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COMPETITIVE ANALYSIS OF CANADIAN LNG



COMPETITIVE ANALYSIS OF CANADIAN LNG

Competitive Analysis of Canadian LNG

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ISBN 1-927037-57-7

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July 2018

Printed in Canada

Front cover photo courtesy of Google images

Acknowledgements:

The authors of this report would like to extend their thanks and sincere gratitude to:

- Geoffrey Cann, Partner (retired), Deloitte
- David Campbell, President, Jupia Consultants Inc.
- John Baguley, COO, LNG Limited/Bear Head LNG
- Selina Lee-Andersen, Partner, Environmental/Aboriginal, McCarthy Tétrault LLP
- Jeremy Llewellyn, Director, Wholesale Markets, Australian Energy Regulator

The authors would also like to thank other industry, government and consulting experts as well as CERI staff that provided insightful comments and essential data inputs required for the completion of this report, as well as those involved in the production, reviewing and editing of the material, including but not limited to Allan Fogwill, Dinara Millington and Megan Murphy.

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Table of Contents

| | |
|---|------------|
| LIST OF FIGURES | v |
| LIST OF TABLES | vii |
| ACRONYMS AND ABBREVIATIONS | ix |
| EXECUTIVE SUMMARY | xi |
| CHAPTER 1 INTRODUCTION..... | 1 |
| Global LNG Overview | 1 |
| Significant Trends in LNG | 12 |
| Technological Changes..... | 12 |
| The Changing Business Model | 13 |
| Pricing and Contracts | 15 |
| Carbon Management | 18 |
| Canadian LNG Developments | 19 |
| Eastern Canada Projects | 19 |
| Western Canada Projects..... | 23 |
| Structure of the Report..... | 27 |
| CHAPTER 2 RESEARCH QUESTIONS AND METHODOLOGY..... | 29 |
| Research Questions | 29 |
| Methodology..... | 30 |
| Supply Costs | 31 |
| Pipeline Transportation Costs..... | 33 |
| LNG Shipping Costs | 35 |
| Natural Gas Feedstock Costs | 35 |
| Other Modelling Assumptions | 39 |
| Landed LNG Costs Comparison and LNG Pricing | 39 |
| Optimized Supply Costs: Sensitivity Analysis..... | 41 |
| CHAPTER 3 LNG SUPPLY COSTS AND COST DRIVERS..... | 43 |
| Western Canada..... | 43 |
| Supply Costs and Key Differentiators | 43 |
| Sourcing Natural Gas from AECO-C Hub..... | 48 |
| Government LNG-focused Incentives..... | 49 |
| Economies of Scale Effect | 51 |
| Eastern Canada | 53 |
| Supply Costs and Key Differentiators | 54 |
| Marcellus-sourced Natural Gas Supply..... | 56 |
| Maritime Provinces-sourced Shale Natural Gas Supply | 57 |
| Government LNG-focused Incentives..... | 58 |
| Canadian LNG Projects Supply Cost Comparison | 58 |
| US Gulf of Mexico | 59 |
| Greenfield LNG Project | 60 |
| Brownfield LNG Project..... | 63 |
| Addition of One Train..... | 65 |

| | |
|--|------------|
| Effect of the New US Tax Regime | 65 |
| Australia | 67 |
| CHAPTER 4 LNG COMPETITIVE ANALYSIS | 71 |
| LNG Shipping Advantages and Costs | 71 |
| Path to Competitiveness..... | 72 |
| Western Canada LNG and Asian Market | 72 |
| Eastern Canada LNG and European Market | 79 |
| Optimized Supply Costs for Locally-sourced Gas..... | 84 |
| Comparative Perspective and Other Important Factors | 84 |
| Potential Economic Impacts of LNG Projects | 86 |
| Cooperation with Indigenous Peoples on LNG Developments | 87 |
| LNG Environmental Stewardship Initiative..... | 88 |
| Capacity Building Initiatives..... | 89 |
| Economic Benefit Agreements | 90 |
| CHAPTER 5 CONCLUSION..... | 97 |
| BIBLIOGRAPHY | 105 |
| APPENDIX A SUPPLY COST ASSUMPTIONS..... | 113 |
| General Assumptions for All Liquefaction Plants | 113 |
| Project-specific Assumptions..... | 114 |
| Western Canada..... | 114 |
| Eastern Canada | 115 |
| US, Louisiana, Brownfield | 116 |
| US, Texas, Greenfield | 117 |
| US, Texas (additional train)..... | 118 |
| Australia | 119 |
| APPENDIX B PIPELINE SUPPLY COST MODEL | 121 |
| APPENDIX C SHIPPING COSTS..... | 123 |
| APPENDIX D JURISDICTIONAL COMPARISON OF NON-OPTIMIZED LNG SUPPLY COSTS .. | 125 |

List of Figures

| | | |
|------|--|------|
| E.1 | LNG Supply Costs Comparison in Canada | xiii |
| E.2 | Path to Competitiveness for Western Canada LNG..... | xiv |
| E.3 | Path to Competitiveness for Eastern Canada LNG | xv |
| 1.1 | LNG Value Chain..... | 1 |
| 1.2 | Major Trade Movements, 2017 | 2 |
| 1.3 | LNG Trade Volumes, 1990-2016 | 3 |
| 1.4 | 2016 LNG Exports and Market Share by Country | 4 |
| 1.5 | Australian LNG Supply Capacity by Liquefaction Project..... | 5 |
| 1.6 | Eastern Australia Daily Spot Natural Gas Price and LNG Export Price..... | 5 |
| 1.7 | US LNG Export Capacity | 8 |
| 1.8 | 2016 LNG Imports and Market Share by Country | 9 |
| 1.9 | Japan's Regasification Terminals | 10 |
| 1.10 | Global Regasification Capacity..... | 11 |
| 1.11 | An LNG Tanker at the Canaport LNG Terminal | 12 |
| 1.12 | Non-Long-Term LNG Trade | 14 |
| 1.13 | Historical Natural Gas and LNG Prices | 17 |
| 1.14 | Natural Gas and LNG Prices, 2013-2018..... | 18 |
| 1.15 | Maritime Natural Gas Market..... | 21 |
| 1.16 | Woodfibre LNG Location..... | 25 |
| 1.17 | LNG Canada Location | 26 |
| 2.1 | Natural Gas Transportation Costs..... | 34 |
| 2.2 | Feedstock Gas Costs for Modelled Projects | 38 |
| 2.3 | Feedstock Gas Costs for the Modelled Project..... | 39 |
| 3.1 | Natural Gas Basins, Western Canada | 43 |
| 3.2 | Western Canada LNG Project Supply Cost, Initial..... | 44 |
| 3.3 | Historic LNG Plant Capital Costs | 46 |
| 3.4 | BC LNG Environmental Incentive Program | 50 |
| 3.5 | LNG Project Costs Breakdown | 51 |
| 3.6 | LNG Economies of Scale Effect | 52 |
| 3.7 | Eastern Canada LNG Project Supply Costs (AECO-C) | 54 |
| 3.8 | Eastern Canada LNG Project Supply Costs (Marcellus vs AECO-C natural gas supply) | 57 |
| 3.9 | Eastern Canada LNG Project Supply Cost (local shale gas)..... | 58 |
| 3.10 | LNG Supply Costs Comparison, Canada | 59 |
| 3.11 | Status of LNG Export Terminals in the US Gulf of Mexico | 60 |
| 3.12 | US, Texas, Greenfield Project Supply Cost..... | 61 |
| 3.13 | US, Louisiana, Brownfield LNG Supply Cost..... | 64 |
| 3.14 | US Tax Regime Change – Effect on LNG Projects | 65 |
| 3.15 | Comparison of Former US Capital Allowance and Canada's Current Capital Allowance for LNG Plants | 66 |
| 3.16 | Australia LNG Supply Costs, Queensland..... | 67 |

| | | |
|------|--|-----|
| 3.17 | Capital Costs, Australia, Canada, US Greenfield LNG Projects | 69 |
| 4.1 | LNG Shipping Costs | 71 |
| 4.2 | Landed LNG Cost at Japan | 72 |
| 4.3 | Total Liquefaction Costs Comparison for Western Canada..... | 73 |
| 4.4 | Path to Competitiveness for Western Canada LNG..... | 75 |
| 4.5 | LNG Modules..... | 76 |
| 4.6 | Optimized Supply Cost, Western Canada LNG | 79 |
| 4.7 | Landed LNG Cost in the UK | 79 |
| 4.8 | Total Liquefaction Costs Comparison for Eastern Canada LNG..... | 80 |
| 4.9 | Path to Competitiveness for Eastern Canada LNG | 82 |
| 5.1 | Canadian LNG Project Costs..... | 98 |
| 5.2 | Cost Competitive Analysis Landed at Japan | 99 |
| 5.3 | Cost Competitive Analysis Landed at the UK..... | 100 |
| 5.4 | Optimized Canadian LNG Project Costs | 103 |
| 5.5 | Optimized Eastern Canada LNG Costs | 104 |

List of Tables

| | | |
|-----|--|-----|
| E.1 | Jurisdictional Comparison of Non-Optimized LNG Supply Costs | xvi |
| 1.1 | LNG Liquefaction Projects in Eastern Canada | 20 |
| 1.2 | Current Key LNG Liquefaction Projects in British Columbia | 24 |
| 2.1 | LNG Projects Considered for the Study | 32 |
| 2.2 | LNG Shipping Costs | 35 |
| 2.3 | Natural Gas Feedstock Costs | 37 |
| 2.4 | Key Destination Markets for LNG Projects for the Study | 40 |
| 2.5 | Natural Gas and LNG Prices for Benchmarking | 40 |
| 4.1 | Comparative Perspective on LNG Projects | 85 |
| 4.2 | Summary of Financial Benefits from Natural Gas Pipeline Benefit Agreements Between the Government of British Columbia and Indigenous Groups Potentially Impacted by the Proposed Natural Gas Pipeline Projects | 93 |
| 5.1 | Jurisdictional Comparison of Non-Optimized LNG Supply Cost | 102 |

Acronyms and Abbreviations

| | |
|--------------------|---|
| AGT | Algonquin City-Gate |
| bbl | Barrels |
| BC | British Columbia |
| Bcf | Billion cubic feet |
| Bcm | Billion cubic metres |
| Brownfield project | A project where a liquefaction capacity is added on top of existing liquefaction or regasification capacity |
| CAPEX | Capital expenses |
| CERI | Canadian Energy Research Institute |
| CSG | Coal Seam Gas |
| E&P | Exploration and Production |
| EIA | Energy Information Administration (US) |
| FID | Final investment decision |
| GoM | Gulf of Mexico |
| Greenfield project | A project where an LNG plant is built in full, irrespective of the readiness level of the site |
| HH | Henry Hub |
| km | Kilometres |
| LNG | Liquified natural gas |
| LPG | Liquefied petroleum gas |
| m ³ | Cubic metres |
| mmbtu | Million British Thermal units |
| mmcf | Million cubic feet |
| mtpa | Million tonnes per annum |
| NGL | Natural gas liquids |
| NS | Nova Scotia |
| OPEX | Operating expenses |
| TCF | Trillion cubic feet |
| US | United States |
| WCSB | Western Canadian Sedimentary Basin |
| WP | Wellhead Price |

Common Conversions

1 Million British thermal units (MMBtu) = 1.0551 Gigajoules (GJ) = 1 mcf

1 Cubic metres (m³) natural gas = 35.315 Cubic feet (cf) natural gas

1 Million Tonnes (t) LNG = 48.027 Billion Cubic feet (cf) natural gas

Million Tonnes LNG per year (mtpa) = 0.13158 Billion cubic feet natural gas per day (Bcf/d)

1 Billion cubic feet natural gas per day (Bcf/d) = 7.5997 Million tonnes LNG per year

Source: (NRCan 2016)

Executive Summary

Global natural gas consumption is positioned to grow by 45% over the next 25 years. Developing countries in Asia, Africa, Latin America, and the Middle East account for 80% of the increase in global consumption (IEA 2017).

In 2016, total global natural gas pipeline trade was 737.5 bcm while liquefied natural gas (LNG) trade was 346.6 bcm (BP 2017b). LNG accounts for 32 percent of globally traded gas and this number is expected to increase (IEA 2017). According to BP, global LNG is growing seven times faster than pipeline gas trade, and by 2035, half of all globally traded gas will be LNG (BP 2017b).

With 140 bcm of LNG capacity under construction, gas markets remain well supplied for the next few years (IEA 2017). By the mid-2020s, however, market over-capacity is absorbed by import growth. Investment in the new capacity, therefore, is needed from 2020 onwards to satisfy growing needs (IEA 2017).

The recent plunge of oil and LNG prices have deterred many projects from taking final investment decisions (FID). As the price of oil rebounded to \$75,¹ LNG spot prices followed (\$8.20 in northeast Asia at the time of writing), and project sponsors are going back to the table to review their economics and to meet customers.

Canada has world-scale proven and low-cost natural gas reserves sufficient for domestic demand and export. It also has 15+ projects proposed on the East and West coasts, four of which have received export licenses and environmental approvals and are close to FID (in addition to the 0.3 bcf/d Woodfibre LNG, which has already taken FID).

Will Canada play a role in satisfying natural gas demand globally and join the cohort of 18 export countries? The US predicts that its natural gas net imports from Canada will drop to almost zero by 2040 from its current 5.9 bcf/d (EIA 2018). As such, Canada must either position itself for the decline in natural gas production and associated economic benefits or consider growth through LNG exports.

Canada is not the only country blessed with natural gas resources. Qatar, the US, Russia, Australia, Malaysia, Nigeria, Iran, Algeria, and Mozambique all have vast gas resources. Many of these countries have already monetized them in the form of LNG, gaining valuable experience and lowering the risks for further investments. The top 5 exporters are Qatar, accounting for nearly 30 percent, followed by Australia, Malaysia, Nigeria, and Indonesia (IGU 2017). Australia and the US have recently stood out as the former will reach 85.4 mtpa in 2019 (APPEA 2018) taking a leading position in the market (IGU 2017), and the latter will have an export capacity of 73 mtpa by 2020 (EIA 2017a) almost reaching the same volumes as the current market leader – Qatar. In the US and other countries, there are more projects under regulatory and investment review.

¹ All prices are in 2018 \$US unless otherwise specified.

Qatar has also recently announced its intention to increase its volumes to 100 mtpa (OGJ 2017) from its existing 77 mtpa.

Thus, investors, particularly global energy companies, have choices. The fact that Canada does not have LNG project experience puts it at a comparative disadvantage to existing producing countries which may have options for lucrative liquefaction capacity expansion or new projects leveraging infrastructure and experience.

It means Canada needs compelling arguments for investors to choose it over other options. For the Canadian projects on the east and west coasts to move forward, the projects should be cost-competitive with international options. LNG landed costs also should be consistently lower than the expected prices at the destination markets to earn a return for investors. And finally, Canada's jurisdictions need to be attractive and stable to do long-term business, such as LNG liquefaction and exports.

The change in the pricing environment also needs to be taken into account. The price volatility of the oil market is a major uncertainty for long-term oil-linked contracts on which most financing and economics of LNG projects depend. The situation is challenging for investors as the percentage of the Brent price LNG sellers are realizing where contracts tied to oil prices have been declining from 14.5% to 11.5% as of late.² Thus, for investors to take an FID, the projects need to have solid and profitable economics under current and prudent pricing forecasts.

In this study, CERI explores questions and compares Canada's projects in two jurisdictions (British Columbia and Nova Scotia) with counterparts in the US Gulf of Mexico (Texas and Louisiana) and Australia.³ Supplies from other competitors – Russia, Mozambique, Nigeria and Qatar – were not included in the scope of this study. Approximately 45 mtpa are anticipated by proponents in countries other than the US and Australia that could come onstream after 2021 (LNG Journal 2018).

Our results show that Canadian supply costs (hereinafter supply costs do not include transportation costs, while landed costs do) for Eastern and Western LNG are from \$8.09-\$8.35 per mmbtu for the integrated model, when natural gas is produced by LNG facility owners, to \$9.85-\$11.17 for the merchant business model, when natural gas is bought on the market (Figure E.1). For Eastern Canada, the integrated model implies the development of onshore local shale gas in Nova Scotia, which is currently under a provincial hydraulic fracturing ban. New Brunswick's shale gas could also be a source of natural gas but it is not considered in the study.

For integrated projects, Eastern Canada projects hold a slight advantage of \$0.36 over Western Canada, primarily due to advantages in lower capital and transportation costs as the gas resource

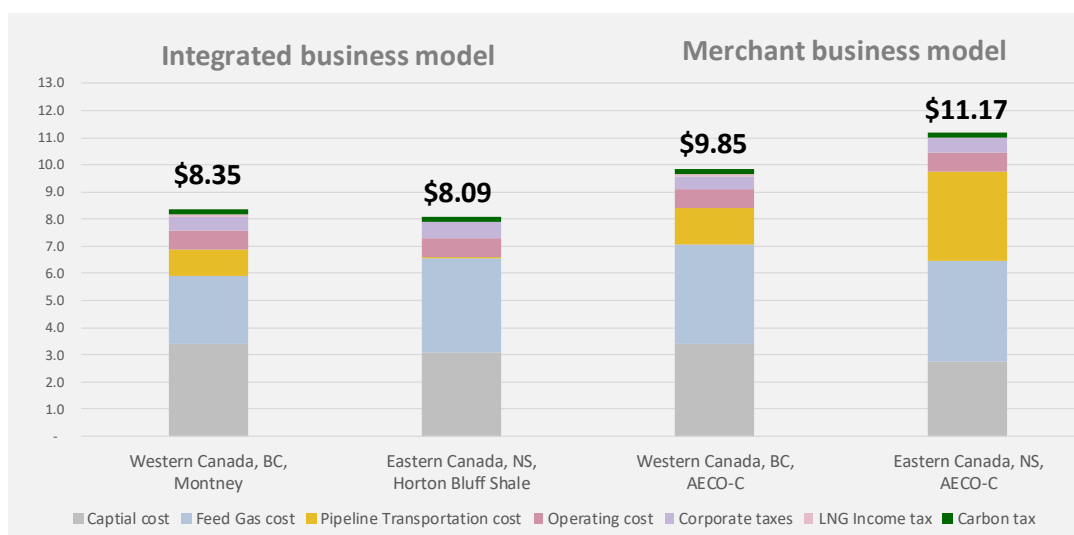
² An oil-linked LNG price is specified in a long-term LNG Sale and Purchase Agreement using a generic formula: percent of Brent price on the market + constant dollar amount. The price of Brent is used at the time of a particular LNG sale (and not fixed during signing of the contract). The constant has recently been reduced to zero dollars for many contracts from around \$0.5 in previous years.

