Assessing the Economic Viability of an LNG Terminal in Newfoundland: With Export to European Markets

by

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Abstract

In this paper I analyze the economic viability of a liquefied natural gas (LNG) terminal in Newfoundland, with export to European markets. Natural gas is extracted offshore Newfoundland & Labrador and transported via pipeline to shore. The natural gas liquids (NGLs) and impurities are then separated from the pure methane. The NGLs are processed at an NGL processing plant and sold on their respective markets. The impurities are discarded and the natural gas is then liquefied and loaded onto double hulled tankers, which will transport the LNG to European markets. Capital and operating expenditures are calculated, with a 20 year production profile. Royalties are analyzed and compared using the Nova Scotia and Newfoundland royalty systems. Provincial and Federal corporate income taxes are also included in the analysis. The pipeline and LNG transport will be contracted out to outside parties. The producer will operate the production facility, as well as the LNG and NGL stations. Three reserve scenarios are analyzed (4-6 trillion cubic feet) and an internal rate of return (IRR) on the project is determined for the producer until different price scenarios, which range from $6 CDN/MMBtu to $16 CDN/MMBtu. The project is considered to be economically viable if the IRR is at least 15%, according to industry standards set by Husky Energy, operating from St. John's, Newfoundland. Given that the price of natural gas in Europe is expected to increase to nearly $14 CDN/MMBtu in 2016, the project is deemed to be economically viable under all reserve scenarios.

Keywords: Natural Gas, Liquefied Natural Gas, Natural Gas Liquids, Newfoundland, European Markets

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List of Acronyms

Term	Initial components of the term (examples are below)
CAPEX	Capital Expenditures
CBM	Coalbed Methane
CDN	Canadian
CDN/bbl	Canadian Dollars per Barrel
CDN/MMBtu	Canadian Dollars per Million British Thermal Units
CIT	Corporate Income Tax
CNLOPB	Canada-Newfoundland Offshore Petroleum Board
DOE	Department of Energy
FERC	Federal Energy Regulation Commission
IRR	Internal Rate of Return
LNG	Liquefied Natural Gas
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units
MMscfd	Million Standard Cubic Feet
NBP	National Balancing Point
NGL	Natural Gas Liquids
NL	Newfoundland
NS	Nova Scotia
OECD	Organisation for Economic Co-Operation and Development
OPEX	Operating Expenses
Tcf	Trillion Cubic Feet
TRR	Total Recoverable Reserves
UK	United Kingdom
US	United States

1. Introduction

This paper aims to assess the economic viability of a liquefied natural gas terminal in Newfoundland, with export to global markets. Currently, there is no gas being produced in Newfoundland and Labrador's offshore, despite the fact that there are ample natural gas resources. For such a project, a production facility will be constructed offshore and natural gas will be transported to Newfoundland via pipeline, where the natural gas liquids will be separated from the methane and sold in their respective markets. The pure natural gas will then be liquefied at a liquefaction facility, where the gas is cooled at very low temperatures so it can be compressed 1/600th its size and loaded onto double-hulled tankers, to be transported to global natural gas markets.

Based on industry estimates, producers require a 15% rate of return on investment in order for the project to be classified as economically viable. Given capital expenditures and operating expenditures, as well as provincial and federal corporate income taxes, after tax returns to producers are analyzed using gas price scenarios ranging from $6 CDN/MMBtu to $16 CDN/MMBtu. Comparisons are made by analyzing the rates of return using the Newfoundland and Labrador royalty structure versus the Nova Scotia royalty structure for three natural gas reserve scenarios.

Relative to oil and coal, natural gas is the fastest growing fossil fuel. With the combination of two natural gas extraction technologies, hydraulic fracturing and horizontal drilling, shale gas production has become economically viable, which has dramatically increased total recoverable natural gas reserves in the US. A decade ago, the US was expected to be a major importer of natural gas, via pipeline from Canada and liquefied natural gas (LNG) imports from the rest of the world. However, the increase in natural gas reserves has been a "game changer", and the US is now expected to become a net natural gas exporter, with plans for several liquefied natural gas export terminals awaiting approval.

Given the increase in natural gas production in the US, it is now able to meet the majority of its natural gas demand requirements. Increased production, combined with the economic recession in 2008, has depressed the price of natural gas in the US relative to other markets. As a result, the US is not a viable liquefied natural gas export destination for emerging foreign NG producers. In contrast, European markets are unable to meet domestic natural gas demand, and require natural gas imports from the rest of the world. This had resulted in elevated natural gas prices in Europe, relative to US natural gas prices.

Given the forecasted price of European LNG, at $13 CDN/MMBtu, the project is economically viable under both the NL and NS royalty structures, and for all natural gas reserve scenarios given that the producer must receive a minimum rate of return of 15%. This minimum rate of return is satisfied at a lower price scenario using the NS royalty structure, as the producer earns a higher rate of return under the Nova Scotia natural gas royalty framework relative to the Newfoundland type royalties. Royalties accruing to the province are higher under the Newfoundland type royalties, and with the objective of maximizing provincial revenue, from the province's perspective the Newfoundland royalty structure is preferable relative to the Nova Scotia royalty structure.

In order to have a clear understanding of the project scope, the reader must first have a general understanding of natural gas, US and European natural gas markets, as well as natural gas prices for these markets

2. What is Natural Gas?

Natural gas is a fossil fuel, which is composed primarily of methane. It has the benefit being the cleanest burning fossil fuel relative to both oil and coal (Canadian Association of Petroleum Producers [CAPP], 2012), which is advantageous for governments who aim to reduce greenhouse gas emissions (U.S. Energy Information Administration [EIA], 2013). Other hydrocarbons or natural gas liquids (NGL) such as ethane, propane, and pentanes, are often also present when the natural gas is extracted from the ground, along with elements such as sulpher, nitrogen, carbon dioxide and water. Natural gas is categorized as either conventional or unconventional gas. The combination of methane, NGLs, and other elements are present in both, independent of conventionality.

2.1. Types of Natural Gas

Conventional gas is trapped in various rock formations, usually sandstone. It is often easier to extract and less costly (CAPP, 2012), relative to unconventional gas, and is classified as either associated or unassociated gas. Associated natural gas is found in addition to oil, while unassociated gas pools are not found in association with oil. In general, conventional gas is often found closer to the surface, whereas unconventional gas deposits are usually found at least 15,000 feet below the surface (National Geographic [NG], 2014), which is equivalent to nearly 42 NFL football fields. Unconventional gas is more tightly packed in rock formations, and until recently, were more difficult to extract (CAPP, 2012).

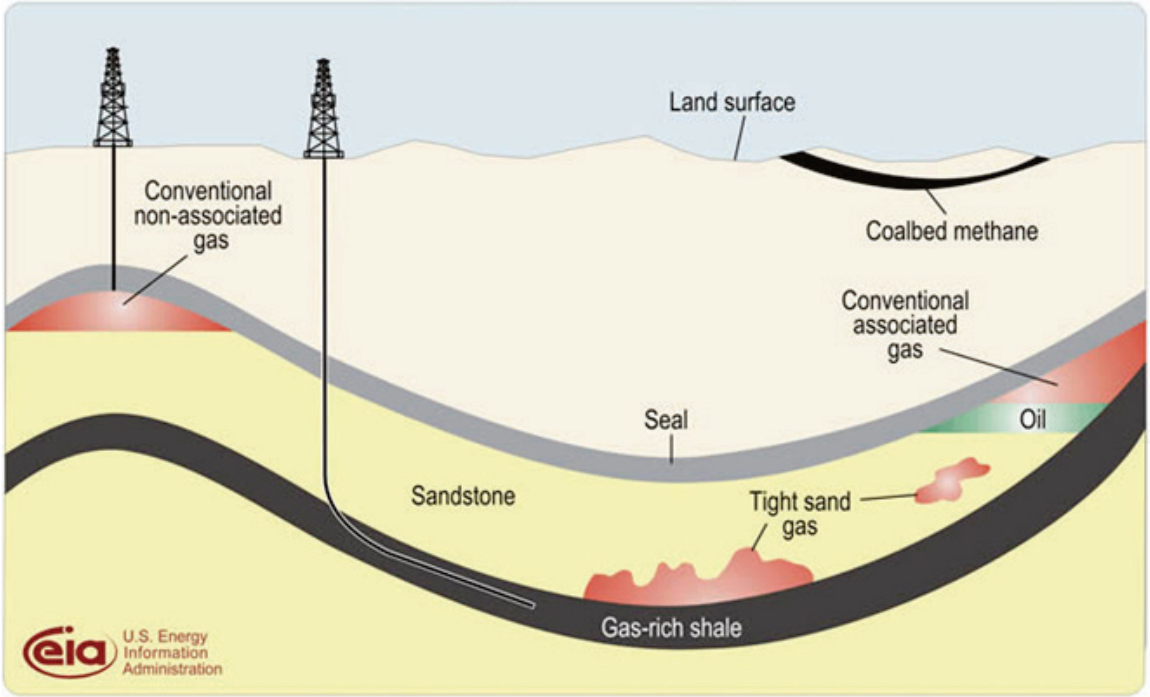

Figure 2.1. Schematic geology of natural gas resources (EIA, 2012)

Coalbed methane (CBM), shale gas, and tight gas are categorized as unconventional gas resources. CBM flows to the surface by decreasing the pressure where the gas is trapped in coal seams that span the length of coal deposits (CAPP, 2012). The extraction process for CBM differs from those of tight gas and shale gas, which both utilize hydraulic fracturing combined with other technologies.

Tight gas is found in tightly packed sands that have very low permeability, which, like CBM, prevents the gas from flowing naturally to the surface (CAPP, 2012). Acidizing is one method of extracting tight gas, which consists of an acid being injected into the area where the tight gas is located. The acid dissolves the tight rock, allowing the gas to flow to the surface. (EIA, 2013). Hydraulic fracturing is another technique used to extract tight gas, which has been used for the past 60 years. A combination of water, chemicals, and sand are pumped into the gas well at a high pressure, which fractures the rock, allowing the gas trapped within the formation to flow through the well to the surface.

Shale gas is the most abundant of unconventional gas resources in North America. It is found in shale formations, which are fine-grained sedimentary rocks.

Shale oil can also be found in certain shale formations along with shale gas. It is extracted using a combination of technologies, which include hydraulic fracturing, which is also used in tight gas extraction, and horizontal drilling. Horizontal drilling consists of laying a pipe horizontally at the base of the vertical gas well, which stretches long distances, maximizing the amount of gas that can be captured per well. In all cases, conventional and unconventional, once the gas has been extracted it must be processed before it is sold to consumers.

2.2. Natural Gas Processing

In order for natural gas to be ready to ship to market, it is first sent to a processing plant, where the hydrocarbons and impurities are separated from the methane. The NGLs are sold at their respective prices, and the impurities are removed and discarded (NG, 2014). Pure methane is the final product that is shipped to consumers and used in a wide variety of industries. It is used for residential and commercial heating, along with transportation and as a means to fuel vehicles (CAPP, 2012). Natural gas is also found in electric and industrial sectors of the economy, for purposes such as providing factories with heat and electricity, as well as powering machinery (EIA, June 2013). Natural gas, like oil and coal, is located in various locations around the world. It is widely used for industrial, residential, and commercial purposes in several countries, including Canada and the United States.

