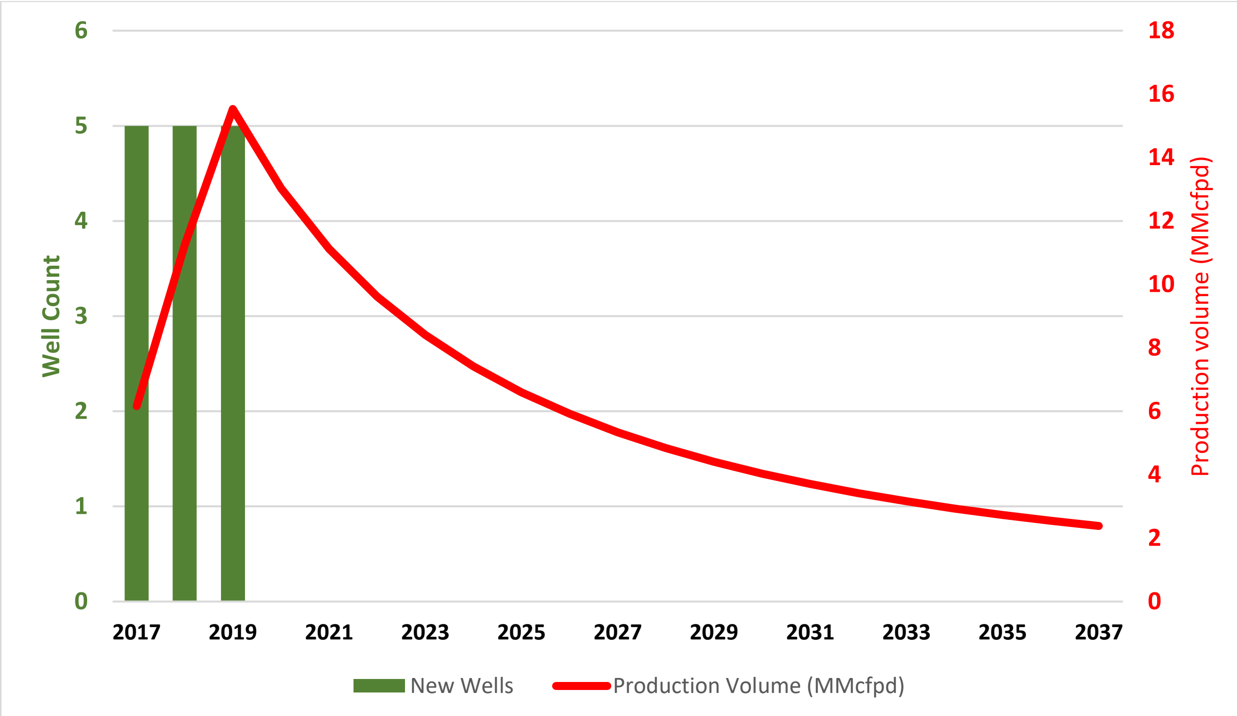


Recall, Scenario 2 considers the 28 existing wells from Scenario 1 that, if left to operate through the 21-year period, would produce 30.5 Bcf of the 88 Bcf resources. As such, the scenario is modelled to result in a production profile to produce the remaining 57.5 Bcf in the McCully.

Utilizing CERI's NILP suggests that under the fracking scenario, 15 new wells would be needed to produce the above mentioned 57.5 Bcf. By 2037, we anticipate those wells will produce up to 49.1 Bcf.

Figure 4.8 illustrates the production development of McCully tight gas.

Figure 4.8: Production Development of McCully Tight Gas (Fracking Case)



Consultations with Corridor Resources regarding the assumptions of the total Estimated Ultimate Recovery (EUR) per well were important and required, as CERI's forecast was limited by a lack of detailed geological data of the play, including pressure data from existing wells. This information is simply not publicly available.

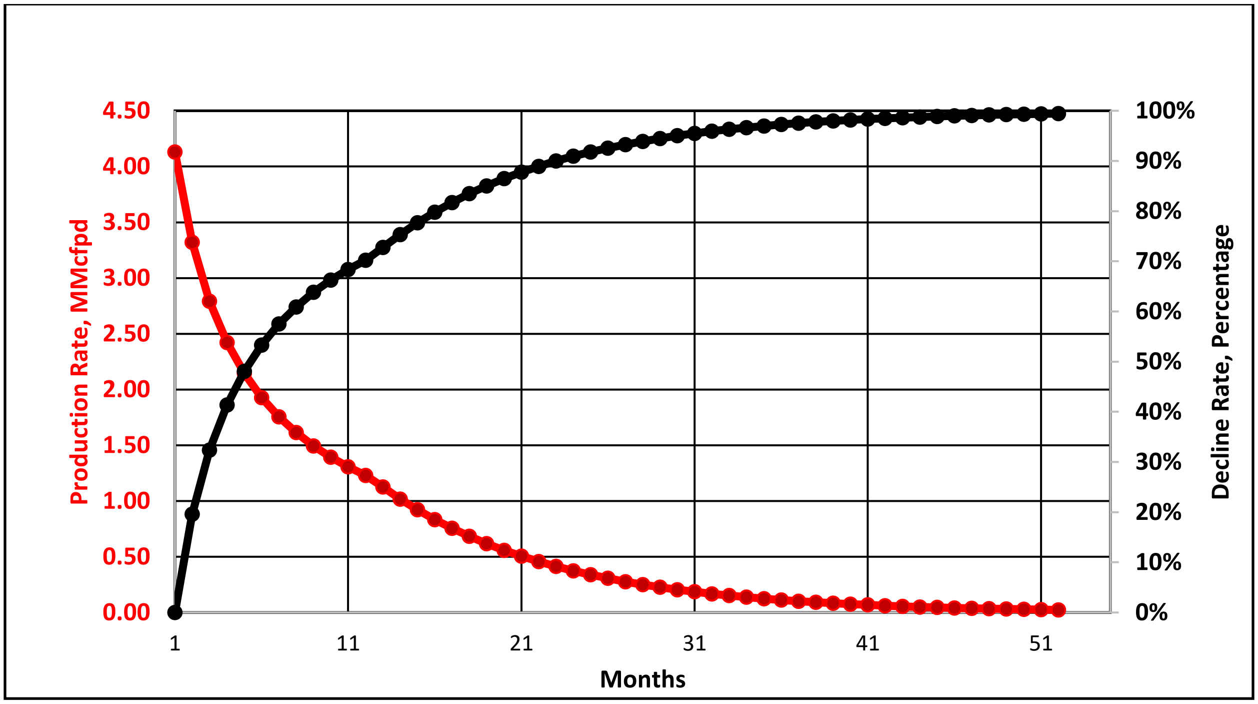
The average EUR per well ranges from 0.29 Bcf/well to a maximum of 8.66 Bcf/well. CERI's analysis of the production data, with the support of Corridor Resources, suggests an average EUR of 3.8 Bcf/well.

In reality, however, each well is unique and an expected EUR is not a uniform number, but rather varies based on well attributes, such as a function of drilling, completion and operations, as well as other factors. It is also important to note that as of end-2016, 28 wells in the McCully produced nearly 55 Bcf over the life of the gas field. Given the past performance in the McCully, CERI suggests it could be possible that up to another 8-10 wells on top of 15 modelled wells could be required to fully deplete the basin, at a later date. This consideration, however, is not illustrated in the above figure and is not used further for capital expenditure calculations.

For the Frederick Brook Shale and Horton Bluff Shale production forecast, the IP and monthly decline rates used are: 4.13 MMcfpd, with a 75 percent decline rate in year 1, with hyperbolic decline factor of 1.21. In the second year, we applied a monthly decline factor of 15 percent, 10 percent decline factor in the subsequent years, and minimum gas production decline of 1.0 MMcfpd after 4 years. These assumptions were previously discussed in this chapter.

The Frederick Brook Shale and Horton Bluff Shale IP rates and decline rates are depicted in Figure 4.9.

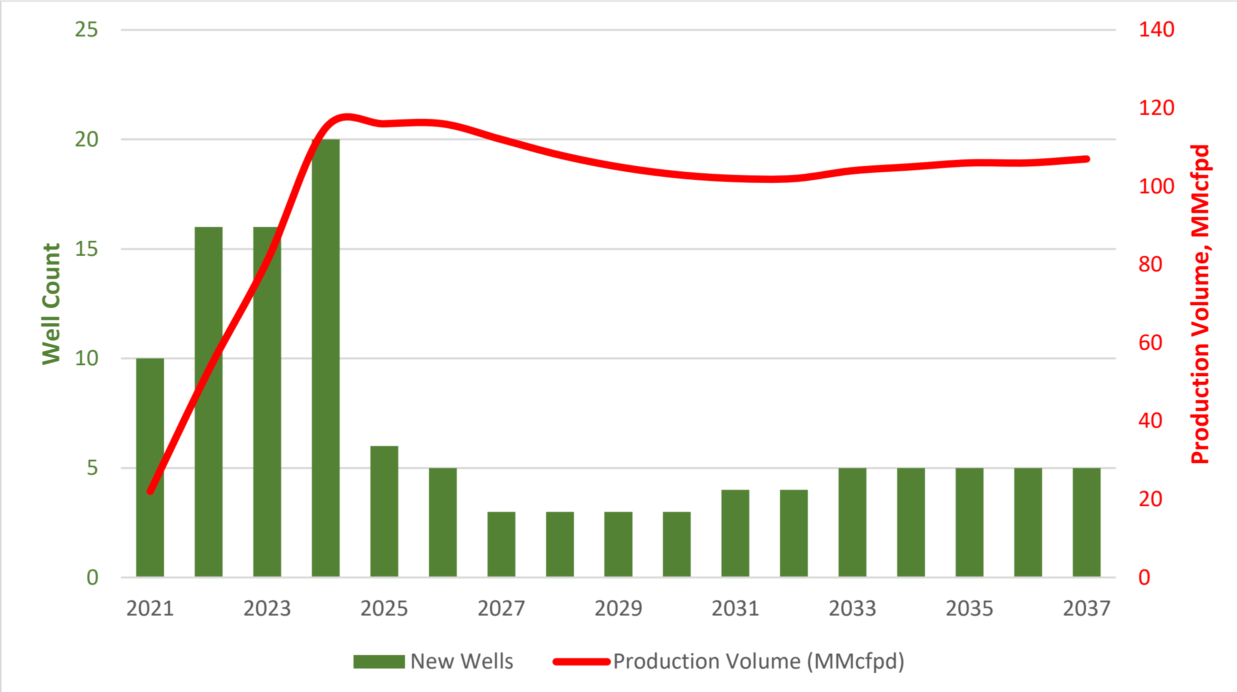
Figure 4.9: Frederick Brook Shale and Horton Bluff Shale Type Well and Decline Curves



The NILP was constrained with demand capacity over the next 21 years at 112 MMcfpd and 152 MMcfpd for the Frederick Brook Shale and Horton Bluff Shale development, respectively. In addition, the production outlook is optimized to meet local demand levels. This exercise adds another layer of realism to the production outlook for this scenario and its set of assumptions.

For the Frederick Brook Shale, the NILP estimated that 118 new wells are added, producing an estimated 607 Bcf of natural gas from this play for the period 2021-2037. This accounts for approximately five percent of the total estimated recoverable gas reserves of 13.3 Tcf. Production commences in 2021. This is illustrated in Figure 4.10.

Figure 4.10: Frederick Brook Shale Production Development and Well Count (No LNG and Demand Constraint: 112 MMcfpd)

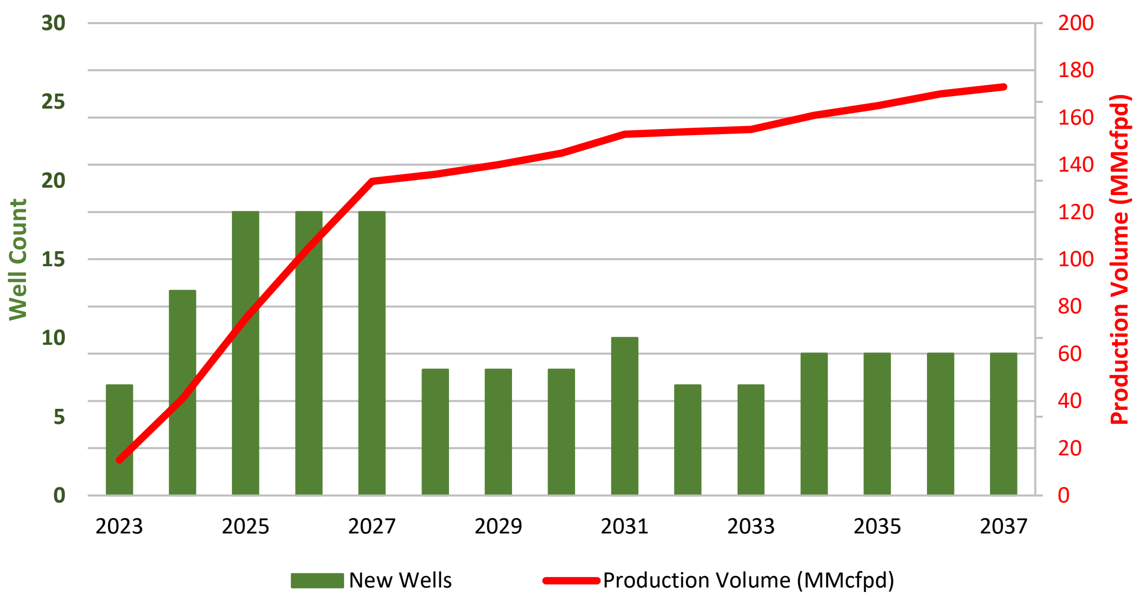


The reason production volume and number of new wells decreases in 2027 and then slowly increases in the early 2030s, is that supply from the Frederick Brook Shale is scaled back, together with McCully field production output to meet and not exceed local demand, as forecasted by the NEB's Energy Future gas demand for New Brunswick (NEB 2016a), illustrated in Figure 4.1. This also explains the reason why the production volume is not a straight line peaking at 112 MMcfpd, but rather fluctuates slightly, dropping down to approximately 100 MMcfpd in the early 2030s.

It is important to note that for all the assets in the study, a 10 percent shrinkage of gas is modeled to arrive at sales gas, which is then used to meet and not exceed local demand. As such, total raw production of McCully field (from existing and new wells) and Frederick Brook Shale is higher than local demand forecasts.

For the Horton Bluff Shale, the NILP estimated that 158 new wells are added, producing an estimated 701.2 Bcf of natural gas. This accounts for approximately 10 percent of the total estimated recoverable gas reserve of 7 Tcf. Production commences in 2023. This is illustrated in Figure 4.11.

Figure 4.11: Horton Bluff Shale Production Development and Well Count (No LNG and Demand Constraint: 153 MMcfpd)



Like the Frederick Brook Shale, the Horton Bluff's production profile was limited to meet and not surpass local demand. As previously mentioned, raw production levels are likewise higher than demand levels as a 10 percent shrinkage factor is used to arrive at sales gas. The NEB's natural gas forecast for Nova Scotia is different than its southern neighbor. Demand in Nova Scotia increases and peaks at 152 MMcfpd at the end of the 21-year period of this study. This explains the increase in production volumes.

Supply Costs

This section is divided into three parts: McCully, Frederick Brook Shale and Horton Bluff Shale.

New Brunswick - McCully Field

Gas supply cost calculation for the McCully field is based on general assumptions stated above in the beginning of the chapter and specific assumptions for capital, operating costs and the production profile.

Specific assumptions for the scenario (all costs are in $CAD 2017):

- IP rate – 4.1 MMcfpd (as illustrated by the production profile provided in the previous section).
- Capital cost is assumed to be $7.07 million per well including fracking costs (2 fracks per well). The calculations are based on the drilling and fracking historical costs taken from Corridor Resources quarterly reports (Corridor Resources Inc. 2017a), and rebased to 2017 dollars.

- Operating cost is assumed to be $1.07 per Mcf. The calculations are based on the operating costs taken from Corridor Resources annual reports for 2014-2016 (Corridor Resources Inc. 2017a), and rebased to 2017 dollars.

- Gathering and processing plant costs - $0 (due to existence of infrastructure).

Based on these assumptions, supply cost of conventional tight sand gas production in the McCully field with fracking is $5.77 per Mcf. Table 4.4 also illustrates sensitivities of a 25 percent variation in capital costs and operating costs and its impact of the supply costs.

Table 4.4: Supply Cost of McCully Conventional Tight Sand Gas Production

Costs	Reference $/Mcf	Capital costs +25%	Capital costs -25%	Operating costs +25%	Operating costs -25%
Capital Costs	3.35	4.18	2.51	3.35	3.35
Operating Costs	1.16	1.16	1.16	1.45	0.87
Royalties	0.95	1.23	0.72	0.97	0.94
Taxes	0.32	0.58	0.19	0.32	0.32
Total Supply Costs	**5.77**	**7.15**	**4.57**	**6.08**	**5.47**

New Brunswick – Frederick Brook Shale

Gas supply cost calculation for the Frederick Brook Shale is based on general assumptions stated above in the beginning of the chapter and specific assumptions for capital, operating costs and the production profile.

Specific assumptions for the Frederic Brook Shale (all costs in $CAD 2017):

- IP rate – 4.13 MMcfpd (as illustrated by the production profile provided in the previous section);

- Capital cost – $8.43 million per well including:

  - well cost is assumed to be $3.75 million per well for a typical horizontal well at the total vertical depth (TVD) of 2500 m – upper part of the shale depth, and horizontal leg of 1500 m; total measured depth (TMD) – 4150 m; Parkland BC BC2F well costs were taken as a proxy from Montney play adjusted for target TVD (PSAC 2017);

  - fracking costs (12 multi-staged fracks per well) in the amount of $4.68 million;

  - economies of scale are assumed for drilling and fracking activities as a decreasing factor of 25 percent compared to standalone drilling/fracking operation;

  - in addition, 10 percent increase of drilling costs and 60 percent increase of fracking costs are assumed compared to Montney to account for the need to attract drilling and fracking contractors from other provinces or the United States;

- Operating cost – $1.07 per Mcf, based on the same calculations as those done for the McCully field;
- Gathering and processing plant costs - $1.2 million per well.

Based on these assumptions, the supply cost of Frederick Brook shale play well is $4.28 per Mcf. Table 4.5 also illustrates sensitivities of 25 percent in variation in capital costs and operating costs and its impact of the supply costs.

Table 4.5: Supply Cost of Frederick Brook Shale Gas Production

Costs	Reference $/Mcf	Capital costs +25%	Capital costs -25%	Operating costs +25%	Operating costs- -25%
Capital Costs	2.13	2.66	1.60	2.13	2.13
Operating Costs	1.19	1.19	1.19	1.48	0.89
Royalties	0.70	0.89	0.53	0.72	0.69
Taxes	0.26	0.40	0.17	0.26	0.26
Total Supply Costs	**4.28**	**5.14**	**3.48**	**4.60**	**3.97**

Nova Scotia – Horton Bluff Shale

Gas supply cost calculation for the Horton Bluff Shale is based on general assumptions stated in the beginning of the chapter and specific assumptions for capital, operating costs and the production profile.

Specific assumptions for the Horton Bluff Shale (all costs are in $CAD 2017):

Specific assumptions are the same as for Frederick Brook Shale, except for the well cost:

- Well cost is assumed to be $2.67 million per well for a typical horizontal well at the TVD of 1300 m, and horizontal leg of 1500 m; TMD – 2950 m; Parkland BC BC2F well costs were taken as a proxy from Montney play (PSAC 2017);
- Capital cost is assumed to be $7.35 million per well, including fracking.

Based on these assumptions, supply cost of Horton Bluff shale play well is $3.57 per Mcf. Table 4.6 illustrates sensitivities of 25 percent in variation in capital costs and operating costs and its impact of the supply costs.

Table 4.6. Supply Cost of Horton Bluff Shale Gas Production

Costs	Reference $/Mcf	Capital costs +25%	Capital costs -25%	Operating costs +25%	Operating costs- -25%
Capital Costs	1.89	2.36	1.42	1.89	1.89
Operating Costs	1.19	1.19	1.19	1.48	0.89
Royalties	0.22	0.27	0.17	0.23	0.21
Taxes	0.28	0.41	0.17	0.28	0.28
Total Supply Costs	**3.57**	**4.23**	**2.95**	**3.88**	**3.26**

Infrastructure Costs

Two pipelines are modeled in the scenario to deliver natural gas from the site to main pipelines and further to distribution pipelines. The capital costs estimation was based on several proposed pipeline projects proponent's websites in Canada (Prince Rupert Gas Transmission, Westcoast Connector Gas Transmission, Coastal Gas Link), Corridor Resources annual reports (for estimation of the pipeline costs from the plant to M&NP), and industry exports estimations (BC OGC 2017; Corridor Resources Inc. 2017a; Spectra Energy 2017b; TransCanada 2017a, 2017b). Based on this data, costs per inch per mile were assumed for pipelines under and above 30" – $0.14 million and $0.2 million, respectively.

In New Brunswick, CERI's scenario assumes a 50 km, 12" pipeline will be required delivering natural gas from the drilling site at the Frederick Brook Shale to M&NP. A capacity of 112 MMcfpd is required for the pipeline. Total costs for this pipeline are calculated to be $53.02 million.

In Nova Scotia, it is assumed that a 75 km, 14" pipeline from the Horton Bluff Shale will be required, delivering natural gas directly to Halifax. A capacity 152 MMcfpd is assumed for the pipeline, with a total cost of $92.8 million. This route allows for gas to be transmitted to Nova Scotia's capital and then further transmitted to the north of the province through the existing Halifax Lateral. The direction of flow in the pipeline, which is historically southward, is assumed to change in this scenario, and production commences per the profile in the previous section.

Pipeline costs are used as an input for the Input-Output model, but are not included as part of capital costs in the supply cost calculations.

Market Dynamics

In Scenario 2, there are two major shale sources of gas due to come on-stream: the Frederick Brook Shale in 2021 and the Horton Bluff Shale in 2023. In addition, the McCully field is also assumed to drill new wells to tap additional resources available in a no moratorium world.

This increased production will lead to local production ramping up to the level when the need for imports will likely be gradually displaced. For New Brunswick, almost all local demand is satisfied from local production as early as 2024, while for Nova Scotia it could be as early as 2027. It is important to remember that all gas flows are confined within two provinces' borders in this scenario. Until two provinces are self-sufficient in gas supply from shale, a mix of three sources is expected to be used to fill in the gap between mounting local production and demand: dwindling offshore project from Nova Scotia, Canaport LNG, and gas imports from M&NP from the US.

Figure 4.12 and Figure 4.13 illustrate the gas dynamics between supply and demand in New Brunswick and Nova Scotia, respectively (both figures do not include supply from Canaport LNG and offshore projects in Nova Scotia). As such, the former show the supply from the existing McCully gas wells, production from the new wells to be drilled at McCully and the new wells drilled at Frederick Brook Shale. The latter shows the production from the new wells at Horton Bluff Shale.

Figure 4.12: Demand and Sales Gas from Producing Assets in New Brunswick Under Scenario 2

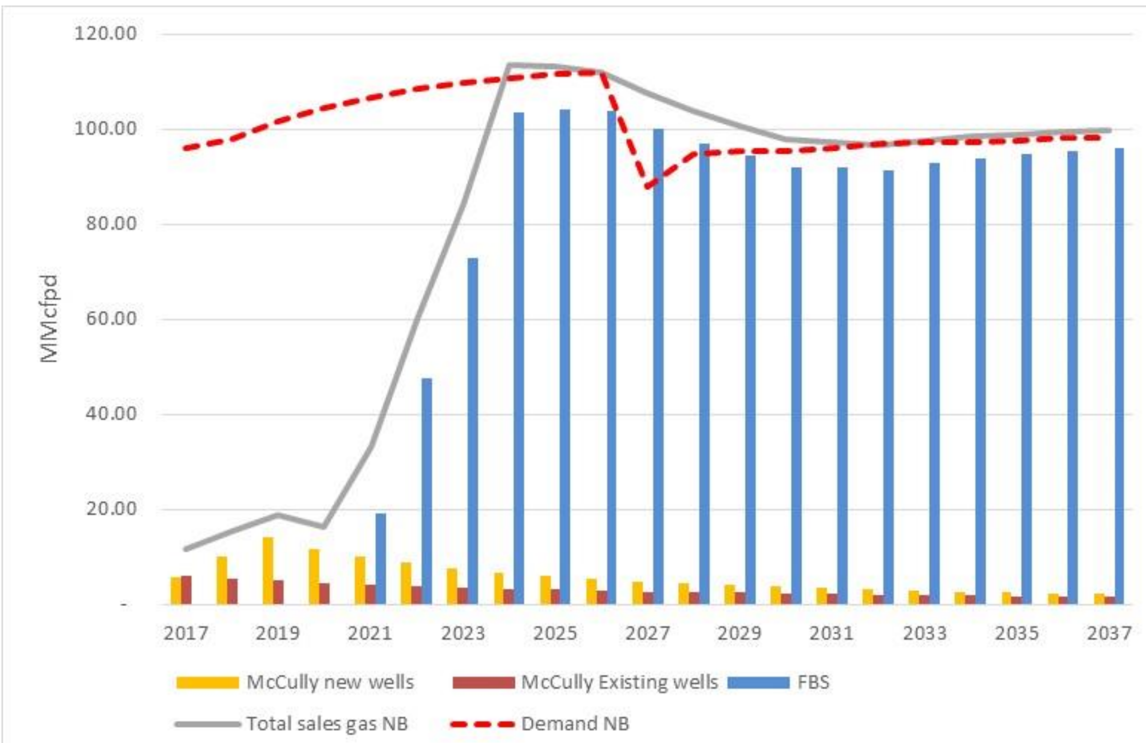
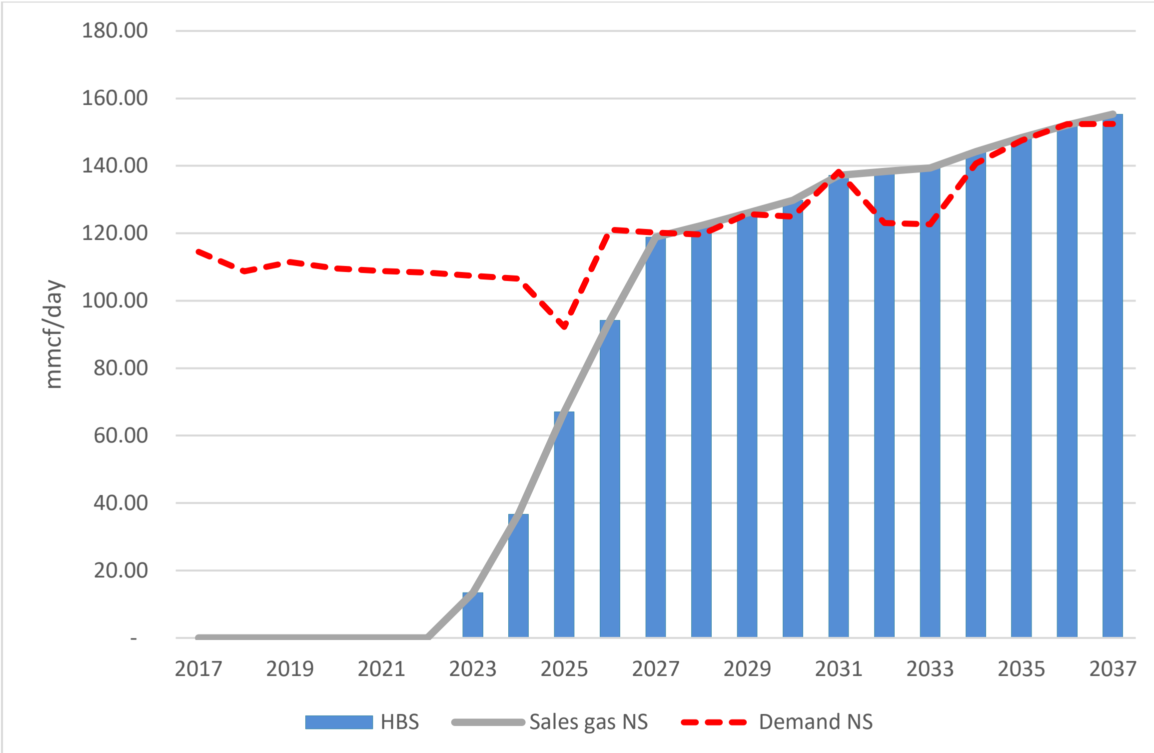


Figure 4.13: Demand and Sales Gas from Producing Assets in Nova Scotia Under Scenario 2

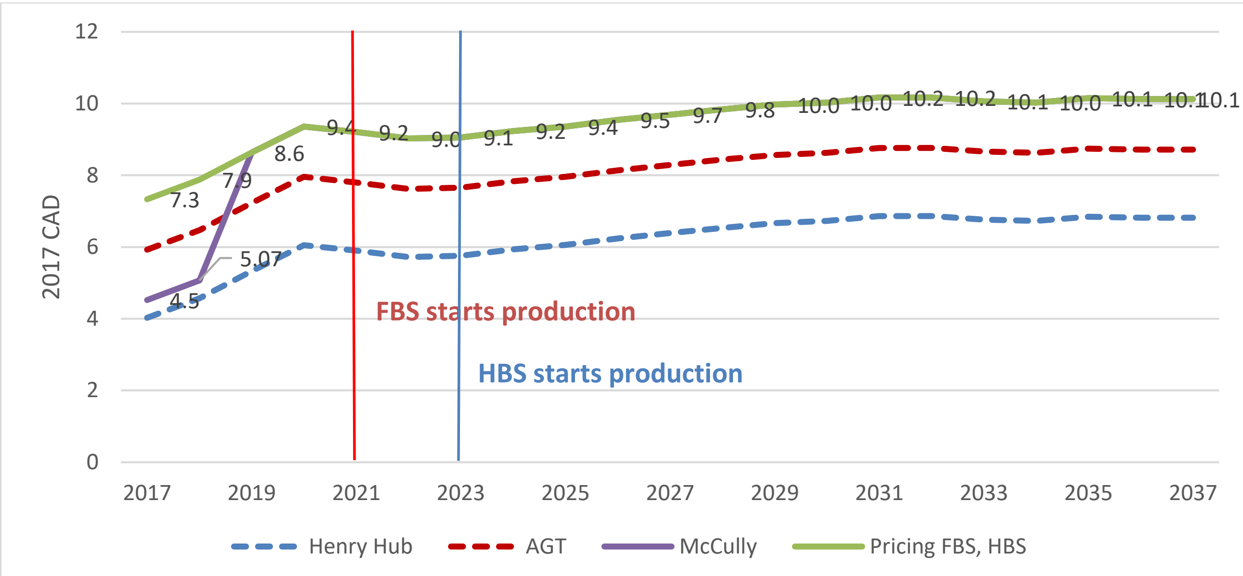


Figures 4.12 and 4.13 also illustrate the production of both shale plays is constrained to where supply meets local demand. For example, in New Brunswick between 2026 and 2028, there is an expected drop in local demand according to NEB projections (NEB 2016a). The modelled gas flows are higher than the New Brunswick demand for these years, up to 2031, as shut-down of wells has not been simulated. The NEB's natural gas forecast for Nova Scotia is different than for its southern neighbor. Demand in Nova Scotia increases and peaks at 152 MMcfpd at the end of the 21-year period of this study, explaining the increase in production volumes. Accordingly, the modelled production of gas in Nova Scotia is higher than the demand in 2032-2034, which drops abruptly for several years, but then regains its growth.