³ Note: all costs are shown in 2018 \$US per mmbtu unless otherwise specified.

is adjacent. British Columbia's project, on the other hand, edges Nova Scotia's on natural gas cost by \$0.93.

For the merchant model (when both Eastern and Western projects are supplied from Alberta), the Western Canada LNG gains a \$1.32 cost advantage over their Eastern counterpart due to its proximity to the AECO-C hub. This location advantage translates into cheaper gas transportation by almost \$2, while capital costs are better by \$0.65 in the east. If natural gas is sourced from Marcellus for the Eastern project, British Columbia's LNG plant maintains its feedstock advantage but it is reduced to \$1.1 (the Marcellus gas-sourced project is \$10.95 per mmbtu).

Figure E.1: LNG Supply Costs Comparison in Canada (\$US/mmbtu)



The study has found that without additional efforts to decrease supply costs both from business and governments, Western Canada and Eastern Canada LNG landed costs (supply cost with shipping cost) are higher than the current spot price in Japan by \$0.80 at the time of writing (May 2018). At the same time, the landed cost is below the historical average of \$9.2.

Also, Western Canada LNG projects will need an oil price of approximately \$80 or higher over the life of the project to break-even under long-term LNG contracts (11.5% of Brent is used as the benchmark for all project economics) or \$8.99 per mmbtu on the spot market.

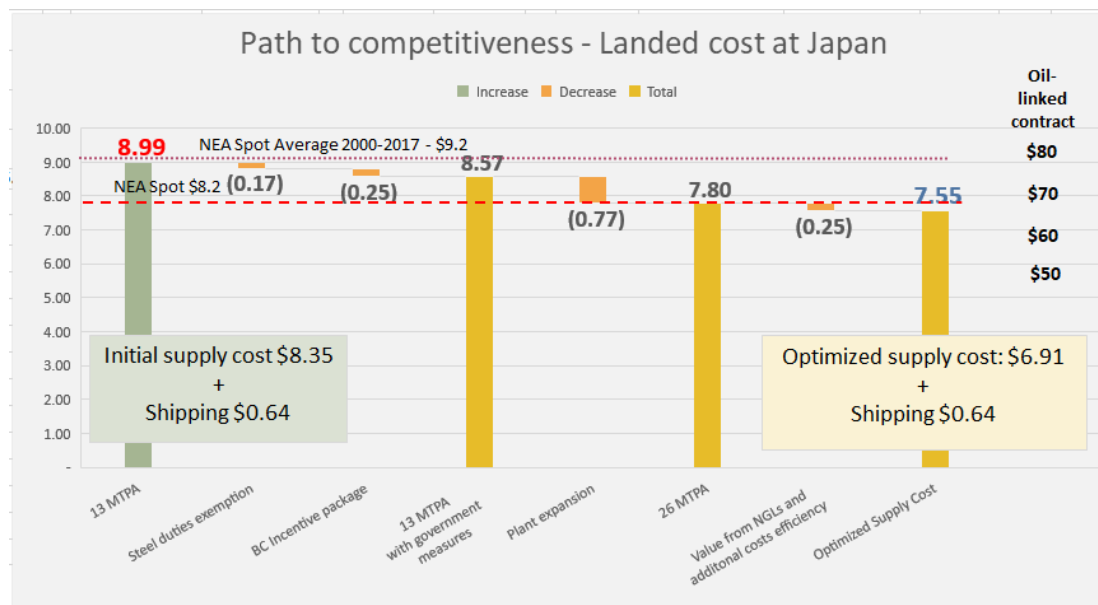
As well, the study has found that Eastern Canada and Western Canada LNG landed costs are higher than the current spot price in the UK. The difference between Western Canada LNG and the UK spot price is \$2.5 per mmbtu, while for Eastern Canada LNG with Marcellus and AECO-sourced gas the difference is \$4 to \$4.2, respectively. The closest landed cost to the UK market price is locally-sourced shale gas in Nova Scotia where the cost difference is \$1.1.

Eastern Canada LNG projects will need an oil price of approximately \$100 over the life of the project to break-even under long-term LNG contracts, or \$11.6-\$11.4 per mmbtu or higher at European markets (the historical average for the last ten years in the UK is \$6.3).

To improve the cost competitiveness of Canadian LNG, CERI reviewed some of the incentives that governments have already implemented or could implement, as well as costs savings measures that are available to LNG producers.

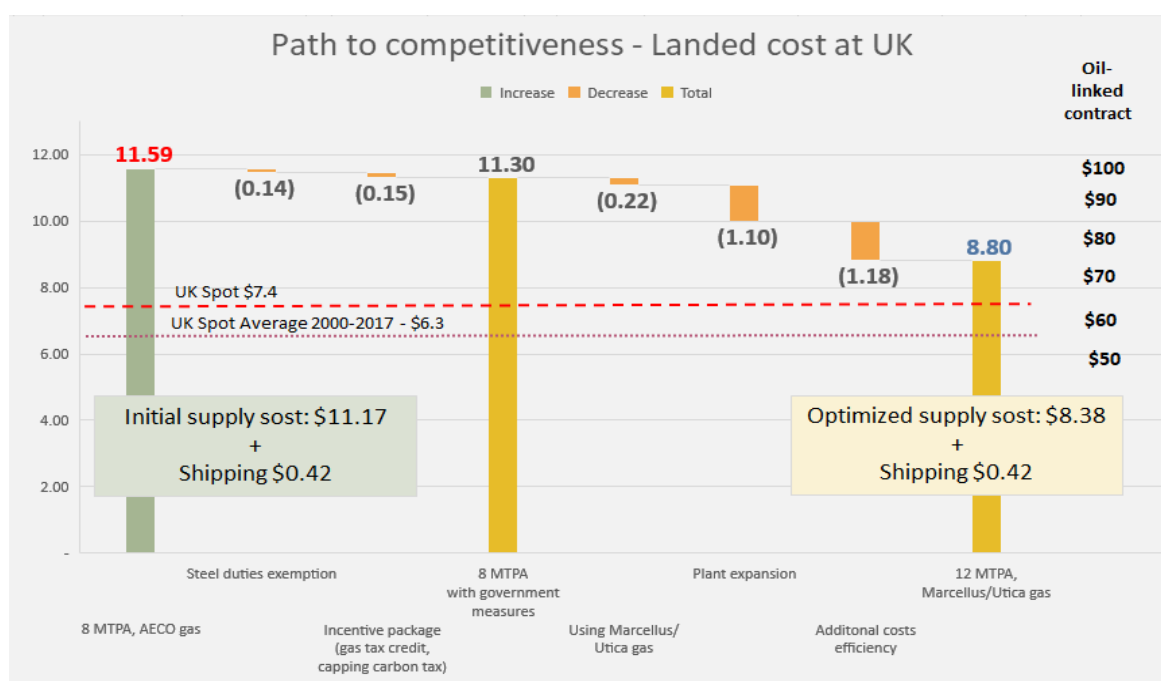
Provided that specific actions are taken by governments and proponents (shown on Figure E.2 and detailed in the Path to Competitiveness section of Chapter 4), the total landed costs for a Western Canada LNG project could be reduced to \$7.55 per mmbtu (Figure E.2) from \$8.99 in the northeast Asia market. The resulting landed cost is recovered by an LNG project with a Brent price of \$65 (compared to initial \$80).

Figure E.2: Path to Competitiveness for Western Canada LNG



CERI has not found a viable path to lower Eastern Canada projects landed cost below the European market price if the project sources gas from AECO-C or Marcellus. The final optimized landed cost is \$8.8 (Figure E.3), while the market price is \$7.4. To make these projects cost-competitive, more solutions than those modelled are required. Further cost savings could be considered regarding capital costs and transportation costs.

Figure E.3: Path to Competitiveness for Eastern Canada LNG



At the same time, if local shale gas was available in Nova Scotia, the optimized cost for such a case reduces the landed costs from \$8.5 to \$7.35, making such an option viable under current spot prices.

Western Canada LNG has an overall landed cost advantage in the Asia market compared to US Gulf of Mexico (GoM) projects by \$1.7 per mmbtu (US greenfield), and by \$0.3 (US brownfield). If supply costs of Canadian LNG are optimized, the difference with US greenfield grows to \$3.1 per mmbtu, and to \$1.8 per mmbtu compared with US brownfield.

At the same time, US GoM projects hold an advantage over Marcellus-sourced gas for Eastern Canada LNG in the European market by \$1.5 (US greenfield), and by \$2.9 (US brownfield). If supply costs of Canadian LNG are optimized, Eastern Canada LNG edges a US greenfield project by 1 dollar but loses to a US brownfield by 40 cents.

British Columbia appears to be more competitive than Nova Scotia globally. British Columbia has more incentives and lower corporate taxes than Nova Scotia (26%⁴ versus 31%). Also, the Asian LNG market is better priced than European gas markets (10-year historical average is \$9.2 versus \$6.3 per mmbtu). The cost of Montney gas and transportation to a BC facility is half compared to the case when an Eastern Canada project sources gas from AECO-C or Marcellus.

The jurisdictional comparison is presented in Table E.1 (non-optimized supply costs for Canadian LNG are used). The two lowest cost per major project element is presented in green.

⁴ 27% beginning January 2018 as British Columbia has increased its corporate tax rate from 11% to 12%

Table E.1: Jurisdictional Comparison of Non-Optimized LNG Supply Costs (\$ per mmbtu)

| | Western Canada | Eastern Canada AECO-C/Local Gas | US GoM (greenfield) | Australia |
|--|-----------------------|--|--------------------------------|------------------|
| Supply Cost (non-optimized) | \$8.35 | \$11.17 / \$8.09 | \$9.07 | \$13.06 |
| Natural Gas Cost | \$2.51 | +47% / +37% | +80% | +92% |
| Capital Cost/tpa | +23% | \$2.77 / +12% | +3% | +102% |
| Operating Cost | \$0.69 | \$0.69 | +33% | +96% |
| Natural Gas Transportation Cost*** | \$0.96 | \$3.33 / \$0.07** | \$0.42 | 0.14** |
| Shipping to Europe | +270% | \$0.42 | +79% | +338% |
| Shipping to Asia | +9% | +201% | +181% | \$0.58 |
| Tax Burden | +112% | +96% / +118% | \$0.37 | +228% |
| Capital Allowances | 25.8%* | 25.8%* | 100% | 13.3% |

* A 25.8% yield produces an almost identical result as a 100% allowance if ring-fencing is not removed; if ring-fencing is removed, the capital allowance rate of US GoM becomes superior compared to Canada. See additional federal incentives in the Path to Competitiveness section of Chapter 4 for more detail.

** These costs represent operating costs of transportation only, unlike other jurisdictions.

*** Natural gas transportation costs are only shown in absolute dollar amounts as for some cases they represent only operating transmission costs (because a pipeline is part of the LNG project), while in other cases they represent full gas transportation costs (toll).

The US also appeared as a more cost-effective jurisdiction than either of Canada's provinces, if natural gas costs are not considered. Total liquefaction costs (all costs except for natural gas) are lower by \$0.7-\$0.8 for the GoM compared to Western Canada, and by a substantial \$2.8-\$3.0 compared to Eastern Canada. Thus, the costs of doing LNG business is 13-41% lower per mmbtu in the GoM than in Western or Eastern Canada inducing further work of business and governments to reduce the deficiency in cost-competitiveness.

The recent change in corporate taxes in the US gave a boost to the US industry. The corporate tax share per mmbtu of LNG has decreased by almost 60% (or \$0.44-\$0.52 per mmbtu). Canadian incentives to the LNG industry are estimated to equal around 51 cents per mmbtu (includes increased capital cost allowances, the BC government Natural Gas Development Framework and the Natural Gas Tax Credit). Still, even with these measures, US greenfield projects have 27.5% lower taxes per mmbtu than for a large 26 mtpa project in Canada after all modelled Canadian incentives are applied. This leaves room for further improvement of the tax regime

competitiveness in Canada, for instance exempting projects from ring-fencing and further increasing capital tax allowance.

As mentioned above, Canada has a number of active LNG projects which are expected to make FID soon. So far, Canada has seen a number of projects cancelled rather than move forward, while other jurisdictions are building out capacity. **The study shows that Canadian integrated projects on both coasts, with additional incentives of government and certain cost-savings, are not only competitive and can outperform not only US greenfield and brownfield projects, but also can reach destination market price levels in Europe and Asia.**

Chapter 1: Introduction

Global LNG Overview

Liquefied natural gas (LNG), as the name implies, is simply natural gas that has been cooled to the point (-256° Fahrenheit) where it condenses into its liquid state. It is a clear, colourless, odourless liquid that weighs slightly less than water. In this state, natural gas occupies only $1/600^{\text{th}}$ of its gaseous volume, making it economical to transport between continents and over long distances in specially designed LNG tankers (Shell 2011).

The four main components of the LNG value chain are exploration and production, liquefaction, shipping, and regasification. This is illustrated in Figure 1.1.

Figure 1.1: LNG Value Chain



Source: (Wärtsilä Technical Journal 2017)

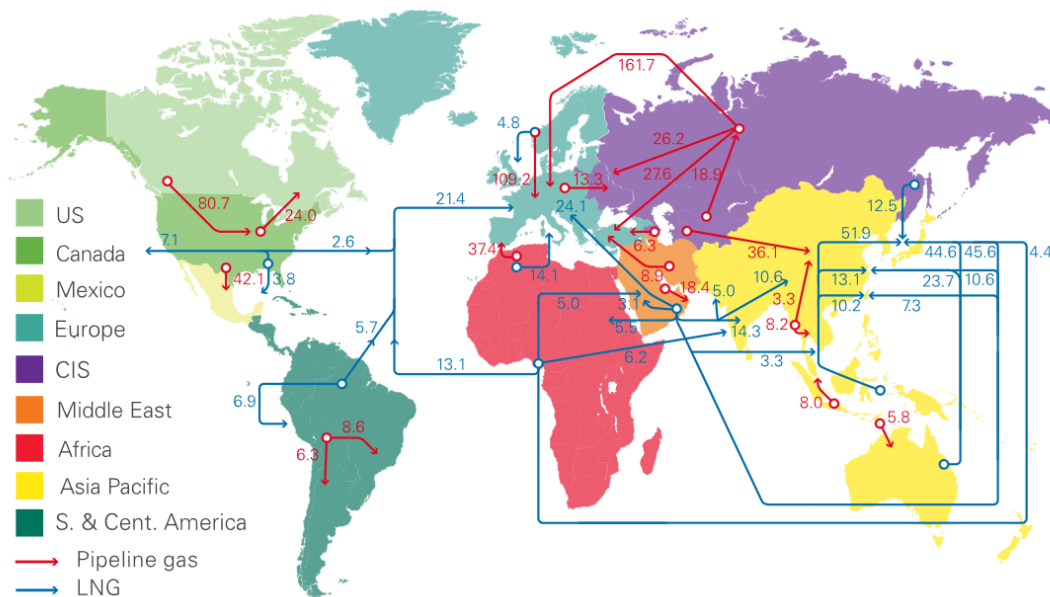
Facilities that export LNG, where LNG is loaded onto specially-designed double-hulled tankers, are liquefaction facilities. The tankers and their cargo are greeted by regasification plants or import terminals. To return LNG to a gaseous state, it is fed into a regasification plant. LNG is pumped into a double-walled storage tank, like those used in the liquefaction plant, where it is subsequently pumped through various terminal components (Shell 2011). It is warmed in a controlled environment. The vaporized gas is then compressed up to line pressure and enters the pipeline system as natural gas (Shell 2011).

Whether the terminal is a liquefaction or regasification facility, storage plays an important role. Access to large amounts of storage is key to economic success for the LNG marketer. Ships may or may not arrive precisely when the market needs the gas, especially considering the cyclical behaviour of gas consumption, both daily and seasonal.

This section reviews the role of LNG in natural gas trade and LNG global trade flows, as well as discusses important global LNG supply and demand centres (liquefaction and regasification terminals).

Figure 1.2 illustrates the major trade movements in 2016 (in billion cubic metres or bcm). Gas movements are shown by pipeline (red) and by LNG (blue). In 2016, total global pipeline trade was 737.5 bcm while LNG trade was 346.6 bcm (BP 2017b). LNG accounts for 32 percent of

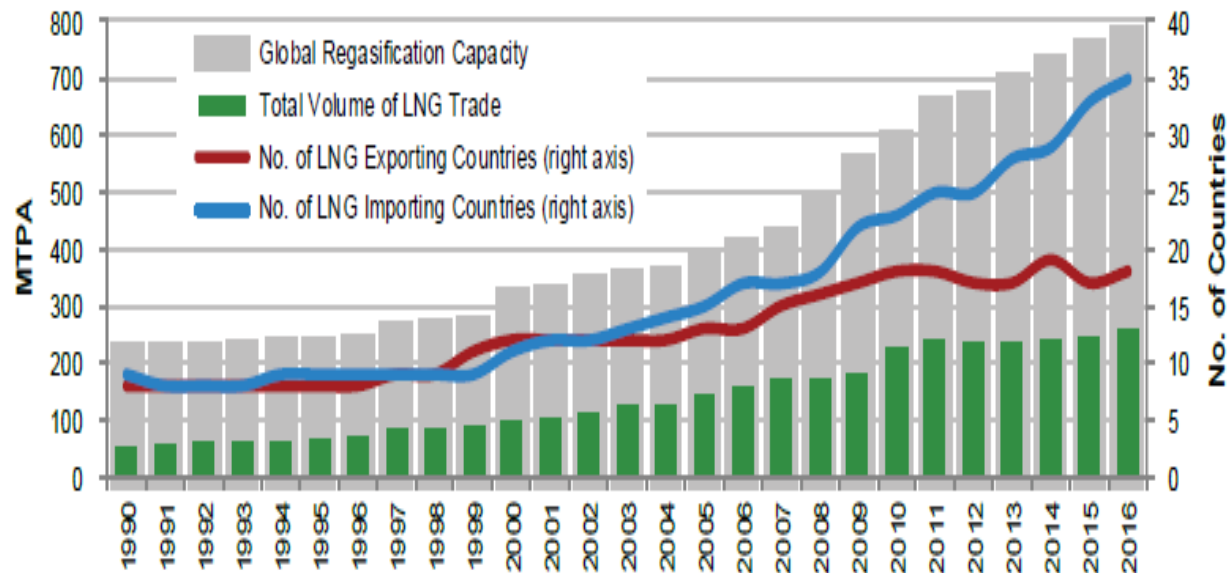
Figure 1.2: Major Trade Movements, 2017



Global LNG trade increased to 258 million tonnes (MT) in 2016 from 244.8 MT in 2015 and 241.1 MT in 2014. It is the third consecutive year of establishing a new record level for global LNG trade (IGU 2017).