3. Natural Gas Reserves

Proven global natural gas reserves totaled over 6,600 trillion cubic feet (tcf) in 2012, which is the equivalent of 70% of world oil reserves.[1] North American[2] natural gas reserves account for 6% of total global gas reserves, with the US's and Canada's reserves totaling 300 tcf and 70 tcf, respectively. (BP, 2013). North American gas reserves, with respect to cubic feet, are the equivalent of 10,000 Empire State Buildings.[3]

Figure 3.1. North American Natural Gas Reserves (CAPP, 2012)

[1] 1billion cubic feet of natural gas = 0.025 million tons of oil
Total oil reserves = 235.8 thousand million tons, Total gas reserves = 165.3525 thousand million tons or 6614.1 trillion cubic feet. (BP, 2013).

[2] North American reserves in this paper consist of natural gas reserves from the US and Canada, and excludes Mexico.

[3] Total North American natural gas reserves = 370,000 million cubic feet
Empire State Building (excluding the antennae) = 67 million cubic feet
Source for Empire State Building: "The Empire State Building--1.8 Trillion Pennies". http://www.kokogiak.com/megapenny/fifteen.asp.

Total recoverable reserves (TRR) in North America have increased dramatically over the past decade as a result of combining two commonly used technologies, hydraulic fracturing and horizontal drilling. This has made it economically viable to extract unconventional gas reserves, specifically shale gas, that were previously unrecoverable before the utilization of the two technologies. The expansion of recoverable unconventional gas reserves, in combination with existing conventional gas production, has changed the natural gas market in North America, primarily in the United States.

3.1. US Natural Gas

Globally, the US's Marcellus and Haynesville[4] shale gas plays rank in the top five largest unconventional gas fields (EIA, 2011). The Marcellus shale play is the largest in the US, accounting for 55% of technically recoverable shale gas resources. This totals 410.3 tcf, which, if converted to water volume, would exceed that of lakes Michigan, Huron, Erie, and Ontario combined.[5] Haynesville is the second largest US shale gas play, accounting for 10% of shale gas reserves, and totaling 74.7 tcf of natural gas. Barnett shale, at 43.4 tcf, ranks third, and accounts for 6% of recoverable shale gas resources in the US (EIA, July 2011). It was also the first shale play in which hydraulic fracturing was combined with horizontal drilling, which resulted in a dramatic increase in unconventional natural gas production in the United States.

[4] Marcellus shale is located in West Virginia, Pennsylvania, and New York. Haynesville shale is located in Louisiana and some parts of Texas.

[5] 1 cubic mile = 147,197,952,000 cubic feet
Lake Erie = 116 cubic miles; Lake Ontario = 393 cubic miles; Lake Huron = 850 cubic miles; Lake Michigan = 1,180 cubic miles. (Source: United States Environmental Protection Agency, 2012).

Figure 3.2. U.S. Shale Gas Reserves (EIA, December 2012)

In 1995, the implementation of hydraulic fracturing increased production in five of six wells in the Barnett shale play, which began producing more than 2 million cubic feet per day (MMcfd) (Halliburton, 2008), which is the equivalent of filling nearly 23 Olympic sized swimming pools a day.[6] Shortly thereafter, horizontal drilling was implemented into the extraction process (Halliburton, 2008). In 2005, the combination of hydraulic fracturing and horizontal drilling in the Barnett shale play in the Fort Worth basin, Texas, marked the beginning of the surge in shale gas exploration, drilling, and production in the US (Rogers, 2011). By 2006, successful shale gas operations in the Barnett shale play, improvements in shale gas recovery technologies, and attractive natural gas prices encouraged the industry to accelerate its development activity in other shale plays (EIA, April 2011). There were 35,000 wells drilled in 2006, across 19 natural gas basins (Halliburton, 2008). Production continued to increase, with the number of new wells totaling 12,000 in 2008, after the addition of 3,000 new wells in the Barnett shale play

[6] Volume of water of 1 Olympic sized swimming pool = 88,263 cubic feet.

(Rogers, 2011). The US experienced an annual increase in shale gas production of 48% from 2006 to 2010.

More information about technological well requirements will be discovered as the level of production increases. There is not a uniform standard that is used to extract shale gas. The five major basins in the US all have different characteristics. For example, the Woodford shale is more complex, making drilling and fracturing more difficult relative to Barnett shale, and requiring more stages. Haynesville shale is deeper than most shale plays, and as a result, "wells in the Haynesville require almost twice the amount of hydraulic horsepower, higher treating pressures and more advanced fluid chemistry than the Barnett or Woodford Shale" (Halliburton, 2008, p.4). Shale gas exploration, production, and development are still in their infancy; with additional information being gathered as well production stretches into the long term.

3.1.1. Natural Gas Transportation

As technological advancements into shale gas extraction and production continue, infrastructure for processing plants and natural gas transportation will also expand as a result. Natural gas is transported by pipeline or shipped via liquefied natural gas tankers. Combined, Canada and the US have over a million kilometers of pipeline, which transports natural gas across North America. To put this number into perspective, a million kilometers of pipeline is equivalent to travelling from the eastern tip of Newfoundland and Labrador to the most westerly point in the Yukon and back nearly 91 times.[7] All natural gas trading between Canada and the US is currently via pipeline. With the growth in shale gas production, natural gas imports to the US fell by 5% in 2012, and have been decreasing almost every year since 2007. The largest decrease is Eastern exports to the US, occurring as a result of the expansion of the Marcellus shale play (EIA, July 2012).

[7] It is 5,514 kilometers from the most easterly point in Newfoundland and Labrador to the western tip of the Yukon (Government of Canada, 2011).

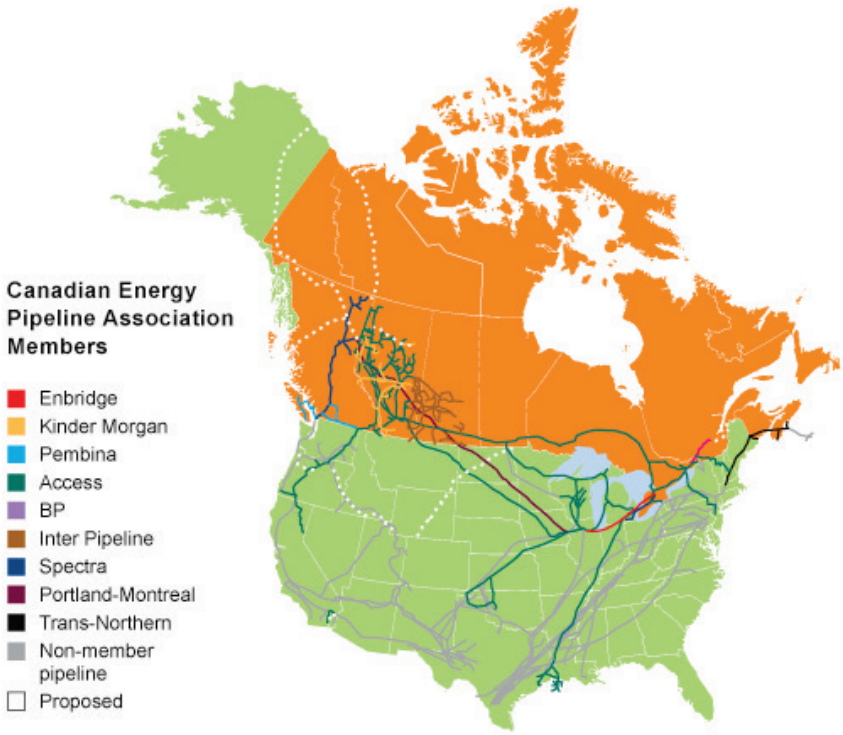

Figure 3.3. Canadian and US Natural Gas Pipelines (Centre for Energy, 2014)

The US also imports natural gas from other countries via liquefied natural gas (LNG) tankers that deliver natural gas to liquefied natural gas import facilities. LNG is natural gas that is cooled at -160°C and converted from its natural gaseous state into a liquid. During this process, the natural gas is compressed to 1/600th its original volume making it easy to store and transport (NG, 2014) to various locations via double-hulled tankers. These tankers can be up to 1000 feet long and carry varying amounts of LNG depending on the size of the vessel (California Energy Commission, 2014). Upon arrival, LNG is processed and returned to its gaseous state, then transported via pipeline to market. With the surge in shale gas production in the US, plans for LNG export terminals have been submitted for approval, with exports expected to begin in 2016.

The shift to LNG exports from the US is driven by relatively lower US gas prices, an increase in global LNG trade movements, and an increase in US gas production (EIA, January 2012). There are currently five LNG import terminals in the US, as large volumes of natural gas were required prior to the development of shale gas technologies. LNG imports fell 50% from 2011 to 2012 (EIA, July 2012), and global LNG

is being diverted to other markets, such as Europe and Asia. With the massive increase in natural gas production, the US has shifted its position on natural gas trade and will shift from a net importer of natural gas to a net exporter. As of the end of May, 2013, 26 applications were filed to the US Department of Energy (US) for authorization to export LNG from the US. The Federal Energy Regulatory Commission (FERC) must then grant permission to construct the LNG export terminal. Sabine Pass Liquefaction LLC is currently the only company that has been approved by both the DOE and the FERC. The export terminal in Sabine Pass, Louisiana, is expected to begin production in 2016 (EIA, July 2012).

LNG exports are now economically viable for two primary reasons. The surge in shale gas production has increased domestic supply of natural gas, which means that the US is better equipped to meet its own demand. Increased production has also kept downward pressure on domestic prices for natural gas in the US. Natural gas in other markets, such as European and Asian markets, is selling for up to 3 or 4 times more than the US price, which makes export to other markets more attractive. Although the US will begin to export natural gas in 2014, it will not have a significant influence on prices in the European LNG market, with exports from the US expecting to target LNG markets in Japan and India (Daly, 2014).

4. Natural Gas Pricing

In addition to the increased domestic supply of natural gas in the US, the economic recession in 2008 also had a drastic effect on the demand for natural gas in North America. Together, these forces led to a fall in price. The US Henry Hub price fell 56% from 8.85 $US/MMBtu[8] to 3.89 $US/MMBtu in 2009 (BP, 2011). Relative to other global natural gas markets, natural gas prices are expected to remain depressed in North America, as the production costs remain low relative to other markets (EIA, April 2011). Natural gas wellhead prices are expected to remain below 4.89 $US/MMBtu until 2023, when prices will begin to rise, eventually reaching 6.37 $US/MMBtu in 2035 (EIA, January 2012). Based on natural gas pricing, European markets are a more attractive option for LNG export from Newfoundland. Compared to the US, the price of European LNG was $11.50 $US/MMBtu in 2010, and is expected to increase to $13.86 $US/MMBtu in 2016 (France Oil & Gas Report, 2012).