The pricing for gas in two provinces from local producers is expected to be AGT plus tolls (AGT +), reflecting the fact that local gas will be competing for the local Maritimes gas market with gas also supplied from AGT (Figure 4.14). Despite being self-sustaining, the local gas market in the Maritimes is not isolated, and will still compete with gas from the US Northeast region. Because US natural gas can be priced at Maritimes only at AGT plus tolls or higher, local producers have latitude to market their gas at the same price or lower if they choose to protect their market share. Another option is the Canaport LNG regasification facility, importing LNG mostly from Trinidad. However, for the study purposes this option was not considered as pricing at Canaport is not publicly available.

In this scenario, it is important to note that the McCully pricing (indicated by the purple line) is the same as Scenario 1, as of 2019, merging together. Figure 4.14 shows the start dates of production in the respective shale plays.

Figure 4.14: Pricing Forecast under Scenario 2 ($CAD 2017)



Scenario 3: We are Exporters

Outline of Scenario

In Scenario 3, similar to Scenario 2, it is assumed that the moratoria are removed, and New Brunswick and Nova Scotia pursue a higher growth path in developing the two shale plays, beyond the level of self-sustenance. This scenario is characterized by the region becoming exporters of natural gas via an LNG option, as well as by pipeline to the US via the existing M&NP.

However, even though natural gas can be potentially exported via LNG and pipeline, for this study, the LNG option is assumed to be the primary destination of exporting natural gas from the Maritimes. This is done for several reasons.

First, the New England market has been flooded with low-cost, high-quality shale gas from the Marcellus Shale. It is thus assumed for the study that Marcellus gas will likely satisfy the demand in the US, leaving little space for Maritime-produced gas. This makes it more likely that the Maritimes will utilize the LNG option to export gas, targeting a major buyer for shale gas from the two provinces. Second, there are already several LNG projects that are being considered for development in Nova Scotia, including the Goldboro LNG facility in Goldboro, Nova Scotia and the Bear Head LNG facility, located at Point Tupper, Nova Scotia. Both applications have been approved by the NEB.

Scenario 3 requires the development of four assets: a) McCully (case identical to Scenario 2), b) Frederick Brook Shale, c) Horton Bluff Shale, and d) LNG export facility. In this scenario, the development of the McCully asset is identical to its development in Scenario 2 (and is not reviewed again in this section), while the development of the Frederick Brook and the Horton Bluff are assumed to be limited by the size of the M&NP's capacity, or 550 MMcfpd. This scenario also includes a fourth asset, an LNG export facility with a minimum capacity of 0.7 Bcfpd. For simplicity sake, and to take advantage of the existing infrastructure, CERI assumes its location to be Goldboro, Nova Scotia.

All assets and additional infrastructure are described in Table 4.7.

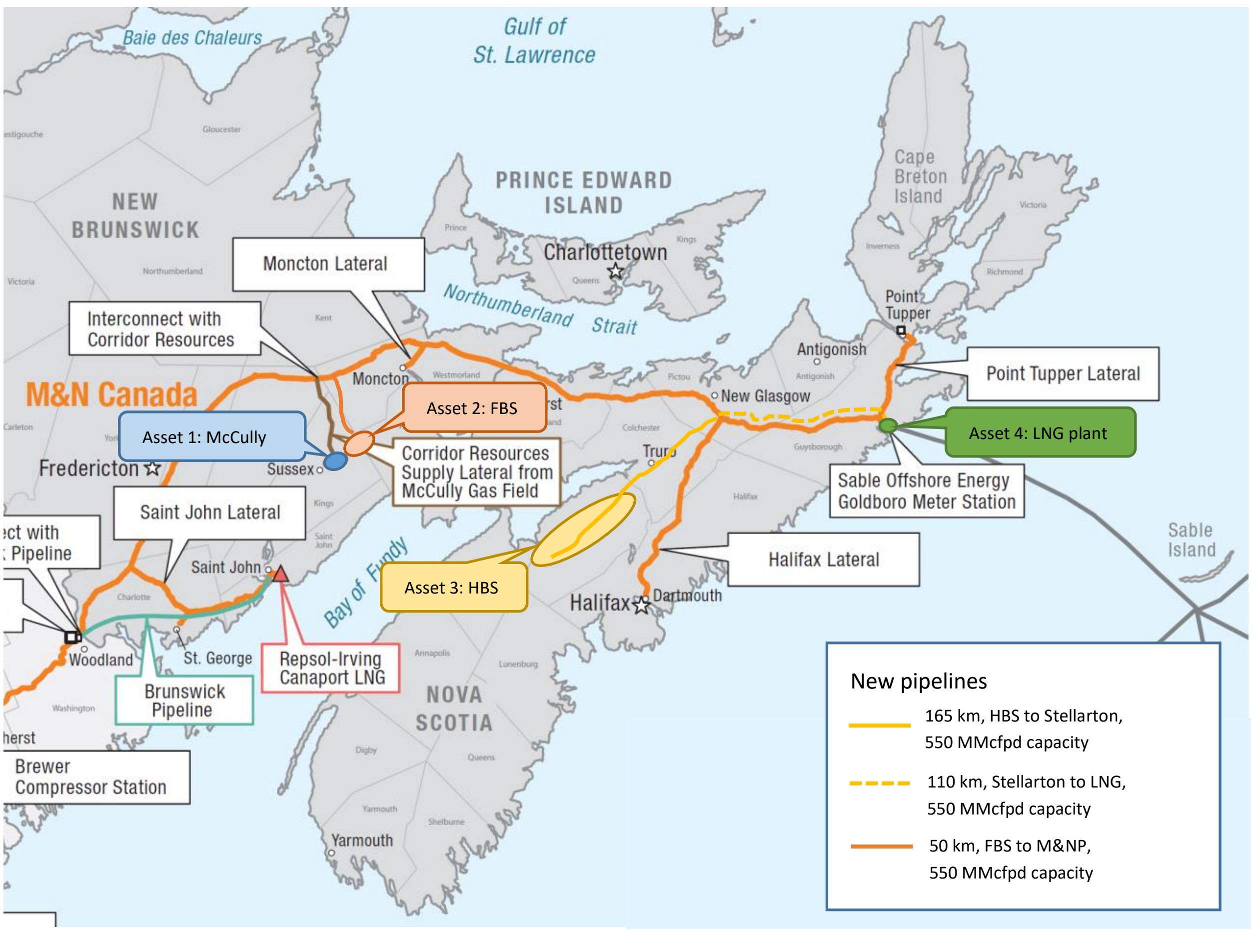
Table 4.7: Produced Assets under Scenario 3

No	Asset	Province	Recoverable remaining reserves	Production flow constraints	Additional infrastructure
1	McCully field, tight gas	New Brunswick	2P, 30.5 Bcf – existing wells Corridor Resources: 22.9 Bcf Potash Corporation: 7.6 Bcf 2P, 57.5 Bcf – new wells Corridor Resources: 43.1 Bcf Potash Corporation: 14.4 Bcf	Capacity of the pipeline (35 MMcfpd)	None required
2	Frederick Brook Shale	New Brunswick	13.4 Tcf	550 MMcfpd	50 km pipeline from the site to M&NP, capacity 550 MMcfpd
3	Horton Bluff Shale	Nova Scotia	7 Tcf	550 MMcfpd	1) 165 km pipeline to M&NP near Stellarton, NS, capacity 550 MMcfpd 2) 110 km from Stellarton, NS, capacity 300 MMcfpd to Goldboro in parallel to main line. The 300 MMcfpd allows for moderate growth of supply to LNG beyond planned in the study
4	LNG Plant	Nova Scotia	--	Capacity: 0.7 Bcfpd and more	--

Figure 4.15 illustrates the four assets, as well as the location of the necessary, accompanying pipeline infrastructure. In this scenario three pipelines are necessary, one in New Brunswick and two in Nova Scotia. It is important to note that shapes of assets and routes of pipelines are shown in simplified form. In New Brunswick, a 50 km, 30" pipeline is required from the site of Frederick

Brook Shale to the M&NP mainline; the pipeline will need a capacity of 550 MMcfpd to match the production constraint. The first pipeline assumed in Nova Scotia is a 165 km, 30" pipeline from Horton Bluff Shale to Stellarton, where the gas will be able to flow to Halifax via Halifax Lateral, to be consumed locally, while the rest of the gas will flow east to the LNG plant, via the existing M&NP. Under this scenario, a limited amount of gas could flow to Point Tupper. Nova Scotia's second pipeline is assumed to be from Stellarton to the LNG plant to allow for larger transmission capacity to LNG. This line is assumed to be a 110 km, 22" pipeline with capacity of 300 MMcfpd.

Figure 4.15: Scenario 3 Assets and Infrastructure



Source: (Maritimes & Northeast Pipeline 2009), map modified by CERI

This scenario includes the three production assets (McCully, Frederick Brook Shale and Horton Bluff Shale) destined to four separate customers: a) consumers in New Brunswick, b) consumers in Nova Scotia, c) consumers in the US, and d) the LNG Plant (consumers abroad). Per se, this scenario includes six different gas flows:

- McCully: 1) to local market in New Brunswick;
- Frederick Brook Shale: 2) to AGT in the US, 3) to local market in New Brunswick, and 4) to the LNG plant in Nova Scotia;
- Horton Bluff Shale: 5) to local market in Nova Scotia and 6) to the LNG plant in Nova Scotia.

The description of the physical gas flows and the pricing for each asset and end-user are reviewed in greater detail later in this section.

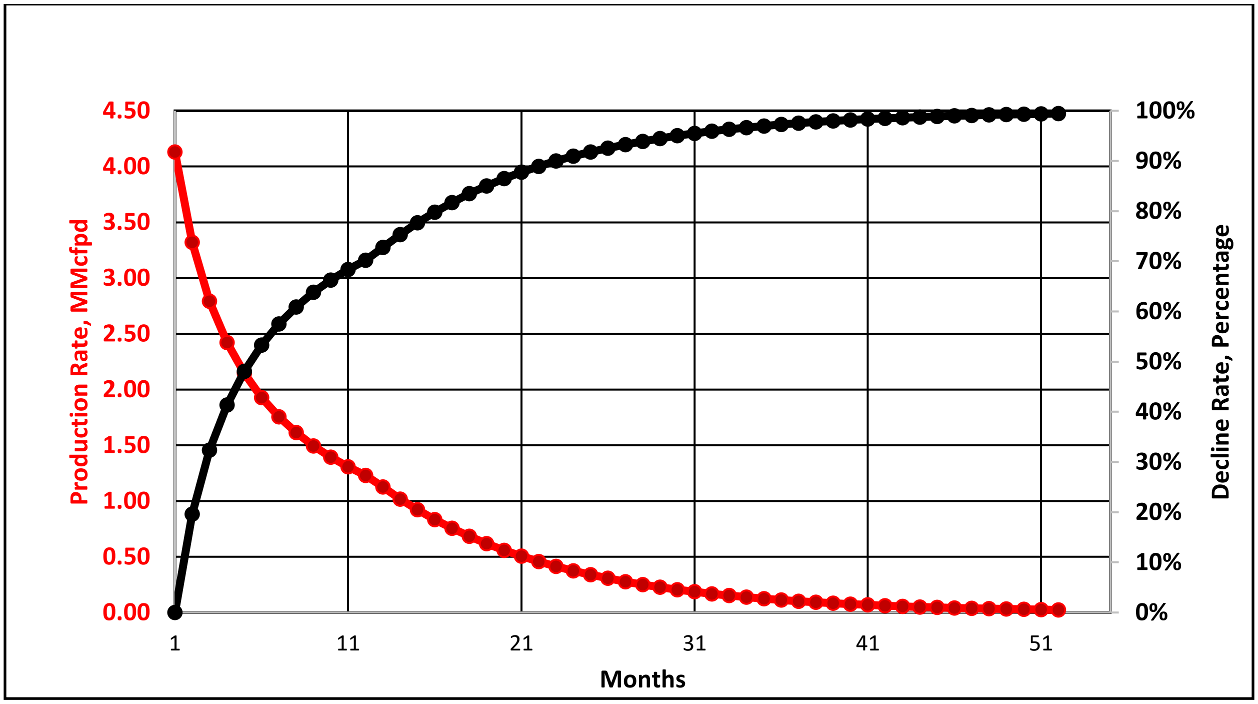
Production Outlook

The production outlook for Scenario 3 includes three cases: McCully (frack case), Frederick Brook Shale and Horton Bluff Shale. The production outlook for the McCully frack case is identical to Scenario 2 and is not reviewed in this section.

With regards to the Frederick Brook Shale and Horton Bluff Shale, there are some similarities and differences. They differ from Scenario 2 in that they are not constrained by meeting local demand, but by the existing pipeline capacity of the M&NP (550 MMcfpd). However, while the production profiles under this scenario are different than Scenario 2, the IP rates and monthly decline rates per well are assumed to be identical. Recall, for the Frederick Brook Shale and Horton Bluff Shale production forecast, the IP and monthly decline rates used are: 4.13 MMcfpd, with a 75 percent decline rate in year 1, with hyperbolic decline factor of 1.21. In the second year, CERI applied a monthly decline factor of 15 percent, 10 percent decline factor in the subsequent years, and minimum gas production decline of 1.0 MMcfpd after 4 years.

These curves are indicated in Figure 4.16.

Figure 4.16: Frederick Brook Shale and Horton Bluff Shale Type Well and Decline Curves



The NILP was also used to generate the number of new wells required to develop the Frederick Brook Shale and Horton Bluff Shale, respectively, for the case where there is an LNG export facility. The NILP model was constrained by the gas delivery line capacity of the M&NP and the estimated gas reserves in the Frederick Brook Shale and Horton Bluff Shale, respectively.

While the Frederick Brook Shale and Horton Bluff Shale production profiles are identical, they are separated by the year of development. As in Scenario 2, the Frederick Brook Shale commences development in 2021, while the Horton Bluff Shale commences in 2023, two years later, simply because the Frederick Brook Shale is better defined and the E&Ps in Nova Scotia will likely need a couple of years to drill exploratory wells to define the resource.

Figure 4.17 illustrates the production development and well count of the Frederick Brook Shale. Over the 21-year period of the study, the NILP estimated drilling 597 new wells. Over the 21-year period, approximately 23 percent of the total recoverable gas reserve of 13.4 Tcf is depleted under this scenario. This is illustrated in Figure 4.17.

Figure 4.17: Frederick Brook Shale Production Development and Well Count (LNG Available and Pipeline Capacity: 550 MMcfpd)

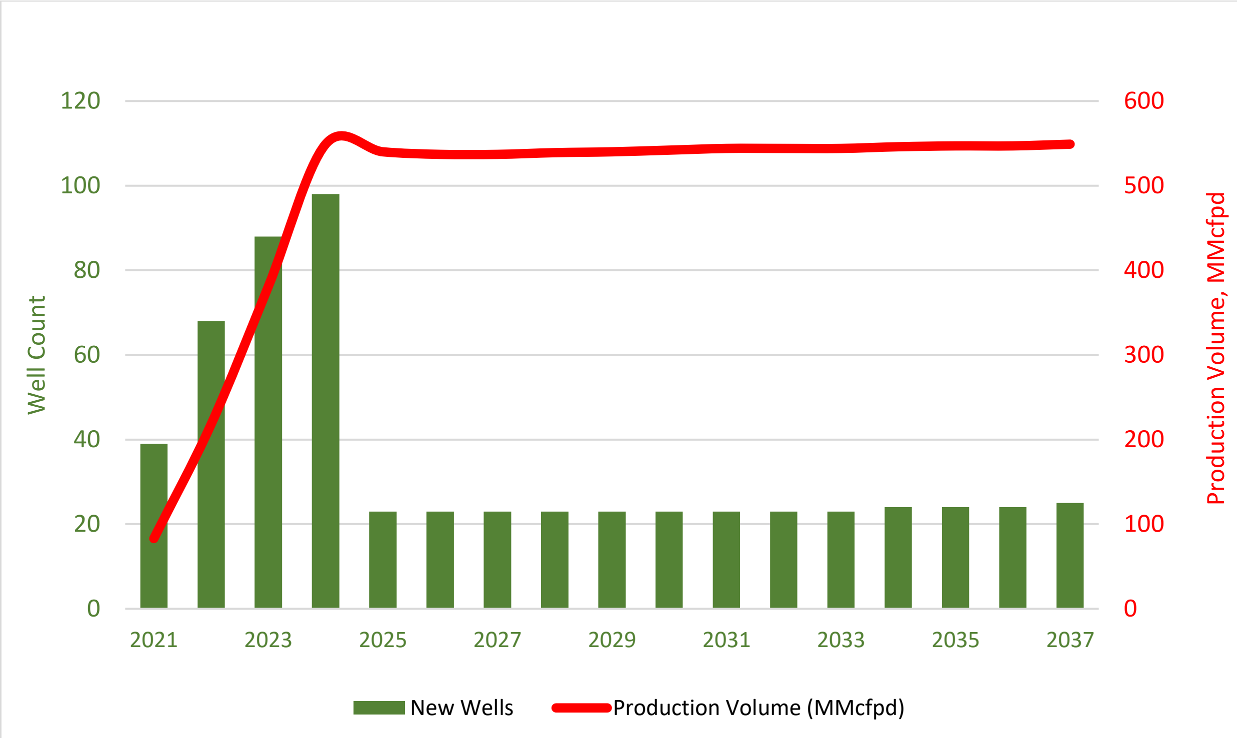
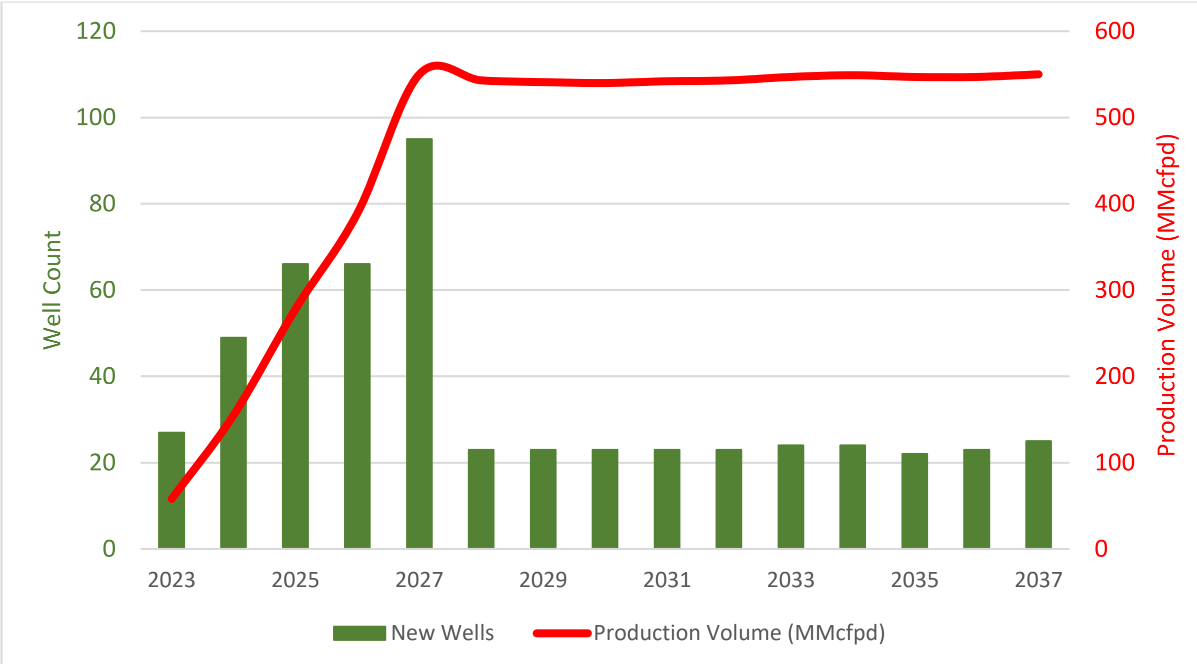


Figure 4.18 illustrates the production development and well count of the Horton Bluff Shale. Over the 21-year period of the study, the NILP estimated drilling 548 new wells. Over the 21-year period, approximately 20 percent of the total recoverable gas reserve of 7 Tcf is depleted under this scenario.

Figure 4.18: Horton Bluff Shale Production Development and Well Count (LNG Available and Pipeline Capacity: 550 MMcfpd)



Supply Costs

Supply costs are the same as in Scenario 2 and are not reviewed in this section.

Infrastructure Costs

Three pipelines are modeled in the scenario to deliver natural gas from the site to main pipelines and further to distribution pipelines. Similar to calculating the pipeline costs in Scenario 2, the capital costs estimation was based on several proposed pipeline projects proponent's websites in Canada (Prince Rupert Gas Transmission, Westcoast Connector Gas Transmission, Coastal Gas Link), Corridor Resources annual reports (for estimation of the pipeline costs from the plant to M&NP), and industry exports estimations (BC OGC 2017; Corridor Resources Inc. 2017a; Spectra Energy 2017b; TransCanada 2017a, 2017b). Based on this data, costs per inch per mile were assumed for pipelines under and above 30" – $0.14 million and $0.2 million, respectively.

In New Brunswick, a 50 km, 30" pipeline from the Frederick Brook Shale site to the M&NP is assumed. This pipeline is assumed to have a pipeline capacity of 550 MMcfpd. Total costs for the pipeline were calculated to be $185.9 million.

In Nova Scotia, a 165-km pipeline with a capacity of 550 MMcfpd from the Horton Bluff Shale location to Stellarton is assumed. The total cost of the 30" pipeline is $613.3 million. As previously mentioned, the Horton Bluff shale gas is assumed to flow from Stellarton to Halifax via the Halifax Lateral or via the existing M&NP line to the east to the LNG plant. Under this scenario, a limited amount of gas could flow to Point Tupper as well. Additional capacity is assumed to be added to the M&NP from Stellarton to the LNG plant to allow for larger transmission capacity to the export terminal. This line is assumed to be 110 km, with a diameter of 22” and capacity of 300 MMcfpd. The associated costs for this line are $213.8 million.

Pipeline costs are used for the Input-Output model, but are not included as part of capital costs in the supply costs calculations.

Market Dynamics

Under Scenario 3, both provinces produce close to 360 Bcf per year after 2026, nearly 1 Bcfpd in total. Such production is enough to satisfy local demand (0.23-0.25 Bcfpd for both provinces for 2026-2037) and export approximately 260 Bcf per year to the LNG plant (0.71 Bcfpd).

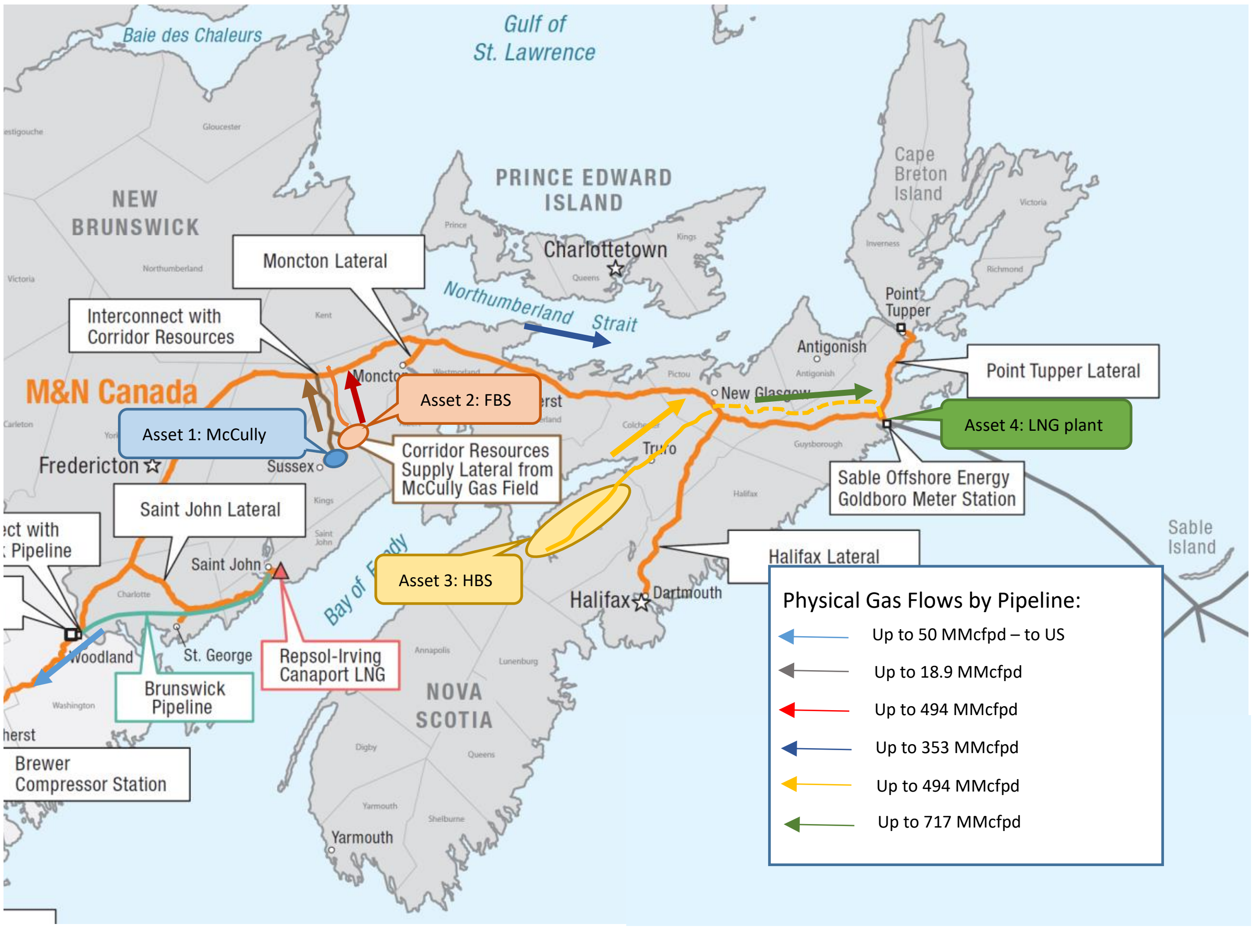
Gas flows and its pricing for each asset and end-user are reviewed in this section. This scenario includes six different gas flows from three assets destined to four customers: a) consumers in New Brunswick, b) consumers in Nova Scotia, c) consumers in the US, and d) the LNG Plant (consumers abroad). These relationships are illustrated in Table 4.8. It is important to note that the physical flow volume includes a 10 percent loss, resulting in volumes different than the capacities of pipelines illustrated in the previous sections.