Figure 1.3 illustrates the LNG trade volumes between 1990 and 2016. The figure also shows the number of exporting and importing countries over that time. Trade volumes are increasing rapidly, as are the number of countries exporting and importing LNG. As of 2016, LNG is exported by 18 countries and is imported by 35 countries (IGU 2017). At end-2007, LNG was exported by 15 countries and imported by 18 countries (California Energy Commission n.d.).

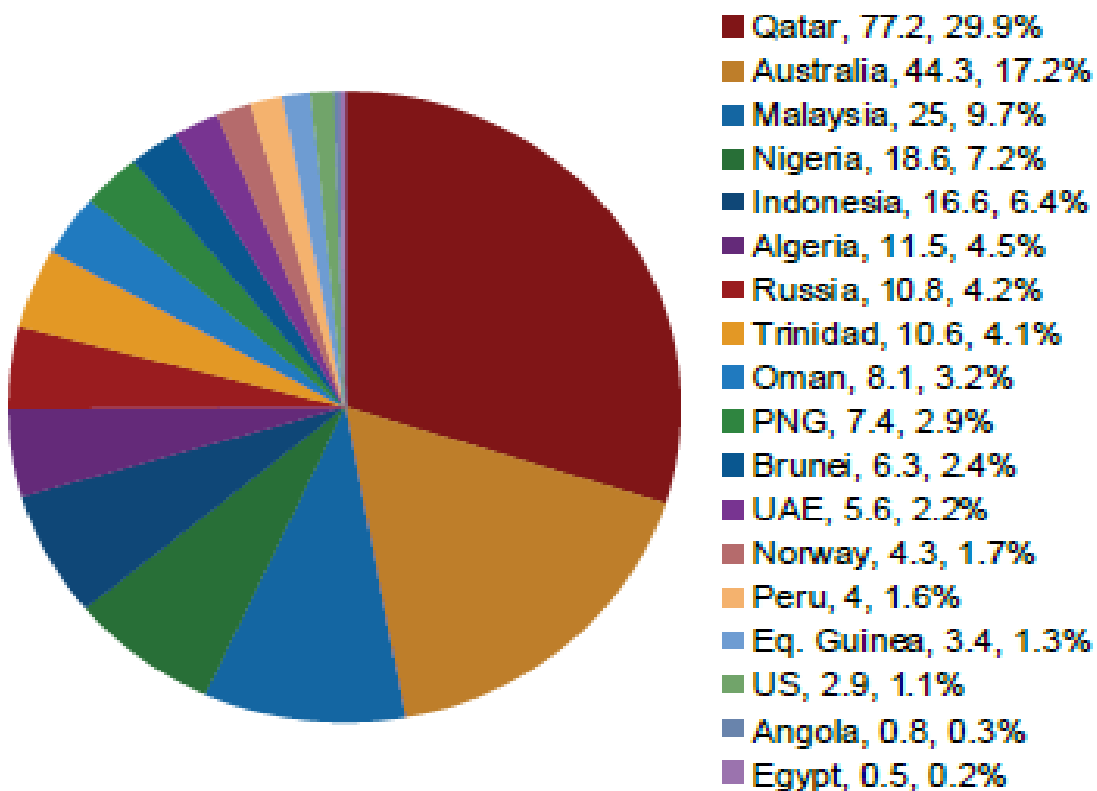
Figure 1.3: LNG Trade Volumes, 1990-2016



Source: (IGU 2017)

Global liquefaction capacity as of January 2017 was 340 million tonnes per annum (mtpa), adding 35 mtpa of capacity over the previous year with the completion of Australia's Gorgon LNG and Australia Pacific LNG as well as Sabine Pass LNG in the US (IGU 2017). Trains were also added at Gladstone LNG, Queensland Curtis LNG, and Malaysia LNG. The former two are also based in Australia. An additional 114.6 mtpa of liquefaction capacity is under construction (IGU 2017).

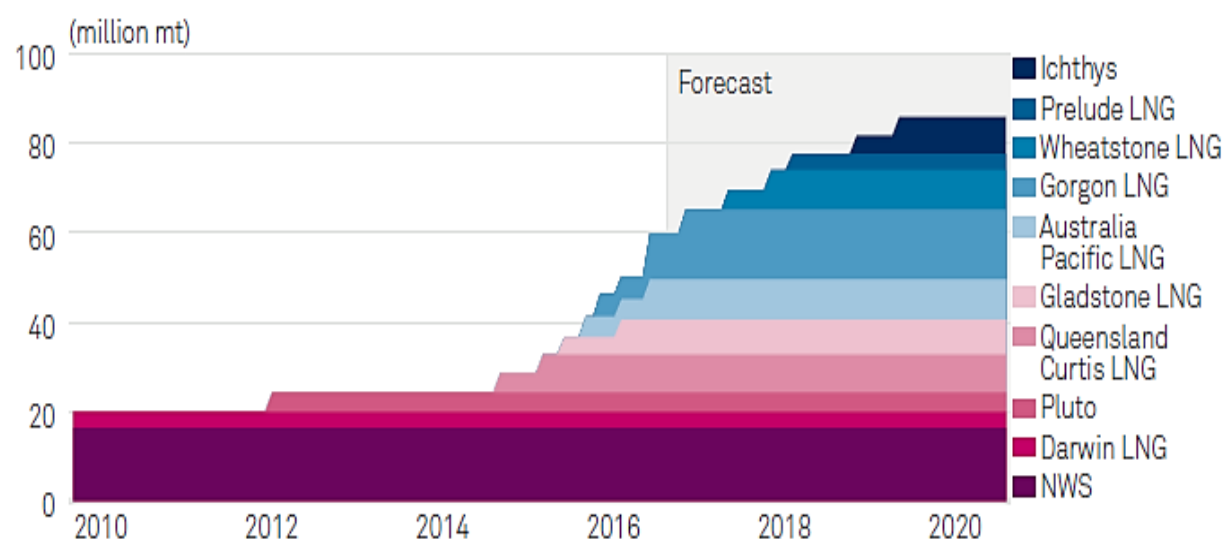
Figure 1.4 illustrates 2016 LNG exports and market share in both mtpa and percentage, respectively. The top 5 exporters are Qatar, accounting for nearly 30 percent, followed by Australia, Malaysia, Nigeria, and Indonesia (IGU 2017). In December 2003, Qatar was the fourth largest LNG exporter at 14.9 MT, preceded by Indonesia (23 MT), Algeria (19.6 MT) and Malaysia (15.6 MT) (EIA n.d.).

Figure 1.4: 2016 LNG Exports and Market Share by Country (mtpa and percentage)

Source: (IGU 2017)

Qatar has been the largest LNG player for a decade, capitalizing on its large natural gas reserves that are difficult to transport with pipelines and vehicles. While its LNG exports remain stable, its market share is decreasing, due to the growth of LNG exports from Australia and the US. Both countries dominate LNG export capacity additions, fueled by their respective large natural gas resource bases. In Australia, it's the growth of coalbed methane, and in the US, it's the production of shale gas.

Australia is gaining market share rapidly, adding 15 MT of LNG exports in 2016 (IGU 2017). With several additional projects and trains coming online, amounting to a total of 81 mtpa, Australia is slated to become the largest exporter of LNG by 2019 (S&P Global Platts 2017) when Wheatstone LNG train 1-2, Ichthys LNG train 1-2 and Prelude LNG (floating) are slated to come online (S&P Global Platts 2017). Figure 1.5 illustrates the rapid growth of the Australian liquefaction projects from 2010 to 2021.

Figure 1.5: Australian LNG Supply Capacity by Liquefaction Project

Source: (S&P Global Platts 2017)

While Australia is poised to surpass Qatar in 2019, there is not a lot of optimism. Numerous LNG liquefaction terminals have not only been hampered by cost overruns and delays, but also by depressed prices in Japan. Figure 1.6 shows the price of natural gas in eastern Australia (Wallumbilla Hub) and the LNG export price to Japan.

Figure 1.6: Eastern Australia Daily Spot Natural Gas Price and LNG Export Price (\$US per million British thermal units)

Source: (EIA 2017c)

Figure 1.6 tells two stories. First, of the 73 mtpa of Australian LNG contracted in 2019, the majority is sold into northeast Asia, particularly to Japan and China, on an oil-indexed basis (EIA 2017c). Several years ago, this was not a problem. However, the price of LNG has been decreasing in Japan since 2015. Australia's business model is structured by oil-indexed long-term contracts, limiting the destination of LNG (such a limitation is now fought by buyers and government agencies, e.g., Japan Fair Trade Commission). Second, Figure 1.6 also shows the price of natural gas at Wallumbilla, located in southern Queensland, near the country's largest population centres. As Australia's LNG exports have increased, primarily from LNG projects in eastern Australia, Australia has experienced domestic natural gas supply shortages in eastern and southeastern Australia (EIA 2017c). This is shown by two separate price spikes (mid-2016 and early 2017).

Since the start of LNG projects in Queensland (Gladstone LNG, Australia Pacific LNG and Queensland Curtis), domestic natural gas prices at several hubs in eastern and southeastern Australia have more than doubled, and on several occasions exceeding the LNG export price to Japan (EIA 2017c).

On June 20, 2017, the Australian government established the Australian Domestic Gas Security Mechanism (Australian Government 2017a) (ADGSM). Its objective is to "ensure there is a sufficient supply of natural gas to meet the forecast needs of Australian consumers by requiring, if necessary, LNG projects which are drawing gas from the domestic market to limit exports or find offsetting sources of new gas." (Australian Government 2017a). In other words, the ADGSM authorizes the government to limit LNG exports if companies are exporting more natural gas from Australia than they are supplying to the domestic market (Australian Government 2017b).

While these are uncertain times for Australia, things are looking up in the US.

February 24, 2016 is an important date in the LNG landscape in the US, marking the beginning of a shift from a net importer to a net exporter. The tanker Asia Vision transported approximately 3 billion cubic feet (Bcf), or 160,000 cubic meters of LNG, from Cheniere's Sabine Pass LNG facility in Louisiana to Brazil, making it the first ever domestically-produced LNG export from the Lower-48 (EIA 2016).

Aside from the Kenai LNG Export Terminal, a small export facility in Alaska with 11 import terminals, the US has been historically an importer of LNG (FERC 2018a). Shale gas, however, has had a profound effect on the natural gas production in the Lower-48. Fueled by advances in drilling and hydraulic fracturing technology and techniques, the production of shale gas reached 48.3 Bcfpd in November 2017, with the Marcellus Shale alone accounting for 18.5 Bcfpd (EIA n.d.). This is up from 6.1 Bcfpd produced in November 2007 (EIA n.d.). As a result, the shale gas boom is having a significant effect on the LNG landscape in the US. With the glut of natural gas, companies began lining up to build liquefaction terminals or to alter their regasification facilities to accommodate the export of LNG. Increasing production has also resulted in decreased imports from Canada.

There are currently two existing liquefaction terminals in the US: Sabine Pass LNG (Cheniere Sabine Pass LNG), located in the Gulf of Mexico, and Kenai (ConocoPhillips). The former has three trains operating at a total capacity of 2.1 Bcfpd (FERC 2018a).

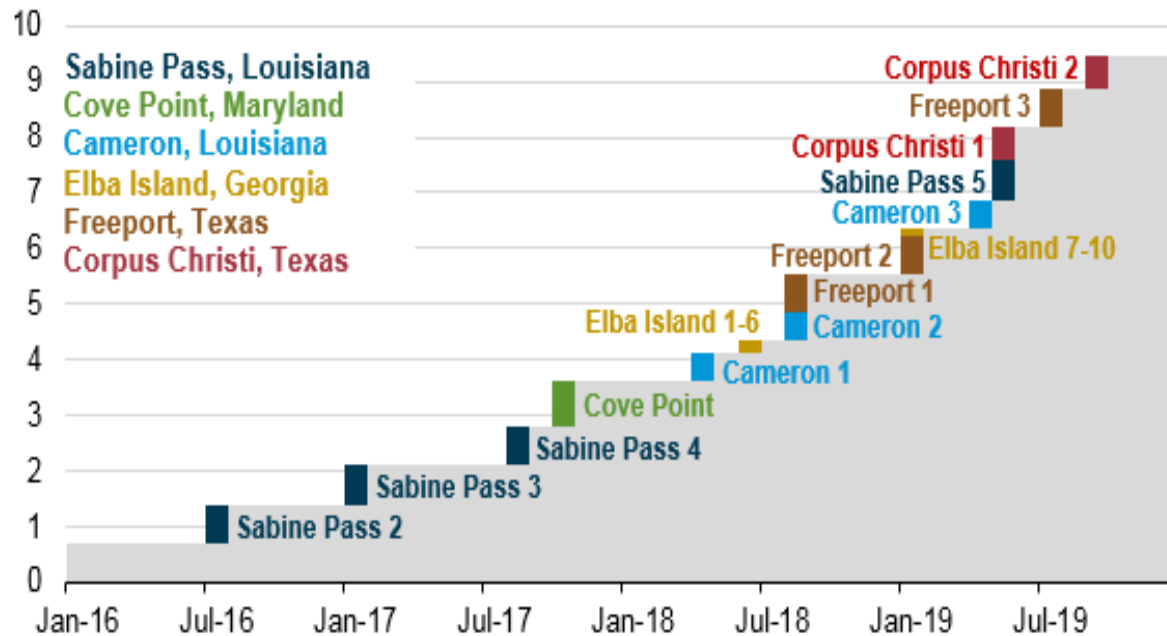
In total, the US added 2.5 MT in 2016 but is poised to become one of the largest LNG players over the next few years.

Since the first shipment in February 2016, the US has exported nearly 730 Bcf of domestically-produced LNG via Sabine Pass LNG (EIA 2017d). Thus far, Mexico accounts for 21.1 percent of exports, followed by South Korea (13.5 percent), China (10.5 percent), Chile (7.1 percent) and Japan (6.9 percent) (EIA 2017d). That being said, 37.7 percent, or 274.4 Bcf, of receipts of the total volume exported are destined for Latin America and the Caribbean; East Asia and Pacific destinations account for 32.2 percent while South Asia accounts for 30.5 percent (EIA 2017d).

As of end-March 2016, there are six export facilities that are approved by the US Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) and are already under construction: Sabine (Cheniere-Sabine Pass LNG), Hackberry (Sempra-Cameron LNG), Freeport (Freeport LNG), Cove Point (Dominion-Cove Point LNG), Corpus Christi (Cheniere-Corpus Christi LNG), and Sabine Pass Liquefaction and Elba Island (Southern LNG Company) (FERC 2018a). A fourth and fifth LNG train is under construction at Sabine Pass LNG (EIA 2017d). According to FERC, these terminals have a capacity of 9.65 Bcfpd (EIA 2017d). In addition, there are four export terminals which have received approval but are not yet under construction (EIA 2017d) and an additional 17 proposed export terminals (16 proposed to FERC and a single terminal to the MARAD/US Coast Guard (FERC 2018b)). Note that all proposed terminals are located in the Gulf of Mexico, except Nikiski, Alaska and Coos Bay, Oregon. Of the approved projects, only Cove Point, Maryland is not located in the Gulf of Mexico.

Figure 1.7 illustrates the US LNG export capacity coming online over the next few years.

Figure 1.7: US LNG Export Capacity (Bcfpd)

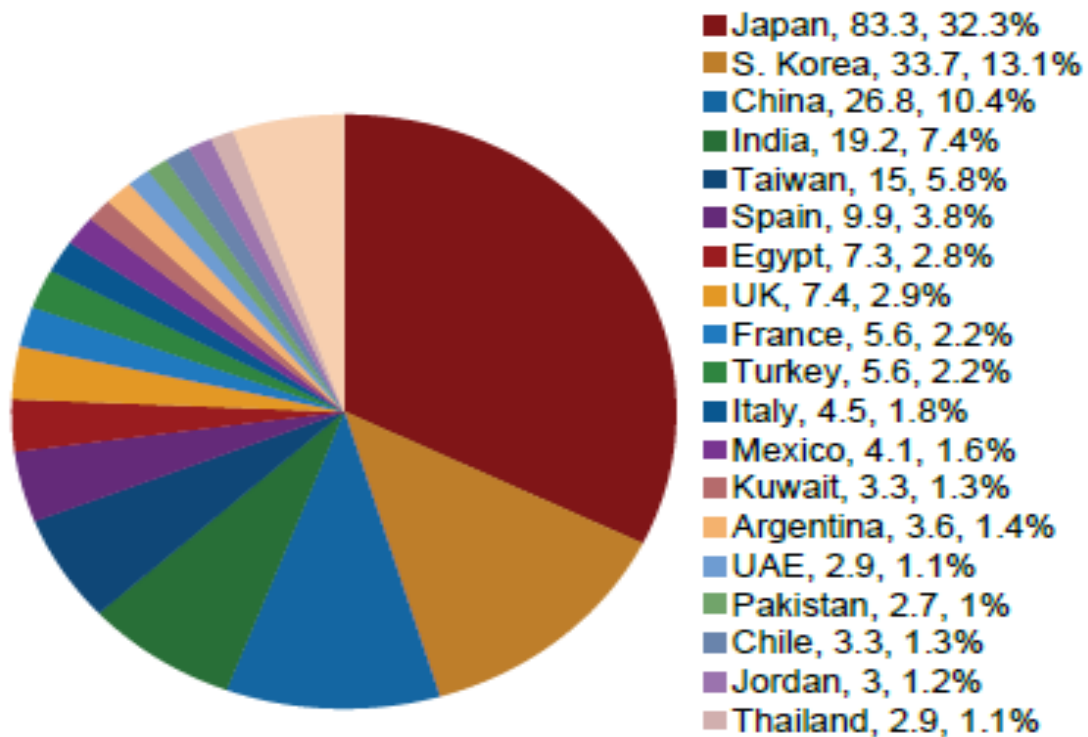


Source: (EIA 2017a)

While the quantity of LNG supply from liquefaction facilities and the supply requirements for the existing and proposed regasification terminals appears to be narrowing – at least in North America – the number is growing globally. Recall that the number of countries importing LNG increased from 18 in 2007 to 35 in 2016.

Global regasification capacity as of January 2017 was 795 mtpa, up from 776.8 mtpa in 2016, due in particular to additional capacity from China, Japan, France, India, Turkey, and South Korea (IGU 2017). New markets in 2016 include Jamaica, Colombia and Malta. An additional 90.4 mtpa of capacity is currently under construction, dominated by China and India (IGU 2017).