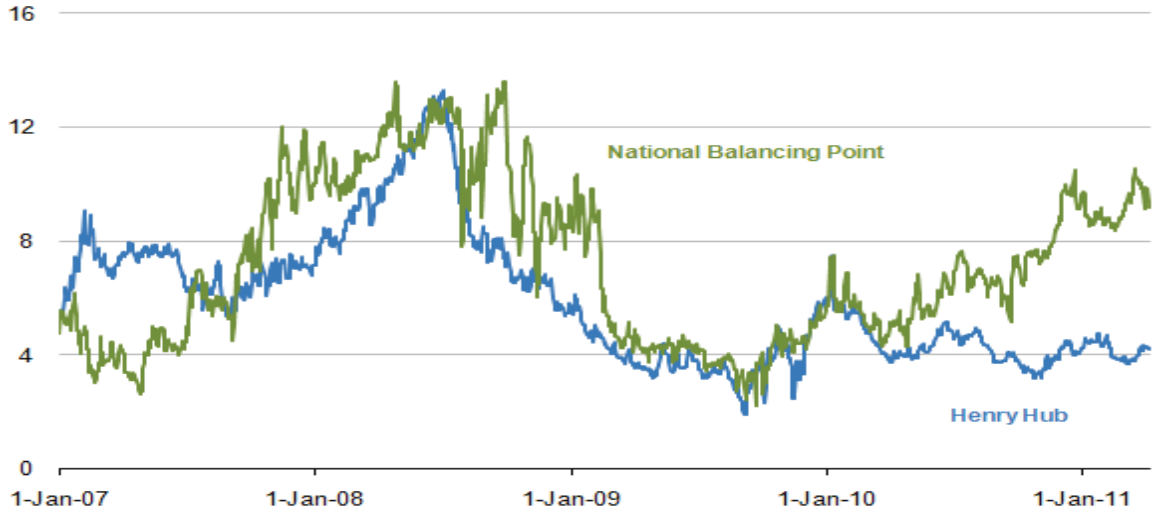

Figure 4.1. Daily Spot Natural Gas Prices (USD/MMBtu), (EIA, January, 2012)

[8] MMBtu = million british thermal units. It is a thermal (heat) measure. A Btu is the amount of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

In addition to having higher natural gas prices relative to the US, European markets also have a greater demand for natural gas imports. This has a significant influence on the higher price of natural gas in Europe, using the National Balancing Point prices in the UK as a benchmark.

5. European Natural Gas Market

Given the fact that the US is becoming a net exporter of natural gas, in combination with depressed US natural gas prices, the US is not a viable LNG export destination. A decade ago, exporting LNG to the US from Canada would have been a viable option given the proximity of the US to Canadian markets which would have resulted in lower LNG transport costs and travel days for LNG tankers to reach their destined markets.

Currently European markets are unable to fill their domestic demand for natural gas, and will continue to rely on imports, either via pipeline or LNG. Natural gas demand for the Organization for Economic Co-operation and Development (OECD) for European countries is expected to increase 17% from 2009 to 2035, from 19.5 tcf to 23.5 tcf. By 2035, imports are expected to total 16.9 tcf, which will fill nearly 70% of natural gas demand in OECD Europe. Gas production in the EU alone is expected to fall 57% by 2035, requiring significant natural gas imports to meet domestic demand (EIA, April 2011). As the quantity supplied in Europe decreases, combined with an outward shift in demand for natural gas, there is an excess demand for natural gas in European markets, which will prevent the price of natural gas from falling to US levels.

Figure 5.1. LNG Terminals in Europe (Blikom, 2011)

Currently, the three largest European LNG importers are Spain, importing 972.1 billion cubic feet (bcf), followed by the UK with 659.1 bcf, and finally France, with LNG imports totaling 492.1 bcf. Spain, the UK, and France accounted for 10%, 6%, and 5% of European imports, respectively, in 2010.

Spain is expected to remain the largest LNG importer through to 2016. From 2009 to 2016, UK imports are expected to overtake LNG imports in flowing into France.[9] From 2008 to 2009, the UK experienced a 90% growth in LNG imports, from 35.3 bcf to 360 bcf, despite a 6% drop in consumption. Decreased consumption was offset by a further decrease in natural gas production of 18%, from 2.46 tcf to 2.09 tcf from 2008 to 2009, explaining the increase in LNG imports. The increase in US shale gas supply and the economic crisis were major factors which contributed to decreased global demand of

[9] See Appendix A

natural gas in 2008, leading to decreased production.[10] Demand has since recovered and the price of LNG in Europe reflects the demand for European natural gas imports.

In addition to European LNG import capabilities and requirements, Newfoundland and Labrador has the benefit of being in close proximity to European markets relative to other markets, such as Asia, which results in lower LNG transportation costs. To date, natural gas in Newfoundland and Labrador's offshore has been associated gas that is used for fueling the production structures offshore. Although there is no natural gas being traded in from the offshore, there are significant natural gas reserves, as well as existing oil production and infrastructure currently in place.

[10] See Appendix A

6. Oil & Gas: Newfoundland and Labrador

Offshore oil production in Newfoundland and Labrador currently accounts for 10% of total crude oil production in Canada, with roughly 270,000 barrels being produced per day. The Newfoundland and Labrador offshore is estimated to have reserves totaling 2.9 billion barrels (CAPP, 2010). Royalties from oil production account for nearly a third of government revenue in the province, with cumulative royalties paid to the Government of Newfoundland and Labrador totaling $5.5 CDN billion.

Newfoundland and Labrador receive the benefits of offshore oil production, although they do not have official rights to the resource. Offshore oil does not qualify within the province's jurisdiction. The signing of the Atlantic Accord by the Mulroney government in 1985 granted Newfoundland and Labrador the rights to offshore oil and gas revenues, as if they were on provincial soil. Although royalties accrue to the provincial government, the Canadian government has not relinquished all rights to production decisions in Newfoundland and Labrador. The Newfoundland Offshore Petroleum Board (CNLOPB) approves all oil projects offshore, in which the provincial and federal governments have joint management over offshore oil resources. Three members of the panel represent Newfoundland and Labrador, while three members represent the Canadian Federal Government. The seventh member is a neutral party that is appointed by both the provincial and federal governments.

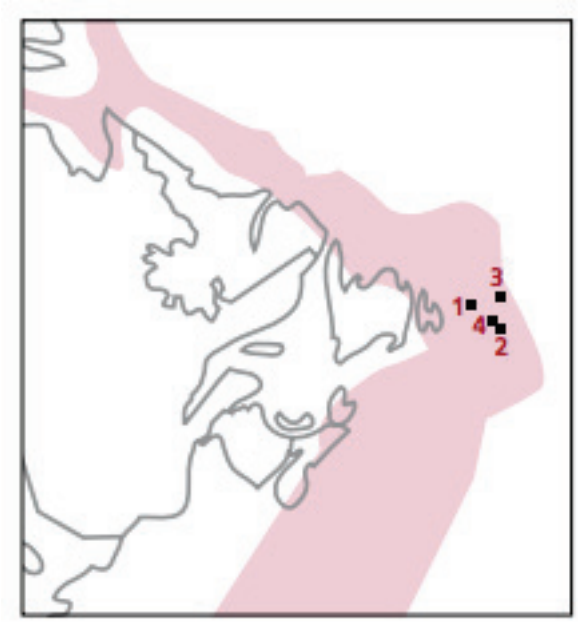

Figure 6.1. Offshore Drilling Projects: Newfoundland & Labrador Oil Fields (CAPP, 2010)

There are currently four oil fields in the Newfoundland and Labrador offshore. Hibernia, Terra Nova, and White Rose are currently producing oil. Hebron is the fourth development project and will begin production by the end of 2017. Production at the North Amethyst site began in 2010, which is a satellite expansion of White Rose.

Hibernia is the largest oil field, and was the first oil project to be approved by the Canada-Newfoundland Offshore Petroleum Board (CNLOPB). Production began in 1997 and is the production site 1 in Figure 7. Reserves for Hibernia are estimated to be 1.24 billion barrels. The proven probable and possible natural gas reserves (with 50% probability) total 2.67tcf of natural gas at the Hibernia site. Terra Nova began production in 2002, with 419 million barrels of oil discovered at the site to date. 283 million barrels of oil have been discovered at the White Rose oil fields (labeled 3 in Figure 7) since startup at the end of 2005. North Amethyst contributes an additional 68 million barrels of oil to discovered oil resources however it is blanketed under the White Rose production project. As stated above, Hebron (labeled 4 in Figure 7) will not come online and begin producing until 2017. It is estimated to contain 400-700 million barrels of recoverable oil (CAPP, 2010).

Currently there is no natural gas production in Newfoundland and Labrador's offshore. There is an estimated 10.86tcf of natural gas reserves. "One trillion cubic feet of natural gas will heat all gas-heated homes in Canada – 5.5 million – for a year and a half" (CAPP, 2010). With a population under 527,000 people (Economics & Statistics Branch (Newfoundland & Labrador Statistics Agency), 2013), Newfoundland and Labrador does not have a significant enough population to sustain the level of natural gas consumption required to justify a natural gas pipeline with delivery to residents of Newfoundland & Labrador. An LNG export station allows for more flexibility, as natural gas can be exported to markets with adequate demand, as well as natural gas prices that are high enough to ensure that the project is economically viable.

According to industry estimates, natural gas producers require a minimum 15% rate of return on their investment in order to begin producing natural gas offshore Newfoundland and Labrador. This estimate was provided by Husky Energy and Nalcor, stating that 15% is the minimum acceptable rate of return for natural gas production offshore Newfoundland and Labrador.

6.1. NL & Labrador LNG Project

The purpose of this project is to assess the economic viability of a hypothetical LNG project[11] in NL, given the capital expenditures (CAPEX) and operating expenditures (OPEX). Natural gas royalties and Federal and Provincial corporate income tax (CIT) associated with natural gas production are included as well. After natural gas has been extracted, it is sent from the production facility via pipeline from the offshore to a location on land, where the methane is separated from the NGLs. The NGLs are sold at their respective market prices (see Table 2), and the natural gas is liquefied at the LNG facility and put on a tanker, destined for European markets.

The project requires construction of a production facility offshore, a natural gas liquids (NGL) plant, and an LNG terminal, which are assumed to take five years to

[11] There is no specific timeline for completion of an LNG export terminal, and it is assumed that the exchange rate between $CDN and $US is a one to one ratio.

complete.[12] There is a gas production profile of fifteen years, which begins upon completion of the facilities.[13] Throughout the analysis, production uptime is assumed to be 90%, with production totaling 329 days per year. Production uptime represents the time when the production facility is extracting natural gas. Downtime results from maintenance activities on the production facility.[14] Shrinkage estimates are included for each of the three facilities, which is the natural gas that is lost due to usage in the production process. This is located in Table 1 below.

Table 6.1. Shrinkage due to fuel usage, LNG and NGL plants (%)[15]

Source	Shrinkage
Fuel Usage	3%
LNG Plant	4%
NGL Plant	6%

The natural gas liquid (NGL) content consists of the hydrocarbons that are often associated with methane, or natural gas. The amount of NGLs per barrel of natural gas, the NGL breakdown, and the market price per barrel are found in Table 2.