Table 4.8: Physical Volumes and Pricing under Scenario 3

Asset	Flow destination	Physical volume	Pricing for I/O model
McCully field	To local market in New Brunswick	Up to 18.9 MMcfpd. Average 8.8 MMcfpd for 2017-2037	AGT minus tolls (before 2019). Here and after M&NP tolls include US and Canadian parts AGT plus tolls after 2019
Frederick Brook Shale	To AGT, US	Up to 50 MMcfpd	AGT minus tolls as gas will compete with other supply to AGT
	To local market in New Brunswick	Up to 104 MMcfpd (the difference with demand of 110 MMcfpd is covered by McCully)	AGT plus tolls as local supply will compete for market with gas from AGT
	To LNG plant	Approximately 342-353 MMcfpd after 2024	Priced at supply costs of FBS. It is assumed that producer of the gas will sell the product to LNG plant at price equaled to supply costs at site, thus recovering costs and getting minimum rate of return
Horton Bluff Shale	To local market in Nova Scotia	Up to 152 MMcfpd	AGT plus tolls as local supply will compete for the local market with gas from AGT
	To LNG Plant	Approximately 371-339 MMcfpd after 2026 (supply to LNG is declining as NS local demand grows over time)	Priced at supply costs of HBS. It is assumed that producer of the gas will sell the product to LNG plant at price equaled to supply costs at site, thus recovering costs and getting minimum rate of return

The directions of the assumed physical flows of the various pipelines are illustrated in Figure 4.19. It is important to mention that the pipeline flows indicated in the figure are not capacity constraints, but rather physical gas flows under Scenario 3.

Figure 4.19: Physical Gas Flows by Pipeline under Scenario 3



Source: (Maritimes & Northeast Pipeline 2009), map modified by CERI

It is important to note that gas flows for both provinces are modelled to initially satisfy local demand, and after that divert the majority of capacity to the LNG plant, with the exception of modelling an additional 50 MMcfpd to flow to the US. The objective is to leave the southern part of the Canadian M&NP operating at minimum required throughput.

Gas flows in New Brunswick and Nova Scotia are illustrated in Figure 4.20 and Figure 4.21, respectively. Figure 4.20 also shows the demand for gas in New Brunswick (plotted red line), as per the NEB's Energy Futures (NEB 2016a), while Figure 4.21 shows the demand for gas in Nova Scotia, as per the NEB's Energy Futures (NEB 2016a).

Figure 4.20: Gas Flows in New Brunswick under Scenario 3

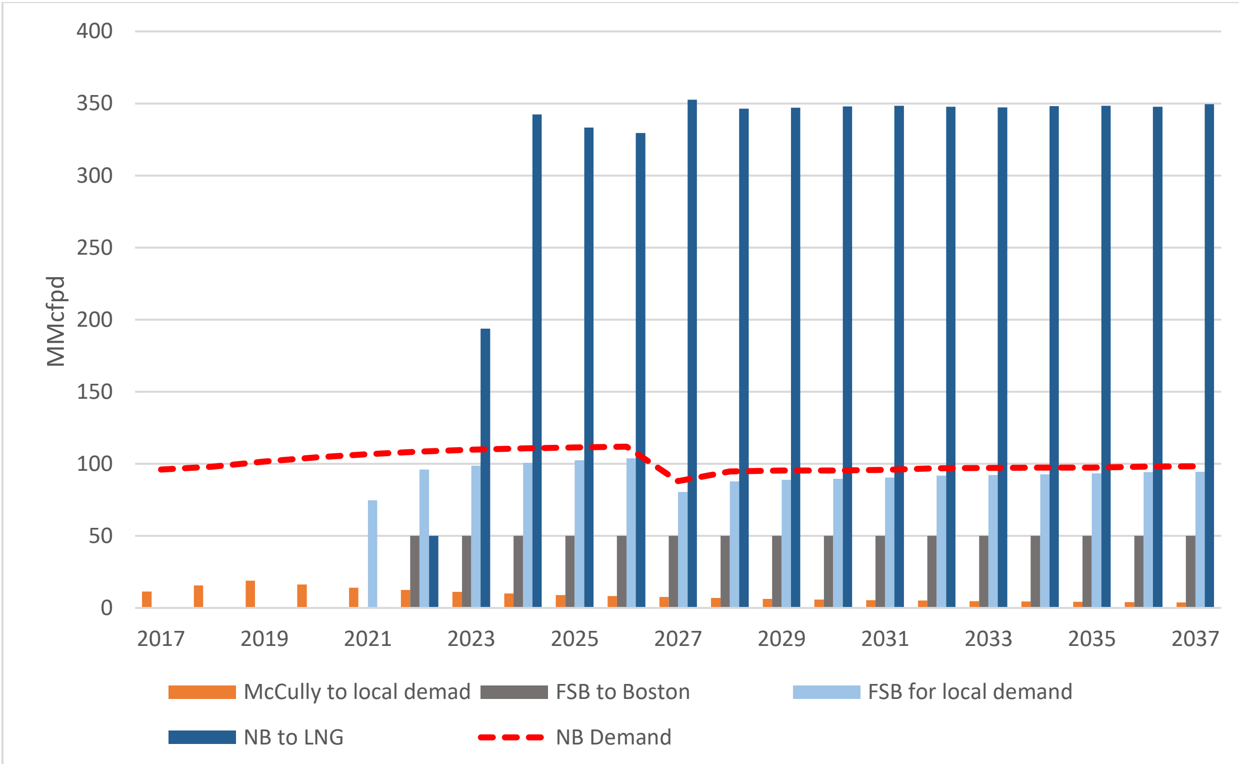
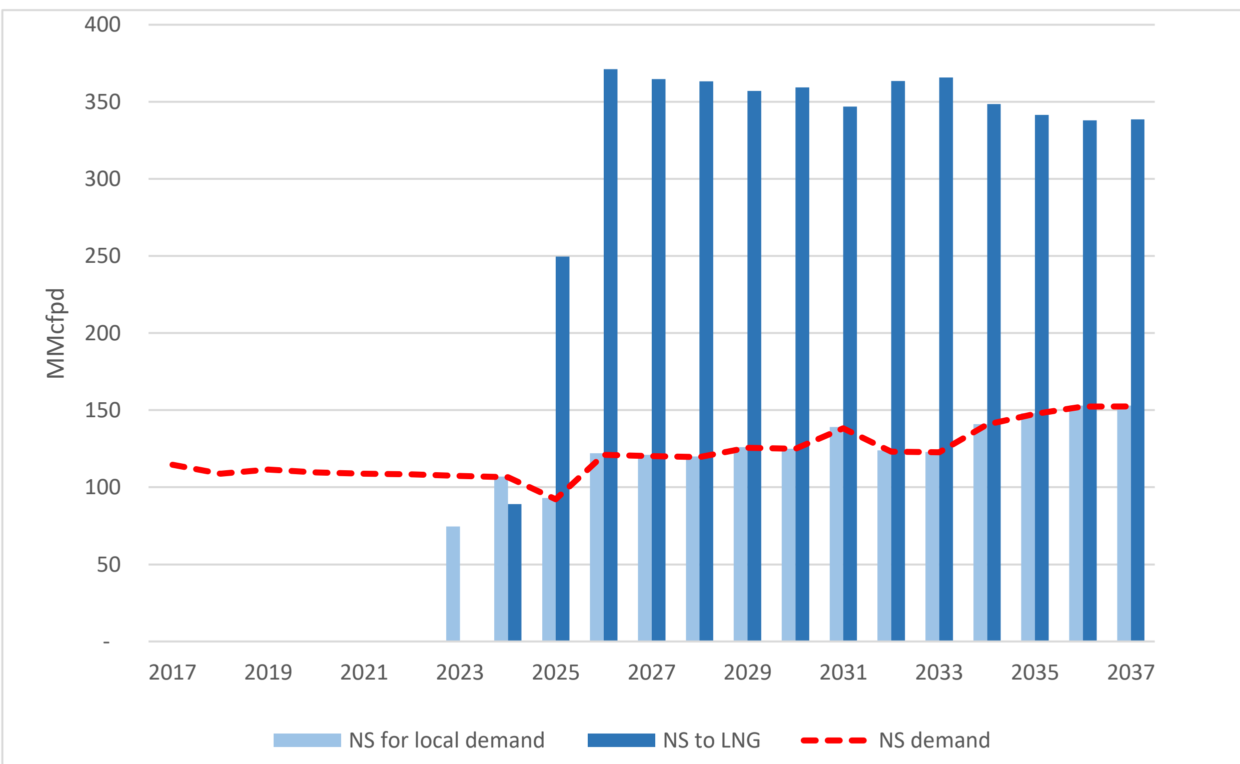


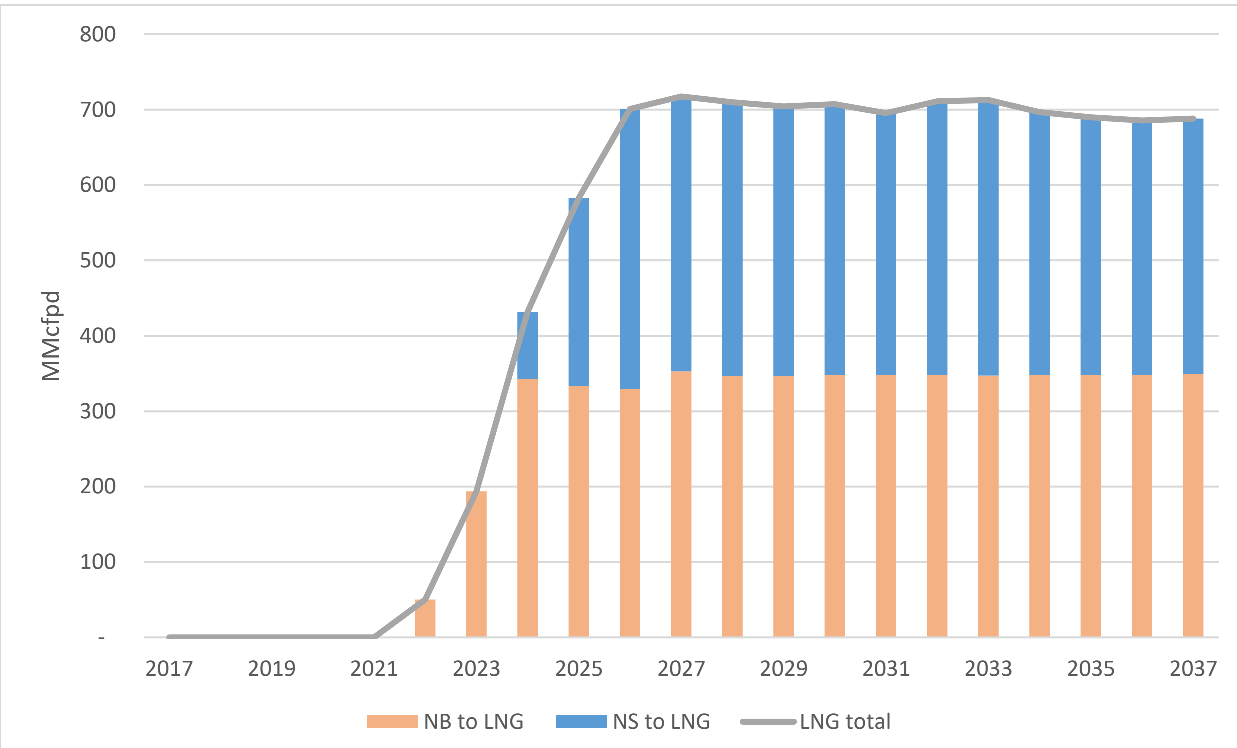
Figure 4.21: Gas Flows in Nova Scotia under Scenario 3



Initial flows to the LNG plant are available in 2022, however, the facility is assumed to be able to operate at constant supply of around 700 MMcfpd only in 2026. After that, production plateau can be sustained for many years, as the Frederick Brook Shale produces only 3.02 Tcf out of an estimated recoverable reserve of 13 Tcf until 2037, and the Horton Bluff Shale produces only 2.51 Tcf out of 7 Tcf. Provided there is a market for LNG, such a large resource base may be conducive for faster development of gas resources and installing additional LNG trains. Such upside is not modelled however in this study.

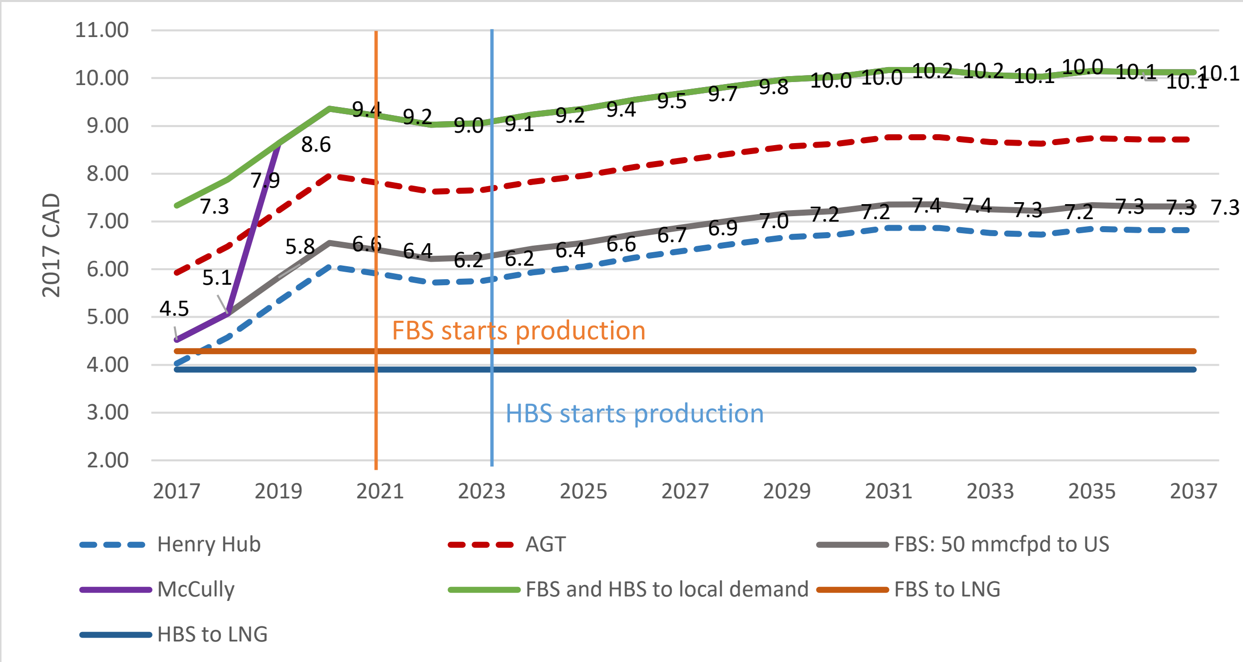
Figure 4.22 shows the gas flows destined for the LNG plant in Nova Scotia, originating from both provinces, including their total volumes.

Figure 4.22: Gas Flows to LNG Plant under Scenario 3



The price forecasts for each flow are shown in Figure 4.23. Recall that in this scenario, the McCully pricing (indicated by the purple line) merges together with pricing of gas from the Frederick Brook Shale and Horton Bluff, as of 2019.

Figure 4.23: Pricing under Scenario 3 ($CAD 2017)



Local users in New Brunswick and Nova Scotia will likely have to pay AGT plus tolls price after the Maritimes stop being a gas exporter to the US, which is assumed to happen in 2019. If shale gas producers opt to sell all gas entirely to the LNG plant and not market it in the provinces, the Maritimes should import it from AGT or through the Canaport LNG facility. If importing from the US is going to prevail, then the local gas price will be AGT plus tolls. It therefore underpins the pricing level for shale producers if they sell gas in the local market as modeled in the study.

LNG is modelled in this scenario to purchase gas at least at the supply costs level for the Frederick Brook Shale, at $4.28 per Mcf, leveraging the price for a long-term contract. The price for Horton Bluff Shale is assumed to be $3.90 per Mcf, with supply costs at $3.57 per Mcf. The premium in price to Horton Bluff Shale compared to supply costs was introduced using the following rationale.

The LNG facility is assumed to have independent ownership from upstream shale gas businesses. Thus, to diversify its sources of gas and limit risks of dependence on one supplier, the LNG facility will strive to have two suppliers in its portfolio. This will provide a leverage for a Horton Bluff Shale producer to arrive at a price in the range between its supply costs ($3.52 per Mcf) and other suppliers' supply costs ($4.28 per Mcf). Based on CERI's assumption regarding LNG contracting and trading, the range between $3.70 – $4.00 per Mcf is likely as a potential outcome of such price negotiations. As a result, the price of $3.90 per Mcf was assumed for the study.

Supply Costs, Investments and Revenues

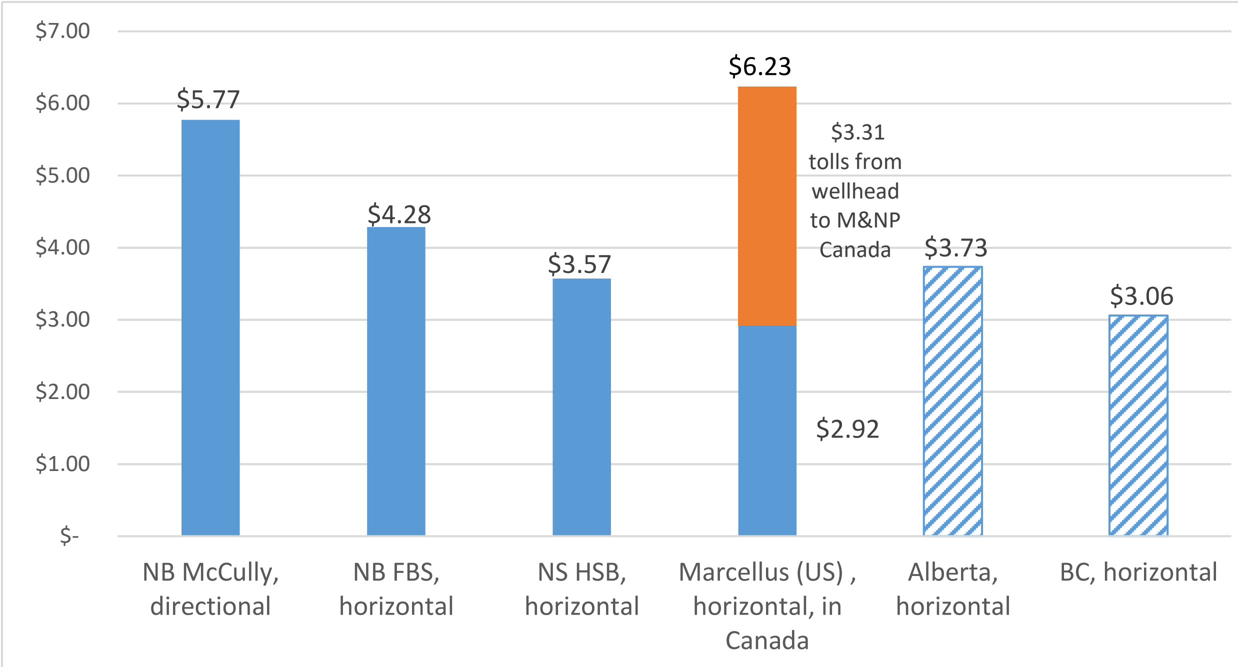
Three scenarios yield distinctively different outcomes for gas supply, investments, and revenues generated in the two provinces. All three scenarios ensure enough supply of gas for local demand, securing end-users with the needed product.

The first scenario does not generate any level of new investments in provinces, while the other two bring about medium- to large-size gas industries to the Atlantic provinces. This activity translates to economic impacts (taxes, employment and GDP) discussed further in Chapter 5.

Supply costs for the considered resources are generally higher than in other jurisdictions (Figure 4.24). New Brunswick supply costs are higher than the average costs in British Columbia, Alberta, Nova Scotia and the Marcellus. Nova Scotia supply costs are, overall, on par with Alberta's, but more expensive than Marcellus and British Columbia shale gas. Marcellus gas is the cheapest, but if it is brought into the Maritimes via pipeline on the Canadian side (via TGP Bullet and Constitution and M&NP),[3] the price of the gas is higher than any supply costs calculated in this study – $6.23 per Mcf. It is $0.46 higher than gas from new wells from McCully field, $1.95 higher than Frederick Brook shale gas, and $2.66 higher than Horton Bluff shale gas. Tolls for TGP Bullet and Constitution are assumed to be $1.91 and for M&NP, $1.40. The transportation tolls add up to $3.31 in total. The costs of Western Canadian gas at the Maritimes is beyond the scope of this study, only Marcellus, due its proximity, is compared to potential gas in New Brunswick and Nova Scotia.

[3] Tolls are calculated based on (ICF Consulting Canada 2013).

Figure 4.24: Gas Supply Costs per Mcf ($CAD 2017) in Different Jurisdictions, 2017



Supply cost differences for three assets are driven by several major factors, including IP rates, production profile per well, well costs, number of fracks per well, royalty regimes and provincial tax levels. Comparison of supply costs is illustrated in Table 4.9.

Table 4.9: Supply Costs in New Brunswick and Nova Scotia

Costs	NB McCully $/Mcf	% Share of supply cost	NB FBS $/Mcf	% Share of supply cost	NS HBS $/Mcf	% Share of supply cost
Capital Costs	3.35	50%	2.13	*50%*	1.89	53%
Operating Costs	1.16	20%	1.19	*28%*	1.19	33%
Royalties	0.95	17%	0.70	*16%*	0.22	6%
Taxes	0.32	5%	0.26	*6%*	0.28	8%
Total Supply Costs	**5.77**	**100%**	**4.28**	***100%***	**3.57**	**100%**

This does not necessarily mean that New Brunswick and Nova Scotia assets are not competitive locally, as average projected prices for the period are significantly higher than the supply costs of these assets. This is illustrated in Table 4.10.

Table 4.10: Projected Average Gas Prices in New Brunswick and Nova Scotia ($CAD per Mcf)

	We Are Importers	We Are Self-sustaining		We Are Exporters	
	NB	NB	NS	NB	NS
Average gas price per asset 2017-2037 in M&NP pipeline, 2017 $CAD per Mcf (not including distribution)	9.16	9.48	9.48	6.69	6.81
Average gas price per asset 2017-2037 for local demand in M&NP pipeline, 2017 $CAD per Mcf (not including distribution)	9.16	9.48	9.48	9.48	9.48

This leaves flexibility for producers to set prices as low as supply costs and as high as competing prices from other sources (e.g., from AGT or Canaport LNG) to maintain price advantage for customers. Local shale assets are also more cost competitive compared to Marcellus gas – the closest large source of gas. Marcellus gas is cheaper than New Brunswick and Nova Scotia supply, but if it is brought into the Maritimes via various pipelines,[4] it will cost as low as $6.23 per Mcf, or $1.95-$2.66 per Mcf higher than local shale producers' gas.

On the other hand, from the perspective of the consumers, the average price of commodities to local consumers could be characterized as stable, in relations to current levels, for the next 20 years (as illustrated in the second row of Table 4.10). For example, in June 2017, the price of gas in New Brunswick (total costs before distribution) was $8.99 per Mcf (or $8.52 per GJ) which is comparable to this study's price outlook (Enbridge Gas New Brunswick 2017). Likewise, in Nova Scotia, the commodity price is virtually identical – the gas price for the period May-October 2017 is expected to be $9.09 per Mcf (Heritage Gas Limited 2017). However, it is possible that local consumers could in fact enjoy lower commodity prices from local producers' who experience an advantage between the average gas price per asset and their supply costs. This could occur if increased competition from the Marcellus or imports via Canaport LNG, creates a downward pressure on prices.

Producer's gross revenues (or operations) and investments per province, in turn, are driven by the amount of gas produced, capital costs and pricing for each producing asset for each scenario. Gross revenues per scenario per asset are calculated by multiplying sales gas production from this asset by pricing for this asset for each modelled year.

[4] Tolls are calculated based on (ICF Consulting Canada 2013).

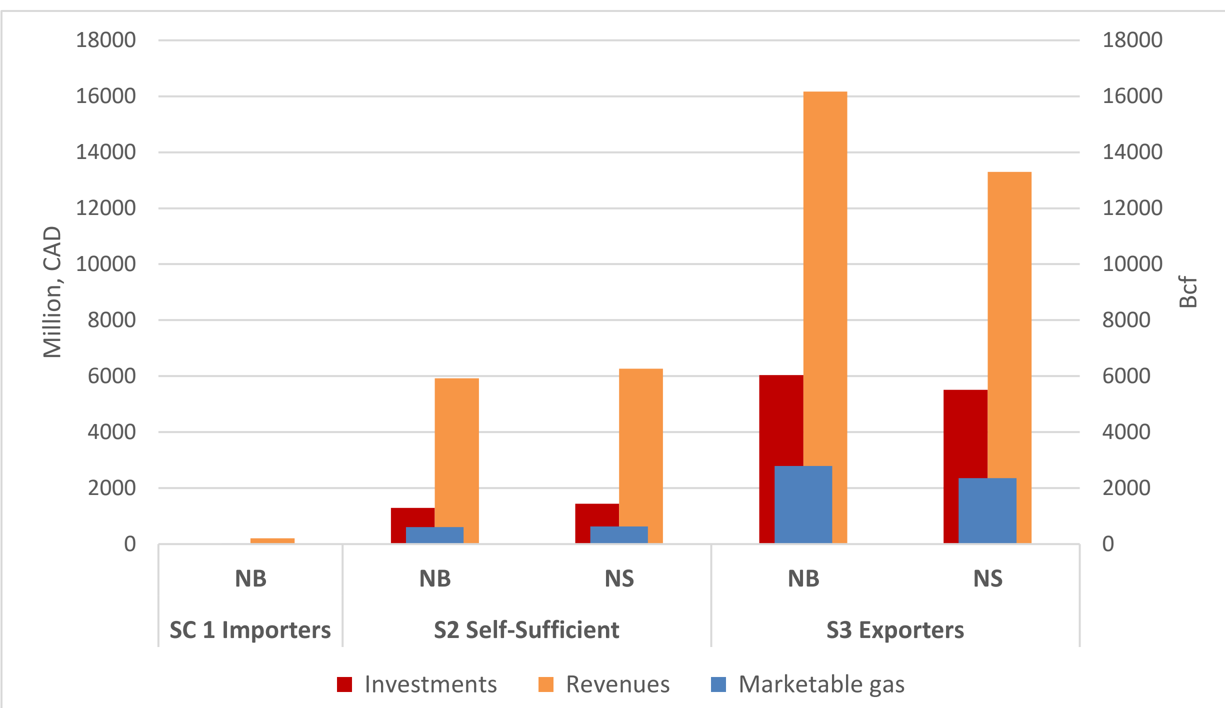
Scenario 3 brings in the most investments and revenues to provinces, however, the producer's gross revenues growth compared to investments growth is less significant than in Scenario 2. The difference is largely explained by, in Scenario 3, a significant amount of gas is sold to LNG at supply and close-to-supply cost for both Atlantic Shale plays, while in Scenario 2, the gas is sold at AGT plus tolls (AGT +) price. In the Self-sufficiency scenario, $2.73 billion are expected to be invested in the two provinces for the 21-year study period (2017-2037), and $11.6 billion in the Exporters' scenario. Total revenues are expected to be $12.2 billion in Scenario 2 and almost $30 billion in Scenario 3.

Results are illustrated in Table 4.11 and Figure 4.25.

Table 4.11: Investments, Revenues and Marketable Gas

Category	Unit	S1 Importers	S2 Self-Sufficient		S3 Exporters	
		NB	NB	NS	NB	NS
Investments, including new pipelines	Million dollars	--	1,295	1,443	6,041	5,510
New pipelines	*Million dollars*	--	*53*	*93*	*186*	*827*
Operations (producer's gross revenues)	Million dollars	203	5,925	6,267	16,170	13,293
Marketable gas	Bcf	23	611	629	2,788	2,360

Figure 4.25: Investments, Revenues and Marketable Gas Production



Chapter 5: Economic Impacts of Gas Development in New Brunswick and Nova Scotia

This chapter presents and reviews the economic impacts of gas development in New Brunswick and Nova Scotia. It is divided into two parts. The first is divided into three sections: 1) discusses the methodology of CERI's proprietary Input/Output (I/O) Model, 2) reviews various general assumptions and constraints of the I/O Model, and 3) examines in greater detail the three scenarios, including their assumptions regarding the relevant capital investments and operations. These inputs, determined by the production outlook and supply cost model in Chapter 4, are inputs in the I/O model. The second part presents and discusses the results of modelling the three scenarios. The results of developing gas in New Brunswick and Nova Scotia are presented for each scenario, to illustrate the impacts over the 21-year period (2017-2037). Economic impacts under consideration include economy-wide impacts such as value-added gross domestic product (GDP), jobs created (given in person-years, one person year being one person working for one year), as well as various forms of government revenue, including indirect, personal and corporate taxation revenues. Economic impacts are calculated for Canada, with Canadian impacts broken down to the provincial level.