Figure 1.8 illustrates 2016 LNG imports and market share in both mtpa and percentage, respectively. The top 5 importers are Japan, accounting for 32.3 percent, followed by South Korea, China, India, and Spain (IGU 2017). In 2007, Japan imported 65 Mt, while South Korea and Spain imported 35 Mt and 24 Mt, respectively (World Gas Intelligence 2009). The northeast Asia region was the largest consumer of LNG, with Japan, South Korea and Taiwan leading the way. At the time, the Pacific Basin, more specifically, Malaysia and Indonesia, were the primary suppliers. Today, it is Australia and the Middle East that are the main suppliers.

Figure 1.8: 2016 LNG Imports and Market Share by Country (mtpa and percentage)

Source: (IGU 2017)

In terms of the largest market, the Asian Pacific accounts for 53.6 percent of the total imports in 2016. LNG regasification capacity in Japan, South Korea, China, and India is 198 mtpa, 99 mtpa, 49 mtpa and 27 mtpa, respectively (NEB 2017). It is interesting to note that the US has the second highest regasification capacity at 132 mtpa, made up of the 11 importing terminals. In 2017, Everett, MA received 53.9 Bcf, followed by small shipments into Elba Island, GA and Cove Point, MD (EIA 2017d). The clear majority of a once-diverse and thriving trade is currently dominated by Trinidad & Tobago.

Japan's extensive regasification facilities are illustrated in Figure 1.9.

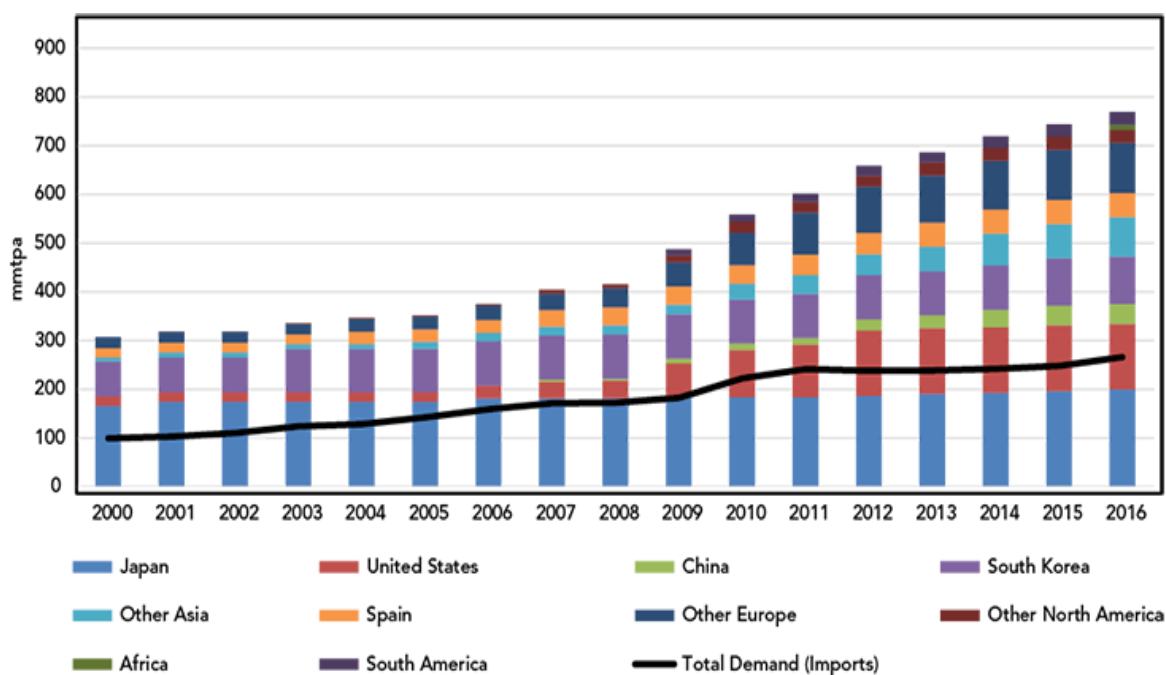
Figure 1.9: Japan's Regasification Terminals



Source: (GIIGNL 2017)

Figure 1.10 shows the global regasification capacity between 2000 and 2016. While Japan is still the largest LNG importer, the largest gains are China (6.9 MT) and India (4.5 MT) in 2016 (IGU 2017). The rapidly growing economies of China and India, which account for over 2 billion people, are currently demanding more gas. Currently, China and India import 17.8 percent of global LNG, ranking them third and fourth, respectively (IGU 2017). In 2010, China and India imported 4 percent and were ranked 7th and 8th, respectively (IGU 2010). Western European growing imports are also playing a key role in world LNG trade.

Figure 1.10: Global Regasification Capacity



Source: (NEB 2017)

March 2011 marked the Fukushima nuclear disaster, resulting in the closure of Japan's 54 nuclear reactors, creating a demand for LNG imports to fuel the country's natural gas-fired power plants (Michael D. Tusiani and Gordon Shearer 2016). The impact on the global LNG market was profound. Japan is now determined to restart many nuclear plants (Ken Silverstein 2017). In fact, Japan's Ohi 3 & 4, operated by Kansai Electric Company, are cleared to restart (Nuclear Energy Institute 2017). More are likely to follow. Just as the closure of its nuclear program created a boon for LNG exporters, its restarting could have the opposite effect.

Canada currently has a single facility, located in Saint John, New Brunswick. Canaport LNG is an importing or regasification terminal. The facility has a capacity of 1.2 Bcfpd and began operations in June 2009 (Canaport LNG n.d.). Canaport LNG is a partnership between Spain-based Repsol (75 percent) and Irving Oil (25 percent) (Canaport LNG n.d.). An LNG tanker is shown at the Canaport LNG receiving terminal in Figure 1.11.

Figure 1.11: An LNG Tanker at the Canaport LNG Terminal



Source: Alberta Oil Magazine

Significant Trends in LNG

The LNG industry has experienced noteworthy changes over the last decade. Increases in demand for the product, improvements in liquefaction technologies, carbon management policies, and the evolution of the standard business model has meant greater interest in the sector and higher levels of investment. These trends provide a context for new investment in Canada.

While it is difficult to determine if investment risk has increased, it is fair to say it has changed. The market, technology, and operational risks are being redistributed to a greater number of actors in the sector including gas producers, pipeline companies, LNG plant owners, shipping companies, marketers, regasification operations, utilities, and other end users.

Technological Changes

Three technological changes are impacting the LNG market:

- The increased availability of natural gas through the production of unconventional plays;
- Offshore regasification; and,
- Offshore liquefaction.

The availability of natural gas supply has increased. Hydraulic fracturing and horizontal drilling have combined to increase gas production from existing and new supply areas. In North America, this trend has led to decreased natural gas pricing, higher quantities of supply and availability

and the reversal of the trend from expecting to import LNG to where both Canada and the US have the potential to be major suppliers of LNG to world markets.

One reason for the importance of this study is the growing concern in Canada about its natural gas market. Increased domestic production in the US is reducing the opportunity for Canadian natural gas to be exported. Approximately half of the Canadian production is destined for the US market, and to date, Canada has no other export option.

In addition, US production in the Marcellus and Utica are increasingly looking to Eastern Canadian markets, which also creates a market challenge for natural gas originating in Western Canada. CERI tracks this impact through an annual analysis of Canadian natural gas production. Thus, the increased use of hydraulic fracturing and horizontal drilling in the US is creating effective competition for Canadian natural gas suppliers. That means providing LNG to either Asian or European markets is an important consideration in the future viability of natural gas production in Canada.

Offshore regasification and liquefaction, while different parts of an LNG supply chain, open the market to diversification. Offshore regasification platforms, called floating storage and regasification units (FSRUs), floating storage units (FSUs) or floating regasification units (FRUs) are becoming more common in areas where local onshore development is either too expensive or logistically problematic. The difference between them is that the FSRU has built-in storage while the FRU depends on storage tanks onshore. These platforms are connected to shore via risers and pipelines.

Offshore facilities, while more expensive per mmbtu, have the benefit of being built on prefabrication plants where construction expertise is high. It also allows for the construction of these facilities for locations where local labour or manufacturing is not able to support construction. In addition, floating platforms allow for owners to maintain optionality. They can move the plants to new locations if the market advantage warrants. Offshore regasification represents 83 mtpa or 10% of the total regasification capacity at the end of 2016 (IGU 2017).

Similarly, offshore liquefaction platforms known as Floating LNG (FLNG) share the same economic and construction characteristics as FSRUs and FRUs but fundamentally open offshore gas reserves to be economically harvested. At the end of 2016, there was 340 mtpa (IGU 2017) of liquefaction capacity globally with 2 mtpa of that FLNG (IGU 2017) and 9 mtpa more proposed by 2020. This still represents a small percentage of overall liquefaction because of the greater engineering challenges and costs of liquefaction compared to regasification.

The Changing Business Model

The traditional business model for LNG was characterized by integrated producers and buyers with long-term contracts, typically 20 years linked to an international oil price (e.g., Brent crude) and a fixed or variable differential to that crude price index. The market was developed based on predictability and low risk. Final investment decisions waited for long-term, back-to-back contracts all the way from production to the final consumer.

LNG plant owners usually owned the upstream assets or had long-term operational commitments for the commodity or a related service. They usually owned the ships transporting the LNG to the buyers and had strictly limited provisions related to obligations to service written into contracts.

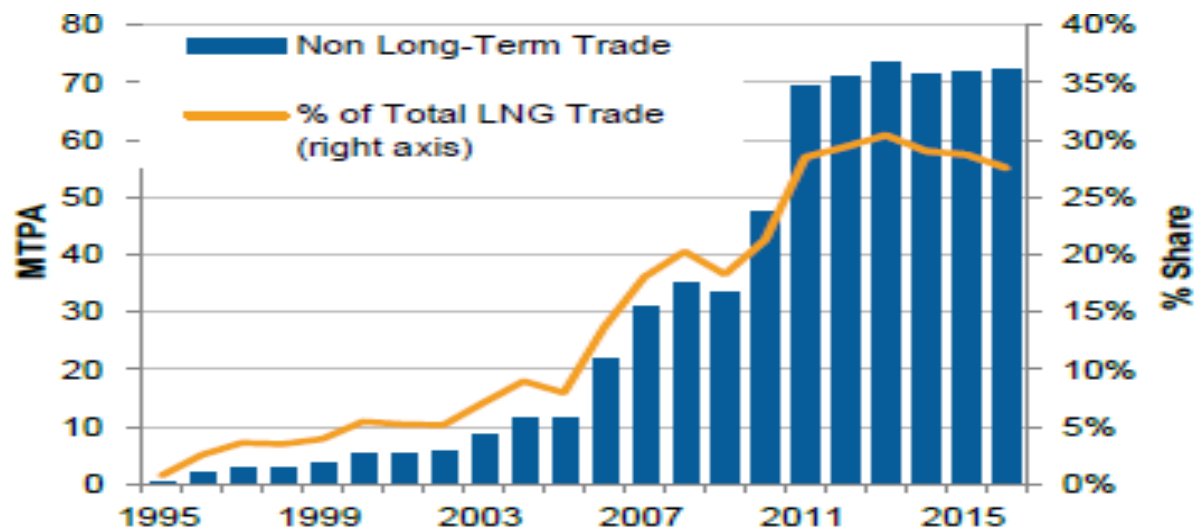
On the other hand, buyers were usually creditworthy natural gas or electricity utilities, often backstopped by the government with dedicated end-use consumers and monopoly franchises. This market structure in many ways mirrored onshore market structures for natural gas production, transportation, and distribution systems and similarly, their electricity counterparts. Risk-based returns in such circumstances could easily be justified around 10%.

This low risk integrated utility type model began eroding by the mid-2000s. It first started with the challenge of surplus LNG. This surplus could be generated by a reduction in forecasted demand from buyers or more efficient operations by liquefaction plant operators. Small in volume, these surplus volumes nonetheless allowed for a market opportunity to be explored.

Starting out, the surplus volumes were sometimes offered to existing customers at their long-term contract price and quality. In the 1990s, the Asian economic downturn created surplus LNG even while new liquefaction capacity was coming online. As the amount of volume increased, traders began entering the market, seeking arbitrage opportunities.

The expansive set of actors in the market has led to the development of a spot and short-term market, which now accounts for approximately 30% of trade (Figure 1.12). Spot, in this case, would be for deals with product deliveries over the following few months. Short-term contracts could last upward of 5 years.

Figure 1.12: Non-Long-Term LNG Trade



Source: (IGU 2017)

Two of the new key players are portfolio players and LNG traders. Portfolio players, as the name implies, have contracts or investment interests in numerous LNG projects at different parts of the value chain. They normally deal in the spot market and hold long-term contracts. LNG traders engage in the spot and sometimes short-term markets. They have much less invested in infrastructure and focus on pricing arbitrage of the commodity.

In addition to contract durations being shorter, new arrangements are included in contracts such as different ownership for liquefaction, shipping, and regasification from that of the natural gas producer and final buyer. Leasing arrangements for shipping are becoming more common as are tolling arrangements for liquefaction services and regasification. In such situations, the volume, price, and delivery point risks are spread out to encompass multiple investors and stakeholders.

Most liquefaction projects still rely on long-term contracts for financing purposes and stability of sales as approximately 70% of LNG is sold under such contracts with take-or-pay provisions. However, the spot market and short-term markets have become significant considerations and trade options for many projects due to their volume and price opportunities.

One consequence of the spot and short-term market evolution is its impact on pricing.

Pricing and Contracts

Pricing formulas have played a role in the development of the LNG market. Traditionally LNG is indexed to oil price. When oil prices were high and increasing up to 2014, this allowed for profit opportunities for new LNG facilities. Moreover, after the earthquake and tsunami that hit Japan and the ensuing nuclear accident at Fukushima, the resulting shut down of Japan's nuclear fleet caused a spike in the spot and short-term prices for LNG. Japan struggled with buying sufficient natural gas for electricity generation to offset the loss of its nuclear generation capacity.

Because of the unexpected increase in demand, LNG prices spiked to over US\$14/mmbtu in 2011 and US\$16/mmbtu in 2012 based on the delivered price in Japan. The average price for the preceding 10 years was around US\$7/mmbtu. This high price was sustained until new Australian, Qatari, and US liquefaction plants came online. LNG prices dropped to US\$7/mmbtu in 2016 and US\$6/mmbtu in 2017.

Buyers, more interested in the security of supply, such as utilities, will continue to rely on long-term oil-indexed prices. For buyers with more price sensitivity, spot and short-term market pricing will play a larger role. The indexing for the spot and short-term markets is based more on recognized natural gas hubs such as the Henry Hub point in the US. Natural gas hub pricing tends to be cheaper than oil-indexed pricing.

One development in pricing is the portfolio approach. Buyers are looking to blend their price mechanisms with exposure to both an oil index and a gas index. It is not clear what the long-term pricing result will be with a portfolio approach, but like the ownership and service fragmentation of the LNG trains themselves, the portfolio approach allows for innovative mechanisms to be used.

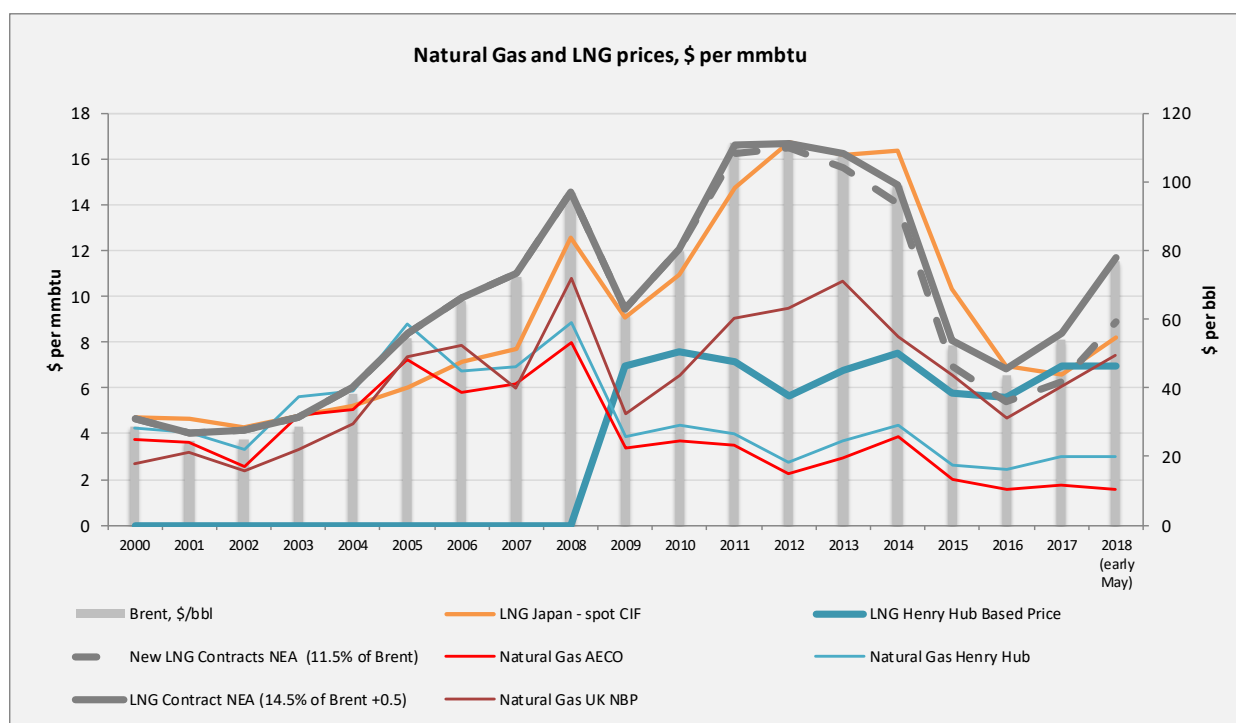
Another dynamic of pricing is the price differential between Asia and Europe. The differential between these two markets provides another consideration in the market evolution of LNG.

Depending on the differential between Asia and Europe and even within those regional markets, traders and shippers are more often changing the destination of their cargos to take advantage. This price arbitrage is new to the market as traditionally, ships were constrained from being redirected.