Table 6.2. NGL Content & Composition per Mcf of Natural Gas

NGL	Breakdown of NGL Content[16]	Amount of Total NGL	Market Price per bbl ($CDN)[17]
Propane	2.46%	47.8%	$45.42
Butane	1.38%	26.8%	$72.71
Condensate	1.31%	25.4%	$111.59

[12] The five year construction profile was assumed using information from representatives at Husky Energy in St. John's, NL.

[13] The 15 year production profile is provided by Husky Energy, which is based on the reserve scenarios in this paper.

[14] The amount of uptime was based on current uptime for production facilities offshore Newfoundland. The information was provided by Husky Energy.

[15] Shrinkage refers to the amount of natural gas that is lost during the production process.

[16](Husky Oil Operations Limited, 2001).

[17](GLJ Petroleum Consultants, 2012).

NGL	Breakdown of NGL Content[16]	Amount of Total NGL	Market Price per bbl ($CDN)[17]
Total	5.15%	100%	

The raw gas, or methane, contains 5.15% NGLs per thousand cubic feet upon extraction. Propane accounts for the majority of the NGL content, totaling nearly half of the NGL content (47.8%), followed by butane and condensates, which make up the remainder. The NGLs are then sold on their respective markets for different prices. Condensates sell for the highest price, at 111.59 $CDN/bbl, followed by butane and propane. Due to the high selling prices of NGLs relative to pure natural gas, the NGL facility helps to offset some of the major costs associated with the project in the form of other revenues, in addition to LNG sales.

6.2. Cost Structure

Throughout the analysis, there is an implicit 15% rate of return on the production facility, pipeline, and LNG terminal that is incorporated into the model.[18] The cost structure for the project includes capital expenditures (CAPEX) and operating expenditures (OPEX). Capital expenditures are costs that do not occur annually throughout the production profile. The CAPEX are in Table 3, which include the costs for the development wells that must be drilled, the production facility (GBS and NGL plant), as well as the LNG facility, with CAPEX totaling $7,300 CDN million. There will be eight development wells drilled throughout the 20-year period. Three wells will be drilled in the first 3 periods at a cost of $375 CDN million, followed by 5 additional development wells with a cost of $75 CDN million, respectively. The production facility consists of a gravity-based structure (GBS) structure that will be constructed offshore Newfoundland and Labrador. The cost of the production facility used in this analysis is $1,500 CDN million[19], which is based on industry estimates.[20] To construct the production facility, a

[18] Using information provided by Nalcor and Husky Energy, 15% rate of return is a standard minimum acceptable return for a project to be considered economically viable.

[19] The cost breakdown of the production facility is detailed in Appendix B.

GBS must be constructed, as well as two topsides. Topsides are surface installations on the GBS, which aid in the natural gas processing and extraction processes. A GBS is used to prevent against the threat of icebergs and other elements which cause harsh offshore conditions in Newfoundland. The cost of the GBS includes the cost of the topsides, labeled Production Facility in Table 3 below. The cost of the NGL plant is is estimated to be $300 US million. The LNG facility has CAPEX of $3,300 CDN million, which is detailed in Appendix D.

Table 6.3. CAPEX ($CDN million)

Development Wells	1,500
Production Facility	1,500
LNG Facility	3,300
NGL Facility	300
Total CAPEX	**6,900**

The operating expenditures (OPEX) are included in the table below, and occur on an annual basis. Operating costs are included for the production facility (GBS) and the LNG facility. Total OPEX costs are $443 CDN million, $450 CDN million, and $462 CDN million for recoverable gas reserve scenarios of 4 trillion cubic feet (TCF), 5TCF, and 6TCF, respectively. OPEX for the production facility are $150 CDN million, and an additional $0.2 CDN/thousand cubic feet (Mcf), according to industry estimates. The OPEX are fluctuating, as they are dependent on the amount of natural gas that is produced.[21]

Table 6.4. OPEX ($CDN million) for 3 Reserve Scenarios

Source:	**4TCF**	**5TCF**	**6TCF**
Production Facility	323	330	342
LNG Facility	120	120	120

[20] The detailed cost breakdown for the GBS and topsides are included in Appendix B. Refer to table B9 for total cost of GBS and topsides.

[21] Operating expenses were provided by Husky Energy.

Source:	4TCF	5TCF	6TCF
Total OPEX (per year)	443	450	462

For each of these gas reserve scenarios, there is an implicit 15% rate of return for the production facility, pipeline, and LNG terminal that is incorporated into the model.

The producer will pay a transportation tariff per thousand cubic feet (Mcf) for the pipeline and LNG transport, which are included in the table below. The pipeline tariff is lower the more reserves that are estimated to be found offshore, as more gas is passing through the pipeline and it requires fewer $/Mcf to receive a 15% rate of return.[22] The most cost effective pipeline route is a 640km pipeline with 10% trenching.[23] Based on industry estimates, the cost of transportation from Newfoundland to European markets is $0.46 CDN per thousand cubic feet of gas, which has been converted into LNG.

Table 6.5. Tariff for 3 Reserve Scenarios

Source:	4TCF	5TCF	6TCF
Pipeline Tariff/Mcf[24]	$1.19	$1.04	$0.89
LNG Transport/Mcf	$0.46	$0.46	$0.46
Total Tariff	**$1.65**	**$1.50**	**$1.35**

Natural gas royalties must also be paid to the provincial government. In this analysis, the Newfoundland & Labrador (NL) natural gas royalties and Nova Scotia (NS) natural gas royalties are compared. There is currently no natural gas royalty in place in Newfoundland & Labrador, however the provincial government has outlined a natural gas royalty structure to be implemented upon commencement of natural gas production offshore. Although Newfoundland will use the royalty structure that they have outlined, the NS royalty structure is also included as a comparison to the NL royalty regime. The

[22] The pipeline tariff is calculated using the pipeline cost (discussed below), and fixing the IRR at 15% using the amount of natural gas reserves.

[23] Information on pipeline routes provided by the Government of Newfoundland and Labrador.

[24] An OPEX of $50 US million is included in the pipeline tariff. The pipeline tariff is the price per Mcf required to ensure that the pipeline owner earns a 15% rate of return, given the different CAPEX costs associated with different pipeline diameters.

NL royalty system uses a Basic and Net royalty system. The NS royalty structure uses a Gross Revenue Royalty and a Net Revenue Royalty. The NS royalty structure was used to compare with the NL royalty structure, as both are within Canadian jurisdiction and NS is currently an offshore producer of natural gas. The NL and NS royalty structures are detailed in Appendix E. Provincial and Federal corporate income taxes (CIT) are also included. Newfoundland corporate income taxes are 14%, while Federal corporate income tax is 15%.

Natural gas royalties and both Provincial and Federal CIT are calculated using LNG gas price scenarios ranging from $6 CDN/MMBtu to $16 CDN/MMBtu for three different natural gas reserve scenarios. Reserve scenarios range from 4 trillion cubic feet (tcf) to 6 tcf of natural gas offshore that is available for production.

6.3. Natural Gas Reserve Scenarios

Costs vary depending on the amount of natural gas that is being produced. In the 4tcf scenario, 750 million standard cubic feet per day (MMscfd) of natural gas is being produced. This is calculated by dividing the total reserves (4tcf) by 4,860 days, given that there is production uptime of 90% for 15 years. Shrinkage is also taken into account. The same process is used for the 5tcf and 6tcf scenarios. For the 5tcf scenario, daily production totals 950 MMscfd, while 1,150 MMscfd is produced using the 6tcf scenario.

As a result of the length of the pipeline (640km), different pipeline diameters must be used for different flowrates. For the 4tcf scenario, 34” diameter pipeline must be used to ensure adequate pressure flow through the pipeline. A 38” pipeline is used for the 5tcf and 6tcf scenarios, with a pipeline cost of $1,600 CDN million. All pipeline costs are found in Appendix C.

Given the CAPEX and OPEX costs associated with the project, the NL and NS royalties, and the NL and Federal corporate income taxes (CIT); producer return and the associated rate of return for gas price scenarios ranging from $6 CDN/MMBtu to $16 CDN/MMBtu are analyzed using the three natural gas reserve cases.

6.4. Results

6.4.1. 4 TCF Reserve Scenario

The revenue impacts under the Newfoundland and Labrador royalty framework are profiled in Table 6, while the results for the Nova Scotia royalty structure are presented in Table 7.

Table 6.6. NL Royalty Structure: Revenues (Millions of $CDN) at Various Gas Price Scenarios: Discounted @ 10% (4TCF)

Gas Price Scenarios	NL Royalties	NL CIT	NL CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$6 CDN/MMBtu	$330	$379	$709	$406	$(1,558)	5.6%
$7 CDN/MMBtu	$651	$506	$1,157	$542	$(864)	7.7%
$8 CDN/MMBtu	$1,057	$625	$1,682	$670	$(239)	9.4%
$9 CDN/MMBtu	$1,542	$733	$2,275	$785	$330	10.8%
$10 CDN/MMBtu	$1,935	$854	$2,789	$915	$963	12.3%
$11 CDN/MMBtu	$2,339	$975	$3,315	$1,045	$1,585	13.7%
$12 CDN/MMBtu	$2,784	$1,091	$3,875	$1,169	$2,178	15.0%
$13 CDN/MMBtu	$3,264	$1,202	$4,466	$1,287	$2,746	16.2%
$14 CDN/MMBtu	$3,783	$1,307	$5,090	$1,400	$3,286	17.3%
$15 CDN/MMBtu	$4,344	$1,406	$5,750	$1,507	$3,796	18.3%
$16 CDN/MMBtu	$4,938	$1,501	$6,439	$1,608	$4,284	19.3%

Table 6.7. NS Royalty Structure: Revenues (Millions of $CDN) at Various Gas Price Scenarios: Discounted @ 10% (4TCF)

Gas Price Scenarios	NS Royalties	NS CIT	NS CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$6 CDN/MMBtu	$177	$400	$577	$429	$(1,448)	6.0%
$7 CDN/MMBtu	$300	$554	$855	$594	$(614)	8.4%
$8 CDN/MMBtu	$496	$702	$1,198	$752	$163	10.4%
$9 CDN/MMBtu	$750	$841	$1,591	$902	$897	12.2%
$10 CDN/MMBtu	$1,138	$965	$2,103	$1,034	$1,530	13.6%

Gas Price Scenarios	NS Royalties	NS CIT	NS CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$11 CDN/MMBtu	$1,524	$1,089	$2,613	$1,166	$2,165	15.0%
$12 CDN/MMBtu	$1,951	$1,207	$3,158	$1,293	$2,771	16.3%
$13 CDN/MMBtu	$2,322	$1,332	$3,655	$1,428	$3,416	17.6%
$14 CDN/MMBtu	$2,879	$1,432	$4,311	$1,535	$3,930	18.6%
$15 CDN/MMBtu	$3,305	$1,550	$4,855	$1,661	$4,537	19.7%
$16 CDN/MMBtu	$3,558	$1,693	$5,251	$1,814	$5,266	21.0%

At $12 CDN/MMBtu, private producers receive the required 15% rate of return on investment under the NL royalty framework. The NS royalty framework allows for a higher return to producers relative to the NL framework, thus reaching the minimum 15% rate of return at $11 CDN/MMBtu. At $11 CDN/MMBtu, producer after-tax revenue is 37% higher under the NS royalty structure, totaling $2,165 CDN million versus $1,585 CDN million under the NL royalty structure. This allows producers to reach a 15% rate of return sooner relative to the NL royalty framework, at $11 CDN/MMBtu versus $12 CDN/MMBtu.