CERI's Input/Output Model

Methodology

There are several ways to estimate the impact of oil and gas development in New Brunswick and Nova Scotia, not only on their respective economies but on the Canadian economy as well. This type of analysis is usually done using some form of a General Equilibrium model, useful models to evaluate the impact of economic or policy shock in the economy as a whole.[1] The results of this study are computed using CERI's Multi-Regional Input/Output 4.0 (UCMRIO 4.0) Model, a computable version of the Walras General Equilibrium model.[2]

Input/Output analysis in general addresses the way economic circumstances in one part of an economy can ripple through the rest of it. In particular, it is concerned with inter-industry relationships, notably the use of output from industry as an input into another industry's production process. The model determines an approximate impact on various economic

[1] General equilibrium modelling reproduces the structure of the whole economy and therefore the nature of all existing economic transactions among diverse economic agents (productive sectors, households, and the Government, among others). Moreover, computable general equilibrium (CGE) analysis, in comparison to other available techniques, captures a wider set of economic impacts derived from a shock or the implementation of a specific policy reform. In that sense, the CGE approach is especially useful when the expected effects of economic activity implementation are complex and materialize through different transmission channels.

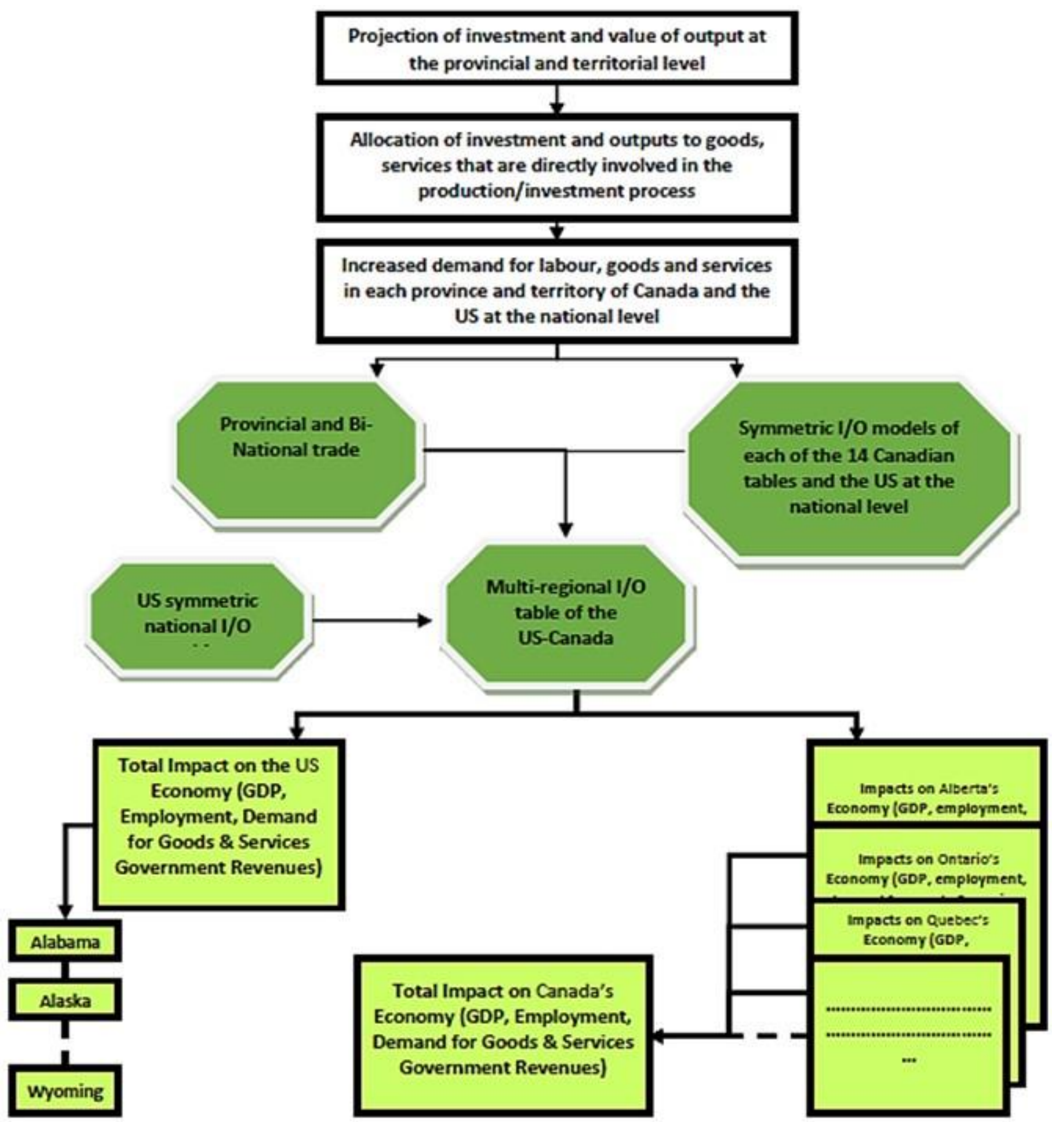
[2] Modelling methodology and model limitations are described in detail in Appendix E.

variables due to the introduction to the economy of a particular set of expenditures or 'shocks'. In the case of resource or infrastructure developments, the expenditures include those for the investment and operation phases of the project. An I/O model is one way to estimate the economic impact of a set of expenditures.

Any activity that leads to increased production capacity in an economy has two components or phases: a) the construction or development of the capacity, and b) the operation of the capacity to generate outputs. The first component is referred to as investment phase, while the second is as operation phase. Both activities affect the economy through purchases of goods and services, as well as labour.

Figure 5.1 illustrates the overall approach CERI uses to assess economic impacts resulting from these activities.

Figure 5.1: Overall Bi-National Multi-Regional I/O Modelling Approach



The first step is to estimate and forecast the value of investment (i.e., construction or development expenditure) and operations. The total investment is then disaggregated into purchases of various goods and services directly involved in the production process (i.e., manufacturing, fuel, business services, etc.) as well as labour required, using the expenditure shares. Hence, these are the economic impacts on value-added GDP, jobs and tax revenues that occur during the construction of the energy producing facilities (i.e., pipelines).

The second step is to estimate and forecast the value of total operations from an economic activity (i.e., conventional oil or gas production, petroleum refinery, etc.) that is allocated to the purchase of goods and services, payment of wages, payments to government (i.e., royalty and taxes), and other operating surplus (profits, depreciation, etc.). Likewise, these are the economic impacts on value-added GDP, jobs and tax revenues that occur during the operation of the energy producing facilities. It is important to note that CERI utilizes producer's gross revenues as proxy for operations (refer to Chapter 4 for gross revenues calculations).

The forecasted values of investment and operations are then used to estimate demand for the various goods and services and labour used in both phases. These demands are met through two sources: a) domestic goods production, and b) goods imports. Domestic contents of the goods and services are calculated using Statistics Canada's data.

Impacts are calculated for Canada, broken down to the provincial level. As mentioned, economic impacts under consideration include economy-wide impacts such as value-added GDP, jobs created and preserved (given in thousands of person-years) and various forms of government tax revenues. The latter includes indirect, personal and corporate taxation revenues, on the provincial level and the Federal level.

The estimated bi-national trade flow tables, developed by CERI, are used to derive imports or exports of each type of good and service for all provinces and territories in Canada (including Government Abroad) at the national level. The value of goods and services used by a particular industry and produced in a different province or territory in Canada can then be calculated. This method captures the trade supply chains among all trading partners in Canada and the US, as well as their feedback effects. The latter are changes in goods production in one region that result from changes in intermediate and final demand in another region, which are in turn brought about by demand changes in the first region.

This section briefly discusses the modelling methodology. For greater detail on the development of the I/O model, refer to Appendix E.

Assumptions and Limitations

While the I/O model is useful, no model is ideal. The I/O modelling approach does suffer from several shortcomings. This section discusses various assumptions and limitations to the I/O analysis in general.

There are two main assumptions. The first assumption of any I/O analysis is that the economy is in equilibrium. Despite partial equilibrium analysis, it is assumed in the general equilibrium approach that the economy as a whole is in equilibrium. This is a realistic assumption in the long run, as it is difficult to imagine an economy remaining in disequilibrium for a long period.

A second important assumption in the I/O analysis is the linear relationship between inputs and outputs in the economy. Each sector uses a variety of inputs in a linear fashion in order to produce various final products under the assumption of fixed proportions. Though the form of the "Leontief production function" is simple, it could be viewed as an approximation of the real world's production function. Unlike other production functions, the Leontief production function contains no provision for substitution among inputs. A very interesting aspect of this assumption is the constant return to scale property of the Leontief production function, which turns out to be a proven property in the real-world economy. Though the linearity of the production function gives a constant average and marginal products, these are justified if the analysis focuses on the medium term. Long run changes in the economy (beyond 20 years) may affect the fixed relationship between sectors.

Although the I/O approach has been widely used around the world for economic impact assessment, there are certain limitations that should be noted. Several other well-known limitations of the I/O approach are discussed below.

Static Relationships

I/O coefficients are based on value relationships between one sector's outputs to other sectors. The relationship and, thus, the stability of coefficients, could change over time due to several factors including:

- Change in the relative prices of commodities;
- Technological change;
- Change in productivity; and
- Change in goods production scope and capacity utilization.

Since these attributes cannot be incorporated in a static I/O model, these models are primarily used over a short-run time horizon, where relative prices and productivity are expected to remain relatively constant. These models can be used for the comparison between two periods when the model incorporates new tables and coefficients. The model can then show the changes in productivity and energy efficiency.

Unlimited Resources or Supplies

The I/O approach simplistically assumes that there are no supply or resources constraints. In reality, increasing economic activities in a particular sector of the economy may put pressure on wages and energy prices in the short run. However, in the long run, the economy adjusts through the mobility of the factors of production (i.e., labour and capital).

Lack of Capacity to Capture Price, Investment, and Production Interactions

An I/O model is incapable of representing the feedback mechanism among price change, investment, and operations. For example, an increase in oil price provides a signal to drivers to consume less gasoline or drive a more fuel-efficient car. This response would in turn impact car manufacturing, the oil refining industry and tourism. However, this type of interaction cannot be modeled in a simple I/O model.

Lack of Supporting Data

There are segments of energy information that cannot be quantified due to lack or confidentiality of Statistics Canada data. These data are either estimated by using other sources or have been incorporated in aggregate levels without damaging the Input/Output (IO) model's integrity or functionality. Therefore, several assumptions have been made on a case-by-case basis for every province or the US. The energy data from Statistics Canada in many cases are incomplete and energy tables are imbalanced due to lack of, or confidentiality of, data. Also, the energy definitions used by Statistics Canada are not necessarily consistent with the provincial and company sources. For instance, pentanes plus in Statistics Canada's Energy Supply and Demand tables (57-003-X) is included under oil, while in provincial sources it is under Natural Gas Liquids (NGLs).

Modelling Assumptions for the I/O Model

As mentioned previously, the results from the investments and producer's gross revenues (operations) in Chapter 4 are used as inputs, or injections, into CERI's I/O Model. This model, in turn, calculates the various economic impacts associated with the level of activity stemming from the outlook models over the 2017-2037 period.

The following section reviews the assumption concerning investments and operations (producer's gross revenues) per province by scenario. Investments include the cost of drilling wells, gathering pipelines and the cost of necessary pipelines within each scenario. They are driven by the gas production outlook determined in Chapter 4. Operations are, on the other hand, driven by the amount of gas produced and the pricing for each producing asset.

Overall results regarding investment and operations are illustrated in Table 5.1. It is important to note that these are aggregate values, while the inputs used in the I/O model are values allocated over the 2017-2037 period; this is discussed later in this section.

Table 5.1: Investments, Production and Marketable Gas ($CAD)

Category	Unit	S1 Importers	S2 Self-Sufficient		S3 Exporters	
		NB	NB	NS	NB	NS
Investments, including new pipelines	Million dollars	-	1,295	1,443	6,041	5,510
New pipelines	Million dollars	-	*53*	*93*	*186*	*827*
Operations (producer's gross revenues)	Million dollars	203	5,925	6,267	16,170	13,293

Scenario 1 (*We are Importers*) was the only scenario existing within a moratorium; investments and gas production were limited to operating within a world constrained by no fracking. This limited the producing assets to New Brunswick's McCully gas field. The 28 existing gas wells in the field are assumed to produce the remaining proven and probable reserves (30.5 Bcf). No additional wells are assumed, equal to no capital investments, in terms of new wells, pipelines or any other infrastructure investment. Operations, however, exceed C$200 million over the life of the study (2017-2037).

Scenario 2 (*We are Self-Sustainable*) is more multifaceted. Existing without a moratorium, the possibility of fracking opens three potential producing assets: the McCully, Frederick Brook Shale and Horton Bluff Shale.

In terms of investment by province, the first phase of economic impacts, beyond the afore-mentioned 28 existing wells producing 30.5 Bcf, the McCully is expected to add 15 new wells to produce the 57.5 Bcf proven and probable reserves made possible through fracking. Investments between 2017 and 2037 total $106 million for the McCully.

Capital investment in the Frederick Brook Shale totals $1,189 million over the outlook period. Recall, there is an investment to drill 118 wells over that same period. Drilling costs are estimated at $995 million, gathering lines at $142 million and pipeline costs at $53 million. The latter includes one additional pipeline in New Brunswick, a 50-km pipeline from the Frederick Brook Shale to the M&NP, with a capacity of 112 MMcfpd. The pipeline is constructed over a 2-year span (2020-2021).

Over the 2017-2037 period, the gas production outlooks in the Horton Bluff Shale suggests that 158 new wells will be required to develop the Horton Bluff Shale in the self-sustaining scenario. Over this time, a capital investment of $1,443 million will be required, including $1,161 million in drilling costs, $190 million in gathering costs and $93 million in the development of a single pipeline. The latter is a 75-km pipeline from the Horton Bluff site to Halifax, with a capacity of 152 MMcfpd.

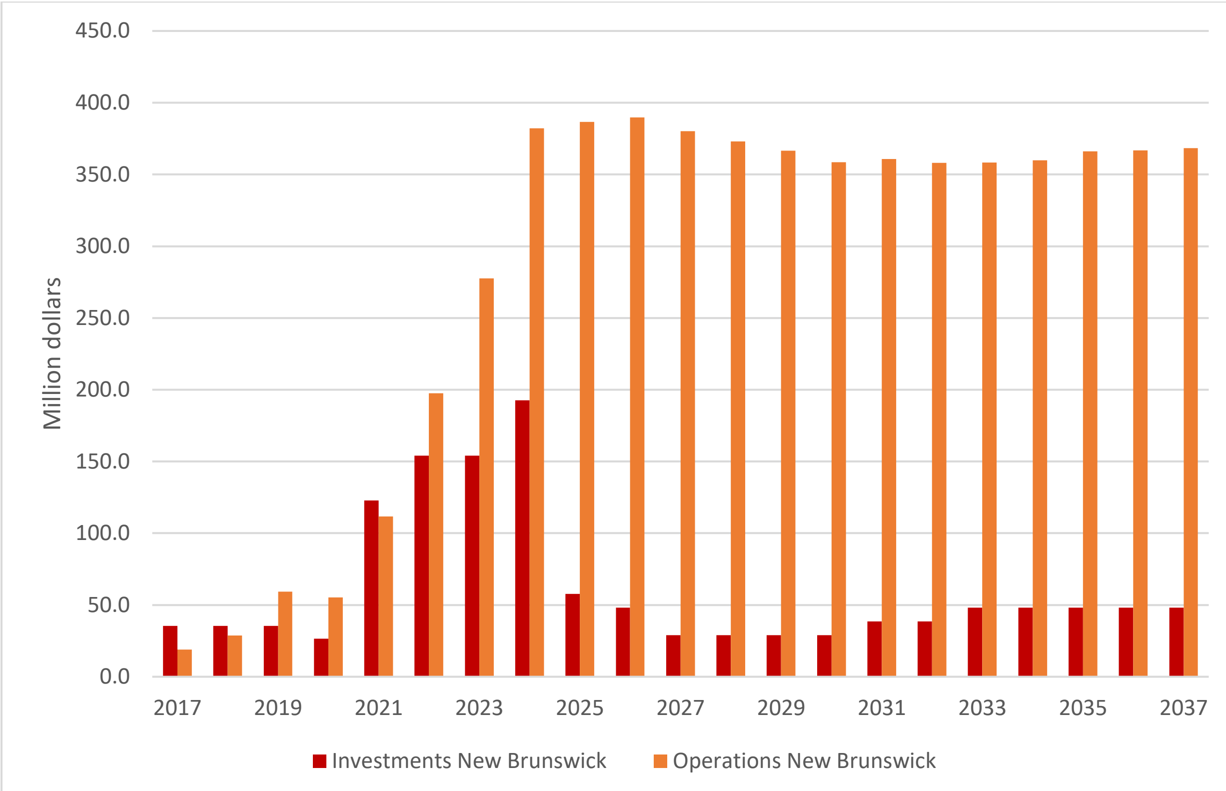
Total capital investments in the two provinces total $2,738.3 million over the next 21 years. In terms of sector break down measuring economic impacts, the investments will be felt most in Engineering Construction (90 percent), followed by Non-Residential Building Construction (9 percent) and Financial (1 percent).

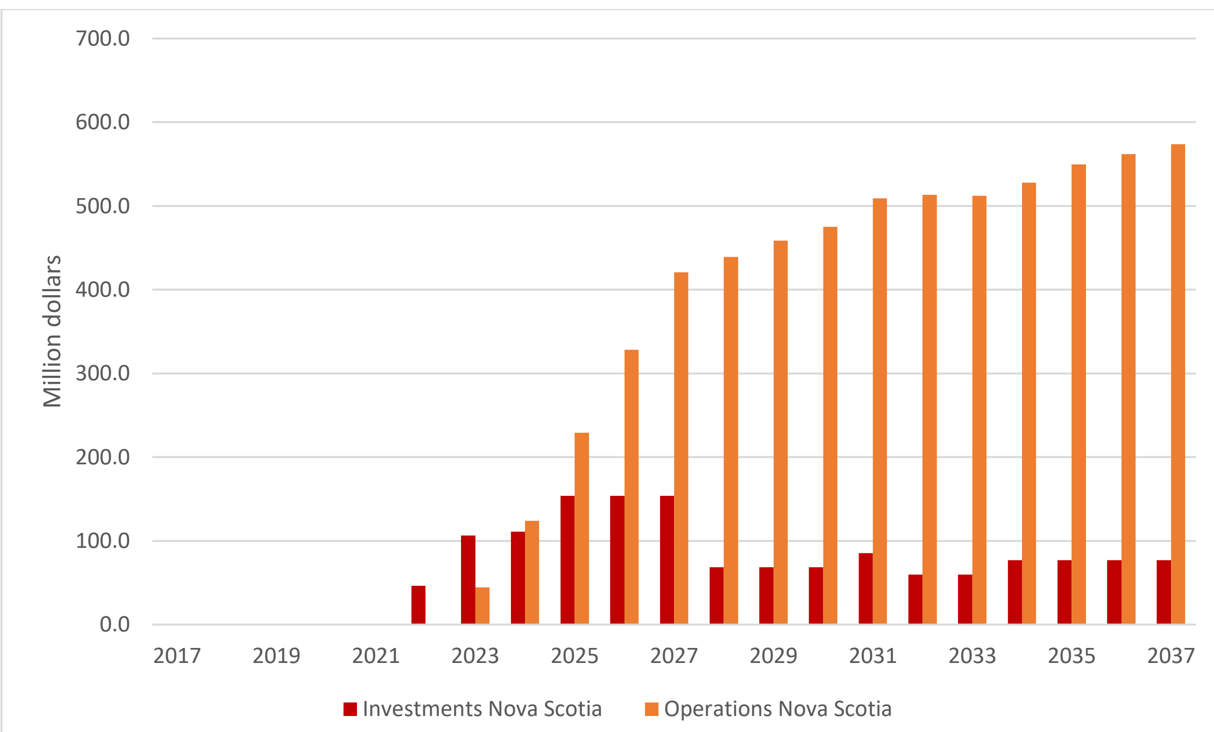
With regards to more specific capital costs and costs of pipelines, please refer to Chapter 4.

In terms of the second phase of economic impacts for Scenario 2, the operations total over the 2017-2037 period is $5,924.7 million in New Brunswick and $6,267.3 million in Nova Scotia. In New Brunswick, the operations in the McCully totals $592 million while the total in the Frederick Brook Shale is $5,331.9 million. In the Horton Bluff Shale, the operations total is $6,267.3 million. Over that 21-year period, New Brunswick is expected to produce 611.3 Bcf of marketable gas while Nova Scotia will produce 629.0 Bcf. It is important to note that production or operation inputs into the I/O model are experienced entirely in the Gas + NGL sector.

Figure 5.2 shows investments and operations for the 2017-2037 period by scenario and by respective province. This figure illustrates the values of the inputs (both investment and operation) utilized in the I/O model over the 2017-2037 period. Investment in New Brunswick increases between 2021 and 2024, peaking at $192.6 million in 2024, before dropping to $57.8 million in 2025. Operations, on the other hand, exceed the $300 million level from 2024 to the end of the study period. Nova Scotia's investment schedule peaks at $153.8 million between 2025 and 2027. Projected operations, however, peak in the last year of the study, at $573.9 million in 2037. This due to the fact that Nova Scotia's natural gas demand is expected to increase over the next 20 years.

Figure 5.2: Scenario 2: Investments and Operations in New Brunswick (Above) and Nova Scotia (Below)





With regards to pricing for the I/O model, after 2019, pricing (CAD$) is assumed to be AGT + tolls. For specific assumptions and the pricing forecast, refer to Chapter 4.

Like Scenario 2, in Scenario 3 (*We are Exporters*), the possibility of fracking opens up further the three potential producing assets: McCully, Frederick Brook Shale and Horton Bluff Shale.

In terms of investment by province, the first phase of economic impacts, the McCully operator adds 15 new wells to produce the 57.5 Bcf proven and probable reserves made possible through fracking. Investments between 2017 and 2037 total $106 million. This is the same as Scenario 2. The Frederick Brook Shale is, however, constrained by the 550 MMcfpd, the capacity of the M&NP pipeline. The investment in the Frederick Brook Shale totals $5,934.9 million over the next 20 years, including an investment to drill 597 new wells as well as a 50-km pipeline from the Frederick Brook Shale to the M&NP, with a capacity of 550 MMcfpd. Drilling costs are estimated to be $5,030 million, gathering lines at $719 million and pipeline costs at $186 million.

Over the 2017-2037 period, 548 new wells will be required to develop the Horton Bluff shale in the self-sustaining scenario. Over this time, $5,510.0 million will be required to be invested, including $4,025 million in drilling costs, $658 million in gathering costs and $825 million in the development of two pipelines in Nova Scotia. The latter includes a 165-km pipeline from the Horton Bluff site to Stellarton, Nova Scotia, with a capacity of 550 MMcfpd, as well as a 110-km pipeline from Stellarton to Goldboro, with a capacity of 300 MMcfpd, running parallel to the M&NP mainline. It is important to note that the assumed export LNG facility at Goldboro, Nova Scotia in Scenario 3 is not included in the I/O model. This component lies beyond the scope of this study.

With regards to capital costs, refer to Scenario 3, as they are identical for the two jurisdictions. For more specific assumptions, including pipeline costs, refer to Chapter 4.

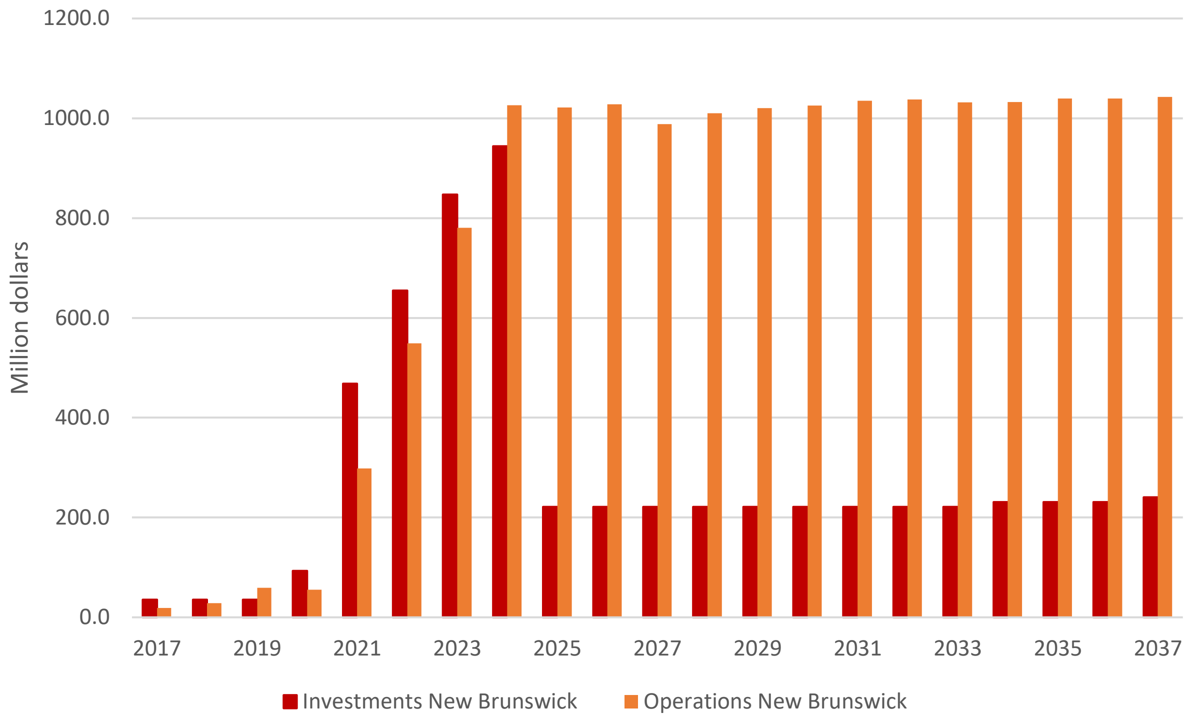
Total investments in the two provinces total $11,550.9 million over the next 20 years. In terms of sector break down measuring economic impacts, the investment will be felt most in Engineering Construction (90 percent), followed by Non-Residential Building Construction (9 percent) and Financial (1 percent). This is the same as Scenario 2.

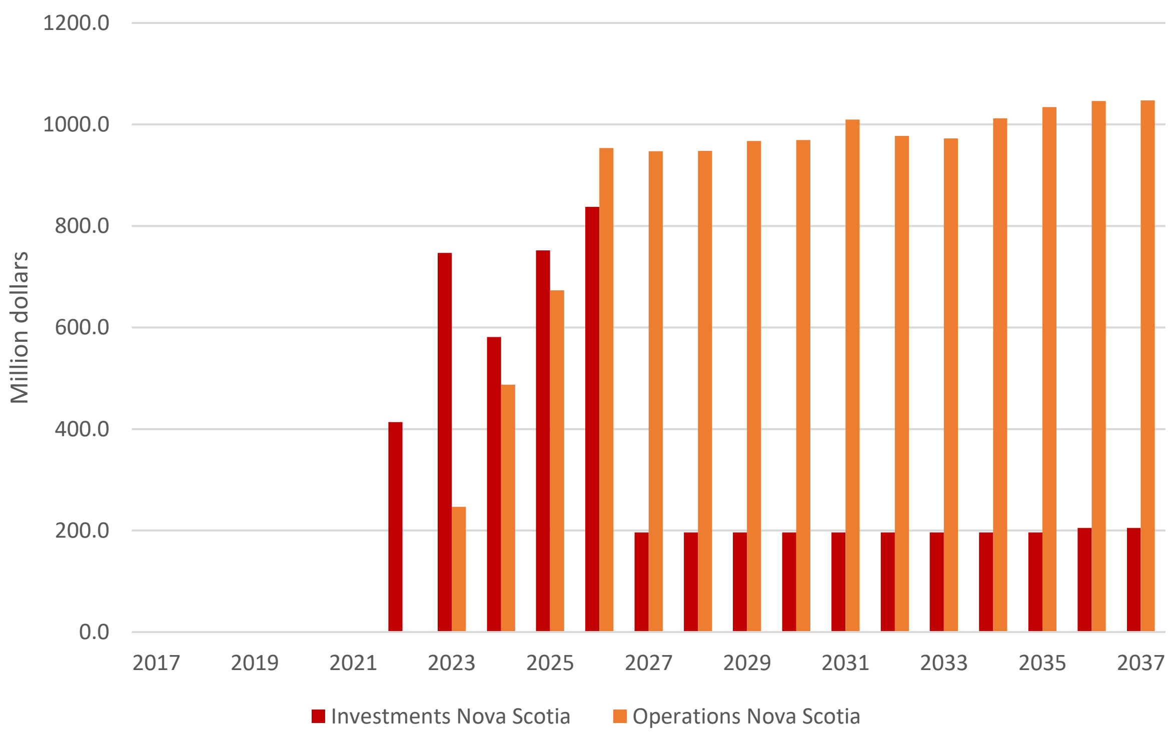
The operations over the 2017-2037 period is $16,346.8 million in New Brunswick and $13,293.0 million in Nova Scotia. Operation in the McCully totals $592 million, while in the Frederick Brook Shale, the total is $15,954 million. In the Horton Bluff Shale, the operations total is $15,754 million.