Historical natural gas and LNG prices are shown in Figure 1.13. The detailed description of pricing trends is beyond the scope of this study; however, it is important to note several important historical characteristics of the market:

1. AECO market in Alberta has been providing historically cheaper gas than US Henry Hub, putting projects which source gas in Alberta at comparative advantage. The differential between AECO and Henry Hub has been widening as of late increasing the advantage (at least in the short term).
2. Japanese and northeast Asia markets have been rewarding LNG producers with higher prices than North American and European continental markets. As oil prices plummeted, the oil-linked contract prices and spot prices followed, falling from \$16.7 per mmbtu in 2014 to \$6.94 in 2016.
3. European market prices versus Henry Hub-based LNG pricing in 2011-2013 has allowed for a profitable arbitrage as shipping costs were much less than the difference. Starting in 2014, this wide differential disappeared but still was in the range of 50-75 cents, close to what is needed to pay for the shipment from the Gulf.
4. In 2016, the prices of UK NBP and Contracts in NEA fell below or very close to Henry Hub-linked pricing based on an LNG liquefaction cost of US\$2.5 per mmbtu, resulting in little margin for profit for producers. Japan was still attractive and profitable with a US\$1.6 difference to Henry Hub pricing.
5. At the time of writing, market prices are as follows: northeast Asia at \$8.15-\$8.3 and the UK at \$7.25-\$7.50. This allows for profitable deliveries to both European and US markets under the Henry Hub-based pricing formula.

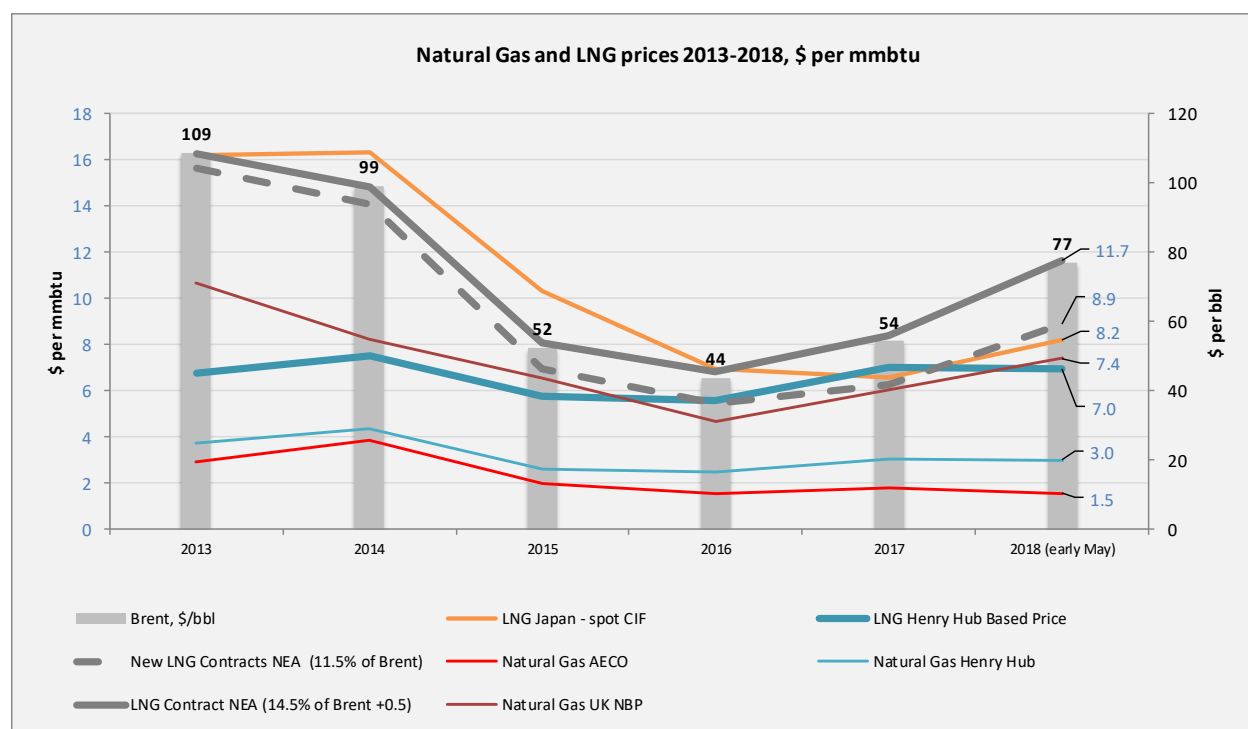
Figure 1.13: Historical Natural Gas and LNG Prices



Note: Henry Hub LNG FOB price is calculated as 115% of HH price + \$2.75 for the period 2000-2015. In 2016, a \$3.5 constant is used. \$2.75 is assumed based on the weighted average for the Sabine Pass project signed SPAs. \$3.5 is assumed based on the Corpus Christi signed SPAs.

Source: CERI based on BP Statistical Review, Platts, EIA, Morgan Stanley, Cheniere.

Figure 1.14: Natural Gas and LNG Prices, 2013-2018



Source: CERl based on BP Statistical Review, Platts, EIA, Morgan Stanley, Cheniere.

Another important element which has been changing recently is shortening of contract terms. Originally, most of the contracts were 20-years in length to secure external financing for the LNG owners. Recently, the market has seen 10, 7 and even 5-year contract executions, however such durations are much more applicable for existing facilities contract extensions and portfolio players, rather than for new projects which still strive to execute 20-year contracts.

Carbon Management

The low carbon dioxide emissions footprint of natural gas consumption as compared to coal is also changing the LNG market. Countries are increasingly looking to natural gas and in some cases, LNG to substitute for coal in their electricity markets.

China is a case in point. Its coal fleet represented approximately 65% of electricity generation capacity at the end of 2015. In their current 5-year plan, the target is to reduce this percentage to 60%, primarily using natural gas-fired generation to meet the growing electricity demand.

The increased reliance on LNG to support electricity generation will increase the seasonality of demand. This will mean increased variations during the year in terms of LNG surplus and price.

Canadian LNG Developments

A total of 35 LNG export/import licences have been issued by the NEB by the end of 2017: 28 in British Columbia, 3 in Quebec, 3 in Nova Scotia, and 1 in New Brunswick (NEB 2018). As of September 2017, the National Energy Board has received 43 applications to export/import LNG (note - not all these are liquefaction projects) (NEB 2018):

- 35 of the 43 applications were approved
- 0 of the 43 applications are under review
- 6 of the 43 applications were deemed incomplete
- 2 of the 43 applications were withdrawn by the applicant.

Canadian LNG activities began in 2012 to catch the opportunity of high LNG prices and growing demand. Since then, despite dozens of projects in Canada having received their export licenses, many projects either became inactive or have been cancelled. However, some on both coasts have the potential to move forward.

Several projects which are close to final investment decision (FID) are described in more detail, as they will serve as a proxy for a generic project used for CERI's supply cost modelling. Each venture is described in terms of its location, proponent information, capacities, capital costs per mtpa, business model, gas supply sources, availability of signed Sales and Purchasing Agreements (SPAs), need for pipeline construction to feed gas and availability of export license.

Eastern Canada Projects

East Coast LNG liquefaction projects include seven projects which have received LNG export licences: Goldboro LNG, Bear Head LNG, H-Energy in Nova Scotia; Saguenay LNG, Stolt LNGaz Inc. (not export-oriented) and TUGLIQ Gaz Naturel Québec Inc. in Quebec; and Canaport LNG in New Brunswick. The Canaport LNG regasification terminal has been considered for conversion to liquefaction. However, in 2016 Repsol announced that it had failed to attract outside investors for this multi-billion dollar project and that the conversion is not currently economical (estimated costs for conversion was \$2-\$4 billion dollars).¹

Eastern LNG projects are located closer to European, Western Asian (specifically India via the Suez Canal) and Latin American markets than the US Gulf of Mexico's projects. This gives Canadian projects a distance advantage. As these markets are expected to grow in their gas consumption in the long term according to the IEA, Eastern Canadian LNG facilities are attracting investors' interest. Table 1.1 illustrates four LNG projects in Eastern Canada.

¹ <http://www.cbc.ca/news/canada/new-brunswick/repsol-canaport-conversion-scrapped-1.3493617>

Table 1.1: LNG Liquefaction Projects in Eastern Canada

| Project | Province | Business Model | Sponsors | Capacity (mtpa/bcf/d) | FID, Status | Export License | Environment Canada |
|---------------|----------|----------------|----------------------|-----------------------|--|----------------|-----------------------------|
| Goldboro LNG | NS | Integrated | Pieridae Energy Ltd. | 5-10 / 0.7-1.3 | 2018, Active | Y | Y |
| H-Energy | NS | N/A | H-Energy Ltd | 4.5-13.5 / 0.6-1.8 | N/A (expected shipments in 2023), Active | Y | N/A |
| Bear Head LNG | NS | Tolling | Bear Head LNG Corp. | 8-12 / 1.1-1.6 | 2018, Active | Y | Y |
| Saguenay LNG | QC | Non-integrated | GNL Québec | 11 / 1.5 | Expected in 2020, Active | Y | In progress since Jan. 2016 |

Note: Only export-oriented facilities are included. TUGLIQ Gaz Naturel Québec Inc. information is not available. Two projects are the closest to FID – Goldboro LNG and Bear Head LNG, both located in Nova Scotia.

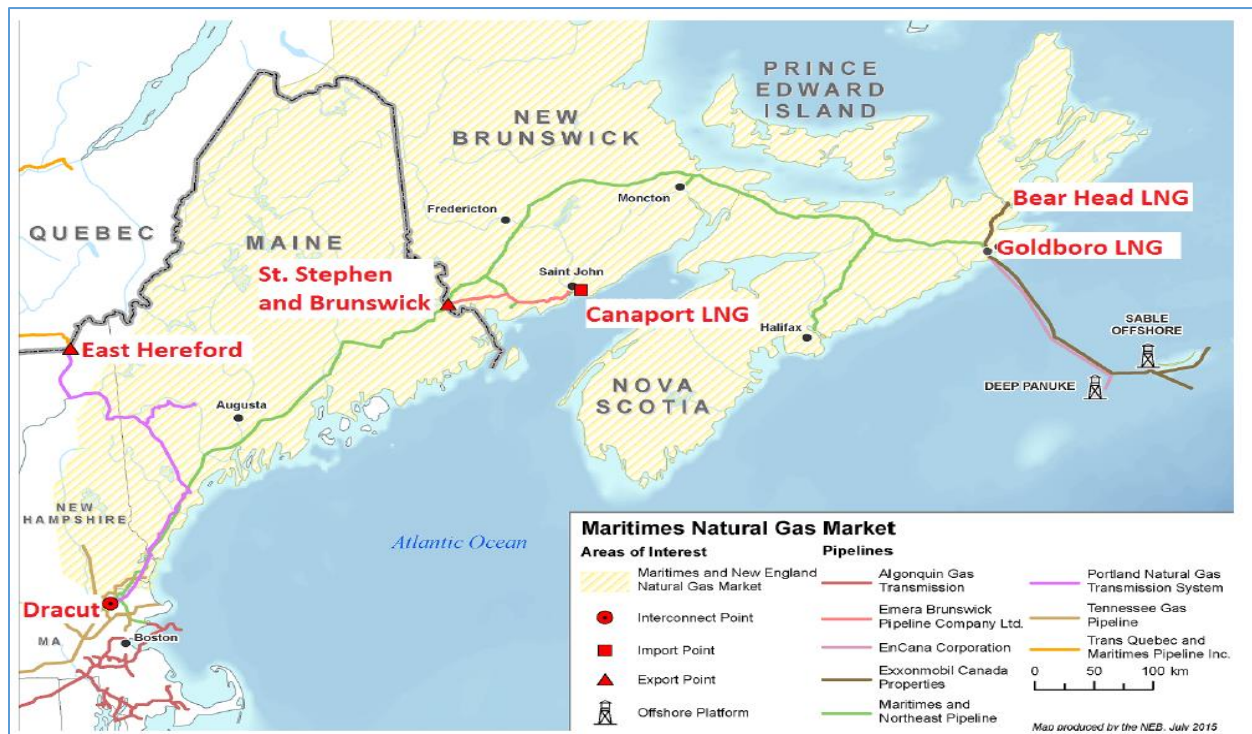
Source: CERI, proponents' websites, Canada Environmental Assessment Agency.

Nova Scotia's current natural gas production is entirely offshore, located approximately 250 kilometres off the coast of Nova Scotia, at Sable Offshore Energy Project (SOEP) and Deep Panuke. These projects are tied to the 0.55 bcf/d, 1,400-kilometre Maritimes and Northeast Pipeline (MNP) pipeline which delivers gas to customers in Nova Scotia, New Brunswick and to the US. Both projects are in decline and cannot provide sufficient gas supply for an LNG project of medium size (5-8 mtpa). Nova Scotia and New Brunswick have significant estimated shale resources of about 69 Tcf and 80 Tcf, respectively (CERI 2017) in place, but existing hydraulic fracturing bans do not allow for further exploration and production of these resources. For more detail, refer to CERI Study 165, "Economic Potential of Onshore Oil and Gas in New Brunswick and Nova Scotia" (CERI 2017).

Consequently, the development of Goldboro LNG and Bear Head LNG hinge on access to abundant and competitive gas sources and availability of additional MNP pipeline capacity to push gas to a liquefaction plant. If local gas is available at some point in the future, this may increase the economic impact of Nova Scotia projects by providing domestic production. It could also improve the economics of the LNG projects themselves by reducing input costs by eliminating the long-term transportation tolls.

Figure 1.15 illustrates the location of two projects in Nova Scotia, as well as the Canaport LNG import terminal in New Brunswick.

Figure 1.15: Maritime Natural Gas Market



Source: NEB

Goldboro LNG

Goldboro LNG is a \$5-\$10 billion project with capacity up to 10 mtpa (Goldboro LNG n.d.). It is being proposed by Pieridae Energy and located in the Goldboro Industrial Park in Guysborough County, Nova Scotia.

Goldboro LNG is based on the integrated business model, where the company is responsible for obtaining its natural gas and liquefaction facility (“a shipper on pipelines”). The project has successfully secured sales for 50% capacity with a purchase contract with Uniper Group (holds 1% in the development of the liquefaction facility) for 4.8 mtpa of LNG a year over a 20-year period. Contract prices are based on Western European gas market prices (UNIPER 2016).

Natural gas supply has been a challenge for Goldboro LNG. As Sable Offshore Energy production is scheduled to cease operations in 2020, Pieridae Energy is investigating reversing the MNP, allowing it to feed natural gas to the facility. Encana’s Deep Panuke project production (1.7 Bcf in November 2016 or 56.6 mmcf/d) is not enough to meet total local demand in New Brunswick or Nova Scotia (210 mmcf/d in 2017 - (CERI 2017)), let alone to provide LNG feedstock.

Goldboro LNG has four potential options for gas supply:

1. Supply from Quebec, New Brunswick and Nova Scotia
2. International supply, from the US, at the AGT hub in Boston. This gas is likely to be sourced from Marcellus
3. Western Canadian natural gas
4. Associated gas from offshore Newfoundland

Several of these options would require additional infrastructure. If coming from the West, there is the possibility of a new natural gas pipeline through Quebec, New Brunswick and Nova Scotia. If coming from offshore Newfoundland, ship loading facilities would be required.

As the Maritimes and Northeast pipeline (MNP) is adjacent to the Goldboro site, this allows the Nova Scotia LNG project the option of transport on the existing, or expanded pipeline. Existing capacity of the MNP is limited. Recall, that MNP's total capacity is 0.55 bcf/d while supplying 5-10 mtpa will require 0.7-1.3 Bcf/d. Also, MNP is used as a transmission line for New Brunswick and Nova Scotia residential and industrial customers, which consume 0.2 Bcf/d for local needs, leaving 0.35 bcf/d to potentially provide natural gas for an LNG project. Using this pipeline for LNG supply would require an expansion.

The Goldboro project obtained its NEB export licence in May of 2016, valid for 20 years (NEB 2018). It has also been granted a 20-year license to export natural gas from the US to Canada to supply the Goldboro LNG facility and to export the resulting LNG from Canada. This latter approval is due to restrictions on re-exports defined in the North American Free Trade Agreement. Both licenses allow for an annual export capacity of 1.61 Bcf/d and a maximum annual import volume of 1.14 Bcf/d (CERI Natural Gas Commodity Report, July 2016).

An FID is expected in 2018.²

Bear Head LNG

Bear Head LNG, initially planned as an import terminal, is a \$9 billion liquefaction project of 8 mtpa capacity with possible extension to 12 mtpa (Nova Scotia Environment 2009). The Bear Head LNG site is located at Point Tupper, in Richmond County, Nova Scotia, on the north bank of the Strait of Canso with direct access to the North Atlantic. The waterway is sheltered, remains ice-free, and requires no dredging.

Bear Head LNG is based on the tolling business model without dedicated upstream natural gas reserves to the project.³ The company states that natural gas is "expected to come from producers in the US and Canada." Recently, the company expressed interest to supply Alberta gas to Nova Scotia. According to the company: "The project's ambitious proposal would see producers in Alberta ship natural gas through TransCanada Corp. pipeline to North Bay, Ont. From there, Bear Head would build a new pipeline to Goldboro, more than 1,700 kilometres.

² <https://www.cbc.ca/news/canada/nova-scotia/pieridae-energy-natural-gas-liquefaction-plant-1.4618786>

³ <http://www.cbc.ca/news/canada/nova-scotia/liquefied-natural-gas-projects-ramp-up-1.4305975>

Building the greenfield pipeline from Ontario to Nova Scotia would require deals from producers up front; the company hopes to have them in place by mid-2018.”⁴

Other natural gas options are like Goldboro LNG’s – US shale gas or local gas if the hydraulic fracturing ban is lifted and resources are proved. The proponent has already received approval to build a 62.5-kilometre \$235-million pipeline that would run between Goldboro to Point Tupper.⁵

In August 2015, the NEB granted Bear Head LNG authorization to export up to 8 mtpa of LNG from Canada starting in 2019 with expanded authority to increase production to 12 mtpa in 2024 (NEB 2018). The export licence extends for 25 years from the date of first LNG export. The US Department of Energy (DOE) has granted Bear Head authorization to export up to 1.2 bcf/d of US natural gas to Canada, and up to 1.05 bcf/d of LNG from Canada to countries with which the US has a free trade agreement (FTA) (Bear Head LNG n.d.). Further, the DOE has granted the company an authority to export LNG derived from the US produced natural gas to all countries with which trade is not prohibited by US law or policy (Non-FTA).

A FID is expected in 2018-2019 given the timelines for the project announced by the company. The assumption is underpinned by a statement of Bear Head CEO that “the company plans to get pipe laid and the terminal up and running by 2022 or 2023”.⁶

Western Canada Projects

As of 2016, there were more than 19 proposed LNG liquefaction projects in British Columbia, and only one – the 2.1 mtpa Woodfibre LNG had a FID according to the BC Oil and Gas Commission. Several projects were cancelled in 2016 and 2017, including Shell’s Prince Rupert LNG on Ridley Island, Nexen’s Aurora LNG on Digby Island, ExxonMobil-led WCC LNG, Alta Gas Triton LNG, and Douglas Channel LNG. The announcement from Petronas’ \$36 billion Pacific NorthWest LNG project on Lelu Island was due in part to low LNG prices.