Although the required rate of return is satisfied at a lower natural gas price using the NS royalties, provincial royalties are higher under the NL framework, totaling 2,784 CDN million at $12 CDN/MMBtu compared to $1,951 CDN million at the same price level under the NS royalty system. The relatively higher royalties collected under the NL royalty framework results in lower CIT collected by the province than CIT that accrues under the NS royalty structure.[25] Total provincial revenue, which is the summation of royalties and provincial CIT, is higher at all price levels under the NL type royalties, relative to the NS type royalty structure.

LNG prices in Europe are expected to increase to $13.86 CDN/MMBtu by 2016 (France Oil & Gas Report, 2012). At a price of $13 CDN/MMBtu, the rate of return under the NL and NS royalty frameworks are 16.2% and 17.6%, respectively. Prices are

[25] Royalties are deductible from the CIT, which explains why the CIT are higher under the NS-type royalty structure. The NL-type royalties are higher relative to the NS-type royalties.

expected to reach a level in which the minimum rate of return is satisfied and exceeded based on the smallest of the three reserve scenarios. This implies that the LNG project will be economically viable under all three reserve scenarios. Any increase in viable natural gas reserves will result in a lower gas price needed to satisfy the 15% rate of return requirement. In addition, higher natural gas reserves yield relatively higher rates of return for all gas price scenarios, when compared to returns using smaller natural gas reserve amounts.

6.4.2. 5 TCF Reserve Scenario

This is apparent when adding an additional trillion cubic feet to total natural gas reserves, from 4tcf to 5tcf. The natural gas price that is required to reach a 15% rate of return is $10 CDN/MMBtu under the NL royalty structure and $9 CDN/MMBtu using NS type royalties. The rate of return for the forecasted price of $13 CDN/MMBtu has also increased relative to the 4tcf scenario. Under the NL framework, the rate of return is 19.5% at $13 CDN/MMBtu, an increase of 33% compared to the 4tcf scenario in which the rate of return at the same price is 16.2%. There is also an increase in the rate of return under the NS royalty framework at the forecasted price of $13 CDN/MMBtu, from 17.6% with 4tcf to 21% in the 5tcf reserve case. Higher natural gas reserves lead to higher returns for the producer.

Table 6.8. NL Royalty Structure: Revenues (Millions of $CDN) at Various Gas Price Scenarios: Discounted @ 10% (5TCF)

Gas Price Scenarios	NL Royalties	NL CIT	NL CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$6 CDN/MMBtu	$625	$596	$1,221	$639	$(392)	9.0%
$7 CDN/MMBtu	$1,121	$746	$1,867	$799	$398	11.0%
$8 CDN/MMBtu	$1,722	$883	$2,605	$946	$1,110	12.7%
$9 CDN/MMBtu	$2,429	$1,006	$3,436	$1,078	$1,743	14.1%
$10 CDN/MMBtu	$3,007	$1,148	$4,155	$1,230	$2,469	15.6%
$11 CDN/MMBtu	$3,630	$1,283	$4,913	$1,375	$3,163	17.1%
$12 CDN/MMBtu	$4,322	$1,408	$5,730	$1,509	$3,808	18.3%
$13 CDN/MMBtu	$5,064	$1,527	$6,591	$1,636	$4,417	19.5%

Gas Price Scenarios	NL Royalties	NL CIT	NL CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$14 CDN/MMBtu	$5,855	$1,639	$7,493	$1,756	$4,992	20.6%
$15 CDN/MMBtu	$6,690	$1,744	$8,434	$1,868	$5,534	21.6%
$16 CDN/MMBtu	$7,569	$1,843	$9,412	$1,975	$6,047	22.6%

Table 6.9. NS Royalty Structure: Revenues (Millions of $CDN) at Various Gas Price Scenarios: Discounted @ 10% (5TCF)

Gas Price Scenarios	NS Royalties	NS CIT	NS CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$6 CDN/MMBtu	$392	$628	$1,020	$673	$(225)	9.4%
$7 CDN/MMBtu	$623	$815	$1,438	$873	$754	11.8%
$8 CDN/MMBtu	$1,138	$964	$2,102	$1,033	$1,526	13.6%
$9 CDN/MMBtu	$1,666	$1,112	$2,778	$1,192	$2,288	15.3%
$10 CDN/MMBtu	$2,217	$1,257	$3,475	$1,347	$3,032	16.8%
$11 CDN/MMBtu	$2,819	$1,396	$4,214	$1,495	$3,742	18.2%
$12 CDN/MMBtu	$3,304	$1,550	$4,854	$1,660	$4,533	19.7%
$13 CDN/MMBtu	$3,845	$1,696	$5,541	$1,817	$5,285	21.0%
$14 CDN/MMBtu	$4,538	$1,821	$6,360	$1,951	$5,929	22.0%
$15 CDN/MMBtu	$4,903	$1,993	$6,895	$2,135	$6,807	23.4%
$16 CDN/MMBtu	$5,574	$2,122	$7,696	$2,274	$7,464	24.4%

Similar to the 4tcf case, royalties accruing to the government of Newfoundland and Labrador are higher under the NL royalty case relative to the NS royalty system. At $9 CDN/MMBtu, royalties under the NL structure total $2,429 CDN/MMBtu, 31% higher than royalties under the NS framework, which total $1,666 CDN/MMBtu. As royalties are deductible from CIT, the NS type royalty system results in higher provincial CIT than the NL royalty framework. At the forecasted price of $13 CDN/MMBtu, CIT under the NS type royalties are $1,696 CDN million, 10% higher than those under the NL structure. However, the relatively higher provincial royalties under the NL framework leads to

higher combined provincial revenue at all price levels, compared to the NS royalty system.

Lower provincial revenue under the NS royalty system results in higher after-tax returns for producers. At the minimum required price for a 15% rate of return under the NL royalty structure ($10 CDN/MMBtu), producer returns total $3,032 CDN million under the NS royalty system, which is 19% higher than producer returns using NL type royalties, which total $2,469 CDN million. As in the 4tcf case, the difference in after-tax producer revenue results in a lower necessary gas price under the NS system relative to the NL royalty structure, in order for producers to reach their minimum required 15% rate of return.

As reserves continue to increase, the higher tiers of the NS royalty begin to take effect[26], which closes the gap between the natural gas prices required for producers to receive a 15% rate of return.

6.4.3. 6 TCF Reserve Scenario

Under the 6tcf reserve scenario, $8 CDN/MMBtu satisfies the 15% rate of return requirement under both royalty structures. At this price, the rate of return is 6% higher under the NS royalty structure (16.4%) relative to the NL royalty framework (15.4%). At $7 CDN/MMBtu, neither of the NS or NL royalty frameworks reaches the required rate of return. Similar to the other reserve scenarios, royalties are higher under the NL royalty framework relative to the NS type royalties. At the forecasted price of $13 CDN/MMBtu, NL type royalties are 25% higher than NS structured royalties, which total $7,212 CDN million and $5,436 CDN million, respectively.

Table 6.10. NL Royalty Structure: Revenues (Millions of $CDN) at Various Gas Price Scenarios: Discounted @ 10% (6TCF)

Gas Price Scenarios	NL Royalties	NL CIT	NL CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$6 CDN/MMBtu	$1,050	$809	$1,859	$866	$727	11.8%

[26] See Appendix E.

Gas Price Scenarios	NL Royalties	NL CIT	NL CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$7 CDN/MMBtu	$1,753	$977	$2,730	$1,047	$1,591	13.7%
$8 CDN/MMBtu	$2,589	$1,127	$3,715	$1,207	$2,360	15.4%
$9 CDN/MMBtu	$3,515	$1,264	$4,779	$1,354	$3,066	16.8%
$10 CDN/MMBtu	$4,333	$1,416	$5,750	$1,518	$3,848	18.4%
$11 CDN/MMBtu	$5,227	$1,558	$6,785	$1,669	$4,577	19.8%
$12 CDN/MMBtu	$6,188	$1,690	$7,878	$1,811	$5,258	21.1%
$13 CDN/MMBtu	$7,212	$1,814	$9,026	$1,943	$5,893	22.3%
$14 CDN/MMBtu	$8,295	$1,930	$10,224	$2,067	$6,487	23.4%
$15 CDN/MMBtu	$9,384	$2,045	$11,429	$2,191	$7,074	24.4%
$16 CDN/MMBtu	$10,487	$2,159	$12,646	$2,313	$7,651	25.3%

Table 6.11. NS Royalty Structure: Revenues (Millions of $CDN) at Various Gas Price Scenarios: Discounted @ 10% (6TCF)

Gas Price Scenarios	NS Royalties	NS CIT	NS CIT & Royalty Revenue	Federal CIT	NCF Private Sector Operator	IRR
$6 CDN/MMBtu	$757	$849	$1,606	$910	$936	12.3%
$7 CDN/MMBtu	$1,368	$1,030	$2,398	$1,104	$1,865	14.4%
$8 CDN/MMBtu	$1,961	$1,214	$3,175	$1,301	$2,808	16.4%
$9 CDN/MMBtu	$2,585	$1,393	$3,978	$1,493	$3,728	18.2%
$10 CDN/MMBtu	$3,317	$1,557	$4,875	$1,669	$4,572	19.7%
$11 CDN/MMBtu	$4,033	$1,724	$5,757	$1,847	$5,427	21.2%
$12 CDN/MMBtu	$4,700	$1,897	$6,597	$2,033	$6,317	22.6%
$13 CDN/MMBtu	$5,436	$2,061	$7,498	$2,209	$7,156	23.9%
$14 CDN/MMBtu	$5,900	$2,265	$8,165	$2,427	$8,187	25.5%
$15 CDN/MMBtu	$6,783	$2,409	$9,192	$2,581	$8,921	26.4%
$16 CDN/MMBtu	$7,697	$2,550	$10,246	$2,732	$9,632	27.3%

Producer revenues, like the 4tcf and 5tcf cases, are higher under the NS royalty framework for all gas price scenarios, which reflects the fact that combined provincial

royalty and CIT revenues are greater under the NL framework compared to the NS type royalties from $6 CDN/MMBtu to $16 CDN/MMBtu. Although the required price scenario is $8 CDN/MMBtu for both the NL and NS royalty scenarios, the producer after-tax revenue under the NS structure is 19% higher relative to producer after-tax revenue under the NL framework. At the forecasted price of $13 CDN/MMBtu, producers earn a higher rate of return under the NS royalty structure (23.9%) versus the 22.3% rate of return with the NL type royalties.