In terms of pricing, Scenario 3 includes six different gas flows from three assets destined to four customers: a) consumers in New Brunswick, b) consumers in Nova Scotia, c) consumers in the US, and d) the LNG Plant (consumers abroad). These relationships are illustrated in Table 4.8 in Chapter 4.

Figure 5.3 shows investments and operations for the 2017-2037 period by scenario and by respective province. This figure illustrates the values of the inputs (both investment and production) utilized in the I/O model over the 2017-2037 period. Investment in New Brunswick increases between 2021 and 2024, peaking at $943.7 million in 2024, before dropping to $221.5 million in 2025. Operations, on the other hand, exceed the $1,000 million level from 2024 to the end of the study period, with the exception of dipping slightly to $988.4 million in 2027. Nova Scotia's investment schedule peaks at $837.5 million in 2026, before dropping drastically for the remainder of the study period. Projected operations, however, peaks in the last year of the study, at $1,047.3 million in 2037. This is because Nova Scotia's natural gas demand is expected to increase over the next 20 years.

Figure 5.3: Scenario 3: Investments and Operations in New Brunswick (Above) and Nova Scotia (Below)





Economic Impacts

This section discusses the results of the three defined scenarios. Economic impacts under consideration include economy-wide impacts such as value-added GDP, jobs created (given in person-years, one person year being one person working for one year), as well as various forms of government revenue, including indirect, personal and corporate taxation revenues. Economic impacts are calculated for Canada, with Canadian impacts broken down to the provincial level.

As previously mentioned, there are two phases that occur during resource development, the impacts that transpire during capital investments, followed by impacts that result in the operation phase of the energy facilities. It is important to note that whether measuring investment impacts, operation impacts or total impacts, there are three separate effects that occur (direct, indirect and induced). Whether measuring GDP, employment or tax revenue impacts, their total is the accumulation of the three. Direct impacts result from the direct capital spending or spending which occurs in the operations phase, stimulating the particular industry directly such as providing engineering construction, capital equipment or other goods and services. Indirect impacts, whether measured in GDP, employment or tax revenue, result in additional spending and further stimulation of the economy and the inter-industry transactions. Increases in GDP, employment and incomes further induce additional spending; induced impacts manifest in wholesale and retail, as well as medical services.

It is important to put the various economic impacts in their proper context. For example, total GDP impacts are presented, and in the case of this study, are spread out over a 21-year period, not on an annual basis. The same applies for jobs created and tax revenues. Unless specified otherwise, they are measured over the 2017 to 2037 period. Even dividing by the total of years can be misleading, as different investment and operation schedules may either be front- or back-loaded, in terms of their impacts. This is a common error with measuring economic impacts of pipeline and other infrastructure projects. For example, some of the jobs created during the construction phase are only during the brief life span of the particular project or capital investment. With regards to measuring employment impacts, recall that the unit is person years, with one person year being one person working for one year. In other words, this is the equivalent of one year of work for one person, sometimes referred to as Full-Time Equivalents (FTEs). For example, an employment impact of 20,000 person years must be divided by the length of the study period (21 years in this case). This resulting number (952) is the annual average number of full-time jobs created over the 21-year life of the study, or 952 full-time jobs are created, on average, over the life of the study period. As with GDP impacts, the employment impacts are not uniformly distributed over the life of the project, with construction jobs typically being front-ended.

Table 5.2 shows GDP and employment impacts on all of Canada's provinces resulting from Scenario 1, in which no new capital investment occurs over the 21-year study in both New Brunswick and Nova Scotia. Thus, total operations phase expenditures from the New Brunswick and Nova Scotia gas industry over the outlook period (2017-2037) amounts to only $202 million.

The figure shows the total GDP and employment impacts from investment and operations, as well as showing the total impacts (Investment + Operation).

Additionally, as the only operations occur in New Brunswick, the Maritime province is expected to gain the majority of the GDP and employment impacts, $153 million and 201 person years of labour, respectively. New Brunswick is expected to account for 92 percent of the GDP impacts and 75 percent of employment impacts. Ontario is expected to gain $5 million, followed by Quebec at $3 million, and Alberta at nearly $2 million. Ontario and Quebec are expected to observe the greatest share of person years of employment at 27 and 17, respectively.

Table 5.2: Economic Impacts of Scenario 1 (2017-2037)
Investment and Operation - GDP and Employment Summary

Province	Investment		Operation		Total	
	GDP ($CAD Millions)	Employment (Person Years)	GDP ($CAD Millions)	Employment (Person Years)	GDP ($CAD Millions)	Employment (Person Years)
Alberta	0	0	2	6	2	6
British Columbia	0	0	1	6	1	6
Manitoba	0	0	0	1	0	1
New Brunswick	0	0	153	201	153	201
Newfoundland/Labrador	0	0	1	2	1	2
Nova Scotia	0	0	1	5	1	5
Nunavut	0	0	0	0	0	0
Northwest Territories	0	0	0	0	0	0
Ontario	0	0	5	27	5	27
Prince Edward Island	0	0	0	2	0	2
Quebec	0	0	3	17	3	17
Saskatchewan	0	0	0	1	0	1
Yukon Territory	0	0	0	0	0	0
Governments Abroad	0	0	0	0	0	0
Total	**0**	**0**	**166**	**267**	**166**	**267**

Table 5.3 shows the tax impacts on a federal level, provincial level as well as a total impact for investment, operation and total. As shown in Table 5.3, New Brunswick's tax impacts are close to $22 million. And while small, they are far in excess of any other province, making up more than 89.5 percent of the total tax impact in Canada. Federal taxes make up $12 million while provincial taxes are $10 million. Both Ontario and Quebec will see just $1 million in added tax revenue.

Table 5.3: Tax Impacts of Scenario 1 (2017-2037)

Province	Investment ($CAD Millions)			Operation ($CAD Millions)			Total ($CAD Millions)		
	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total
Alberta	0	0	0	0	0	0	0	0	0
British Columbia	0	0	0	0	0	0	0	0	0
Manitoba	0	0	0	0	0	0	0	0	0
New Brunswick	0	0	0	12	10	22	12	10	22
Newfoundland/Labrador	0	0	0	0	0	0	0	0	0
Nova Scotia	0	0	0	0	0	0	0	0	0
Nunavut	0	0	0	0	0	0	0	0	0
Northwest Territories	0	0	0	0	0	0	0	0	0
Ontario	0	0	0	1	0	1	1	0	1
Prince Edward Island	0	0	0	0	0	0	0	0	0
Quebec	0	0	0	0	0	1	0	0	1
Saskatchewan	0	0	0	0	0	0	0	0	0
Yukon Territory	0	0	0	0	0	0	0	0	0
Governments Abroad	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**13**	**11**	**24**	**13**	**11**	**24**

Note: Totals may not add up due to rounding.

While total employment is discussed in Table 5.2, Table 5.4 shows total employment impacts broken down into direct impacts, indirect impacts and induced impacts. Direct employment impacts are mainly attributed to New Brunswick, due to it being the only center of production activity. These are jobs directly generated by operations of New Brunswick projects. In this case, they are jobs directly related to the McCully gas field. Indirect and induced jobs are employment associated with the industries that provide goods and services in industries ranging from engineering firms to finance and insurance. In New Brunswick, the amount of indirect jobs created are 53 person years and the amount of induced jobs are 67 person years. Following New Brunswick, Ontario leads the way with 10 person years (indirect jobs) and 17 person years (induced jobs). Quebec's indirect jobs and induced jobs are 7 person years and 10 person years, respectively.

Table 5.4: Detailed Employment Summary for Scenario 1 in Person Years (2017-2037)

Province	Total	Direct	Indirect	Induced
Alberta	6	0	2	4
British Columbia	6	0	2	4
Manitoba	1	0	0	1
New Brunswick	201	82	53	67
Newfoundland/Labrador	2	0	1	1
Nova Scotia	5	0	2	3
Nunavut	0	0	0	0
Northwest Territories	0	0	0	0
Ontario	27	0	10	17
Prince Edward Island	2	0	1	1
Quebec	17	0	7	10
Saskatchewan	1	0	0	0
Yukon Territory	0	0	0	0
Governments Abroad	0	0	0	0
Total	**267**	**82**	**77**	**109**

Table 5.5 shows GDP and employment impacts on all of Canada's provinces resulting from Scenario 2. Recall, total investment expenditures from the New Brunswick and Nova Scotia gas industry over the outlook period (2017-2037) amount to $2,738 million, including $1,295 million in New Brunswick and $1,443 million in Nova Scotia. Operations revenues, on the other hand, totaled $12,192 million over the 21-year outlook period (2017-2037), including a total of $5,924 million in New Brunswick and $6,297 million in Nova Scotia.

Not surprisingly, Nova Scotia's total cumulative GDP impact amounts to $6,923 million, followed by New Brunswick at $5,905 million. This amounts to 47 percent and 40 percent, respectively, of the total GDP impacts in Canada. While the production assets in question are located in the Maritimes, other provinces stand to gain as well, given that the service and manufacturing sectors are located outside of the two provinces. Hence, Ontario and Quebec account for $825 million and $384 million, respectively. Alberta's GDP impact under Scenario 2 is $292 million.

In terms of employment (direct, indirect and induced), Nova Scotia is projected to create 19,032 person years of labour, again followed closely by New Brunswick at 14,089 person years. This is approximately 45 percent and 33.5 percent, respectively, of the total employment impacts in Canada. Ontario is expected to gain 4,300 person years, followed by Quebec at 2,142 person years, British Columbia at 863 person years and Alberta at 856 person years.

Table 5.5: Economic Impacts of Scenario 2 (2017-2037)
Investment and Operation - GDP and Employment Summary

Province	Investment		Operation		Total	
	GDP ($CAD Millions)	Employment (Person Years)	GDP ($CAD Millions)	Employment (Person Years)	GDP ($CAD Millions)	Employment (Person Years)
Alberta	151	444	141	412	292	856
British Columbia	73	462	65	402	138	863
Manitoba	13	73	12	68	26	141
New Brunswick	1,379	7,948	4,526	6,141	5,904	14,089
Newfoundland/Labrador	36	120	52	126	88	246
Nova Scotia	1,762	10,146	5,161	8,887	6,923	19,032
Nunavut	1	2	1	2	1	4
Northwest Territories	1	3	1	3	2	6
Ontario	422	2,213	403	2,087	825	4,300
Prince Edward Island	14	123	16	139	30	263
Quebec	200	1,127	184	1,015	384	2,142
Saskatchewan	11	43	10	41	21	83
Yukon Territory	1	3	1	3	1	7
Governments Abroad	0	0	0	0	0	0
Total	**4,063**	**22,706**	**10,571**	**19,325**	**14,634**	**42,031**

As shown in Table 5.6, tax impacts on the federal and provincial level are dramatically higher than Scenario 1, totaling $2,262 million over the 21-year period. Nova Scotia and New Brunswick's tax impacts are $1,093 million and $855 million, respectively. They account for 48 percent and nearly 38 percent, respectively, of Canada's total tax impact. It is interesting to note that the majority of taxes are collected during the operation phase of economic impacts, rather than the investment portion. Ontario's tax impacts are $147 million, followed by $77 million in Quebec and $45 million in Alberta.

Table 5.6: Tax Impacts of Scenario 2 (2017-2037)

Province	Investment ($CAD Millions)			Operation ($CAD Millions)			Total ($CAD Millions)		
	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Total
Alberta	14	9	23	13	8	22	28	17	45
British Columbia	7	5	11	6	4	10	13	9	22
Manitoba	1	1	2	1	1	2	2	2	4
New Brunswick	112	107	219	342	294	636	454	401	855
Newfoundland/Labrador	2	2	5	3	3	6	5	6	11
Nova Scotia	155	147	302	422	368	790	578	515	1,093
Nunavut	0	0	0	0	0	0	0	0	0
Northwest Territories	0	0	0	0	0	0	0	0	0
Ontario	41	34	75	40	33	72	81	67	147
Prince Edward Island	1	1	3	1	2	3	2	3	5
Quebec	18	22	40	17	20	37	36	42	77
Saskatchewan	1	1	2	1	1	1	2	1	3
Yukon Territory	0	0	0	0	0	0	0	0	0
Governments Abroad	0	0	0	0	0	0	0	0	0
Total	**353**	**328**	**682**	**847**	**733**	**1,581**	**1,201**	**1,062**	**2,262**

Note: Totals may not add up due to rounding.

Table 5.7 shows total employment impacts broken down into direct impacts, indirect impacts and induced impacts. While in Scenario 1 the majority of direct employment impacts are mainly attributed to New Brunswick, in Scenario 2 the impacts are shared between Nova Scotia and New Brunswick: 6,557 person years and 6,055 person years, respectively. These are jobs directly related to the development of the Horton Bluff Shale and Frederick Brook Shale. Indirect and induced jobs are employment associated with the industries that provide goods and services in industries ranging from engineering firms to finance and insurance. Induced employment manifests in industries such as wholesale and retail trade, education or medical services, or activities that are generated more by household spending on additional good and services. In total, there are 11,116 person year indirect employment impacts and 18,302 person years induced employment impacts over the 21-year outlook period. In Nova Scotia, there are 4,781 person year indirect employment impacts and 7,694 person years induced employment impacts over the 21-year outlook period while in New Brunswick there are 3,380 person year indirect employment impacts and 4,653 person years induced employment impacts over the same period.

Table 5.7: Detailed Employment Summary for Scenario 2 in Person Years (2017-2037)

Province	Total	Direct	Indirect	Induced
Alberta	856	0	217	639
British Columbia	863	0	245	619
Manitoba	141	0	43	99
New Brunswick	14,089	6,055	3,380	4,653
Newfoundland/Labrador	246	0	96	149
Nova Scotia	19,032	6,557	4,781	7,694
Nunavut	4	0	1	4
Northwest Territories	6	0	1	5
Ontario	4,300	0	1,445	2,855
Prince Edward Island	263	0	118	145
Quebec	2,142	0	767	1,374
Saskatchewan	83	0	21	62
Yukon Territory	7	0	1	0
Governments Abroad	0	0	0	0
Total	**42,031**	**12,613**	**11,116**	**18,302**

Table 5.8 shows GDP and employment impacts on all of Canada's provinces resulting from Scenario 3. Recall, total investment expenditures from the New Brunswick and Nova Scotia gas industry over the outlook period (2017-2037) amount to $11,551 million, including $6,041 million in New Brunswick and $5,510 million in Nova Scotia. Operations, on the other hand, totaled $29,463 million over the 21-year outlook period (2017-2037), including a total of $16,170 million in New Brunswick and $13,293 million in Nova Scotia.

New Brunswick's total cumulative GDP impact amounts to $18,855 million, followed by Nova Scotia at $17,715 million over the next 20 years. This amounts to 44 percent and 42 percent of the total GDP impacts in Canada, respectively. Ontario and Quebec account for $2,723 million and $1,300 million, respectively. This is up from Scenario 2 where Ontario and Quebec's total cumulative GDP impacts totaled $825 million and $384 million, respectively. Alberta's GDP impact under Scenario 3 is $967 million, up from $292 million in Scenario 2.

In terms of employment (direct, indirect and induced), Nova Scotia is projected to create 57,853 person years of employment, again followed closely by New Brunswick at 53,666 person years. This is approximately 41 percent and 38 percent, respectively, of the total employment impacts in Canada. Ontario is expected to gain 14,232 person years, followed by Quebec at 7,280 person years, British Columbia at 2,925 person years and Alberta at 2,843 person years. Under Scenario 3, Canada is expected to see cumulative GDP impacts of $43 billion and employment impacts of 141,242 person years. This is higher than an expected cumulative GDP impact of $14.6 billion and employment impacts of 42,031 person years in Scenario 2.

Table 5.8: Economic Impacts of Scenario 3 (2017-2037)
Investment and Operation - GDP and Employment Summary

Province	Investment		Operation		Total	
	GDP ($CAD Millions)	Employment (Person Years)	GDP ($CAD Millions)	Employment (Person Years)	GDP ($CAD Millions)	Employment (Person Years)
Alberta	633	1,862	334	980	967	2,843
British Columbia	309	1,961	155	964	463	2,925
Manitoba	56	307	30	161	85	469
New Brunswick	6,395	36,882	12,459	16,784	18,855	53,666
Newfoundland/Labrador	152	501	122	295	274	796
Nova Scotia	6,753	38,903	10,961	18,951	17,715	57,853
Nunavut	2	8	1	5	3	13
Northwest Territories	3	12	2	6	5	19
Ontario	1,772	9,303	951	4,928	2,722	14,232
Prince Edward Island	60	520	37	327	97	847
Quebec	853	4,815	447	2,465	1,300	7,280
Saskatchewan	46	180	25	98	71	278
Yukon Territory	2	14	1	8	3	22
Governments Abroad	0	0	0	0	0	0
Total	**17,036**	**95,269**	**25,524**	**45,972**	**42,561**	**141,242**

As shown in Table 5.9, tax impacts on the federal and provincial level are higher than Scenario 2, totaling $2,262 million over the 21-year period. Tax impacts under Scenario 3 total $6,648 million, with tax impacts of $3,514 million on the federal level and tax impacts of $3,134 million on the provincial level. Nova Scotia and New Brunswick's tax impacts are $2,838 million and $2,766 million, respectively. They account for 42.6 percent and 41.6 percent, respectively, of Canada's total tax impact. Their tax impacts are remarkably similar. Ontario's tax impacts are $486 million, followed by $262 million in Quebec and $148 million in Alberta.

Table 5.9: Tax Impacts of Scenario 3 (2017-2037)

Province	Investment ($CAD Millions)			Operation ($CAD Millions)			Total ($CAD Millions)		
	Federal	Provincial	Total	Federal	Provincial	Total	Federal	Provincial	Grand Total
Alberta	61	36	97	32	19	51	93	55	148
British Columbia	29	20	48	14	10	24	43	30	73
Manitoba	5	5	9	2	2	5	7	7	14
New Brunswick	519	497	1,016	943	808	1,751	1,461	1,305	2,766
Newfoundland/Labrador	9	10	19	7	8	15	16	17	34
Nova Scotia	596	564	1,159	897	782	1,679	1,493	1,345	2,838
Nunavut	0	0	0	0	0	0	0	0	0
Northwest Territories	0	0	0	0	0	0	0	0	1
Ontario	173	142	315	93	77	171	266	219	485
Prince Edward Island	5	6	11	3	4	7	8	9	17
Quebec	79	92	171	42	49	90	120	141	262
Saskatchewan	3	3	6	2	2	3	5	5	10
Yukon Territory	0	0	0	0	0	0	0	0	0
Governments Abroad	0	0	0	0	0	0	0	0	0
Total	**1,478**	**1,374**	**2,852**	**2,036**	**1,761**	**3,796**	**3,514**	**3,134**	**6,648**

Note: Totals may not add up due to rounding.

Table 5.10 shows total employment impacts broken down into direct impacts, indirect impacts and induced impacts. Like Scenario 2, the majority of direct employment impacts are mainly attributed to New Brunswick, the impacts are shared between New Brunswick and Nova Scotia, 23,689 person years and 20,908 person years, respectively. These are jobs primarily related to the development of the Horton Bluff Shale and Frederick Brook Shale. In total, there are 36,020 person years of indirect employment impacts and 60,625 person years of induced employment impacts over the 21-year outlook period. In Nova Scotia, there are 13,645 person year indirect employment impacts and 23,300 person years induced employment impacts over the 21-year outlook period while in New Brunswick there are 12,517 person year indirect employment impacts and 17,460 person years induced employment impacts over the same period.

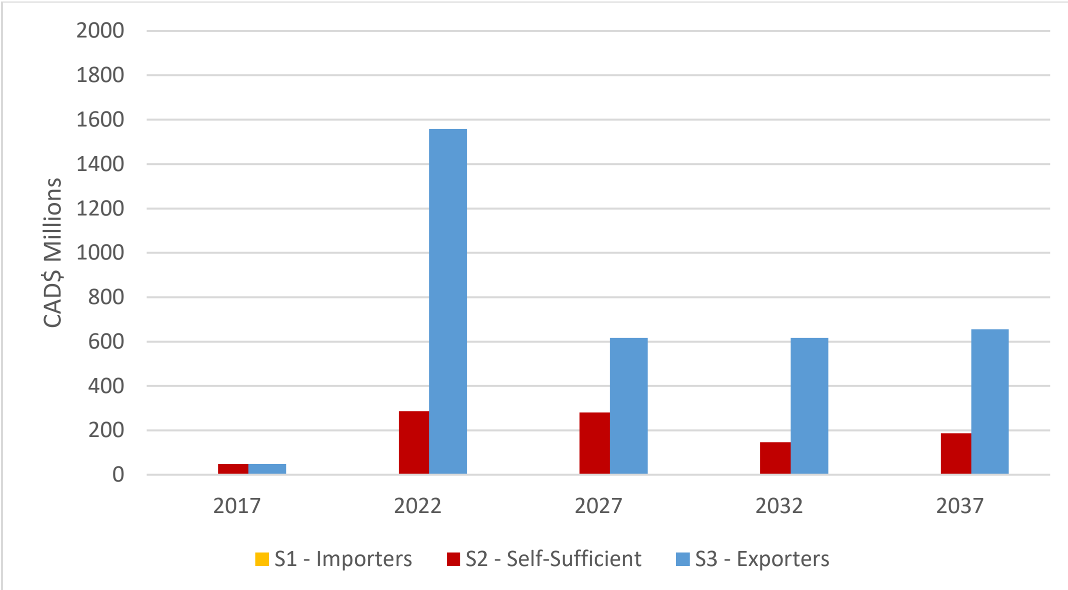
Table 5.10: Five-Year Employment Summary for Scenario 3 in Person Years (2017-2037)

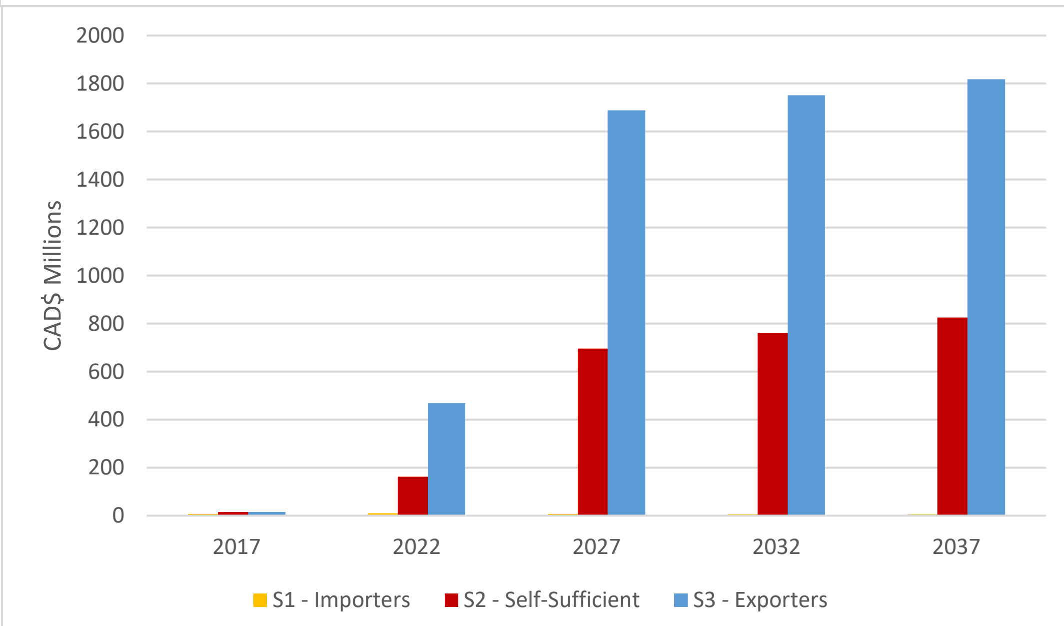
Province	Total	Direct	Indirect	Induced
Alberta	2,843	0	716	2,127
British Columbia	2,925	0	845	2,080
Manitoba	469	0	140	328
New Brunswick	53,666	23,689	12,517	17,460
Newfoundland/Labrador	796	0	309	488
Nova Scotia	57,853	20,908	13,645	23,300
Nunavut	13	0	2	11
Northwest Territories	19	0	4	15
Ontario	14,232	0	4,740	9,492
Prince Edward Island	847	0	380	467
Quebec	7,280	0	2,650	4,630
Saskatchewan	278	0	69	209
Yukon Territory	22	0	3	19
Governments Abroad	0	0	0	0
Total	**141,242**	**44,596**	**36,784**	**59,862**

Whereas the previous GDP impacts are listed over the 21-year outlook period, Figure 5.4 separates the total GDP impact in Canada over 5-year increments, throughout the timeframe of this study, by scenario and by investment and operations phase. As previously mentioned, it is an interesting exercise to map out the GDP impacts of investment and operations separately. It is interesting to note that all three scenarios have a lower GDP impact in 2017, as the development of the Frederick Brook Shale and Horton Bluff commence at later dates, 2021 and 2023, respectively. The scale in the figures are identical to better compare GDP impacts.

Broken down into investment and operations, Figure 5.4 yields several interesting results. Scenario 2 GDP impacts are highest in 2022 at $287 million and in 2027 at $281 million, reflecting the peak of capital investment expenditures in the Frederick Brook Shale and the Horton Bluff. The highest GDP impacts in Scenario 2, however, occur through the operations phase, increasing consistently from $695 million in 2027 to $825 million in 2037.