Currently, five projects are active in British Columbia: Woodfibre LNG, LNG Canada, Kitimat LNG, Grassy Point LNG and Kwispa LNG. All but the Kwispa project are listed in the BC Major Project government list; three of those have received environmental approvals from Canada and British Columbia. The Kwispa project is “the only Canadian LNG project being developed through a co-management relationship between industry and First Nations.” (Steelhead LNG n.d.) Detailed information on current LNG liquefaction ventures can be found in Table 1.2.

⁴ ibid

⁵ <http://www.cbc.ca/news/canada/nova-scotia/liquefied-natural-gas-projects-ramp-up-1.4305975>

⁶ <http://business.financialpost.com/pmn/business-pmn/interest-in-n-s-liquefied-natural-gas-projects-ramps-up-as-producers-look-east>

Table 1.2: Current Key LNG Liquefaction Projects in British Columbia

| Project | BC Major Project List | Business Model | Sponsors | Capacity (mtpa/bcf/d) | FID, Status | Export License | Environment Canada | Environment BC |
|--------------------|-----------------------|----------------|--------------------------------------|-----------------------|--------------------------|----------------|--------------------|-----------------|
| Woodfibre LNG | Yes | Merchant | Pacific Oil & Gas Ltd (part RGE) | 2.1 / 0.3 | Y, Active | Y | Y | Y |
| LNG Canada | Yes | Integrated | Shell, KOGAS, Mitsubishi, PetroChina | 13-26 / 1.7 – 3.4 | Expected in 2018, Active | Y | Y | Y |
| Kitimat LNG | Yes | Integrated | Chevron, Woodside Energy | 10 / 1.3 | N/A, Active | Y | Y | Y |
| Grassy Point LNG | Yes | Integrated | Woodside Energy | 20 / 2.6 | N/A, Active | Y | Pre-Application | Pre-Application |
| Kwispaa LNG | | N/A | Steelhead LNG | 24 / 3.2 | N/A, Active | Y | Not submitted | Not submitted |
| Discovery LNG | | N/A | Quicksilver Resources Canada Inc. | 20 / 2.6 | N/A, not active | Y | Not submitted | Not submitted |
| Stewart Energy LNG | | N/A | Stewart Energy Group | 5-25 / 0.6-3.3 | N/A, Not active | Y | Not submitted | Not submitted |
| Kitsault LNG | | N/A | Kitsault Energy | 20 / 2.6 | N/A, Not active | Y | Not submitted | Not submitted |
| Orca LNG | | N/A | Orca LNG Ltd. | 24 / 3.2 | N/A, Not Active | Y | Not submitted | Not submitted |
| Cedar LNG | | N/A | Cedar LNG Export Development Ltd. | 6.4 / 0.9 | N/A, Not active | Y | Not submitted | Not submitted |

Source: CERI, BC Government, project websites (only projects with existing export licenses and dedicated websites are included).

Two projects – Woodfibre LNG with an FID, and LNG Canada, which is considering an FID in 2018, are described below.

Woodfibre LNG

Woodfibre LNG is planning to build a 2.1 mtpa, \$1.4-\$1.8 billion (CAD) liquefaction facility at the former Woodfibre pulp mill site, about seven kilometres southwest of Squamish, British Columbia (Woodfibre LNG 2016) (Figure 1.16). Woodfibre LNG Ltd., a private Canadian company, is a subsidiary of Pacific Oil and Gas Limited which is part of the Singapore-based RGE group of companies.

Figure 1.16: Woodfibre LNG Location



Source: BC Oil and Gas Commission

Woodfibre LNG's business model is a standalone liquefaction facility. There is no indication that Woodfibre is planning to perform E&P for gas resources. The company is proposing an approximately 47-kilometre expansion of a portion of its existing pipeline system that serves the Sunshine Coast and Vancouver Island. It involves adding new pipe beginning north of the Coquitlam Watershed and ending at the Woodfibre LNG site. The 24-inch diameter pipeline (marked in pink in Figure 1.16) will have a firm capacity of 0.22 BCF/day.

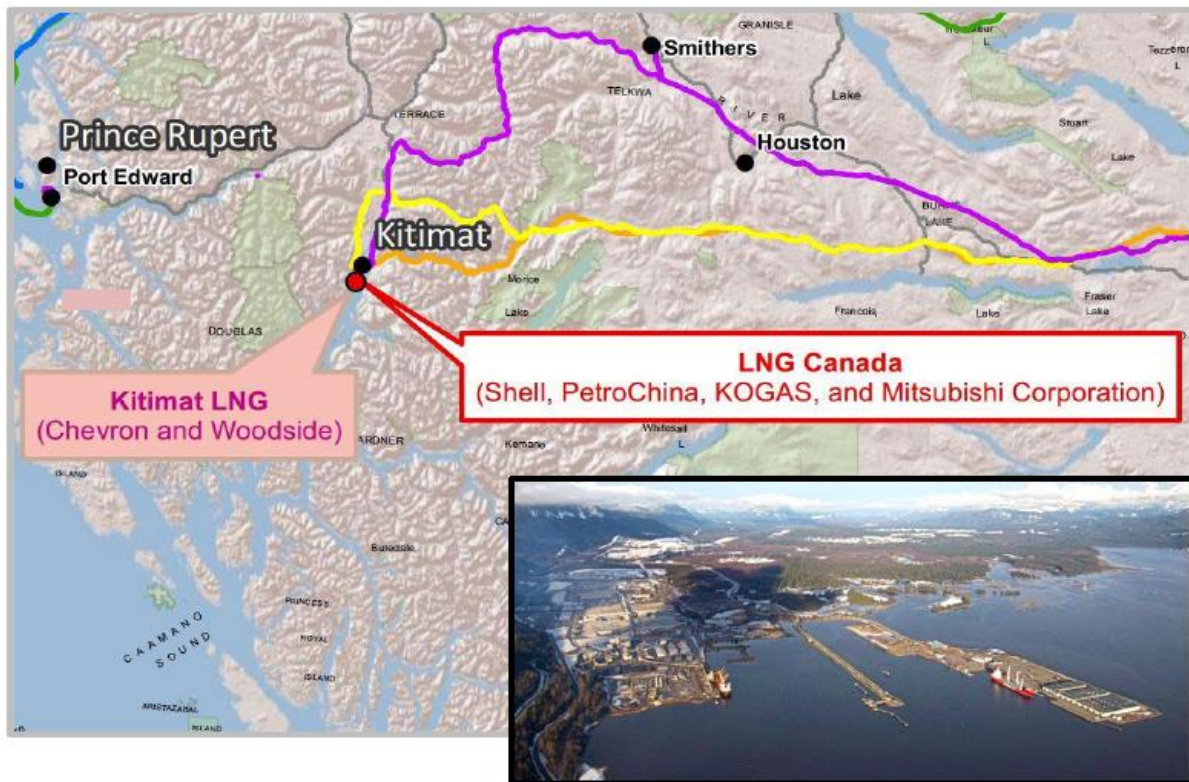
The BC government currently assumes that 100% of the gas to LNG projects is supplied from BC. Alternatively, there could be a split of 75% from BC and 25% from Alberta (Canadian Environmental Assessment Agency 2016). It is likely that Woodfibre will be buying gas from the same suppliers who feed the Sunshine Coast and Vancouver Island.

In June 2016, the project received a 40-year export licence. The project FID occurred in 2016. Pending future permitting, the proponent anticipates exports to Asia could begin in 2020 (BC Oil and Gas Commission 2017c).

LNG Canada

LNG Canada is a \$22.6-\$36 billion (2015, CAD), 13-26 mtpa LNG liquefaction project led by Shell and three other shareholders: KOGAS, Mitsubishi, and PetroChina. The project is expected to operate for a minimum of 25 years. Petronas has also announced an equity interest in this project.

Figure 1.17: LNG Canada Location



Source: BC Oil and Gas Commission

The facility is in Kitimat, BC. The project is expected to be built in two phases. The first phase will be a plant of 13 mtpa. Phase 2 will see this capacity double. The LNG facility will consist of natural gas receiving and treatment facilities, liquefaction facilities, LNG storage tanks, NGLs storage tank, and NGL railcar staging area and loading facility, marine terminal facilities, cryogenic LNG transfer pipelines and supporting facilities and infrastructure (BC Oil and Gas Commission 2017b). A marine terminal will be able to handle LNG carriers with a capacity between 130,000-265,000 m³. The project expects between 170-350 carrier visits per year depending on the size of the LNG carriers.

LNG Canada has an integrated project business model, where its owners are obliged to provide natural gas from E&P activities in the volume proportional to their respective participating interest shares. There is no indication of the specific source of natural gas that will supply the plant. However, it is likely to be the Montney formation using a to-be-built connecting pipeline that will originate in Dawson Creek, BC. At the build-out, the LNG facility will require 3.7 bcf/d of natural gas, out of which 3.4 bcf/d will be processed into 26 mtpa, and 0.3 Bcf/d will be used for fuel (LNG Canada 2013). LNG Canada aims to use grid-supplied electricity which would decrease the needed volumes of gas for fuel. Extracted NGLs are planned to be loaded onto rail cars for transfer to market.

The Coastal GasLink natural gas pipeline project will run approximately 670 km (416 miles) in length. The proposed pipeline will deliver natural gas from the Dawson Creek area of northern BC to Kitimat, BC (TransCanada n.d.) The initial phase of the project would have up to two compressor stations with a capacity of 2.1 BCF/day, with potential expansion to 5 BCF/day and up to eight compressor stations (BC Oil and Gas Commission 2017a). LNG Canada contracted TransCanada to build, own and operate a pipeline which will deliver gas to the site.

The project received its 40-year export licence in May 2016. It has also received positive approval of environmental assessments from both Canada and British Columbia.

LNG Canada is in the pre-FID stage. Originally, FID was expected to take place in 2016, but in July 2016 the company announced a delay. The company expects to make a FID in 2018 and start construction, as the EPC contractors have been recently announced. With a four to five year construction period, that would see the first LNG shipments by 2023.

Structure of the Report

Chapter 1 includes an introduction and review of the LNG industry, recent developments and trends with regards to pricing, business model, carbon management and technological changes. Characteristics of the leading active LNG projects in the east and west coasts are reviewed.

Chapter 2 presents the research questions and the methodology of the study.

Chapter 3 provides the supply costs of LNG plants in jurisdictions under consideration. The influence of major cost components such as capital costs, operating costs, natural gas supply and transportation, and taxes, on the supply cost, is reviewed. Per each location, the key differentiators and cost drivers are discussed as well as existing government incentives for the LNG industry. A focus is made on Canadian and US recent developments, which have a direct impact on the costs. Different options of natural gas supply, as well as economies of scale effects from an expansion of a plant, are shown. For the United States, an effect of the recent change in the tax legislation on the supply costs is estimated and compared to existing Canadian regime.

Chapter 4 puts each project into geographical perspective relative to the destination markets and provides landed supply costs in European and Asian markets. The chapter presents a path to better cost-competitiveness for Canadian projects – some of the measures that the federal government, provincial governments, and LNG project owners could undertake in this regard. A comparative perspective of all jurisdictions is presented as well as potential economic impacts from LNG plant construction and operation in Canada based on the published information from the proxy projects and other studies. The chapter concludes with a review of the agreements with Indigenous Peoples specific to the natural gas and LNG industry.

Chapter 5 summaries several key conclusions of this study.

Chapter 2: Research Questions and Methodology

This section reviews the methodology of the various models and calculations used in this study. It is divided into the following sections:

- research questions, and
- methodology:
 - supply cost model
 - pipeline model
 - shipping cost model, and
 - sensitivity analysis

Research Questions

The study focuses on examining Western and Eastern Canada LNG supply costs and competitiveness factors in comparison with two other major locations – the US Gulf of Mexico (GoM) and Australia. In the study, supply cost does not include shipping cost of LNG to destination markets, while landed costs do include such a cost. The study assesses key elements of supply costs and competitiveness of LNG projects in the abovementioned jurisdictions; in the US GoM, the analysis deals with Texas and Louisiana. The elements include capital costs, operating costs, taxes (including a carbon tax), natural gas costs and gas transportation costs to LNG plants as well as cost drivers and specifics of each jurisdiction, e.g., temperature, need for a dedicated pipeline, experience in delivering LNG projects, and other. In each location, a project is modelled based on an existing proxy.

This research explores five questions:

1. What are the supply costs of greenfield Canadian LNG projects on the East and West coast?
2. Are greenfield Canadian LNG projects cost competitive compared to greenfield and brownfield projects in the US Gulf of Mexico and Australia going to European and Asian markets?
3. What should the LNG price be in Asian and European markets for LNG projects in Canada to break-even and how does the required price correspond with existing market realities?
4. What are the advantages and disadvantages of Canadian jurisdictions in comparison to the US Gulf of Mexico and Australia?
5. What are the paths to make Canadian projects more cost-competitive, including the effects of government incentives?

Methodology

This section reviews the methodology of the various models, calculations and assumptions used in this study including the supply cost model, the pipeline cost model, the transportation model, and natural gas feedstock pricing and sensitivity analysis.

The scope of the study is to compare the competitiveness of Western and Eastern Canada LNG with LNG projects in two other jurisdictions – the US Gulf of Mexico (Texas, Louisiana) and Australia. To do that, LNG supply costs in all the locations are calculated with the sensitivity analysis. LNG transportation costs are estimated from each location to a number of destination markets in order to obtain the landed costs. The study then compares landed costs between projects, compares landed costs with LNG prices at the destination locations, and estimates the required oil price for oil-linked contracts for projects to break-even.

Supply Costs

The study presents supply costs for six projects in five jurisdictions (two in Canada, three in the US, one in Australia) (Table 2.1). Some special cases are calculated and presented in the text, e.g., an expanded 26 mtpa version LNG plant in Western Canada or a 12 mtpa LNG plant in Eastern Canada.

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. The net cash flow is discounted over the lifetime of the LNG plant (assumed 30 years, not including construction) to the first period (2018) using a discount rate of 10 percent. The supply cost is LNG price per mmbtu in 2018 constant dollars that sets the net present value of the net cash flow to zero. General assumptions for supply cost models and detailed configurations and assumptions for each project are provided in Appendix A.

Companies may evaluate individual projects and investments using a higher or lower discount rate than the 10% used in this analysis. This would result in higher or lower supply costs than those presented in the study.

All modelled LNG facilities had a proxy project in each location. A proxy project is used by CERI in each location to model supply cost and to discuss competitiveness factors. However, the latter is generally applicable to any project in a location. The proxy's capacity is a million tonne per annum (mtpa), capital costs, as well as some other characteristics used from a proponent's applications and other documentation. **CERI did not model the existing projects in full detail; rather we used their general configuration to estimate a representative LNG supply cost in each respective location.**

In the selection of the proxies, CERI attempts to find LNG plants which are comparable to selected Canadian LNG projects. A balance of the following factors is taken into consideration:

-
- time of coming on stream (the later, the better to match Canadian project timing)
 - the similarity in size (except for specific cases where it is not possible)
 - type of liquefaction facility (onshore only)
 - type of project (ideally greenfield, but taking into account US liquefaction market realities, brownfield projects are also included)

For the US Gulf of Mexico LNG projects, CERI looked at three distinct cases to assess what is happening in the LNG industry. First, when liquefaction capacity is added to an existing regasification capacity (e.g., Cameron LNG). Second, a greenfield LNG project (e.g., Corpus Christi). Third, when one train is added to an existing liquefaction facility (e.g., Train 5 of the Sabine Pass). For the comparative analysis, we compared greenfield projects in Canada with the greenfields in the US, rather than with brownfields. However, from a commercial perspective, the customer does not differentiate between the two and seeks a lower cost supply if other considerations are equal. Thus, the study presents comparisons across all types of projects.

In Australia, onshore coal seam gas (CSG) projects in Queensland are taken as a proxy as they are more similar to Canadian projects than northwest Australia offshore gas-based projects or floating LNGs.

The proxy projects selected for the study are as follows:

- Western Canada (British Columbia) – LNG Canada, greenfield (expected on-stream year – 2023)
- Eastern Canada (Nova Scotia) – Bear Head LNG, greenfield (expected on-stream year – 2023)
- Australia (Queensland) – Queensland Curtis LNG, greenfield (on-stream year – 2015) (Gladstone and APLNG could also be taken as proxies as they are in the same area and have almost identical CAPEX per tpa)
- US GoM (Louisiana), Cameron LNG, brownfield (on-stream year – 2019), adding liquefaction to existing regasification
- US GoM (Texas), Corpus Christi, greenfield (expected on-stream year - 2019)
- US GoM (Texas), Sabine Pass (additional Train 5, expected on-stream year – 2019)

Table 2.1: LNG Projects Considered for the Study

| Project | Jurisdiction | Capacity, mtpa / Trains / CAPEX \$/tpa | Type, Business Model | Gas Supply Source |
|---------|--|--|--|--|
| 1 | Western Canada, British Columbia, (Proxy – LNG Canada) | 13 / 2 trains \$1,237* | Greenfield, Integrated | BC, Montney |
| 2 | Eastern Canada, Nova Scotia (Proxy – Bear Head LNG) | 8 / 2 trains \$1,006* | Greenfield, Merchant | 1) Canada, AECO-C 2) US, Marcellus/Utica 3) Local shale gas, Nova Scotia |
| 3 | US GoM, Louisiana (Proxy – Cameron LNG) | 15 / 3 trains \$667 | Liquefaction added to existing regasification facility, Merchant | Conventional, tight and shale gas, Henry Hub tied pricing |
| 4 | US GoM, Texas (Proxy Corpus Christi) | 9 / 2 trains \$1,028 | Greenfield, Merchant | |
| 5 | Proxy (Sabine Pass Train 5) | 5 / 1 train \$709 | Brownfield, additional train to existing liquefaction facility | |
| 6 | Australia, Queensland (Proxy - QCLNG) | 8.5 / 2 trains \$2,091 | Greenfield, Integrated | CSG (coal seam gas) |

* Includes fabricated steel duty and countervailing dues (FSCD).

For Eastern Canada, natural gas is modelled to come from one of three sources: Alberta (AECO-C), US Marcellus/Utica, or local shale gas (Horton Bluff Shale). The latter is not in exploration and production at the moment due to the hydraulic fracturing moratorium in Nova Scotia. However, the resource potential is substantial. More detailed information about the Horton Bluff Shale play potential production and supply costs can be found in CERI Study 165, “Economic Potential of Onshore Oil and Gas in New Brunswick and Nova Scotia.”

To ensure a better comparison, all projects are modelled as if they took a FID in 2018, and come on-stream in 2023 (5 years of construction is assumed, which is consistent with the literature and industry averages. The exception is Sabine Pass, where 4 years is used). This is done irrespective of the real proxy projects construction timelines or the start of operations.