7. Discussion

In all gas reserve scenarios, the rate of return for all gas price scenarios is higher under the NS royalty framework, while provincial royalties are higher using the NL royalty system. The provincial government receives greater benefit in terms of royalty revenue using their own royalty system, while producers prefer the NS system, which yields higher private returns for all gas reserve scenarios. Table 12 below summarizes the rates of return for the three reserve scenarios, illustrating both the NL and NS royalty structures.

Table 7.1. Comparison of IRR: Various Price and Reserve Scenarios (NL & NS)

	4 TCF		5 TCF		6 TCF	
Gas Price Scenarios	**NL**	**NS**	**NL**	**NS**	**NL**	**NS**
$6 CDN/MMBtu	5.6%	6.0%	9.0%	9.4%	11.8%	12.3%
$7 CDN/MMBtu	7.7%	8.4%	11.0%	11.8%	13.7%	14.4%
$8 CDN/MMBtu	9.4%	10.4%	12.7%	13.6%	15.4%	16.4%
$9 CDN/MMBtu	10.8%	12.2%	14.1%	15.3%	16.8%	18.2%
$10 CDN/MMBtu	12.3%	13.6%	15.6%	16.8%	18.4%	19.7%
$11 CDN/MMBtu	13.7%	15.0%	17.1%	18.2%	19.8%	21.2%
$12 CDN/MMBtu	15.0%	16.3%	18.3%	19.7%	21.1%	22.6%
$13 CDN/MMBtu	16.2%	17.6%	19.5%	21.0%	22.3%	23.9%
$14 CDN/MMBtu	17.3%	18.6%	20.6%	22.0%	23.4%	25.5%
$15 CDN/MMBtu	18.3%	19.7%	21.6%	23.4%	24.4%	26.4%
$16 CDN/MMBtu	19.3%	21.0%	22.6%	24.4%	25.3%	27.3%

As the amount of recoverable reserves increases, the rate of return increases as well. The price that is necessary to achieve a 15% rate of return decreases as the amount of total reserves increases, implying that as the amount of recoverable reserves increases, the project becomes more profitable.

Based on the 4tcf scenario, the project will earn a 15% rate of return at $12 CDN/MMBtu under the NL royalty framework, and at $11 CDN/MMBtu under the NS royalty structure. Using the 5TCF scenario, a 15% rate of return is satisfied at lower price scenarios for both the NL and NS royalty structures relative to the 4 TCF scenario. The minimum price scenario required under the NL royalty framework is $10 CDN/MMBtu, and $9 CDN/MMBtu under the NS royalty structure. In the case of the 6TCF scenario, a 15% rate of return occurs when the price scenario is $8 CDN/MMBtu for both NL and NS type royalties.

The current National Balancing Point (NBP) and Henry Hub (HH) prices are shown in the figure below. The graph profiles all price ranges for which a 15% rate of return is achieved using both the NS and NL royalty structures.Given the current price of natural gas in European natural gas markets ($10.80 US/MMBtu), none of the reserve scenarios are economically viable. However, given that prices are expected to increase to $13.86/MMBtu by 2016, the project will earn a 15% rate of return under all reserve scenarios. The US is not a viable LNG export destination, as the price is $4.40 US/MMBtu, and is not expected to increase above $7 US/MMBtu before 2035 (EIA, January 2012).

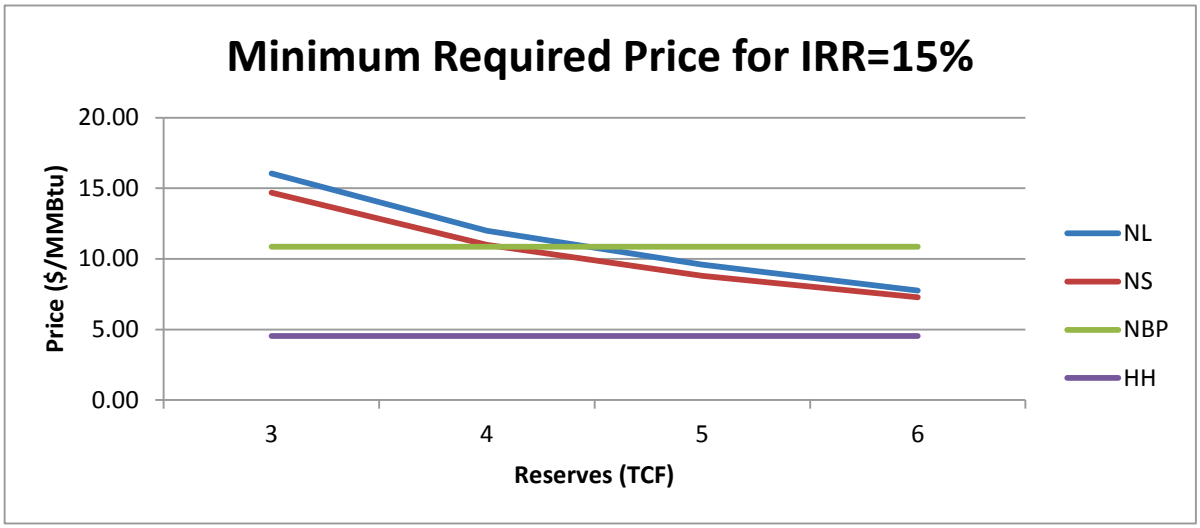

Figure 7.1. Minimum Required Price for IRR=15%

At every price scenario, the rate of return is higher under the NS royalty scenario. The provincial royalties were higher for the NL royalty framework in Tables 6-11,

resulting in relatively lower after-tax producer revenue compared to the NS royalty structure. The higher after-tax producer revenue under the NS royalty structure, for all reserve scenarios, yields a higher relative rate of return compared to the NL royalty framework. With respect to producer revenues and the rate of return earned by the producer, the NS royalty structure is more favorable. In all reserve scenarios, the producer after-tax revenue is greater when the NS royalty structure is applied. From the perspective of the producer, the NS royalty structure is preferable.

The necessary gas price scenarios, in which the minimum 15% rate of return are attained, are comparable for the NL and NS royalty structures. In the case of the 4tcf and 5tcf reserve scenarios, there is only a $1 CDN/MMBtu difference between the minimum gas prices required to ensure the producer receives a 15% rate of return. In the 6TCF reserve scenario, the required price is the same for both royalty structures at $8 CDN/MMBtu.

Based on the results of the analysis comparing the NL and NS royalty structures across various price scenarios and reserve scenarios, the NL-type royalty provides greater revenue generation for the government of Newfoundland and Labrador. In all reserve scenarios, the provincial royalties are higher under the NL-type royalty scenario relative to the NS-type royalty scenario. It is of greater benefit to the province to implement the NL-type royalty structure for a project with similar parameters. Although the NS royalty structure earns higher CIT for the three reserve scenarios, the combined royalty and CIT revenue is higher under the NL type royalty scenario.

With all aspects taken into account, the NL-type royalty structure is preferred to the NS type royalty structure. Given that LNG prices are expected to reach $13.86 CDN/MMBtu by 2016 (France Oil & Gas Report, 2012), the project is economically viable under all reserve scenarios, for both the NS and NL royalty frameworks. Using the NL royalty framework, provincial revenue will be higher relative to the NS royalty framework, which is beneficial to the province of Newfoundland and Labrador.

8. Conclusion

The significant increase in unconventional gas reserves in the US, combined with the economic recession of 2008, resulted in a fall in US natural gas prices. Given that the US has the ability to meet its domestic demand requirements, there is no longer a large excess demand for natural gas in the US market, which decreases natural gas imports into the US. This effectively excludes the US market as a potential importer of liquefied natural gas (LNG) from Newfoundland and Labrador. On the other hand, European natural gas markets have relatively higher prices, given that demand is increasing, making an LNG terminal in Newfoundland, more likely to be economically viable.

The price of natural gas in Europe has to range from $8 CDN/MMBtu to $12 CDN/MMBtu for an LNG export terminal in Newfoundland to be economically viable, given that producers require a minimum 15% rate of return on investment. Within the scope of this analysis, LNG exports are targeted at European markets, where the price of LNG is expected to be $13.86 CDN/MMBtu by 2016. Europe is unable to meet its gas demand requirements, relying heavily on gas imports via pipeline routes and LNG imports.

Based on the analysis conducted in this project, all reserve scenarios are economically viable, as the producer will receive the minimum required rate of return based on the forecasted price of natural gas in Europe. Newfoundland and Nova Scotia royalties were compared, in which the NL royalty structure was found to be more beneficial to the province in the form of increased revenues relative to the Nova Scotia royalty framework. Higher combined royalties and corporate income taxes accrue to the province under the NL royalty structure, without hindering the viability of the project.

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Appendix A: European Markets[27]

Table A1. European Markets: Gas Production (bcm)

Country	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Spain	0	0	0.1	0.1	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
France	2	2	1.6	1.6	0.88	0.84	0.79	0.75	0.72	0.68	0.65	0.61
Italy	12	10	8.9	8.5	8.02	7.6	7	7	7	7	7	6.2
Germany	16	16	14.3	13	14.5	12.7	12.5	12	12	11.6	11	11
UK	88	80	72.1	69.6	59.1	57.1	57	55	55	53	50	48

Table A2. European Markets: Annual Growth in Gas Production

Country	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Spain	0%	100%	0%	-90%	0%	0%	0%	0%	0%	0%	0%
France	0%	-20%	0%	-45%	-5%	-6%	-5%	-4%	-6%	-4%	-6%
Italy	-16%	-11%	-5%	-6%	-6%	-9%	0%	0%	0%	0%	-13%
Germany	0%	-12%	-10%	10%	-14%	-2%	-4%	0%	-3%	-5%	0%
UK	-9%	-10%	-4%	-15%	-4%	0%	-4%	0%	-4%	-6%	-4%

Table A3. European Markets: Gas Consumption (bcm)

Country	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
UK	95	90	90.9	93.8	88.5	87.92	88.83	90.01	91.04	92.21	93.26	94.2
Germany	86	87	82.9	81.2	92.65	97.93	100.3	102.1	105.5	109.6	113.7	117.9
Italy	79	77	77.8	77.8	78.05	79.28	80.15	80.85	81.78	83.04	84.33	85.56
France	46	44	42.4	43.8	49.1	49.1	49.57	50	50.82	51.68	52.59	53.54
Spain	32	34	35.1	38.6	33.88	34.62	35.55	36.54	37.81	39.06	40.33	41.58

Table A4. European Markets: Annual Growth in Gas Consumption

Country	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
UK	-5%	1%	3%	-6%	-1%	1%	1%	1%	1%	1%	1%
Germany	1%	-5%	-2%	12%	5%	2%	2%	3%	4%	4%	4%
Italy	-3%	1%	0%	0%	2%	1%	1%	1%	2%	2%	1%
France	-5%	-4%	3%	11%	0%	1%	1%	2%	2%	2%	2%
Spain	6%	3%	9%	-14%	2%	3%	3%	3%	3%	3%	3%