Figure 5.4: Five-Year GDP Impact Comparison between Three Scenarios ($CAD millions) Investment (Above) and Operation (Below)

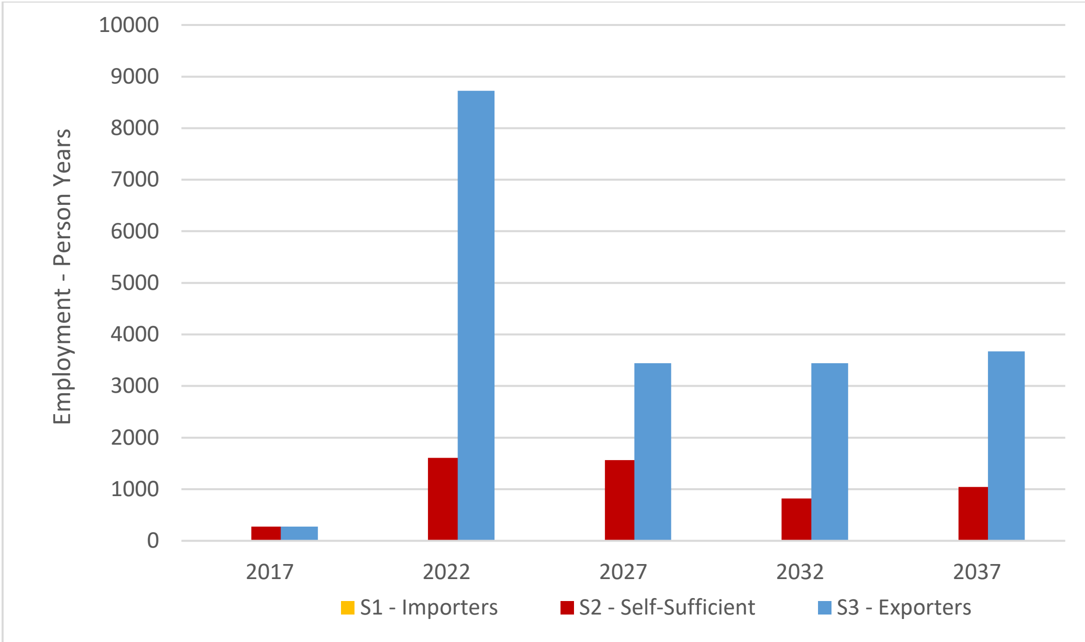


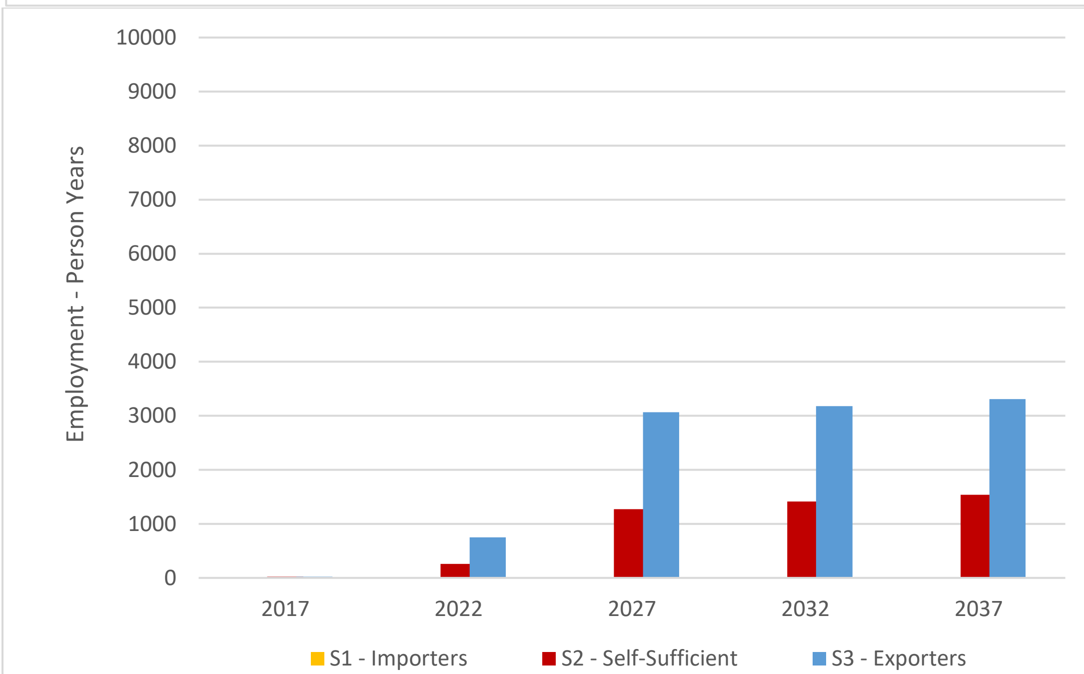


As illustrated in Figure 5.4, GDP impacts peak in 2022 at $1,559 million, before dropping to the $600 million level for 2027, 2032 and 2037. Recall, Scenario 3's capital expenditures are larger than the self-sustaining scenario. Reflecting the higher operations, GDP impacts in Scenario 3 increase from $1,688 million in 2027 to $1,818 million in 2037.

Similarly, Figure 5.5 separates the total employment impact in Canada over 5-year increments, throughout the outlook period of this study, by scenario and by investment (above) and operation (below).

Figure 5.5: Five-Year Employment Impact Comparison between Three Scenarios (Person Years) Investment (Above) and Operation (Below)





Broken down into investment and operations, Figure 5.5 yields interesting results as well. Scenario 2 employment impacts are highest in 2022 at 1,610 person years and in 2027 at 1,566 person years, reflecting the peak of capital investment expenditures in the Frederick Brook Shale and the Horton Bluff, under the self-sustaining scenario. Employment impacts drop off for 2032 and 2037. Unlike the GDP impacts being the highest in the operations phase, the highest employment impacts in Scenario 2 are in the investment phase. In the operations phase, employment impacts increase from 1,274 person years in 2027 to 1,540 person years in 2037.

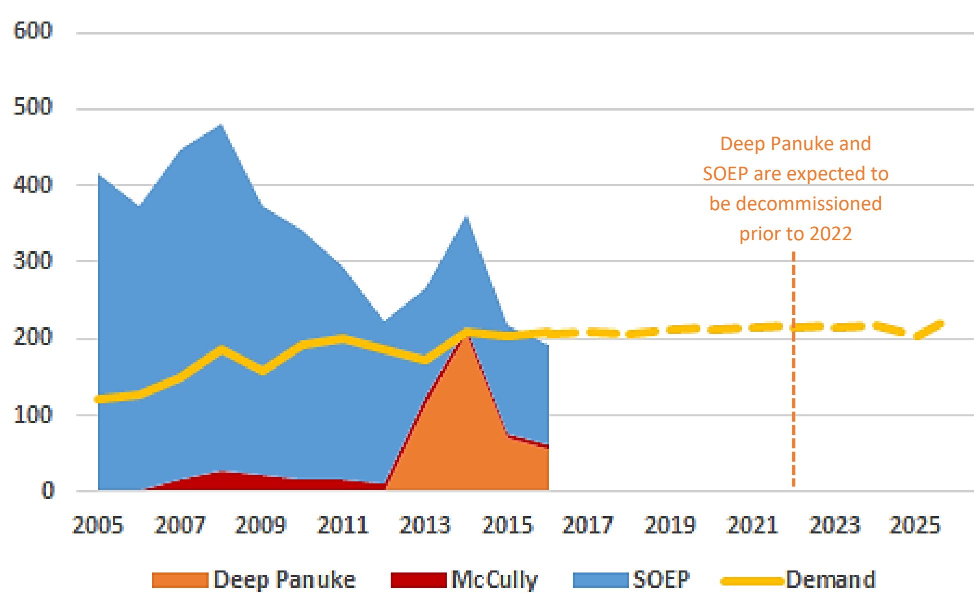
Scenario 3 tells an important story, representing the large amount of construction and engineering jobs created over the building of pipeline infrastructure, etc., but taper off quickly following the completion of the various projects. Scenario 3 employment impacts are highest in 2022 at 8,727 person years, but drop to the 3,000 level for the remaining three years shown. Employment impacts in the operations phase is quite level, increasing slightly from 3,066 person years in 2027 to 3,312 person years in 2037.

Chapter 6: Conclusion

Natural gas is an important fuel in North America. And this is true for New Brunswick and Nova Scotia. Natural gas use in the two provinces has increased dramatically since 1999 — the completion of the M&NP delivering offshore Nova Scotia gas to these provinces and the US Northeast. With its many applications for various end-users, including residential, commercial, industrial and power generation, the demand for natural gas in both provinces is slated to increase over the next 20 years, particularly if mid-size business and residential use in the two Maritime provinces increases. As the cleanest burning fossil fuel, it is seen by many to play a significant role to transition to a low-carbon future.

While both provinces are producers of natural gas, Nova Scotia's two offshore production assets are in decline, as is New Brunswick's McCully gas field. Not only are all three assets in decline, but the decline is rapid, with the region already looking to imports of gas in times of high local demand. Figure 6.1 illustrates the declines in Nova Scotia's offshore production in the backdrop of increasing demand of natural gas in the two provinces. The figure illustrates the impending supply gap between domestic/regional natural gas production and regional demand for natural gas.

Figure 6.1: New Brunswick and Nova Scotia Gas Production and Local Demand (MMcfpd)



Data sources: (CNSOPB 2017b; NB DERD 2017c; NEB 2016a).

Both provinces are without a doubt on the cusp of a fundamental change — a nexus point.

While Nova Scotia estimates its offshore resource potential at more than 8 billion barrels of oil and 120 Tcf of natural gas (CAPP 2017b), the region also has significant onshore oil and gas potential, largely stemming from unconventional resources, including shale gas, CBM and oil shale. Though the latter two are beyond the scope of this study, it is the onshore potential of shale gas of the two provinces that is the focus.

The Frederick Brook Shale in New Brunswick and the Horton Bluff Shale in Nova Scotia, however, certainly have potential, both benefitting from advances in horizontal drilling, 3-D seismic technology and fracking. These developments in technology are opening up new resources, previously determined as non-productive or not feasible to produce, particularly in the ability to economically recover natural gas and oil from shale rock.

The following illustrates the potential in the three productive assets (McCully, Frederick Brook Shale and the Horton Bluff Shale). McCully's recoverable reserves range from their revised proved and probable reserves of 30.5 Bcf at end-June 2016, as reserves were written down following the moratorium on fracking, from proven and probable reserves of 88 Bcf at end-March 2015. Frederick Brook Shale is estimated to contain 67.3 Tcf of shale gas in-place. The NB DERD suggests there could be as much as 80 Tcf of gas in-place in the Frederick Brook Shale, if estimates include an approximate 10.9 Tcf of natural gas resources at Hillsborough, near the existing Stoney Creek Oil Field. The estimates of the Horton Bluff range from 17 Tcf (ARI 2013) to 69 Tcf of gas in-place (NRCan 2016c). CERI assumes the Horton Bluff contains 35 Tcf of gas in-place, between the two wide-ranging estimates.

Supply costs for the considered resources are generally higher than in other jurisdictions. That does not necessarily mean that they are not competitive locally. New Brunswick supply costs are higher than the average costs in British Columbia, Alberta, Nova Scotia and the Marcellus. Nova Scotia supply costs are, overall, on par with Alberta's, but more expensive than Marcellus and British Columbia's shale gas. Marcellus gas is the cheapest, but if it is brought into the Maritimes via pipeline on the Canadian side (via TGP Bullet and Constitution and M&NP),[1] the price of the gas is higher than any supply costs calculated in this study.

While competitive with other nearby jurisdictions such as the Marcellus, above-mentioned changes in technology could be a boon for the region's oil and gas sector and their economies, to utilize hydrocarbons for domestic purposes or to export them, there are also controversies, particularly regarding fracking. Whereas fracking is without doubt a game-changer for shale gas and tight oil, it is also a lightning rod for controversy, and is banned or has led to moratoriums in several jurisdictions, New Brunswick and Nova Scotia among them. On March 27, 2015, New Brunswick enacted an Act to amend the *Oil and Natural Gas Act*, prohibiting fracking in the province, while Nova Scotia banned fracking in the fall of 2014, following the Report of the Nova Scotia Independent Review Panel on Hydraulic Fracturing (Corridor Resources Inc. 2016a; Gorman 2016).

There is an infinite amount of possibilities moving forward for New Brunswick and Nova Scotia from their nexus point. In this study, CERI outlines three plausible scenarios for New Brunswick

[1] Tolls are calculated based on (ICF Consulting Canada 2013).

and Nova Scotia moving forward from the nexus point, depicting the influence of high/low natural gas production and whether the current moratorium remains or is removed. These scenarios take into consideration only onshore gas potential, and excludes oil potential as it was found to be insignificant. Offshore potential is also excluded as it was out of scope for the study.

Scenario 1 (*We are Importers*) suggests that the only onshore production is occurring in New Brunswick, in the McCully gas field where existing wells continue to produce the field's remaining 30.5 Bcf proven and probable reserves. The supply gap between the region's demand and supply can be satisfied by a) reversing the flow of the M&NP, from south to north, delivering natural gas from the US Northeast, from the Marcellus and Utica Shales, through New England and into Atlantic Canada, and b) by importing LNG via the existing Canaport LNG.

On the other hand, Scenario 2 (*We are Self-sustaining*) and Scenario 3 (*We are Exporters*) both suggest that the moratoriums are removed, allowing fracking in onshore resources in both provinces.

In Scenario 2, production increases but the development is restricted to meet only local demand, with the objective that the two provinces become self-sustainable in gas. As such, the development of the three assets is: a) McCully with 88 Bcf of proven and probable reserves (includes the 30.5 Bcf of existing resources from the previous scenario), b) Frederick Brook Shale with production constrained by 111.9 MMcfpd, and c) Horton Bluff Shale with production constrained by 152.4 MMcfpd.

In Scenario 3, the development of the Frederick Brook and the Horton Bluff is further expanded compared to Scenario 2, but limited by the size of the M&NP's current capacity of 550 MMcfpd. As production is higher than total demand for two provinces, the region is characterized by becoming exporters. As such, it is assumed the region builds a 0.7 Bcfpd LNG export terminal in Goldboro, Nova Scotia (the fourth asset in this scenario).

Three scenarios yield distinctively different outcomes for gas supply, investments, and producer's gross revenues generated in the two provinces. All three scenarios ensure enough supply of gas for local demand, securing end-users with the needed product.

In Scenario 1, total investment expenditures from the New Brunswick and Nova Scotia gas industry over the outlook period (2017-2037) is zero, due to the moratorium on fracking. Operations revenue, on the other hand, totals $203 million over the 21-year outlook period (2017-2037).

In Scenario 2, total investment expenditures from the New Brunswick and Nova Scotia gas industry over the outlook period (2017-2037) amount to $2,738 million, while operations revenue totals $12,192 million over the 21-year outlook period (2017-2037). In terms of capital expenditures (as indicated in Table 6.1), the average investment per year in Nova Scotia is $69 million, or an increase in total provincial investment of 1.35 percent per year from 2015 investment levels (Statistics Canada 2016b) (measured in 2017 $CAD), while the average investment per year in New Brunswick is $62 million, or an increase in provincial GDP of 1.39 percent per year from 2015 GDP levels (measured in 2017 $CAD).

In Scenario 3, total investment expenditures from the New Brunswick and Nova Scotia gas industry over the outlook period (2017-2037) amount to $11,551 million, while operations, on the other hand, total $29,463 million over the 21-year outlook period (2017-2037). In terms of capital expenditures (as indicated in Table 6.1), the average investment per year in New Brunswick is $288 million, or an increase in total provincial investment of 6.47 percent per year from 2015 investment levels (Statistics Canada 2016b) (measured in 2017 $CAD), while the average investment per year in New Brunswick is $262 million, or an increase in provincial GDP of 5.15 percent per year from 2015 GDP levels (measured in 2017 $CAD).

Likewise, the three scenarios yield different macroeconomic outcomes. Economic impacts under consideration include economy-wide impacts such as value-added GDP, jobs created (given in person-years), as well as various forms of government revenue, including indirect, personal and corporate taxation revenues. Economic impacts are calculated for Canada, with Canadian impacts broken down to the provincial level. The results of developing gas in New Brunswick and Nova Scotia are presented for each scenario, to illustrate the impacts over the 21-year period (2017-2037). Table 6.1 summarizes the main assumptions and results of this study.

Table 6.1: Summary of the Results

	We Are Importers	We Are Self-Sustaining		We Are Exporters	
	NB	NB	NS	NB	NS
Assets / On-stream date	McCully field with existing wells / 2017	1) McCully field, existing and new wells / 2017 2) FBS / 2021 3) Pipeline to M&NP	1) HBS / 2023 2) Pipeline to M&NP	1) McCully field, existing and new wells / 2017 2) FBS / 2021 3) Pipeline to M&NP	1) HBS / 2023 2) Pipeline to M&NP 3) Expansion of M&NP in NS
Recoverable Resources, Bcf	30.5	13,488	7,000	13,488	7,000
Marketable gas total, Bcf, % of reserves developed in the period of 2017-2023	23 (75%)	611 (4.5%)	629 (9%)	2,788 (20.7%)	2,360 (34%)
Marketable gas, Bcf per year, average per asset, from on-stream date until 2037	McCully: 1.1	McCully: 3.2 FBS: 32	HBS: 41.9	McCully: 3.2 FBS: 160	HBS: 157.4
Flow destinations of gas	- NB local demand	- NB local demand	- NS local demand	- NB local demand - US -LNG in NS	- NS local demand - LNG in NS
Supply costs for new wells, CAD per Mcf	-	McCully: $5.77 FBS: $4.28	HBS: $3.57	McCully: $5.77 FBS: $4.28	HBS: $3.57
Average gas price, CAD per Mcf, per asset 2017-2037, (not including distribution)	$9.16	$9.48	$9.48	$6.69	$6.81
Average gas price, CAD per Mcf, per asset 2017-2037 for local demand (not including distribution)	$9.16	$9.48	$9.48	$9.48	$9.48
Investments, million CAD	--	$1,295M	$1,443M	$6,041M	$5,510M
Gross producer's revenues (Operations), million CAD	$203M	$5,925M	$6,267M	$16,170M	$3,293M
GDP impact, million CAD / average per year, million CAD	Canada: $166M NB: $153M / $7M	Canada: $14,634M NB: $5,905M / $281M NS: $6,923M / $330M Other: $1,806M		Canada: $42,561M NB: $18,855M / $898M NS: $17,715M / $844M Other: $5,991M	
GDP impact per year, %, compared to 2015 base (without compounding)	0.02%	0.85%	0.81%	2.72%	2.07%
Taxes, million CAD	Canada: $24M NB: $22M	Canada: $2,262M NB: $855M NS: $1,093M Other: $314M		Canada: $6,648M NB: $2,766M NS: $2,838M Other: $1,044M	
Jobs (person-years) per jurisdiction	Canada: 267 NB: 201 Other: 66	Canada: 42,031 NB: 14,089 NS: 19,032 Other: 8,910		Canada: 141,242 NB: 53,666 NS: 57,853 Other: 29,723	
Full time jobs	Canada: 13 NB: 10	Canada: 2,001 NB: 671 NS: 906		Canada: 6,726 NB: 2,556 NS: 2,755	

Note: All amounts are in $CAD 2017

The first scenario does not generate any level of new investments in provinces compared with the other two which bring about medium- to large-size gas industries to the Atlantic Provinces. While the *We Are Self-sustaining* and *We Are Exporters* scenarios could provide significant economic gains for New Brunswick and Nova Scotia, they do not include all the potential costs of developing hydrocarbons, such as potential environmental costs.

CERI provided a review of existing concerns and potential impacts related to environment and Indigenous peoples' issues when unconventional resources are developed. With the former, as has been demonstrated in the reviewed sources, even though a very large number of unconventional wells have been drilled across North America over the last twenty years, data on the environmental impacts of shale gas and oil development are still limited. The reasons behind this include, but are not limited to, the lack of sufficient environmental baseline data; the possibility of long-term environmental effects of unconventional resources development that may become evident after many years; the confidentiality regarding settlement of damage claims with the industry, etc. In addition, most peer-reviewed articles on environmental impacts of hydraulic fracturing are based on US studies. However, they are not always applicable to the Canadian context, since the potential environmental impacts associated with unconventional activities may differ between regions. In some cases, practices and regulations appropriate in other jurisdictions may not be relevant for New Brunswick and Nova Scotia. As an example, deep-well wastewater injection has been a common practice and the industry preferred option in Alberta and British Columbia, where detailed regulations for hydraulic fracturing and water management tools have been in place. However, geological conditions in New Brunswick and Nova Scotia are not favourable for deep water disposal, so other options and technologies for wastewater treatment still need to be determined in the two Maritime provinces.

One of the challenges that shale gas presents is that it has not only changed the flows of natural gas on the continent but has redefined the characterization of traditional producers, pushing non-traditional jurisdictions such as Pennsylvania to become the second largest natural gas producer in the Lower-48, only behind Texas. Both have occurred quickly. As such, the relationship between regulator and industry are also forming quickly.

The relationship between regulator and industry is critical in developing hydrocarbons safely and efficiently. The two parties ultimately need to work together to mitigate the potential environmental risks. This is possible with open dialogue between various stakeholders. Environmentally-conscious jurisdictions, such as British Columbia, have a vibrant shale gas industry. Over the years, the provincial government together with the provincial regulator have set policies and regulations to be able to continuously monitor the shale gas development through an extensive system of "checks and balances".

Currently, the comprehensive expert panel reports prepared for both provinces concluded that existing knowledge gaps do not accurately estimate or predict risks and benefits of unconventional gas and oil development for the environment in New Brunswick and Nova Scotia. Therefore, additional data collection, further research and monitoring of environmental and health impacts will be required, along with a science-based, adaptive, and outcomes-based regulatory approach to unconventional gas and oil development in New Brunswick and Nova Scotia.

It is interesting to note that Quebec presents a unique example for a jurisdiction that has employed a listening-learning-leading approach, transitioning from a moratorium on hydraulic fracking to the introduction of Bill No. 106, the introduction of a new hydrocarbons law in Quebec. Beginning with listening, via multiple BAPE hearings, followed by learning (EES CAPA, Strategic Environment Assessment, Additional Knowledge Acquisition Plan), and finally, culminating to leading, and the introduction of the capstone Bill No. 106 (an *Act to Implement the 2030 Energy Policy*).

With regards to Indigenous peoples' issues, the effect that resistance or support of Indigenous people can have on the future of oil and gas development in New Brunswick and Nova Scotia cannot be underestimated. The Maritime Provinces present a unique landscape of treaty and Aboriginal rights and interests, with the history of treaty making substantially different from this process for the rest of Canada. The Mi'kmaq and Maliseet First Nations maintain that in accordance with the signed Peace and Friendship Treaties, they continue to hold both treaty rights, and Aboriginal rights and title through their traditional territory, since they did not cede or surrender their rights to the traditional lands and resources to the Crown. The established or asserted Aboriginal title rights would need to be addressed in any provincial decision-making and regulatory processes related to hydraulic fracturing. Effective consultation and engagement with Indigenous groups is one of the most critical factors for success of the resources development, and it needs to start as early as possible in order to avoid or mitigate possible issues.

While potential environmental and Indigenous peoples' issues are difficult to quantify, they must be weighed into the decision-making process.

With dwindling, offshore production and increasing local demand for natural gas, both jurisdictions will need to weigh the options moving forward, how and where local demand for natural gas will be met. The interesting irony is that Nova Scotia and New Brunswick have extensive histories in oil and gas exploration and production, New Brunswick dating back to 1859 – the same year as Pennsylvania's famous Drake well – and may yet become larger oil and gas players in the future. It was the unconventional resource, bituminous shale, that attracted Abraham Gesner in the mid-1800s. It is now another unconventional resource that may yet play a role in the Maritimes' future.

To what extent, to either satisfy their local needs or to become exporters, or perhaps just to import from the US Northeast or abroad, the decision has many variables and cannot be taken lightly.

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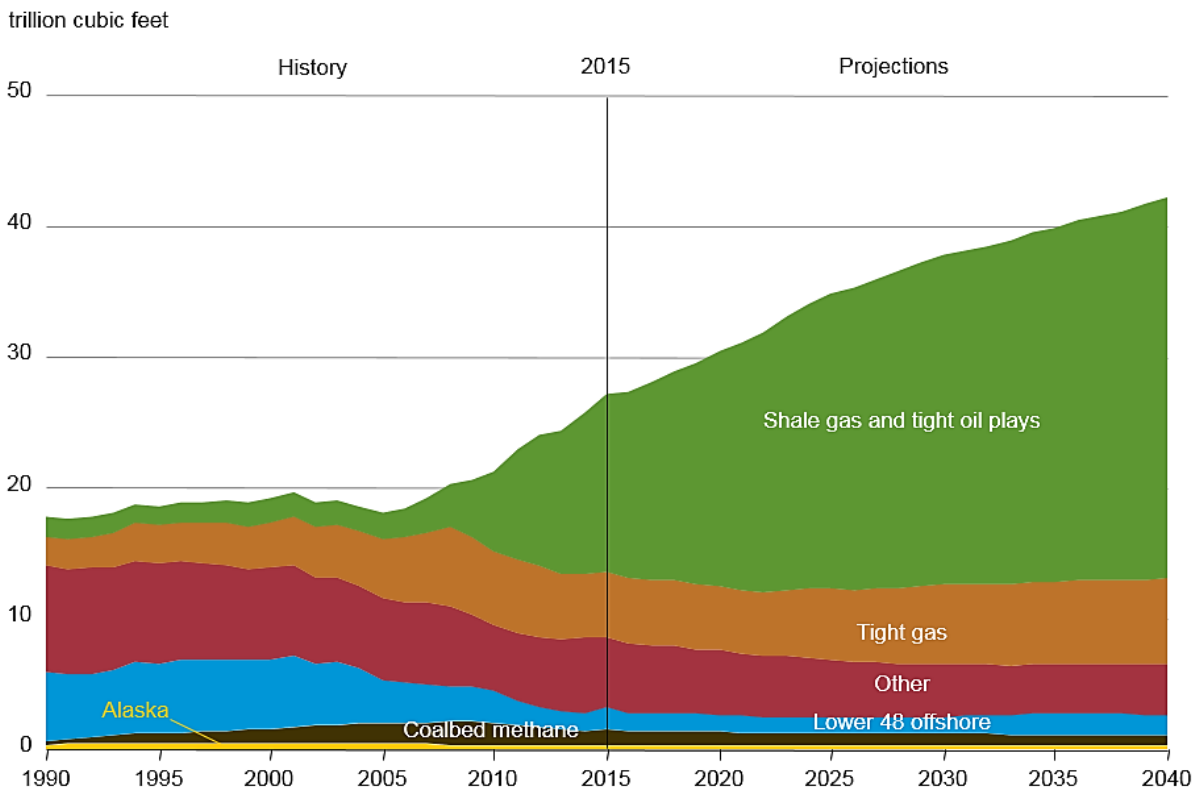
Appendix A: Shale Gas Background

As previously mentioned, the impact of unconventional gas in North America cannot be overstated. According to the EIA's Annual Energy Outlook 2016, by 2035, 35 percent of domestic gas production will come from shale gas (US EIA 2016a). Figure A.1 shows the outlook of natural gas production by source in the US.

Figure A.1: US Dry Natural Gas Production by Source in the Reference Case, 1990-2040



Source: (US EIA 2016a)

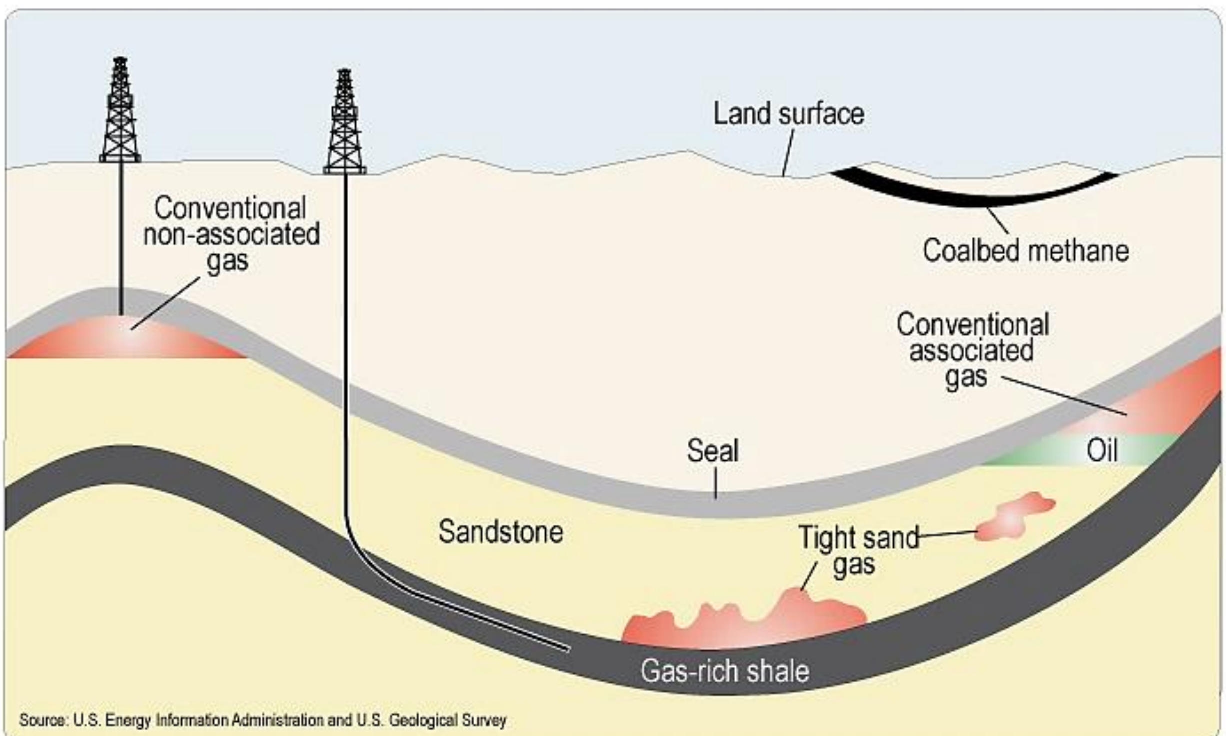
While the Western Canadian Sedimentary Basin (WCSB) is traditionally the largest producer, with Alberta leading the way, the dynamic within the WCSB, however, is changing rapidly, reflecting the fact that unconventional gas resources will play a larger role. British Columbia's wealth as an emerging source of shale and tight gas, including the Montney Shale and the Horn River Basin, already accounts for 35 percent of Canada's natural gas resources.