Thus, the difference between the projects will be driven mostly by country and project specifics: capital costs, operating costs in a particular location (including due to labour productivity and average annual temperature), remoteness of liquefaction locations, distance from the natural gas source, natural gas source type and costs (prices), availability of or need to build pipeline transportation, landscape and terrain and harbor specifics, fiscal regime and incentives, experience in building LNG plants, and other. Transportation costs will be driven mostly by marine distances and the need to navigate canals (Suez, Panama).

Supply cost is presented in dollars per million British thermal units (mmbtu), with a breakdown of total cost by capital cost, natural gas cost, pipeline transportation cost, operating cost, corporate taxes, LNG income tax (if applicable), and carbon tax (if applicable). The total tax burden is shown separately. CERI also presents three benchmarks which are needed for projects to breakeven:

- the price at the destination market in constant 2018 dollars
- a required price of oil for oil-linked Sales and Purchase Agreements which corresponds to a required LNG price in the destination market
- an LNG price curve (on FOB case) in nominal dollars needed on the spot or contract markets

As this study is comparative in nature, and LNG is priced internationally in US dollars as are major publications on LNG projects (CAPEX, OPEX), this currency is used for this study, unless otherwise specified. Resulting supply costs and some other metrics are also shown in Canadian dollars.

Pipeline Transportation Costs

The natural gas transportation costs are presented in Figure 2.1. For Eastern and Western Canada LNG projects, which lack pipeline access to the source gas, CERI ran a separate cash-flow model to estimate a minimum toll required to recover the pipeline costs over 30 years of operation. Three years are assumed for the construction of a pipeline (the construction duration for the Coastal GasLink project is taken as a proxy).

Detailed assumptions for the toll modelling are provided in Appendix B.

Figure 2.1: Natural Gas Transportation Costs

| Location | Pipeline Path and Characteristics | Toll |
|---------------------------|---|---|
| Western Canada LNG | A 48" 650 km Coastal GasLink project is used as a proxy to transport natural gas from Montney area to the coast. The pipeline project is external to the LNG project cash-flow model. | From \$0.92 (2023) to \$1.63 (2052), nominal. \$1.09, constant 2018 |
| Eastern Canada LNG | 1. From Alberta (AECO hub) via TransCanada Mainline to Dawn, ON; further a separate 42" 1,600-km pipeline to Goldboro, NS and 62.5 km pipeline from Goldboro to Port Tupper, NS are modelled as a separate supply cost model to estimate a minimum required toll. | The resulting toll is a combination of A) \$0.75/mmbtu (NIT to Empress plus Empress to Dawn) inflated annually by 2% from 2028, and B) The toll for a new pipeline. From \$1.93 (2023) to \$3.43 (2052). \$2.3, constant 2018 |
| | 2. From the United States, Marcellus/Utica sourced natural gas. A toll from Lebanon, PA to Dawn, ON is used as a proxy to transmit natural gas from the source to the Dawn hub. The same pipeline from Dawn to Port Tupper is modelled further. | The resulting toll is a combination of A) \$0.51/mmbtu (Lebanon, PA to Dawn) inflated annually by 2% and B) Toll for a new pipeline. From \$1.93 (2023) to \$3.43 (2052) nominal. \$2.3, constant 2018 |
| | 3. From local shale gas resources. In the case when local Horton Bluff Shale gas is used, a 337 km 42" pipeline is modelled. | Part of the LNG project capital cost. Operating costs – \$0.05 per mmbtu. |
| US Gulf | a 37-km proxy pipeline is modelled to connect to the transmission line. | Part of the LNG capital cost. |
| Australia | A 540-km pipeline is part of the capital costs. | Part of the LNG project capital cost. Operating costs – \$0.1 per mmbtu. |

LNG Shipping Costs

To estimate LNG marine shipping costs, CERI built a transportation model which predicts LNG transportation costs depending on a) distance between ports, b) cost of fuel, c) price of LNG at the destination market, d) daily charter rate, and e) canal tariffs (Panama, Suez). Key assumptions for the model are shown Appendix C. Representative costs are presented in Table 2.2, while all transportation costs are provided in Appendix C.

Table 2.2: LNG Shipping Costs

| Loading Port | Loading Country | Offtake Port | Offtake Country | Nautical Miles | One way/ Total Trip Days* | Cost of Shipment, (\$ per mmbtu) |
|---------------------|------------------------|---------------------|------------------------|-----------------------|--|---|
| Kitimat | Canada | Thamesport | United Kingdom | 9,708 | 24 / 51 | 1.84 |
| Point Tupper | Canada | Thamesport | United Kingdom | 2,713 | 7 / 16 | 0.42 |
| Sabine Pass | United States | Thamesport | United Kingdom | 5,206 | 13 / 29 | 0.75 |
| Gladstone | Australia | Osaka | Japan | 3,806 | 9 / 22 | 0.58 |
| Kitimat | Canada | Osaka | Japan | 4,217 | 10 / 24 | 0.64 |
| Point Tupper | Canada | Osaka | Japan | 10,761 | 26 / 56 | 1.76 |
| Sabine Pass | United States | Osaka | Japan | 9,825 | 24 / 51 | 1.63 |
| Gladstone | Australia | Hazira | India | 6,150 | 15 / 33 | 0.88 |
| Kitimat | Canada | Hazira | India | 9,574 | 23 / 50 | 1.38 |
| Point Tupper | Canada | Hazira | India | 7,633 | 19 / 42 | 1.31 |
| Sabine Pass | United States | Hazira | India | 11,754 | 29 / 63 | 1.91 |

* Includes time for loading and offloading, round trip.

Natural Gas Feedstock Costs

Securing natural gas feedstock is a major issue and part of the supply cost for an LNG project, and in some cases, it can be a differentiator and constitute a competitive advantage or a disadvantage for a facility as the study will present further.

The large uncertainty comes from the difficulty to predict prices (translated into plant costs) of the natural gas. Integrated, merchant and tolling business models all originate from specific business situations, but are also the product of the risk mitigation measures or profit-seeking measures by LNG owners with regard to natural gas costs for an LNG plant. For instance, a tolling model puts all natural gas pricing risks at the lessor of the facility and their customers (depending on the terms of the LNG Sale and Purchase Agreement). The merchant business model is exposed to the volatility of natural gas pricing but does not require a company to bear the financial burden and exploration/drilling risks. Finally, the integrated model allows a company to control its source

of natural gas and costs of exploration and lifting and leaves the upstream margin within the perimeter of the project, which would otherwise be paid to a third-party.

In each case, the LNG proponent decides which model works best and how certain the project can forecast natural gas prices before it executes a FID.

For the purpose of the study, CERI uses different sources for natural gas pricing (as shown in Table 2.1). In the case of the US and Eastern Canada LNG (except for when local gas is used), natural gas feedstock prices are tied to hub prices – Henry Hub, AECO-C, and Dominion Hub (Marcellus/Utica). To establish these prices, CERI assumes the following:

- Henry Hub price increases by 2% annually.
- AECO-C price (in \$US per mmbtu) is established by subtracting a fixed differential from the Henry Hub price. For 2018, \$1.1 is assumed based on the average difference between the two hub prices for 2016-2017. For reference, the average annual differential has been increasing from \$0.3 in 2014 to \$0.7 in 2015, to \$0.88 in 2016, to \$1.24 in 2017 per mmbtu (CERI). The average differential since the year 2000 was approximately \$0.7 per mmbtu. CERI assumes that over time the AECO market differential will come closer to its historical average especially as LNG projects will provide an additional source of demand for gas. The following differentials between Henry Hub and AECO-C are taken for the study:

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025-further |
|--------|--------|--------|--------|--------|--------|--------|--------------|
| \$1.10 | \$1.05 | \$1.00 | \$0.95 | \$0.90 | \$0.85 | \$0.80 | \$0.75 |

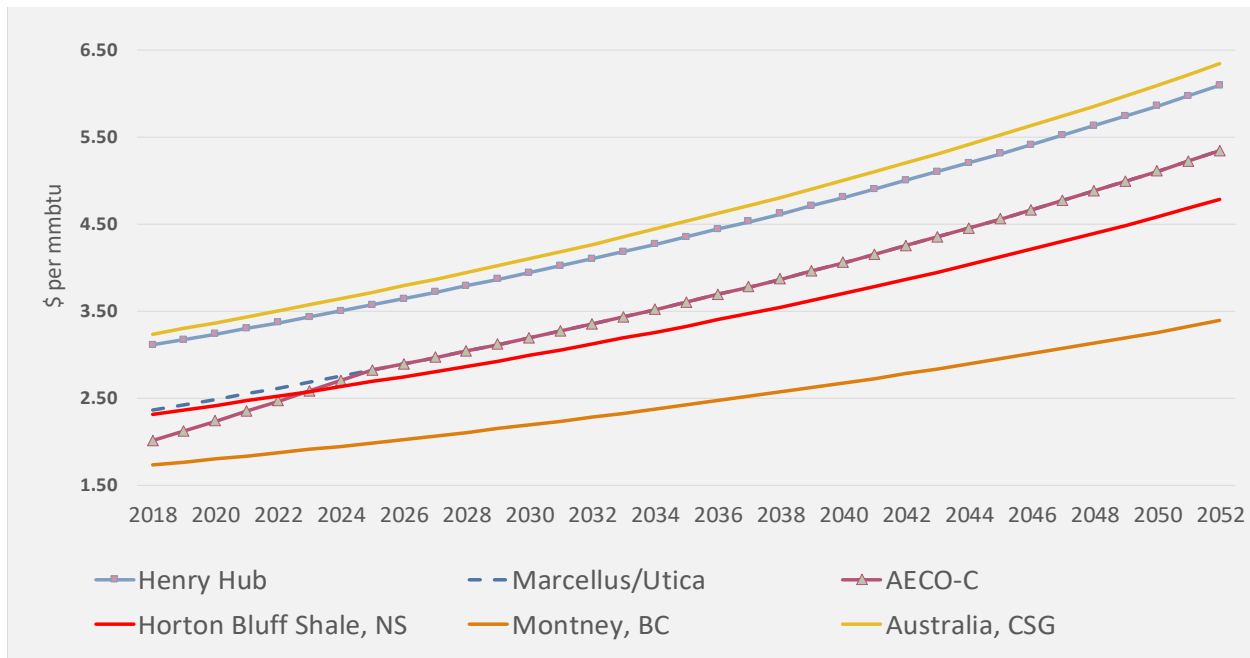
- Dominion Hub (Marcellus/Utica) natural gas is modelled as Henry Hub price minus \$0.75. The differential is assumed based on recent US EIA reports which show decreasing differentials between the hubs as the Marcellus outflow pipeline capacity increases (EIA 2017b). The Marcellus gas is thus more expensive in the years 2023-2024 compared to AECO-C (recall that all projects start output in 2023) but from 2025 they are considered equal in their differential to Henry Hub.

Table 2.3 illustrates natural gas costs used for each project/jurisdiction.

Table 2.3: Natural Gas Feedstock Costs

| Location | Approach | Natural Gas Feedstock Cost |
|-------------------------------|---|---|
| Western Canada LNG | A minimum break-even price at which natural gas must be sold from a Montney area horizontal well. Source: a weighted average of Montney area supply costs (CERI Study, Canadian Crude Oil and Natural Gas Production and Supply Costs 2018). | From \$1.73 (2018) to \$3.39 (2052), nominal |
| Eastern Canada Project | <ol style="list-style-type: none"> 1. Local natural gas costs are taken from Horton Bluff Shale-based model (CERI Study, Economic Potential of Onshore Oil and Gas in New Brunswick and Nova Scotia, 2017). A minimum break-even price at which natural gas must to be sold from a local on-shore horizontal well. 2. AECO-C price for Alberta natural gas-sourced model 3. Marcellus/Utica price for US natural gas-sourced model | <p>From \$2.31 (2018) to \$4.78 (2052), nominal</p> <p>From \$2.01 (2018) to \$5.34 (2052), nominal</p> <p>From \$2.36 (2018) to \$5.34 (2052), nominal</p> |
| US Gulf | 1. Modelled Henry Hub price | From \$3.11 (2018) to \$6.09 (2052) |
| Australia | <p>A weighted future forecast average of several CSG plays – Middle Walloons, Eastern Walloons, Undulla Nose – are taken into the calculation of natural gas costs (Cooper-Eromanga Basin Outlook, 2016, p. 59)</p> <p>Shares: APLNG Middle Walloons – 30%, QCLNG Middle Walloons – 20%, Arrow Energy Middle Walloons – 15%, Arrow Energy Eastern Walloons – 15%, QCLNG Eastern Walloons – 15%, Undulla Nose – 5%.</p> | The resulting costs – \$3.4 per mmbtu (2017). The cost is inflated annually by 2%. |

All prices are in nominal dollars and are shown in Figure 2.2.

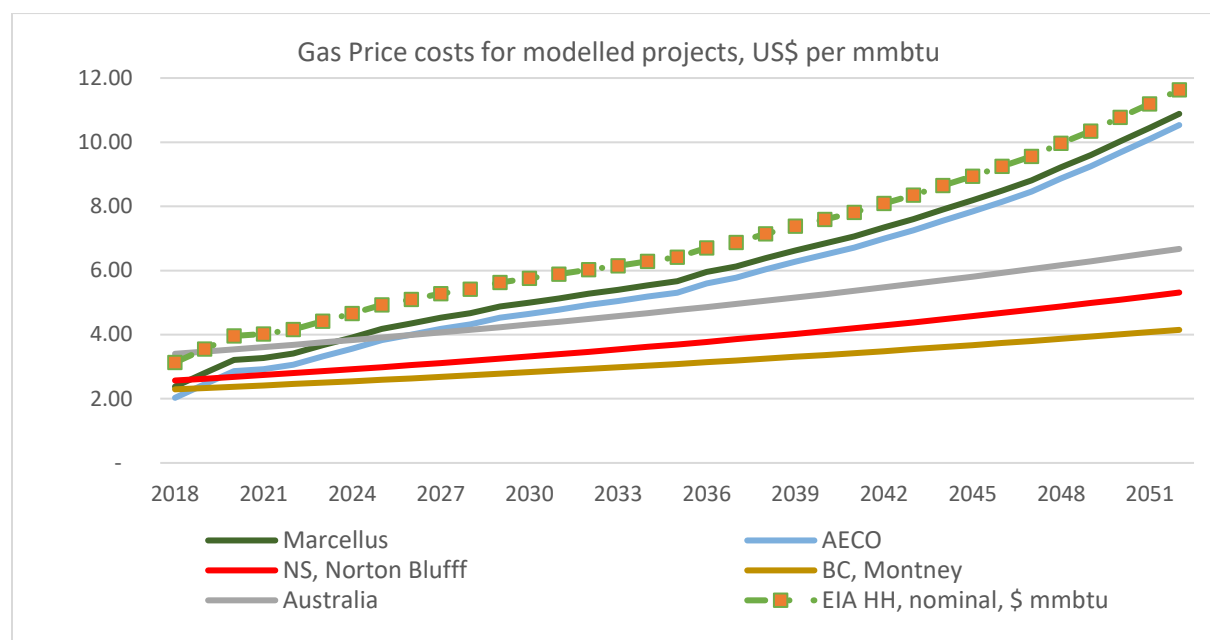
Figure 2.2: Feedstock Gas Costs for Modelled Projects (\$/mmbtu)

Source: CERI

As can be seen in the figure, AECO-C, Montney and Horton Bluff shale natural gas are more competitive as a feedstock than Henry Hub and Australian CSG. In Chapter 4, we consider the comparative analysis more closely.

For reference, the US EIA Outlook 2017 considers a more aggressive price growth at Henry Hub over the next 30 years (3.9% CAGR in nominal prices). For LNG producers, it means that Hub-sourced natural gas – Henry Hub, AECO-C and Marcellus – would follow that path. Natural gas costs for integrated projects would have a lesser impact from feedstock pricing as owners would control upstream processes and costs versus taking the market price. Recall that market prices include both the (assumed) increase of production costs and the dynamics of supply and demand.

The natural gas feedstock prices based on the EIA Energy Outlook 2017 scenario are shown in Figure 2.3.

Figure 2.3: Feedstock Gas Costs for the Modelled Project (based on EIA Energy Outlook 2017)

Source: CERI, EIA Energy Outlook 2017

Other Modelling Assumptions

All other important assumptions, including operating costs, natural gas shrinkage, and the amount of natural gas used for fuel are shown in Appendix A.

Landed LNG Costs Comparison and LNG Pricing

The ultimate cost competitiveness of an LNG plant is presented as a landed cost (\$ per mmbtu) at the destination markets. The regasification cost is not considered as it is regarded as equal for all situations. As the distances and marine paths to the markets differ, they constitute competitive advantages or disadvantages for specific locations.

Table 2.4 highlights the most promising markets based on their historical imports level and the outlook for future growth. The UK market largely represents the whole European market as a) the difference between the UK and other European importing countries (Spain, France) is not significant in the natural gas price, and b) the distance from each considered LNG-plant location to those countries and shipping costs are close (generally within 5 cents).

Table 2.4: Key Destination Markets for LNG Projects for the Study

| | Japan | South Korea | China | India | UK (represents Europe) |
|--------------------|-------|-------------|-------|-------|------------------------|
| Western Canada LNG | X | X | X | | |
| Eastern Canada LNG | | | | X | X |
| US Gulf of Mexico | X | X | X | X | X |
| Australia | X | X | X | X | |

After the marine transportation costs are added to the supply cost (FOB cost), the resulting break-even landed cost is mapped with a benchmark current local LNG or natural gas price (for Europe) in each location, an average 2007-2016 price, and the maximum price over 2007-2016. For the benchmark, CERI used May 2018 prices.

It is important to note that if the landed cost is higher than today's LNG price, the project could still be profitable (at a desired rate of return) provided that the LNG price will increase during the life of the project to the extent that it will compensate the existing difference between landed cost and market price. **Supply costs (and landed costs) represents a price in constant dollars which is required each year for the life of the project for the LNG facility to be profitable at 10% of the rate of return.** Conversely, if the price at the destination market goes below the landed cost presented in the study over the life of the project, the profitability of a project will be lower than 10%.

For this reason, the required price of LNG at FOB base are also shown in future (nominal) dollars for comparison with historical LNG pricing also in nominal dollars, or future outlooks of LNG/natural prices.

Benchmark prices selected for the study are illustrated in Table 2.5.