[27] All calculations in the tables in Appendix A were calculated by the author using the following sources:
2005-2006: (France Oil & Gas Report, Regional Energy Market Outlook, 2008)
2007-2008: (France Oil & Gas Report, Regional Energy Market Outlook, 2010)
2009-2016: (France Oil & Gas Report, Regional Energy Market Outlook, 2012)

Table A5. European Markets: LNG Imports (bcm)

Country	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Spain	21.9	24.4	24.2	28.7	27	27.5	27.8	28.1	28.7	29.2	29.8	30
France	12.8	13.9	13	12.6	13.1	13.9	14	15	15	15	17	17
Belgium	3	4.3	3.2	2.5	6.3	6.4	6	6	6	6	7	7
Italy	3.5	3.1	2.4	1.6	2.9	8	10	12	15	15	15	15
UK	0	3.6	1.5	1	10.2	18.7	19	19.2	19.5	20	20	21

Table A6. European Markets: Annual Growth in LNG Imports

Country	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16
Spain	10%	-1%	16%	-6%	2%	1%	1%	2%	2%	2%	1%
France	8%	-7%	-3%	4%	6%	1%	7%	0%	0%	12%	0%
Belgium	30%	-34%	-28%	60%	2%	-7%	0%	0%	0%	14%	0%
Italy	-13%	-29%	-50%	45%	64%	20%	17%	20%	0%	0%	0%
UK	100%	-	-50%	90%	45%	2%	1%	2%	3%	0%	5%

Appendix B: Production Costs[28]

Table B1. Gravity Based Structure (GBS) Costs ($US)

	Quantity	Unit	Unit Rate	Cost ($US)
MATERIALS				
Concrete	84,624	m³	$215	$18,194,000
Steel (reinforced)	22,848	te	$890	$20,335,000
Steel (pre-stressed)	2,116	te	$2,900	$6,136,000
Solid ballast	108,319	te	$102	$11,049,000
Mechanical outfitting	1,955	te	$4,700	$9,189,000
Conductors	1,942	te	$1,950	$3,787,000
Freight	0		$68,690,000	$5,495,000
Total Materials				$74,185,000
FABRICATION				
GBS	84,624	m³	$2,209	$186,934,000
Mechanical outfitting	1,955	te	$14,632	$28,606,000
Total Fabrication				$215,540,000
INSTALLATION				
Deck mating				$14,315,000
Deck / shaft HUC	12,682	te	$920	$11,667,000
Tow out	10	day	$209,611	$2,096,000
Install	10	day	$209,611	$2,096,000
Total Installation				$30,174,000
DESIGN & PROJECT MANAGEMENT				
Design	212,000	mhr	$180	$38,160,000
Project management	103,500	mhr	$305	$31,568,000
Total Design & Project management				$69,728,000
INSURANCE & CERTIFICATION				
Certification	0		$389,627,000	$3,896,000
Insurance	0		$389,627,000	$15,585,000
Total Insurance & Certification				$19,481,000
CONTINGENCY				
Contingency	0		$409,108,000	$61,366,000
Total Contingency				$61,366,000
Total Cost: GBS Construction				$470,474,000

[28] All tables in Appendix B were sourced using the program Que$tor, and provided by Nalcor Energy.

Table B2. GBS Fabrication Detail Costs ($US)

	Quantity	Meas. Units	Man Hours /Unit	Man Hours (mhr)	Cost/ mhr	Unit Rate	Cost ($USD)
GBS	84,624	m³	24	2,030,976	92	$2,210	$187,019,000
Mechanical	1,955	te	159	310,834	92	$14,600	$28,543,000
Total Fabrication Costs							$215,562,000

Table B3. Total Cost GBS ($US)

GBS Construction	$470,474,000
Fabrication Detail	$215,562,000
Total Cost GBS	**$686,036,000**

Table B4. Primary Costs: Topside A ($US)

	Quantityy	Meas.Unitss	Unit Rate Rate	Cost
EQUIPMENT				
Manifolding	213	te	$17,500	$3,728,000
Oil processing				
Separation	176	te	$21,000	$3,696,000
Heating	15	te	$27,000	$405,000
Shell & tube cooling	8	te	$27,000	$216,000
Oil export	67	te	$41,100	$2,754,000
Gas processing				
Gas cooling				
Shell & tube	39	te	$27,000	$1,053,000
Gas dehydration				
Glycol	237	te	$22,500	$5,333,000
Dewpointing				
LTS / exchanger	215	te	$23,000	$4,945,000
Turbo expander	40	te	$51,000	$2,040,000
Gas metering	38	te	$31,500	$1,197,000
Gas compression				
Compressors and turbine drivers	240	te	$128,700	$30,888,000
Scrubbers	69	te	$23,500	$1,622,000
Shell & tube coolers	66	te	$25,500	$1,683,000
Water injection				
Control and communications	18	te	$640,400	$11,527,000
Quarters and helideck	1,002	te	$15,400	$15,431,000
Process utilities	688	te		$29,177,000
Flare structure	609	te	$9,400	$5,725,000

	Quantityy	Meas.Unitss	Unit Rate Rate	Cost
Power				
Power generation	216	te	$56,500	$12,204,000
Power distribution	98	te	$44,000	$4,312,000
Emergency power	24	te	$19,200	$461,000
Freight	7%			$9,688,000
Total Equipment				$148,085,000
MATERIALS				
Primary steel	1,997	te	$2,000	$3,994,000
Secondary steel	2,853	te	$1,810	$5,164,000
Piping	1,143	te	$15,400	$17,602,000
Electrical	338	te	$18,600	$6,287,000
Instruments	352	te	$46,500	$16,368,000
Others	533	te	$7,700	$4,104,000
Freight	7%			$3,746,000
Total Materials				$57,265,000
FABRICATION				
Primary steel	1,997	te	$14,500	$28,957,000
Secondary steel	2,853	te	$19,100	$54,492,000
Equipment	2,467	te	$3,960	$9,769,000
Piping	1,143	te	$39,500	$45,149,000
Electrical	338	te	$70,400	$23,795,000
Instruments	352	te	$72,300	$25,450,000
Others	533	te	$29,000	$15,457,000
Loadout and seafasten	5%			$10,153,000
Total Fabrication				$213,222,000
INSTALLATION				
Tugs transport	30	day	$55,200	$1,656,000
Tugs mob/demob	8	day	$55,200	$442,000
Barge transport	70	day	$12,300	$861,000
Barge mob/demob	8	day	$12,300	$98,000
Installation spread	9	day	$1,584,900	$14,264,000
Installation spread mob/demob	8	day	$1,584,900	$12,679,000
Total Installation				$30,000,000
HOOK-UP AND COMMISSIONING				
Atshore HUC	261,366	mhr	$102	$26,659,000
Inshore HUC	37,338	mhr	$173	$6,459,000
Offshore HUC	136,550	mhr	$245	$33,455,000
Total Hook-up and commissioning				$66,573,000
DESIGN & PROJECT MANAGEMENT				
Design	730250	mhr	$180	$131,445,000

	Quantityy	Meas.Unitss	Unit Rate Rate	Cost
Project management	95640	mhr	$305	$29,170,000
Total Design & Project management				$160,615,000
INSURANCE & CERTIFICATION				
Certification	1%			$6,758,000
Insurance	4%			$27,030,000
Total Insurance & Certification				$33,788,000
CONTINGENCY				
Contingency	10%			$70,955,000
Total Contingency				$70,955,000
Total Cost Topside A:				**$780,503,000**

Table B5. Primary Cost Topside B ($US)

	Quantity	Unit	Unit Rate	Cost ($US)
EQUIPMENT				
Manifolding	22	te	$17,500	$385,000
Water injection				
Control and communications	3	te	$184,000	$552,000
Quarters and helideck	70	te	$15,400	$1,078,000
Process utilities	45	te		$919,000
Flare structure	100	te	$9,400	$940,000
Power				
Power generation	8	te	$51,000	$408,000
Power distribution	6	te	$44,000	$264,000
Emergency power	2	te	$10,500	$21,000
Freight	0.07		$4,567,000	$320,000
Total Equipment				$4,887,000
MATERIALS				
Primary steel	223	te	$2,000	$446,000
Secondary steel	123	te	$1,810	$223,000
Piping	39	te	$15,400	$601,000
Electrical	18	te	$18,600	$335,000
Instruments	16	te	$46,500	$744,000
Others	21	te	$7,700	$162,000
Freight	0.07		$2,511,000	$176,000
Total Materials				$2,687,000
FABRICATION				
Primary steel	223	te	$14,500	$3,234,000
Secondary steel	123	te	$19,100	$2,349,000

	Quantity	Unit	Unit Rate	Cost ($US)
Equipment	86	te	$3,960	$341,000
Piping	39	te	$39,500	$1,541,000
Electrical	18	te	$70,400	$1,267,000
Instruments	16	te	$72,300	$1,157,000
Others	21	te	$29,000	$609,000
Loadout and seafasten	0.05		$10,498,000	$525,000
Total Fabrication				$11,023,000
INSTALLATION				
Tugs transport	30	day	$28,600	$858,000
Tugs mob/demob	8	day	$28,600	$229,000
Barge transport	70	day	$6,650	$466,000
Barge mob/demob	8	day	$6,650	$53,000
Installation spread	7	day	$194,300	$1,360,000
Total Installation				$2,966,000
HOOK-UP AND COMMISSIONING				
Atshore HUC	5277	mhr	$102	$538,000
Offshore HUC	3877	mhr	$245	$950,000
Total Hook-up and commissioning				$1,488,000
DESIGN & PROJECT MANAGEMENT				
Design	51150	mhr	$180	$9,207,000
Project management	8220	mhr	$305	$2,507,000
Total Design & Project management				$11,714,000
INSURANCE & CERTIFICATION				
Certification	0.01		$34,765,000	$348,000
Insurance	0.04		$34,765,000	$1,391,000
Total Insurance & Certification				$1,739,000
CONTINGENCY				
Contingency	0.1		$36,504,000	$3,650,000
Total Contingency				$3,650,000
Total Cost / Topside				$40,154,000

Table B6. Topsides A&B Fabrication Detail ($US)

	Quantity (te)	Man Hours/Unit	Man Hours (mhr)	Cost/m hr	Unit Rate	Cost ($US)
Primary steel	1,997	158	315,526	92	$14,500	$28,957,000
Secondary Steel	2,853	208	593,424	92	$19,100	$54,492,000
Equipment	2,467	43	106,081	92	$3,960	$9,769,000
Piping	1,143	429	490,347	92	$39,500	$45,149,000

	Quantity (te)	Man Hours/Unit	Man Hours (mhr)	Cost/m hr	Unit Rate	Cost ($US)
Electrical	338	765	258,570	92	$70,400	$23,795,000
Instruments	352	786	276,672	92	$72,300	$25,450,000
Others	533	315	167,895	92	$29,000	$15,457,000
Total Fabrication Cost						$203,069,000

Table B7. Topsides A&B Process Utilities ($US)