Currently, unconventional natural gas is frequently divided into three parts: shale gas, tight gas and coalbed methane (CBM). It is important that shale gas should not be confused with tight gas. Shale gas is natural gas generated from and contained within dark-coloured, organic rich rocks. Shales can act as the source, reservoir, and seal for natural gas. The natural gas molecules are generally stored in three ways: absorbed into the organic matter in the shales, trapped in the pore spaces of the fine-grained sediments interbedded with the shale, or trapped in fractures within the shale itself (Aboriginal Pipeline Group n.d.). Tight gas, on the other hand, is natural gas trapped, by a variety of mechanisms, in unusually impermeable reservoir rocks — usually sandstone, but sometimes limestone as well (USGS 2014).

The third form of unconventional natural gas is CBM, where most, if not all, of the natural gas contained in a coal seam is adsorbed in a non-gaseous state in the matrix of the coal. The hydrostatic pressure in the coal seam is all that is necessary to contain the adsorbed natural gas within the coal structure in this state. Once the pressure in the coal is lowered, the gas is desorbed from the coal matrix and recovered. While CBM production is limited to Alberta (primarily the Horseshoe Canyon and the Mannville Coals to a lesser extent), British Columbia and Nova Scotia have several attractive coal formations, the latter discussed briefly in this report.

A schematic of the geology of natural gas and oil resources is illustrated in Figure A.2, including conventional gas and oil, oil- or gas-rich shale, tight gas, tight sand oil and CBM.

Figure A.2: Schematic Geology of Natural Gas and Oil Resources



Source: (US EIA 2011)

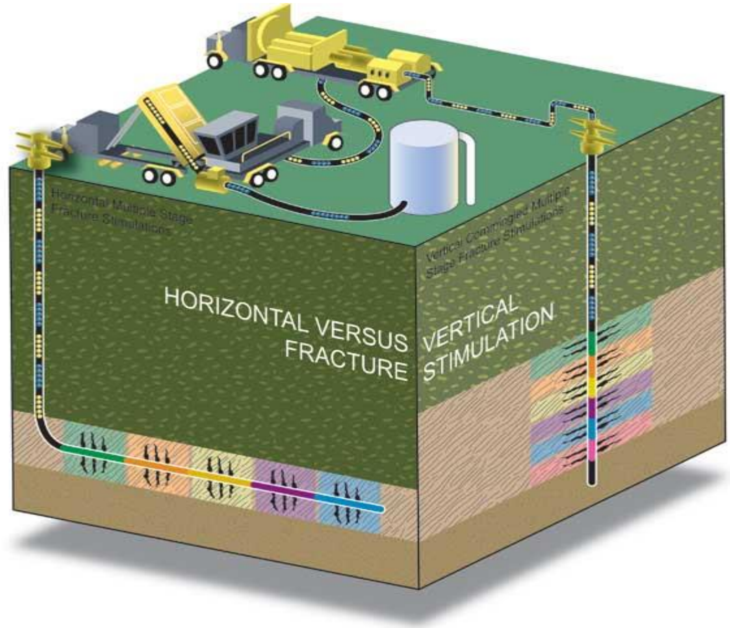
Figure A.2 illustrates two wells. One is horizontal targeting a tight sand gas and an oil- or gas-rich shale while the other is a vertical well targeting a conventional non-associated gas reservoir. The figure also shows other resources such as a tight sand gas, conventional associated gas and oil, as well as CBM. While vertical drilling is more prevalent when developing more porous and permeable plays, this is not typically the case with shale gas, shale oil or tight oil. It is important to note that both vertical and horizontal drilling can be used to develop shale and tight oil, however the latter is far more common, unless the shale is thicker in nature. While more expensive, drilling horizontally exposes the wellbore to more of the reservoir, thereby increasing recovery rates for shale gas or oil (NEB 2009). The direction of the drill path follows the known natural fractures in the shale (NEB 2009). To increase low production rates from the natural fracture system, many E&P companies are relying on improved drilling efficiencies.

The second integral process to improve low permeability reservoirs is fracking. Like horizontal drilling, fracking is not a new technology, first used by Stanolind Oil in the 1940s. It was, however, Mitchell Energy in the 1990s that began utilizing fracking in the Barnett Shale, changing the outlook and role of the shale gas in North America (Geology.com 2017b). Horizontal drilling and multi-stage fracking has been successful for both shale and for tight oil, releasing the gas or crude oil trapped in low permeability shale, sandstone or carbonate rock formations (NEB 2009). Due to low permeability, most shale plays require fracture stimulation.

Fracking is done by pumping fluids (over 98 percent water) down into a well until the pressure cracks the subsurface rock (API 2008). To increase the efficiency of the process further, the multi-stage fracking technique isolates segments of the wellbore to frack them one at a time. This process allows the geologists and drillers to determine what direction the shale is cracking from the increases in pressure (NEB 2009). While infrequently felt on the surface, the energy released in this process can cause seismic activity (CAPP 2017a). Most induced seismicity is less than a magnitude of 2, but some occur in the magnitude 3-4 range, large enough to have been felt on the surface but small enough to rarely cause damage (USGS 2016). These seismic events are typically located within a small region around the well. The largest risk of these events is damage to the drilling and production equipment and associated infrastructure. A magnitude of 3, for example, is roughly comparable to the vibrations of a passing truck (API 2014).

Figure A.3 illustrates horizontal and vertical multi-stage fracking.

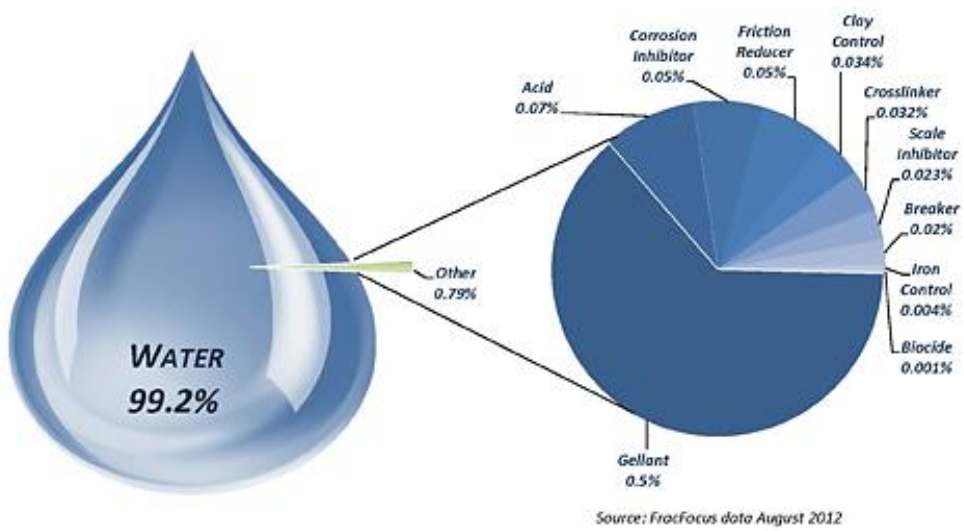
Figure A.3: Horizontal Versus Vertical Multi-Stage Fracture Stimulation



Source: (NEB 2009)

Figure A.4 illustrates the average frack fluid composition for US shale plays. Water and sand typically account for between 98 and 99.5 percent of the fluid, but may also contain other materials, such as gelling agents to make the fluid more viscous (API 2008; U.S. Department of Energy et al. 2009). This is called slickwater fracking. The water fractures the shale while the sand acts as a proppant, keeping the fractures open when the frack fluid is recovered as the well is brought into production (U.S. Department of Energy et al. 2009).

Figure A.4: Average Frack Fluid Composition for US Shale Plays



Source: (FracFocus 2017)

The overall concentration of additives in most slickwater fracturing fluids is a relatively consistent 0.5 to 2 percent (FracFocus 2017). The additives include chemicals such as friction reducers, corrosion inhibitors, gelling agents and scale inhibitors. The additives depicted on the right side of the pie chart vary but generally represent 0.8 percent of the total fluid volume.

It is important to note that frack fluids differ depending on the geology of the shale. For example, the presence of hard minerals such as silica and calcite may determine the chemical composition of the frack fluids used. While clay absorbs the frack fluids, silica-rich shales are excellent candidates for fracking (FracFocus 2017). Another important factor in determining the composition of the frack fluids is the internal pressure of the shale, with over-pressured shales being better candidates for fracking (Geology.com 2017b). The composition of frack fluids also depends on company preference.

With the bulk of frack fluid being comprised of water, it is critical to developing shale gas and tight oil. For this reason, water usage and management issues, from managing withdrawals, to transporting large volumes, to recycling, to disposal issues, are important to stakeholders and regulators. Like water sourcing, water disposal is an issue that stakeholders, regulators and river authorities are managing carefully to protect surface and groundwater resources. This is discussed in more detail in Chapter 3.

Echoed in town hall meetings and the media alike, arguably fracking's most controversial issue is whether potable water aquifers are at risk of being contaminated. While fracking is without doubt a game-changer for shale gas and tight oil, it is also a lightning rod for controversy, and is banned or has led to moratoriums in several jurisdictions, particularly in jurisdictions with limited conventional production, including Nova Scotia and New Brunswick. Regulatory requirements (federally and provincially) for oil and gas projects, major environmental impacts associated with oil and development, and Aboriginal rights and Indigenous people's issues influencing oil and gas development are discussed in Chapter 3.

Despite the ongoing debate, however, technological advancements are certainly having a profound impact on North America's oil and gas industry, improving the low permeability of shale reservoirs, opening up new resources previously determined as non-productive or not feasible to produce, and changing the energy landscape in the process.

These techniques, learned in the Barnett Shale, were quickly utilized to release shale gas in other shale gas plays across North America. Economically- and technically-feasible shale gas on a large-scale arrived and shale plays were 'discovered' by the dozen. Figure A.5 illustrates major shale gas basins in North America. While the big five shale plays in North America – the Barnett (Texas), Fayetteville (Arkansas), Haynesville (Louisiana), Marcellus (Appalachia) and Woodford (Oklahoma), are the most well-known, there are literally dozens more that are also being developed or studied for their gas potential, the Maritime's Frederick Brook Shale and Horton Bluff among them.

Figure A.5: Major Shale Gas Basins in North America

Source: (NEB 2009)

Appendix B: Coalbed Methane

Coalbed methane (CBM) occurs where most, if not all, the natural gas contained in a coal seam is adsorbed in a non-gaseous state in the matrix of the coal, in a near liquid state. The pressure in the coal seam is all that is necessary to contain the adsorbed natural gas within the coal structure in this state. Once the pressure in the coal is lowered, the gas is desorbed from the coal matrix and recovered. It is important to note that CBM contains mostly methane with smaller quantities of ethane, nitrogen and carbon dioxide, with very little heavier hydrocarbons, such as propane and butane and almost no natural gas condensate (Alberta Geological Survey 2017).

In the US, CBM resources are considered sizable, located largely in the San Juan Basin and from the Black Warrior Basin (US EIA 2016b). But CBM is overshadowed by its unconventional shale gas and tight gas counterparts, lagging in terms of development and exploration.

The same is true north of the border. Most of Canada's CBM reserves are located within the Western Canadian Sedimentary Basin, within Alberta and British Columbia. The Alberta Energy Regulator estimates the remaining established reserves of CBM to be approximately 2.0 Tcf in areas of Alberta where commercial production is occurring (Government of Alberta 2017). CBM production is, however, thus far limited to Alberta, mostly in the Horseshoe Canyon Coal Zone, along the Calgary-Red Deer corridor; other interesting coal zones are the Mannville Coals and the Ardley Coals (Alberta Energy 2017).

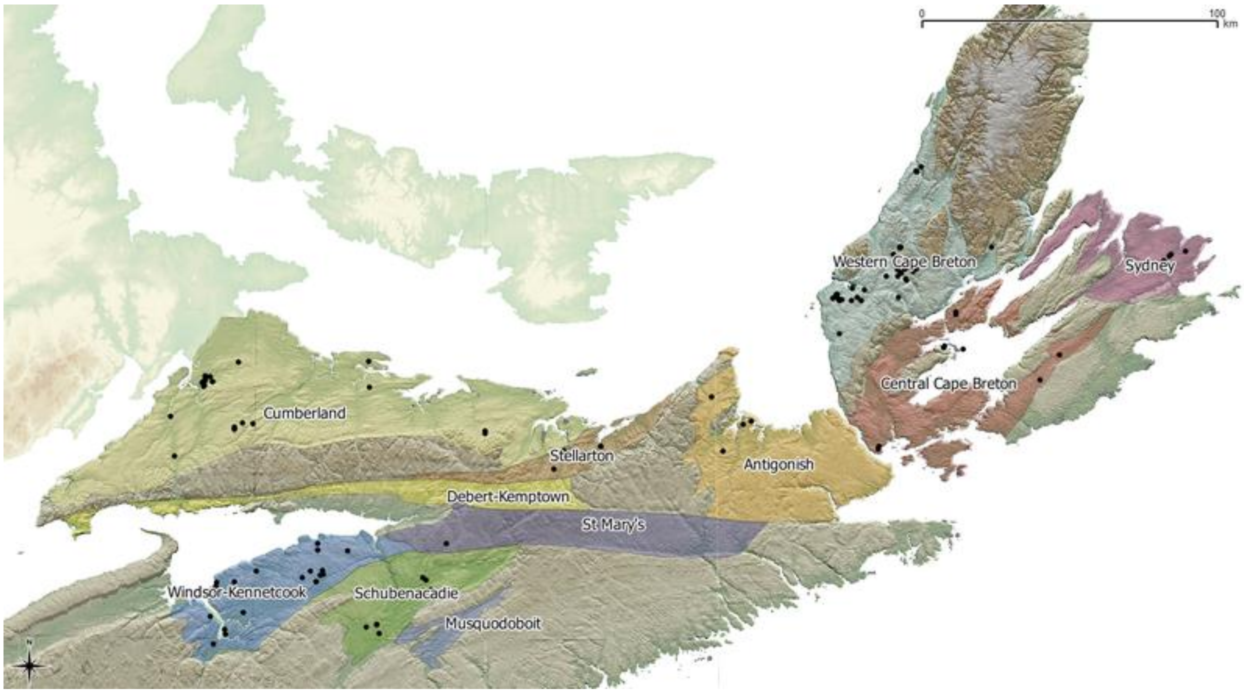
Despite the vast resource in Canada, much of the gas trapped in coal remains undeveloped. This is also likely due to its development being more sensitive to the price of natural gas. It is more expensive to drill and extract the gas from the coal seams. In addition, in a lower price environment, it is easier for E&Ps to target conventional gas or other types of unconventional, such as shale gas or tight gas. As such, detailed discussion on size of the resources and CBM development lies beyond the scope of this study. It is still, however, briefly discussed in this section, as outside of the WCSB, Nova Scotia has several attractive coal formations, perhaps playing a greater role in a higher price environment.

Beginning in Cape Breton in the 1720s, coal mining played an important role in Nova Scotia's economy. It is important to note that Nova Scotia has abundant coal resources, including major coalfields such as Sydney coalfield (Port Morien district, New Waterford district, Sydney Mines district and New Campbellton district), Inverness County coalfields (Port Hood, Mabou, Inverness, St. Rose-Chimney Corner), Pictou coalfield (Westville, Thorburn, Coalburn, Stellarton), Cumberland County coalfields (Springhill coalfield, Joggins-River Hebert coalfield), Kemptown-Debert coal area, Richmond County coal area, and Glengarry (Loch Lomond) coal area (Government of NS 2001).

Some of these areas, once mined, are potentially rich in CBM and have attracted exploratory activity in several areas, including the Cumberland Basin, Stellarton Basin and the Sydney Basin.

Figure B.1 illustrates these basins, including several other sedimentary basins in Nova Scotia. It is interesting to note that oil and gas exploration wells are shown as black dots.

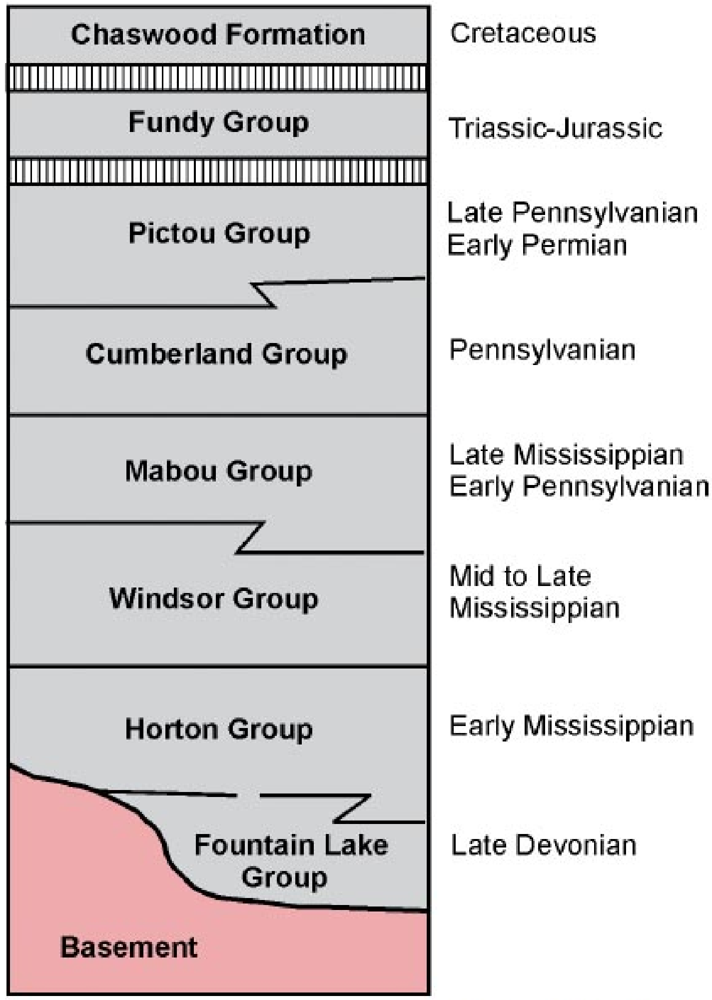
Figure B.1: Eleven Sedimentary Sub-basins in Nova Scotia



Source: (Bianco 2013)

Whereas the medial shales of the Horton Bluff and the Frederick Brook Shale are located within the Horton Group, the CBM that has been assessed thus far is located within the Cumberland and Pictou Groups. This is illustrated in Figure B.2, showing the general stratigraphy of the Maritimes Basin.

Figure B.2: General Stratigraphy of the Maritimes Basin



Source: (Ryan and O'Beirne-Ryan 2009)

Table B.1 illustrates the estimates of gas in-place for three CBM locations in Nova Scotia. The table also includes private companies' estimates, including Stealth Ventures and Amvest, for the Stellarton Basin and the adjacent Cumberland Basin. The combined estimate ranges between 1.6 Tcf and 2.6 Tcf, with the largest estimated reserves occurring in Stealth Ventures' acreage in the Cumberland Basin (1.18 Tcf) and Sydney Basin (0.98 Tcf).

Table B.1: Estimates of Recoverable Coalbed Methane in Nova Scotia

Sydney Basin	Pictou - Cumberland	0.98 Tcf
Stellarton Basin	Pictou - Cumberland	0.28 Tcf
		0.43-0.48 Tcf (CBM) (Stealth, Amvest)
Cumberland Basin	Pictou - Cumberland	0.42 Tcf (CBM)
		1.18 (CBM) (Stealth)

Source: (Hayes and Ritcey 2014)

Other resource estimates from private industry as well as the Geological Survey of Canada estimate a potential for 2.5 Tcf of gas in the various coals (NRCan 2016c). ICF suggests undiscovered recoverable CBM resource potential in Nova Scotia up to 3.9 Bcf (ICF Consulting Canada 2013). ICF's estimate is likely based on Stealth Ventures' 1.6 Tcf estimate, conducted by Sproule Consultants, of their coalbed methane resources and the recoverable resource in their lease areas (ICF Consulting Canada 2013).

East Coast Energy and Stealth Ventures have production agreements for CBM in Cumberland and Stellarton, respectively. East Coast's agreement is a production agreement while Stealth's agreement in the Springhill area of Cumberland is an exploration agreement. Interestingly, Stealth's agreement, approved in October 2007, was the first CBM-related production agreement (NS DOE 2013). Donkin Tenements, on the other hand, has an exploration agreement for CBM. The latter is in Cape Breton, in the Sydney Basin. It is important to note that no commercial CBM production has been established.

It is noteworthy to mention that both provinces also possess large oil shale deposits, some of the most promising in Canada. Their development timeline is, however, also beyond the scope of this study. It is very important not to confuse shale oil with oil shale, they are not the same thing, but quite different, leading the International Energy Agency (IEA) to recommend using the term tight oil instead of shale oil (IEA 2013). Shale oil is an unconventional oil produced from plays that have the oil — medium to light in viscosity — embedded into limestone, sandstone and carbonate, in a low-permeable reservoir. These plays are often referred to as tight oil plays or oil-bearing shale plays (CSUR n.d.). Like shale gas, advances of technology have had a profound impact on unconventional oil, including shale oil. Growth in several oil-bearing shales has been impressive, particularly in the Eagle Ford Shale in Texas and the Bakken Shale in North Dakota and Montana (CSUR n.d.). On the other hand, oil shale, also known as kerogen shale, is an organic-rich fine-grained sedimentary rock containing kerogen from which liquid hydrocarbons called shale oil can be produced (Geology.com 2017c). Even though the US has very large oil shale deposits such as the Green River Basin and the Uinta Basin, the largest players in the world are in Brazil, China, Estonia and Russia (Geology.com 2017a).

Appendix C: Regulatory Requirements for Oil and Natural Gas Projects

Federal Regulatory Requirements

Some federal departments that are pertinent to oil and gas development are as follows:

- Canadian Environmental Assessment Agency (CEA Agency);
- National Energy Board (NEB);
- Natural Resources Canada (NRCan);
- Environment and Climate Change Canada (ECCC);
- Health Canada (HC);
- Fisheries and Oceans Canada;
- Indigenous and Northern Affairs Canada (INAC). Indian Oil and Gas Canada (IOGC) is under the auspices of INAC and regulates oil and gas resources on First Nation reserve lands;
- Transport Canada.

Federal acts and regulations that are relevant to oil and gas development are as follows:

- *Canadian Environmental Assessment Act*, 2012 (CEAA 2012):
  - Law List Regulations (SOR/94-636);
  - Regulations Designating Physical Activities (SOR/2012-147);
- *Canadian Environmental Protection Act* (1999, last amended 2016);
- *Canada Oil and Gas Operations Act* (COGOA, 1985, last amended 2016);
- *Canada Petroleum Resources Act* (1985, last amended 2016);
- *National Energy Board Act* (NEBA, 1985, last amended 2016);
- *Indian Oil and Gas Act* (1985):
  - Indian Oil and Gas Regulations, 1995 (SOR/94-753);
- *Fisheries Act* (1985, last amended 2016):
  - Maritimes Provinces Fisheries Regulations (SOR/93-55);
  - Marine Mammal Regulations (SOR/93-56);
- *Navigable Waters Protection Act* (1985, last amended 2016);
- *Species at Risk Act* (2002, last amended 2015);
- *Migratory Birds Convention Act* (1994, last amended 2010).

The following is a list of federal guidelines, policies and best management practices that are pertinent to the oil and gas industry. It includes but is not limited to:

- Pan-Canadian Framework on Clean Growth and Climate Change (ECCC 2016) that reiterates the federal government commitment to a 30 percent reduction from 2005 levels of GHG emissions (approximately 523 Mt) by 2030, and outlines a benchmark for pricing carbon pollution by 2018;

- NEB Rules of Practice and Procedure (NEB 1995);
- NEB's Filing Manual, 2016-02 (NEB 2016);
- Canadian Association of Petroleum Producers' (CAPP) Hydraulic Fracturing Operating Practices (2012) which were developed in support of CAPP's Guiding Principles for Hydraulic Fracturing (2011). These voluntary operating practices include: fracturing fluid additive disclosure; fracturing fluid additive risk assessment and management; baseline groundwater testing; wellbore construction and quality assurance; water sourcing, measurement and reuse; fluid transport, handling, storage and disposal; and anomalous induced seismicity (CAPP 2012);
- Guidelines for Canadian Drinking Water Quality (HC 2014);
- Canadian Guidelines for the Management of Naturally Occurring Radioactive Materials (NORM) (HC 2011);
- Federal Policy on Wetland Conservation (Government of Canada 1991);
- Canadian Environmental Quality Guidelines for Protection of Agriculture (CCME 1999);
- Canadian Water Quality Guidelines for the Protection of Aquatic Life (CCME 2003);
- Canadian Ambient Air Quality Standards (CCME 2012);
- Migratory Birds Convention Act: A Best Management Practice for Pipelines (CEPA 2013).

These federal regulatory frameworks help to ensure safe operation, protection of the environment and resource conservation.

Environmental assessments (EA) are conducted by provinces, territories and the federal government throughout Canada to determine whether proposed major projects should proceed, and what are the terms and conditions for their approval (CEAA 2016). If a proposed oil or natural gas project meets the thresholds set out in the Regulations Designating Physical Activities under the CEAA 2012, a federal EA may be required. The CEAA 2012 applies to both public and private sector proposed projects where specific federal decisions or approvals must be made or granted. A federal level of assessment is required if a project involves a federal authority making decisions as proponent, land administrator, or regulator under specified provisions of legislation identified on the Law List Regulations (Canada 1994). The federal EA process is focused on assessing potential adverse environmental effects that are within federal jurisdiction, including fish and fish habitat, other aquatic species, migratory birds, federal lands, effects that cross provincial or international boundaries and impacts on Indigenous peoples (CEAA 2016; McCarthy Tétrault LLP 2016).

The CEAA 2012 provides the framework for the federal EA process, with the CEA Agency as the main regulator for intraprovincial pipelines and the NEB as the regulator for pipelines that cross provincial and international boundaries (CEAA 2016). There are two types of EA's conducted under the CEAA 2012: assessment by a responsible authority, and assessment by a review panel. Both types of assessments can be conducted by the federal authority alone or in cooperation with another jurisdiction (such as the province). A typical federal EA process can be expected to take at least 24 to 36 months to complete from the time a project description is submitted (CEAA 2016). In January 2016, the federal Government launched an interim approach (including principles and plans) to review major projects being assessed under federal EA processes. These principles are the first part of a broader strategy to restore confidence in Canada's EA processes and to demonstrate that "a clean environment and a strong economy go hand in hand" (Government of Canada 2016).

Companies regulated by the NEBA or the COGOA are required to seek NEB authorization or approval for various activities. Applications under the NEBA include the construction and operation of international and interprovincial pipelines in Canada, along with related facilities and activities, or modifying or abandoning existing facilities; the export of natural gas liquids, and the export and import of natural gas. Under COGOA, approval is required for exploration and drilling for oil and gas and production, processing and transport of oil and gas on the non-Accord federal lands (Government of Canada and NEB 2016).

Provincial Regulatory Requirements – New Brunswick

The main departments to regulate oil and natural gas development within the Province of New Brunswick are the Department of Energy and Resources Development (NB DERD, previously known as the Department of Energy and Mines [DEM]) and the Department of Environment and Local Government (NB DELG).

There are some other departments that are also involved in the approval process for the oil and natural gas industry (NRCan 2016b):

- Department of Aboriginal Affairs (NB DAA);
- Department of Justice and Public Safety;
- Department of Transportation and Infrastructure;
- Department of Tourism, Heritage and Culture.

Applicable provincial acts and regulations include the following (BC OGC n.d.; ECCC 2017a; NRCan 2016b):

- *Oil and Natural Gas Act* (NB ONGA, 1976, consolidated to December 2016):
    - Survey System Regulation (NB Reg 86-190);
    - Geophysical Exploration Regulation (NB Reg 86-191);
    - Licence to Search and Lease Regulation (NB Reg 2001-66);
    - Prohibition Against Hydraulic Fracturing Regulation (NB Reg 2015-28);
- *Pipeline Act* (2005):
    - Pipeline Regulation (NB Reg 2006-2);
    - Pipeline Filing Regulation (NB Reg 2006-3);
- *Bituminous Shale Act* (1976, consolidated to December 2016):
    - Licence to Search, Development Permit and Lease Regulation (NB Reg 87-14);
- *Clean Air Act* (1997, consolidated to June 2013):
    - Air Quality Regulation (NB Reg 97-133);
- *Clean Environment Act* (NB CEA, 1973, consolidated to December 2016):
    - Water Quality Regulation (NB Reg 82-126);

  - Environmental Impact Assessment Regulation (NB Reg 87-83);
  - Petroleum Product Storage and Handling Regulation (NB Reg 87-97);
- *Clean Water Act* (1989, consolidated to June 2012):
  - Watercourse and Wetland Alteration Regulation (NB Reg 90-80);
  - Wellfield Protected Areas Designation Order (NB Reg 2000-47);
  - Watershed Protected Areas Designation Order (NB Reg 2001-83);
  - Water Classification Regulation (NB Reg 2002-13);
- *Species at Risk Act* (2012, consolidated to December 2016):
  - Prohibitions Regulation (NB Reg 2013-39);
- *Fish and Wildlife Act* (1980, consolidated to December 2016):
  - Maritimes Provinces Fisheries Regulations (SOR/93-55) under the federal *Fisheries Act*;
- *Protected Natural Areas Act* (2003);
- *Agricultural Land Protection and Development Act* (1996, consolidated to June 2012).