	Quantity (te)	Unit Rate	Cost ($US)
PROCESS SUPPORT UTILITIES			
Produced water	4.4	$25,500	$112,200
Heating medium	29.8	$23,000	$685,400
Cooling medium	198.1	$72,000	$14,263,200
Flare and vent	36.5	$15,000	$547,500
Seawater lift	39	$64,000	$2,496,000
Fuel gas	19.2	$43,500	$835,200
Chemical injection and storage	11.7	$40,500	$473,850
Total Process support utilities			$19,413,350
GENERAL UTILITIES			
Closed drains	42.4	$16,700	$708,080
Open drains	7.2	$16,700	$120,240
Diesel storage	1	$30,500	$30,500
Aviation fuel	15	$45,000	$675,000
Instrument and plant air	4.8	$29,500	$141,600
Inert gas	38.9	$60,000	$2,334,000
Potable water	8.2	$35,500	$291,100
Sewage treatment	2.5	$21,000	$52,500
Firefighting	58.1	$35,500	$2,062,550
Total General utilities			$6,415,570
ANCILLARIES			
Mechanical handling	150	$19,000	$2,850,000
HVAC	2.3	$20,500	$47,150
Lifeboats	18.9	$24,000	$453,600
Total Ancillaries			$3,350,750
Total Processing Cost			**$29,179,670**

Table B8. Total Topside Construction Cost ($US)

Source:	Cost ($US)
Topside A Construction	$780,503,000
Topside B Construction	$40,154,000
Fabrication Detail	$203,069
Equipment	$2,917,670

Table B9. Total Cost of GBS & Topsides ($US)

Topsides	Cost ($US)
Topside A Construction	$780,503,000
Topside B Construction	$40,154,000
Fabrication Detail	$203,069
Equipment	$2,917,670
GBS	
GBS Construction	$470,474,000
Fabrication Detail	$215,562,000
Total Cost	$1,509,813,739

Appendix C: Pipeline Costs

Table C1. Pipeline Sensitivity Analysis (Millions of $US)[29]

Distance: 640 km Trenching: 64 km			
	Cost (Millions $US)		
Pipeline Diameter (inches)	500MMscfd	750MMscfd	1000Mcfd
24	977	1,122	1,399
26	1,085	1,103	1,310
28	1,104	1,221	1,284
30	1,172	1,310	1,327
32	1,236	1,335	1,481
34	1,258	1,416	1,572
36	1,313	1,425	1,647
38	1,426	1,484	1,599
40	1,483	1,544	1,665

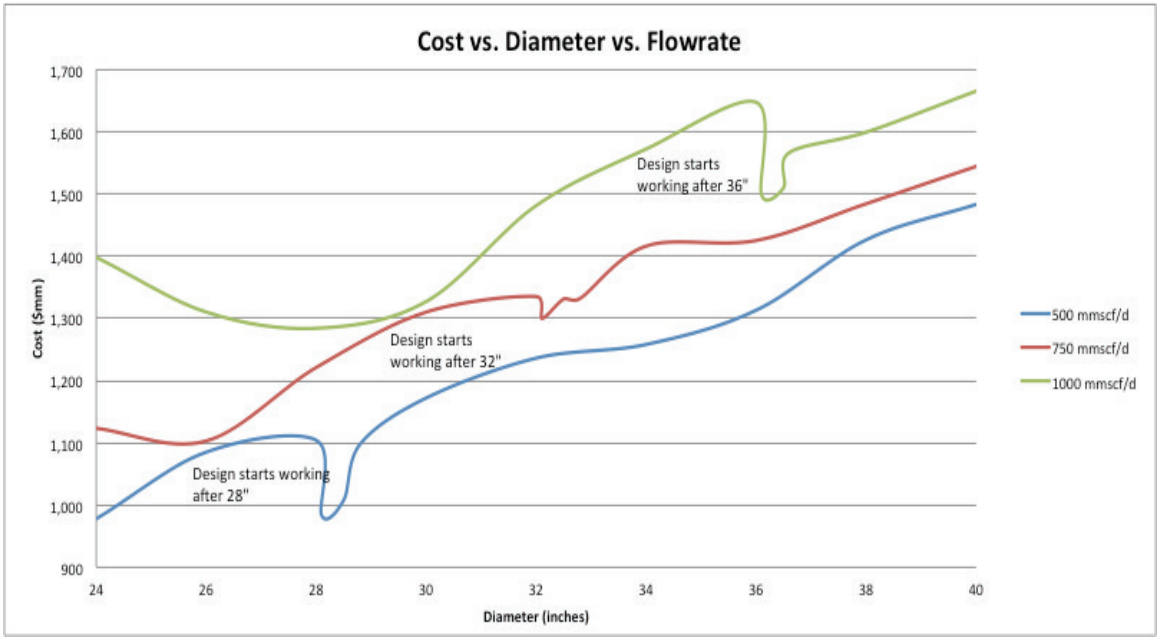

Figure C1. Pipeline Cost vs. Diameter vs. Flowrate[30]

[29] Nalcor Energy has provided all tables (using Que$tor) and graphs in Appendix C.

Table C2: Pipeline CAPEX (Millions of $US)

Distance: 640 km **Trenching: 64 km** **Throughput: 750 MMscfd** **Pipeline Diameter: 34”**				
	Quantity	**Meas. Unit**	**Unit Rate ($US)**	**Cost ($US)**
MATERIALS				
Linepipe	640	km	$993,259	$635,686,000
Coating	640	km	$97,000	$62,080,000
Weight Coating	640	km	$74,000	$47,360,000
Anodes	1736	te	$5,000	$8,680,000
Subsea emer. shutdown valve systems	1		$4,150,000	$4,150,000
Export end riser	110	m	$2,150	$237,000
Export spools, flanges & fittings	1		$760,000	$760,000
Freight	5	%		$37,948,000
Total Materials				$796,901,000
INSTALLATION				
Pipelay spread	522	days	$521,472	$272,208,000
Pipelay spread mob / demob	8	days	$521,472	$4,172,000
Diving support vessel tie ins	26	days	$112,474	$2,924,000
Diving support vessel test & commissioning	50	days	$112,474	$5,624,000
Diving support vessel mob / demob	8	days	$112,474	$900,000
Testing & commissioning equipment	62	days	$37,832	$2,346,000
Trenching	30	days	$400,000	$12,000,000
Trenching mob / demob	8	days	$184,049	$1,472,000
Surveying	141	days	$117,587	$16,580,000
Surveying sail and return	8	days	$117,587	$941,000
Shore approach				$7,260,000
Total Installation				$326,427,000
DESIGN & PROJECT MANAGEMENT				
Design	77,000	mhr	180	$13,860,000
Project Management	115,500	mhr	305	$35,228,000
Total Design & Project Management				$49,088,000
INSURANCE & CERTIFICATION				
Certification	1	%		$11,724,000

[30] Note: Pipeline diameters below the following measurements will exceed the planges rating, which will negatively affect the flowrate. 500MMscfd: 30”; 750MMscfd: 34”; 1000MMscfd: 38”

Distance: 640 km **Trenching: 64 km** **Throughput: 750 MMscfd** **Pipeline Diameter: 34”**				
	Quantity	**Meas. Unit**	**Unit Rate ($US)**	**Cost ($US)**
Insurance	4	%		$46,897,000
Total Insurance & Certification				$58,621,000
CONTINGENCY				
Total Contingency	15	%		$184,656,000
Total Cost ($US)				$1,415,693,000

Appendix D: LNG Terminal Costs[31]

Table D1. Total Cost LNG Project ($US)

Production: 6Mpta	Cost ($US)	High Level Nalcor Estimate ($US)
LNG Facility	$2,928,000,000	$2,930,000,000
Total Cost	$3,276,183,000	$3,281,800,000

Table D2. LNG Project CAPEX Costs ($US)

Component	Quantity	Unit	Unit Rate	Cost ($USD)	High Level Nalcor Cost Estimate ($USD)
MARINE INFRASTRUCTURE					
Unloading arm	3		$1,058,000	$3,174,000	$3,200,000
Vapour return arm	1		$1,058,000	$1,058,000	$1,000,000
LNG metering	268	te	$51,300	$13,748,000	$14,000,000
LNG STORAGE	2,829,000	bbl	$97	$274,413,000	$275,000,000
MATERIALS					
Berth	345	m	$37,500	$12,938,000	$13,200,000
Jetty	750	m	$25,000	$18,750,000	$20,000,000
Breakwater	900	m	$3,400	$3,060,000	$3,200,000
CONSTRUCTION					
Berth construction	345	m	$16,800	$5,796,000	$6,000,000
Jetty construction	750	m	$16,800	$12,600,000	$13,200,000
Breakwater construction	900	m	$2,940	$2,646,000	$3,000,000
Total				$348,183,000	$351,800,000

[31] All tables in Appendix D have been provided by Nalcor Energy, using the program Que$tor.

Appendix E: Royalties

Table E1. Newfoundland Basic Royalty: Offshore Natural Gas Royalty[32]

Netback Price (NP)*	Basic Royalty Rate (BRR)
<Cdn \$4(NP_{min})	2% (BRR_{min})
>Cdn \$8 (NP_{max})	10% (BRR_{max})
*Netback Price is the calculated price to the project net of transportation costs	
Basic Royalty = (revenue – transportation costs) × BRR $BRR = BRR_{min} + \{[(NP - NP_{min}) \div (NP_{max} - NP_{min})] \times (BRR_{max} - BRR_{min})\}$	

Table E2. Newfoundland Net Royalty: Offshore Natural Gas Royalty[33]

R Factor (R)*	Net Royalty Rate (NRR)
<1 (R_{min})	0% (NRR_{min})
>4 (R_{max})	50% (NRR_{max})
*R = (cumulative revenue less cumulative transportation costs less cumulative royalty paid) ÷ (cumulative project capital & operating costs)	
Net Royalty = (revenue – transportation costs – project capital & operating costs – basic royalty paid) × NRR $NRR = NRR_{min} + \{[(R - R_{min}) \div (R_{max} - R_{min})] \times (NRR_{max} - NRR_{min})\}$	

Table E3. Nova Scotia Generic Royalty Structure[34]

	Gross Revenue Royalty
Tier 1	2% GR, until simple payout + RA based on 5% + LTBR
Tier 2	5% GR, until simple payout + RA based on 20% + LTBR
	Net Revenue Royalty
Tier 3	20% NR until simple payout + RA based on 45% + LTBR*
Tier 4	35% NR*
*Minimum of 5% GR payable	
Gross Revenues (GR): The value of petroleum leaving the boundary of an offshore project	
LTBR: Long Term Government of Canada Bond Rate (10 year)	
Net Revenue (NR): The gross revenue of a project less the costs associated with getting the petroleum to the project boundary.	
Return Allowance (RA): A percentage of unrecovered project costs. Once simple payout is achieved, the return allowance ceases to be calculated.	

[32] (Government of Newfoundland & Labrador [Gov't NL&Lab], 2006).

[33] (Gov't NL&Lab, 2006).

[34] (Government of Nova Scotia, 2009).