Provincial guidelines, policies and best management practices that are pertinent to the oil and gas industry include, but are not limited to (ECCC 2017a):

- Transitioning to a Low-Carbon Economy: New Brunswick's Climate Change Action Plan (2016) that establishes provincial GHG emissions reduction targets of 14.8 Mt (10 percent below 1990 levels) by 2020, 10.7 Mt by 2030 (35 percent below 1990 levels), and 5 Mt (80 percent below 2001 levels) by 2050 (Government of NB 2016);
- Stronger Requirements for Oil and Natural Gas Exploration (2011) that establish minimum set-backs for seismic testing and oil and gas drilling and require full disclosure of all fluids and chemicals used in the hydraulic fracturing process (Government of NB 2011);
- Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick: Rules for Industry (2013). The rules focus on several key topics, including well bore integrity; managing wastes; monitoring and protecting water quality; addressing air emissions, including GHG emissions; protecting communities and the environment (Government of NB 2013);
- The New Brunswick Oil and Natural Gas Blueprint (2013) that focuses on six key objectives (including environmental responsibility, effective regulation and enforcement and First Nations engagement) and sets out 16 key action items to help achieve those objectives (NB DEM 2013);
- Groundwater in the Province of New Brunswick is managed under provincial regulatory bodies but the following federal guidelines apply:
  - Canadian Environmental Quality Guidelines for Protection of Agriculture (CCME 1999);
  - Health Canada's Guidelines for Canadian Drinking Water Quality (HC 2014);
- Long-Term Wetland Management Strategy (Government of NB 2012);
- Wetlands Conservation Policy (Government of NB 2002);
- Coastal Areas Protection Policy (NB DELG n.d.).

In the Province of New Brunswick, the environmental impacts potentially resulting from a proposed oil or natural gas project are identified and assessed early in the planning process through an Environmental Impact Assessment (EIA) process. If a project/undertaking is of a type that is listed in Schedule A of the Environmental Impact Assessment Regulation under the NB CEA, then it must be registered with NB DELG for an EIA review (NB DELG 2016). There are two types of an EIA review: determination review and comprehensive review. All registered projects undergo a determination review by a technical review committee to determine whether further study is required, i.e., whether or not a comprehensive review is warranted. The EIA review process must be completed before any project subject to an EIA can proceed. The determination review typically takes up to 120 days to complete from the date the project was registered (NB DELG 2012). The comprehensive review which is usually required for approximately 95 percent of registered projects can take much longer (NB DELG 2012, n.d.).

For oil and gas development, the Province has implemented a phased EIA process that enables beginning the EIA review much earlier, during the project planning phase. However, some types of exploration activities can be undertaken along with the EIA process (Government of NB 2017a). For the last five years (2011-2016), nine phased EIA applications for oil and gas development have been submitted to the NB DELG, including seven projects where a certificate of determination or approval was issued and two projects with a determination review in progress (NB DELG 2017a, 2017b).

Provincial Regulatory Requirements – Nova Scotia

The main department to regulate oil and natural gas development within the Province is the Nova Scotia Department of Energy (NS DOE).

Some other departments that are involved in the approval process for petroleum exploration and activities include (NRCan 2016c):

- Nova Scotia Environment (NSE);
- Department of Natural Resources;
- Office of Aboriginal Affairs (NS OAA);
- Transportation and Infrastructural Renewal;
- Labor and Advanced Education.

The following is a list of provincial acts and regulations relevant to oil and natural gas development (BC OGC n.d.; ECCC 2017b; NRCan 2016c; NS DOE 2017):

- *Petroleum Resources Act* (NS PRA, 1989, amended 2000):
  - Petroleum Resources Regulations (NS Reg 178/85, amended to NS Reg 145/2015);
  - Onshore Petroleum Geophysical Exploration Regulations (NS Reg 24/2000, amended to NS Reg 28/2015);
  - Onshore Petroleum Drilling Regulations (NS Reg 29/2001, amended to NS Reg 144/2015);

  - Amendments to the *Petroleum Resources Act* (2014), which place a moratorium on high-volume hydraulic fracturing for onshore oil and gas shale development (Government of NS 2014);
- *Underground Hydrocarbons Storage Act* (2001):
  - Underground Hydrocarbons Storage Regulations (NS Reg 148/2002, amended to NS Reg 163/2015);
- *Pipeline Act* (1989, amended 2000):
  - Pipeline Regulations (NS Reg 66/98, amended to NS Reg 199/2004);
  - Gas Plant Facility Regulations (NS Reg 22/2000, amended to NS Reg 99/2015), made under both the *Pipeline Act* and the *Energy Resources Conservation Act* (1989);
- *Environment Act* (NS EA, 1994-95, amended 2011):
  - Air Quality Regulations (NS Reg 28/2005, amended to NS Reg 179/2014);
  - Activities Designation Regulations (NS Reg 47/95, amended to NS Reg 120/2016);
  - Environmental Assessment Regulations (NS Reg 26/95, amended to NS Reg 171/2016);
  - Environmental Assessment Review Panel Regulations (NS Reg 19/2013);
  - Petroleum Management Regulations (NS Reg 44/2002);
  - Water and Wastewater Facilities and Public Drinking Water Supplies Regulations (NS Reg 186/2005, amended to NS Reg 181/2009);
  - Well Construction Regulations (NS Reg 382/2007).
- *Environmental Goals and Sustainable Prosperity Act* (2007, amended 2012);
- *Endangered Species Act* (1998);
- *Importation of Hydraulic Fracturing Wastewater Prohibition Act* (2013);
- *Water Resources Protection Act* (2000);
- *Wilderness Areas Protection Act* (1998, amended 2009);
- *Wildlife Act* (1989, amended 2010)
  - Wildlife Habitat and Watercourses Protection Regulations (NS Reg 18/2001, amended to NS Reg 166/2002) made under the *Forest Act* (1989).

Provincial guidelines, policies and best management practices that are pertinent to the oil and gas industry include, but are not limited to (ECCC 2017b):

- Towards a Greener Future: Nova Scotia's Climate Change Action Plan (2009) that sets GHG emissions reduction targets of 5 Mt annually by 2020 and at least 10 percent below 1990 levels by 2020 (NSE 2009);
- Environmental Best Management Practices for Formation Water from Coal Bed Methane Exploration and Production Activities (NSE 2008);
- Water for Life: Nova Scotia's Water Resource Management Strategy (Province of NS 2010);
- Nova Scotia Wetland Conservation Policy (Government of NS 2011);
- Our Parks and Protected Areas – A Plan for Nova Scotia (Province of NS 2013).

Oil and natural gas projects developed in the Province of Nova Scotia that meet the thresholds set out in Schedule A of the Environmental Assessment Regulations under the NS EA are considered as “designated Class I or Class II undertakings” and trigger an EA at the provincial level. Most midstream and downstream oil and gas projects can be designated as Class I undertakings, in terms of the EA Regulations, whereas some oil refineries that produce more than 15,000 L of hydrocarbons per day or use a feedstock that contains halogenated compounds or more than 1 percent sulphur can be designated as Class II undertakings (Province of Nova Scotia 1995). Some oil or natural gas projects may also be designated as Class II undertakings if they include an energy generating facility that meets the thresholds for a production rating or a daily fuel input rating set up in Schedule A of the Regulations. For example, the proposed Goldboro LNG Project was designated as a Class II undertaking due to the proposed 180 MW on-site gas-fired power plant component (Pieridae Energy Canada Ltd. 2013). Provincial EA process can also be triggered if a company sought permits to withdraw large quantities of water to use in a hydraulic fracturing operation (Wheeler et al. 2014). An EA process for Class I undertakings typically takes 50 calendar days to complete, whereas an EA process for Class II undertakings typically requires 275 calendar days to complete, including 110 days for the EA Panel to conduct a public review or hearings (NSE 2001; Government of NS 2016).

Appendix D: Major Legal Cases Clarifying the Nature of Aboriginal and Treaty Rights and Aboriginal Title

- *Royal Proclamation* (1763) was the first important step toward the recognition of existing Aboriginal rights and title, including the right to self-determination. It also set a foundation for the process of establishing treaties in much of Canada (UBC First Nations & Indigenous Studies 2009). However, the Proclamation did not mention the Maritime colonies, and its provisions related to Aboriginal people in these colonies had a complex history. As a result, most post-treaty European settlers were ignorant of Mi'kmaq rights (McGee 2008).
- Section 35 of the *Constitution Act* (1982) states that the "existing Aboriginal and treaty rights of the Aboriginal people of Canada are hereby recognized and affirmed", however, the nature, scope or extent of these rights were not defined in the *Act*.
- *Simon v. The Queen* (1985). The SCC's decision in the *Simon* case (with appellant who was a registered Mi'kmaq Indian) recognizes that the treaty and treaty hunting rights cannot be restricted (in certain circumstances) by provincial legislation (SCC 1985). The SCC confirmed that the Mi'kmaq have Indigenous rights to the lands described in the Peace and Friendship treaties of the 1700s (McGee 2008).
- *R. v. Sparrow* (1990). The SCC made a precedent-setting decision that establishes a list of criteria to determine whether an Aboriginal right is existing, and if so, how a government may be justified to infringe upon it (SCC 1990).
- *R. v. Denny* (1990). The appeals in the *Denny* case involved Aboriginal and treaty rights of Nova Scotia's Mi'kmaq First Nations to fish for food. The appellants were three Nova Scotia Mi'kmaq Indians convicted of offences contrary to the *Fisheries Act* and regulations under the *Act* (NSCA 1990).
- *Delgamuukw v. British Columbia* (1997). The SCC's decision in the *Delgamuukw* case confirmed that Aboriginal title does exist and that it's a right to the land itself, not just the right to hunt, fish or gather. When dealing with Crown land, the government must consult with, and may have to compensate, First Nations whose rights may be affected (BC Treaty Commission 1999; SCC 1997).
- *R. v. Marshall* (1999). The SCC's landmark *Marshall* decision recognizes the constitutionally protected treaty rights of the Mi'kmaq First Nations in Nova Scotia to catch and sell fish. The SCC confirmed that Mi'kmaq and Maliseet First Nations continue to have treaty rights to hunt, fish and gather to earn a moderate livelihood, and these treaty rights must be implemented (SCC 1999; INAC 2010a, 2013).
- *Haida Nation v. British Columbia (Minister of Forests)* (2004). The SCC established that the Crown is required to consult with Aboriginal groups with respect to Crown-authorized activities that might affect Aboriginal interests, and that the extent of the consultation is proportionate to 1) preliminary assessments of the strength of the case for the claimed

Aboriginal rights and title; and 2) the seriousness of the potential impact of Crown action or activity on Aboriginal interests (BC Treaty Commission 2008; SCC 2004a). The court strongly urged the parties to negotiate rather than litigate, noting that "while Aboriginal claims can be and are pursued through litigation, negotiation is a preferable way of reconciling state and Aboriginal interests" (SCC 2004a).

- *Taku River Tlingit First Nation v. British Columbia (Project Assessment Director)* (2004). Similar to the *Haida* case, the SCC ruled that the Province should have consulted with the First Nations about the decisions, and possibly accommodated Aboriginal interests, even though the First Nations had not legally proved the existence of their Aboriginal rights and title (Olynyk 2005; SCC 2004b).
- *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)* (2005). The SCC extended the Crown's obligation to consult and accommodate Aboriginal interests (established earlier in the *Haida* and *Taku* cases) in order to include existing treaty rights (BC Treaty Commission 2008; SCC 2005). These general principles were later reaffirmed in the *Grassy Narrows First Nations v. Ontario (Natural Resources)* case (SCC 2014b).
- *R. v. Sappier; R. v. Gray* (2006). The SCC upheld the Aboriginal rights of the Maliseet and Mi'kmaq First Nations in New Brunswick to harvest wood for domestic uses on Crown land. The Court confirmed that this right does not have a commercial dimension to it (SCC 2006; INAC 2010b).
- *Beckman v. Little Salmon/Carmacks First Nation* (2010). It is the first SCC decision to address modern treaties in the context of the Crown's duty to consult with Aboriginal people. The Court ruled that the honor of the Crown is a constitutional principle and it exists independently of any treaty or contract with Aboriginal people. The duty to consult is part of the "essential legal framework within which the Treaty is to be interpreted and performed" (SCC 2010; Adkins and Isaac 2010).
- *Tsilhqot'in Nation v. British Columbia* (2014). The SCC's *Tsilhqot'in* decision (2014) clarified the test for Aboriginal title relating to the elements of sufficient and exclusive occupation at the time of assertion of European sovereignty in 1846 (SCC 2014a). This is the first time that any court has formally declared that Aboriginal title exists to a particular tract of land outside of a reserve. The SCC's decision also stated that without consent from First Nations which hold Aboriginal title to land, the government cannot approve developments on that land unless this infringement can be justified (SCC 2014a; Tsilhqot'in National Government 2014).

Appendix E: Input-Output Model

This section discusses the multi-stage process to build CERI's US-Canada Multi-Regional Input-Output Model (the UCMRIO 4.0 model). This section is divided into two parts: the development of the UCMRIO 4.0 and the industries of the UCMRIO 4.0. The US-Canada trade table and model structure are also discussed.

Development of the UCMRIO 4.0

The following illustrates how the bi-national UCMRIO 4.0 was developed, and how one can trace direct, indirect, and induced effects of the Canadian energy sector on the Canadian and US economies. The model provides insights at the provincial level for Canada and at the state level for the US. The base year for the I/O tables is 2011.

Compilation of the bi-national UCMRIO 4.0 includes the following:

1) Statistics Canada provides S level Symmetrical I/O tables (SIOTs) and Final Demand tables for 13 provinces and territories plus Government Abroad. Therefore, there are 14 regional tables for Canada plus one national table. Provincial data are only available at the S level due to confidentiality of more disaggregated data for some sectors in various provinces. The I/O tables used are at producer's prices (Basic Prices), meaning that CERI did not construct symmetrical tables from the Use and Make tables, as the compiled tables were available. As previously mentioned, the base year for the I/O tables is 2011.[1]

2) SIOTs are balanced. Hence, the use of inputs in the economy is equal to the production of outputs.

3) The US national Use and Make tables were sourced from the US Bureau of Economic Analysis (U.S. Bureau of Economic Analysis 2017). These tables also use 2011 as the base year. These tables are at producer's prices (Basic Prices), and consist of 65 sectors and 13 final demand categories. CERI compiled the US SIOT table and combined industry sectors in order to arrive at 24 industry sectors, consistent with Canadian S level aggregation.

   The intermediate and final demand part of the US SIOT table is constructed as follows:

$$\mathbf{B=V(diag(q\text{-}m))^{-1}U \text{ and } F=V(diag(q\text{-}m))^{-1}Y} \qquad \textbf{(Equation 1)}$$

   Where:

   B: Transformed intermediate part of use table to symmetric I/O table

[1]Use tables show the inputs to industry production and commodity composition of final demand. Make tables show the commodities that are produced by each industry.

F: Transformed final demand part of use table for symmetric I/O table
V: Transpose of make table excluding imports
U: Intermediate demand part of use table
Y: Final demand part of use table
q: Vector of total supply of products
m: Vector of imports by products
diag(q-m): Matrix with q-m on the diagonal

By using these equations, the rectangular commodity by industry Use and Make tables are transformed to a symmetrical square I/O table and its corresponding final demand matrix.

4) In order to highlight the energy sectors in the Canadian provincial SIOTs, CERI disaggregated the "Mining and Oil and Gas Extraction'' industry into five subsectors: Conventional Oil, Oil Sands, Natural Gas and LNG, Coal, and Other Mining. In the same fashion, the manufacturing sector is divided into three subsectors: Refinery, Petrochemical, and Other Manufacturing.

5) It is important to note that the construction sector in this version is already split into the following five sub-sectors by Statistics Canada: Residential Construction, Non-residential Building Construction, Engineering Construction, Repair Construction and Other Activities of the Construction Industry.

6) Whereas the trade flow between Canadian provinces and territories is provided by Statistics Canada, the trade flow pattern between the individual provinces and the US is not available. The data is gathered from a variety of sources and compiled by CERI into a trade flow pattern between the two countries.

7) In the UCMRIO 4.0, an exchange rate is needed in order to link data from US and Canada to a common currency. CERI uses a parity exchange rate between the US and Canadian dollar for the base year 2011 to convert the trade flow matrix into Canadian dollars.

8) CERI combines 15 SIOTs (13 provincial tables, one for Government Abroad and one for the US at the national level) to compile one bi-national I/O matrix. The bi-national matrix is then merged with the trade flow matrix, and inverted to generate direct, indirect, and induced effect multipliers.

US-Canada Trade Table and Model Structure

An important component to the modeling process is the construction of the trade flow matrix. The trade flow matrix connects the US I/O table to the Canadian I/O tables, and depicts a trading pattern between each Canadian province or territory and the US national economy. The trade flow table for UCMRIO 4.0 depicts the export/import flows of each Canadian province with the US and with each other. In particular, the Alberta trade flow table shows the import (export) flows of Alberta from (to) other Canadian provinces and territories, as well as the US. It is important to mention that the industry specification of this table is the same as SIOTs, and thus covers the trade flows among all sectors of the economies.

The following is a brief discussion of the modeling.

Based on a standard I/O model notation, and considering total gross outputs vector (**X**) and final demand vector (**FD**), the following relationship in I/O context holds as:

$$AX+FD = X \rightarrow (I-A)X=FD \rightarrow X= (I-A)^{-1}FD \rightarrow X= L.FD \qquad \textbf{(Equation 2)}$$

Where:

A = the matrix of input coefficients (n×n),
I = identity matrix (n×n), and
L = the Leontief inverse matrix (n×n).

This is the core formula of the Leontief quantity model. This relationship estimates direct and indirect impacts for a single economy (i.e., no trade flow). CERI can expand this model to include induced effects by endogenizing the most important component of local final demand, namely private consumption. This captures the economic impact of increased consumption due to earned wages from new jobs.

After endogenizing the private consumption expenditure, CERI arrives at the following relationship:

$$X = (I-Aind)^{-1}FD^* \qquad \textbf{(Equation 3)}$$

CERI endogenizes the household's private consumption expenditures and earnings by adding one column and one row to every province or to the US *intermediate matrix* which then creates a new matrix of input coefficients labeled as **Aind**. This relationship estimates direct and indirect impacts.

CERI can extend the model to involve other economies (regions) by incorporating the interregional trade flow matrix **C**(n×n). After several steps of calculation, we arrive at the final interregional formula:

$$X = (I-C.Aind)^{-1}C.FD^* \qquad \textbf{(Equation 4)}$$

The above equation, to have a finite solution (**I-C.Aind**), must be a non-singular matrix.[2] As is the case for standard I/O models, the impact of an industry, such as the oil sands industry, is calculated by modeling the relationship between total gross outputs and final demand as follows:

[2]For further information on Interregional I/O analysis please see (Howard et al. 2009; Hertwich and Peters 2010; Miller and Blair 2009; Oosterhaven, Stelder, and Inomata 2008; Sim, Secretario, and Suan 2007).

$$\Delta X = (I - C.Aind)^{-1} C.\Delta FD^* \quad \text{(Equation 5)}$$

Where:

ΔX – Changes (or increases) in total gross outputs of the US and all provinces and territories, at the sectoral level, due to construction and operation of projects (i.e., oil sands). Dimension is either n=485 or 500. As a result, this vector is a 485x1 or 500×1 vector.

I – is a 485x485 or 500×500 identity matrix, unity for diagonal elements and zero for off-diagonal elements.

A – is a 485×485 block diagonal matrix of technical coefficients at the sectoral level for the US and Canada. It is composed of 14 blocks of 33×33 matrix corresponding to each province (or territory's) input technical coefficient matrix and one block of 23x23 matrix for the US.[3] An element of such a matrix is derived by dividing the value of a commodity used in a sector by the total output of that sector. The element represents requirements of a commodity in a sector in order to produce one unit of output from that sector.

Aind – is a 500×500 block diagonal matrix of technical coefficients at the sectoral level for the US and Canada. It is composed of 14 blocks of 34×34 matrix corresponding to each province's (or territory's) input technical coefficient matrix and one block of 24x24 matrix for the U.S.[4] An element of such a matrix is derived by dividing the value of a commodity or household expenditure and earnings used in a sector by the total output of that sector or household expenditure. The element represents requirements of a commodity in a sector in order to produce one unit of output from that sector.

C – is a 485x485 or 500×500 transposed matrix of multiregional trade coefficients. It includes import and export shares of a sector's total output in the US and province or territory. Each element on the row of this matrix measures the share of export to a particular sector in the US or a province from a given sector in another province or territory or the US.[5]

ΔFD* – is a 485x1 or 500×1 vector of changes (or increases) in the exogenous part of final demand at the sectoral level. Outputs from Canada and the US resulted from any change in the final demand components in the US or any province or territory, including commodities directly demanded (or purchased) for the construction and development of any sector.

The calculation of total impact is based on the multiplication of direct impact and the inverted matrix. Based on the direct impact on a sector, Equation 5 above is used to estimate all the direct, indirect, and induced effects on all sectors in all provinces, particularly in terms of changes in consumption, imports, exports, production, employment, and net taxes. The direct impact is

[3] In other words, one can say all 14 Canadian tables (13 provinces and one Government abroad) and one US input technical coefficients matrices are stacked together in construction of a diagonal block matrix at the national level.
[4] ibid.
[5] This matrix is a bridge matrix which connects the US, or any province, to other provinces through import and export coefficients. See (Miller and Blair 2009).

referred to as **ΔFD*** in Equation 5. The change in final demand (**ΔFD***) consists of various types of investment expenditures, changes in inventories, and government expenditures. In the current model, the personal expenditures are not part of the final demand and have been endogenized to accommodate the induced impact.

Direct impacts are quantitative estimations of the main impact of the programs, in the form of an increase in final demand (increase in public spending, increase in consumption, increase in infrastructure investment, etc.). The assumption of increased demand includes a breakdown per sector, so that it can be translated into the following matrix notation:

Direct, indirect, and induced impacts:

$$\Delta X = (I - C.Aind)^{-1} C.\Delta FD^{*} \qquad \textbf{(Equation 6)}$$

Direct and indirect impacts:

$$\Delta X = (I - C.A)^{-1} C.\Delta FD \qquad \textbf{(Equation 7)}$$

The difference between Equation 6 and 7 is referred to as the induced impact of any changes in final demand components.

Once the impact on output (change in total gross outputs) is calculated, the calculation of impacts on GDP, household income, employment, taxes, and so forth, are straightforward. As previously mentioned, the base year for the I/O tables used in this report is 2011. CERI utilizes the tax information derived from these tables and federal and provincial tax information from the Finances of the Nation, where these numbers reflect the tax structure of the Canadian economy in the year 2011 (Treff and Ort 2012). CERI acknowledges that there have been changes, and there would be imminent changes to the corporate income tax structure and the goods and services sales tax (GST) since 2011. Any changes to the tax regime will result in changes in estimated tax figures as business responds to the new incentives. Therefore, tax estimates should be interpreted on a 2011 basis.

These impacts are estimated at the industry level using the ratio of each (GDP, employment, etc.) to total gross outputs. Using the technical Multi-Regional I/O table, CERI is able to perform the usual I/O analysis at the provincial and national levels.

Industries in the UCMRIO 4.0

This section illustrates the various classification of industries in the UCMRIO 4.0. Table E.1 also provides a brief description of the 34 sectors or commodities.

Table E.1: Sectors/Commodities in the CERI US-Canada Multi-Regional I/O Model

Serial No.	Sector or Commodity	Examples of Activities Under the Sector or Commodity
1	Crop and Animal Production	Farming of wheat, corn, rice, soybean, tobacco, cotton, hay, vegetables and fruits; greenhouse, nursery, and floriculture production; cattle ranching and farming; dairy, egg and meat production; animal aquaculture
2	Forestry and Logging	Timber tract operations; forestry products: logs, bolts, poles and other wood in the rough; pulpwood; custom forestry; forest nurseries and gathering of forest products; logging
3	Fishing, Hunting and Trapping	Fish and seafood: fresh, chilled, or frozen; animal aquaculture products: fresh, chilled or frozen; hunting and trapping products
4	Support Activities for Agriculture and Forestry	Support activities for crop, animal and forestry productions; services incidental to agriculture and forestry including crop and animal production, e.g., veterinary fees, tree pruning, and surgery services, animal (pet) training, grooming, and boarding services
5	Conventional Oil[6]	Conventional oil, all activities e.g., extraction and services incidental to conventional oil
6	Oil Sands	Oil sands, all activities e.g., extraction and services incidental to oil sands
7	Natural Gas and NGL	Natural gas, NGL, all activities e.g., extraction and services incidental to natural gas and NGL
8	Coal	Coal mining, activities and services incidental to coal mining
9	Other Mining	Mining and beneficiating of metal ores; iron, uranium, aluminum, gold and silver ores; copper, nickel, lead, and zinc ore. Mining; non-metallic mineral mining and quarrying; sand, gravel, clay, ceramic and refractory, limestone, granite mineral mining and quarrying; potash, soda, borate and phosphate mining; all related support activities
10	Utilities	Electric power generation, transmission, and distribution; natural gas distribution; water and sewage
11	Residential Construction	Residential building construction
12	Non-residential Building Construction	Industrial, commercial and institutional buildings
13	Engineering Construction	Engineering construction includes transportation, oil and gas, electric power, communication and other engineering construction

[6]Statistics Canada reports the oil, gas, coal, and other mining as one sector due to some confidentiality issues. CERI uses an in-house developed approach to disaggregate this sector into five sectors: oil sands, conventional oil, natural gas + NGL, coal, and other mining.

Serial No.	Sector or Commodity	Examples of Activities Under the Sector or Commodity
14	Repair Construction	Repairing and renovating construction
15	Other Activities of the Construction Industry	Other activities of the construction industry
16	Refinery	Petroleum and coal products; motor gasoline and other fuel oils; tar and pitch, LPG, asphalt, petrochemical feed stocks, coke; petroleum refineries
17	Petrochemical	Chemicals and polymers: resin, rubber, plastics, fibres and filaments; pesticides and fertilizers; etc.
18	Other Manufacturing	Food, beverage and tobacco; textile and apparel; leather and footwear; wood products; furniture and fixtures; pulp and paper; printing; pharmaceuticals and medicine; non-metallic mineral, lime, glass, clay and cement; primary metal, iron, aluminum and other metals; fabricated metal, machinery and equipment, electrical, electronic and transportation equipment, etc.
19	Wholesale Trade	Wholesaling services and margins
20	Retail Trade	Retailing services and margins
21	Transportation and Warehousing	Roads, railways; air, water and pipeline transportation services; postal service, couriers and messengers; warehousing and storage; information and communication; sightseeing and support activities
22	Information and Cultural Industries	Motion picture and sound recording; radio, TV broadcasting and telecommunications; publishing; information and data processing services
23	Finance, Insurance, Real Estate and Rental and Leasing	Insurance carriers; monetary authorities; banking and credit intermediaries; lessors of real estate; renting and leasing services
24	Owner Occupied Dwellings	Owner-occupied dwellings
25	Professional, Scientific and Technical Services	Advertising and related services; legal, accounting and architectural; engineering and related services; computer system design
26	Administrative and Support, Waste Management and Remediation	Travel arrangements and reservation services; investigation and security services; services to buildings and dwellings; waste management services
27	Educational Services	Universities; elementary and secondary schools; community colleges and educational support services
28	Health Care and Social Assistance	Hospitals; offices of physicians and dentists; miscellaneous ambulatory health care services; nursing and residential care facilities; medical laboratories; child and senior care services

Serial No.	Sector or Commodity	Examples of Activities Under the Sector or Commodity
29	Arts, Entertainment and Recreation	Performing arts; spectator sports and related industries; heritage institutions; gambling, amusement, and recreation industries
30	Accommodation and Food Services	Traveler accommodation, recreational vehicle (RV) parks and recreational camps; rooming and boarding houses; food services and drinking establishments
31	Other Services (Except Public Administration)	Repair and maintenance services; religious, grant-making, civic, and professional organizations; personal and laundry services; private households
32	Non-Profit Institutions Serving Households	Religious organizations; non-profit welfare organizations; non-profit sports and recreation clubs; non-profit education services and institutions
33	Government Sector	Hospitals and government nursing and residential care facilities; universities and government education services; other municipal government services; other provincial and territorial government services; other federal government services including defence
34	Household (Labour)	Household labour