Table 2.5: Natural Gas and LNG Prices for Benchmarking

| Market | Benchmark, early May 2018 | Average 2000-2017 | Maximum for 2000-2016 |
|--|---|-------------------|-----------------------|
| Japan Spot (proxy for Japan, Korea, China) | \$8.2 | \$9.2 | \$16.8 (2012) |
| Old Northeast Asia (NEA) Contract price (14.5% of Brent + \$0.5) | \$11.6 | \$9.8 | \$16.7 (2012) |
| New Northeast Asia (NEA) Contract price (11.5% of Brent price) | \$8.9 (-\$2.7 or 24% compared to old contracts) | - | - |
| India | \$8.0 | N/A | N/A |
| UK NBP | \$7.4 | \$6.3 | \$10.8 (2008) |
| TRS France / Spain (MIB Gas) | \$7.6 | N/A | N/A |

Optimized Supply Costs: Sensitivity Analysis

As the research focuses on competitiveness, the study explores different options which could decrease the LNG supply cost or increase the value for Canadian LNG projects. Below are the major options considered in the study. All the options are presented in Chapter 4 (Path to Competitiveness section). Many of them are derived from the existing information or market events.

For Western Canada LNG projects, the effects of the following changes are estimated and discussed:

1. Application of the recently announced package by the BC Government with regard to the LNG Canada project – Natural Gas Development Framework (referred to in some cases as the BC Package for simplicity). The Package intends to abolish the LNG Income Tax, defer PST payments on capital expenditures (with payback by the project later), cap the carbon tax at CAD\$30 dollars per tonne CO₂eq, and provide access to lower electricity costs.
2. Providing an exemption to LNG projects from Canada's anti-dumping tariff of 45.8 percent on foreign fabricated industrial steel components duty and countervailing duties.
3. Expanding LNG plant capacity.

For Eastern Canada LNG projects, the effects of the following changes are estimated and discussed:

1. Introducing some of the BC incentives to Nova Scotia projects.
2. Providing an exemption to LNG projects from Canada's anti-dumping tariff of 45.8 percent on foreign fabricated industrial steel components and countervailing duties
3. Expanding LNG plant capacity.
4. Sharing costs for the pipeline (built from Dawn, ON to Goldboro, NS) between two LNG projects.

Each effect is captured independently of the other as well as in combination.

In addition, CERI considers the most important factors and cost components which drive cost competitiveness in each jurisdiction, focusing on Canada. In the sensitivity analysis, CERI varies operating costs, capital costs, costs of gas, and transportation costs from -75% to +75% to assess project risk and cost-saving opportunities.

Chapter 3: LNG Supply Costs and Cost Drivers

From a customer perspective, the single major element of LNG competitiveness at a particular location is the LNG cost at the FOB (free on board or, simply, the plant location). Other elements of competitiveness – e.g., security and stability of supply, diversification of supply, transportation distance, terms of LNG Sale and Purchase Agreements and other factors also come into play, but are more difficult to quantify. This chapter focuses on the costs of the value chain from natural gas production to the jetty where the LNG is offloaded onto the ship.

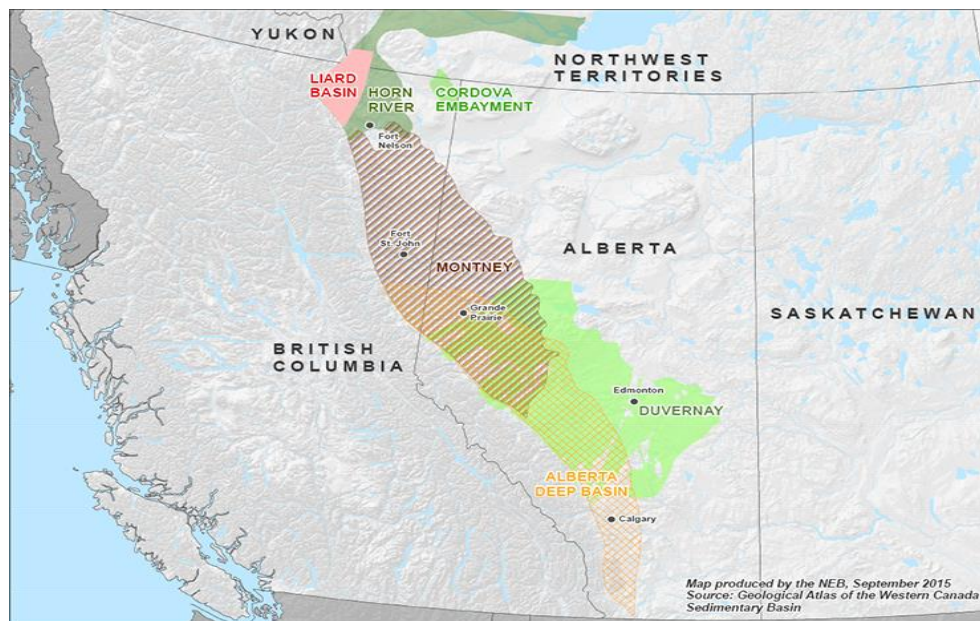
Note that this chapter presents non-optimized supply costs, meaning that these FOB costs should be expected if no additional financial incentives or exemptions are provided by governments to the LNG industry. In addition, it means that proponents cannot find additional cost savings. Chapter 4 explores possible ways to improve cost-competitiveness and presents optimized supply costs.

Western Canada

Supply Costs and Key Differentiators

The value chain of a Western Canada LNG project consists of three components: upstream, transportation, and liquefaction. Natural gas can be sourced from British Columbia's resources (Montney, Horn River, Liard basins – shown in Figure 3.1) as well as from Alberta at the AECO-C market.

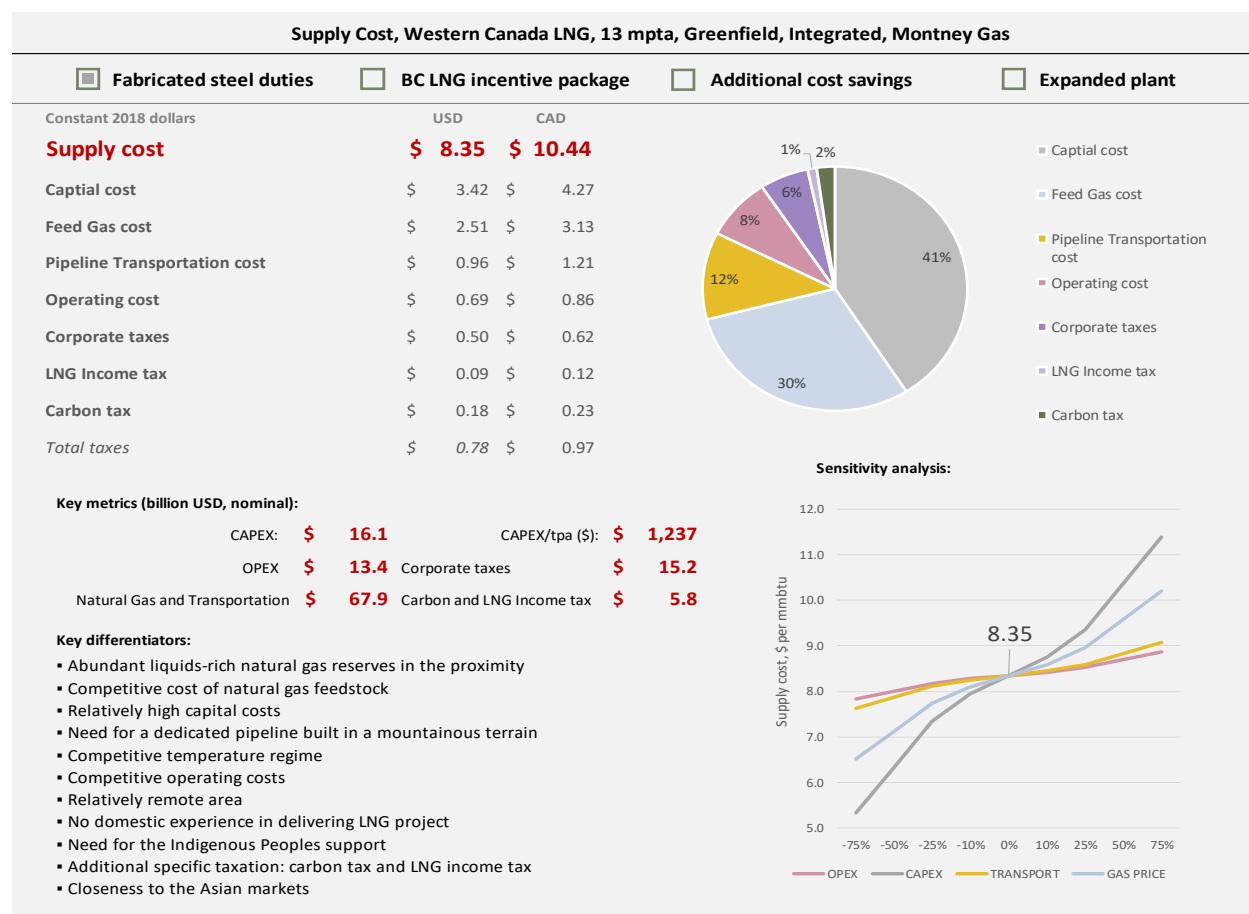
Figure 3.1: Natural Gas Basins, Western Canada



Source: NEB

The resulting supply costs are depicted in Figure 3.2. The optimized costs are shown in Chapter 4, Path to Competitiveness.

Figure 3.2: Western Canada LNG Project Supply Cost, Initial



Note: For British Columbia, an 11% corporate tax rate is utilized for the study effective in 2017. BC enacted a 12% rate, beginning in January 2018. If the 12% rate is used, the supply cost would be higher by 3 cents.

The largest drivers for the supply cost are the capital cost (41%), natural gas feedstock expenditures (30%), followed by pipeline transportation costs (12%) and operating cost (8%). The total tax burden comprises 9%.

The project supply cost is most sensitive to the change in the capital expense and gas price, while the change in the operating and transportation costs does not yield a substantial effect. Capital cost overruns by 25% will add an additional \$1 to the required LNG costs to be recovered; similarly, natural gas price increases of 25% will increase LNG costs by \$0.6.

Proponents with access to experience in LNG plant delivery will likely have an advantage over new entrants to the LNG business with their capacity to find efficiencies in capital expenditures. Also, an integrated model where a company has its stake in the upstream could be an advantage and a risk mitigation measure to control the costs of the natural gas feedstock compared to

sourcing fully from the AECO-C market. Another viable option is a mixed model – sourcing some portion of natural gas from the controlled upstream and the rest from the market.

British Columbia, as any jurisdiction, has its advantages and disadvantages for the LNG investor. Below is a summary of the key differentiators which have a direct influence on the supply cost and landed cost.

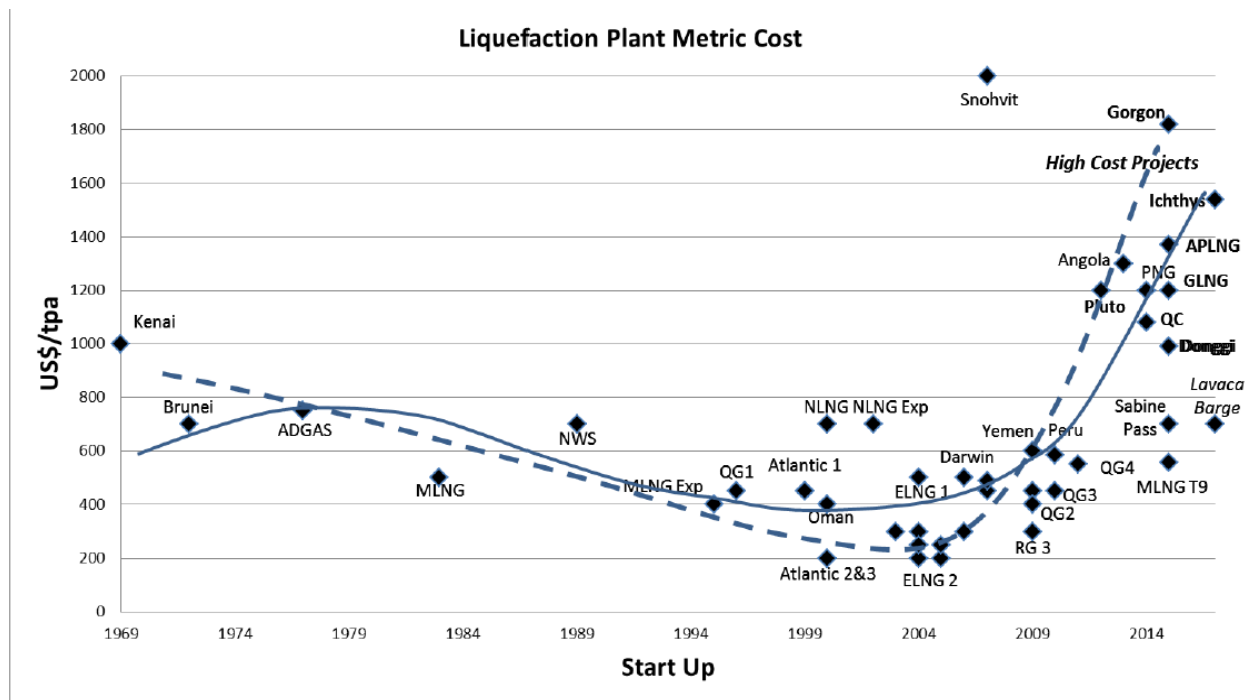
Proximity to abundant liquids-rich natural gas reserves. British Columbia has 41.1 TCF of remaining recoverable raw gas reserves as of 2016, with more than 70% in the Montney area, and approximately 26% in the Horn River area, with an estimated ultimate potential resource base of 532 TCF (BC Oil and Gas Commission 2016). To put this into perspective, if current production is constant for non-LNG purposes (4.8 bcf/d) and the ultimate resource base proves to be as noted, the province can feed up to 12 LNG plants of 13 mtpa size for 50 years (156 mtpa in total). In addition to that, natural gas feedstock could also be sourced partially from Alberta which also has a substantial resource base. The Montney area is also rich in natural gas liquids. While the average LPG and condensate content is 16.2 barrels per mmcf (BC Oil and Gas Commission 2016), a number of areas can reach 40-150 barrels per mmcf. If an LNG project controls the upstream, the liquids stream can generate additional revenue, especially from the condensate which is in high demand in Alberta. Finally, the resource is relatively close to the coast – within 650 km of pipeline distance.

Competitive cost of natural gas feedstock. Not only is the natural gas abundant, but it can also be recovered at a relatively low cost or purchased at the AECO-C hub at lower prices compared to the US Henry Hub. For instance, the cost of production of 1 mcf in the Montney area could vary between CAD\$1.6 to \$2.7; CERI uses CAD\$2.2 (constant 2018 price) based on its own model, or US\$1.8. The price at Henry Hub has been approximately \$1.1 per mmbtu higher in the last two years.

Relatively high capital cost and remote area. As many projects on the British Columbia coast are greenfield and located in relatively remote areas from the centres of labour, manufacturing, construction, and transportation, it has its impact on the capital costs. The capital costs of \$1,237 per tpa (with FISCC duty) or \$1,184 per tpa (without FISCC duty) positions BC projects in the upper-middle range of historical costs of LNG projects (see Figure 3.3). Note that Australian projects – GLNG, APLNG and Gladstone – all went above \$2,000 based on actual costs.

There are many factors beyond location which influence capital costs including the design, technology, manufacturing and construction process, material purchase costs and labour, import tariffs and more. It is beyond the scope of this study to delve into those elements. As CERI has used official project proponent's documents filed with the regulatory bodies, it is assumed that the capital costs for all the projects under consideration have been scrutinized to a) reach maximum cost-effectiveness and b) have proper contingency costs allocated. In the capital costs estimate, CERI has also used 75% of the High Cost and 25% of the Low Cost, thereby making the estimate more conservative and inclusive of some level of contingency.

Figure 3.3: Historic LNG Plant Capital Costs



Source: LNG Plant Cost Escalation, Oxford Institute for Energy Studies, 2014

Need for a dedicated pipeline built in mountainous terrain. Another important factor and component of the cost is the transport of the natural gas feedstock. Current pipeline systems connect the producing areas in the Montney, Horn River and Liard basins to the South and East: Vancouver, AECO and Chicago (BC Oil and Gas Commission 2016), but there are no pipelines going to the coast. As a rule, each LNG plant in BC has proposed to build a dedicated pipeline. This is largely founded on the large volumes of natural gas going to each plant; hence, many pipelines are of large size (48 inches). The cost of these pipelines varies, but they are generally higher than the industry average due to a number of factors including mountainous terrain. The Coastal GasLink project is used as a proxy for this study with a cost of CAD\$7.4 million/km (US \$5.9 million/km) versus the industry average of CAD\$4.3 million per km (US\$3.41 million).¹ Distances also vary from 650-900 km from the Montney basin to Kitimat and Price Rupert locations, respectively. As a pipeline goes directly to the facility and is dedicated in nature, the economics of the LNG plant need to fully cover the costs of building, operating and decommissioning the pipeline, as well as the rate of return for a midstream company.

Competitive temperature regime. The relatively low average temperature at the location of liquefaction can be an advantage as it translates to lower energy demand to cool the natural gas to produce LNG. The Kitimat location has an annual average temperature of 7.4 degrees Celsius compared to, for example, Corpus Christi, TX, with an annual average temperature of 22.3 degrees.

¹ CERI based on the Oil and Gas Journal Pipeline Costs Survey 2016

Competitive operating costs. Operating cost for an LNG plant is dependent on many factors similar to capital cost, including labour cost, general and administrative cost, natural gas used for fuel or electricity cost, the technology used, cost of supplies and maintenance, annual average temperature and other factors related to the location. In our analysis, CERI used public documentation rather than attempting to estimate these costs directly. The operating costs of \$0.52 per mmbtu for a Western Canada LNG project is found to be lower than the actual operating costs of the Sabine Pass LNG project in Texas (actual operating cost - \$0.92 per mmbtu in 2017²). For our analysis, \$0.7 was used for the US projects (see Appendix A for details).

No domestic experience in delivering an LNG project. As Canada has no experience in delivering LNG projects (except for a regasification terminal in New Brunswick and small liquefaction plants used to produce LNG for fuel), this could ultimately contribute to delays and higher costs of construction. A range of issues are possible with regard to lack of experience which can cause such delays: challenges with mobilization of contractors and qualified labour, developing local labour qualifications, longer customs import procedures for equipment not previously imported to Canada (modules), need for various permits after the FID stage and ensuring compliance with permits by government agencies.

Need for Indigenous Peoples support. The pipelines and the LNG plant itself are likely to cross First Nations land in British Columbia or have an impact on Indigenous Peoples use of crown land. The environmental impact assessment processes include consultation with the First Nations. Gaining First Nations support in Canada is an additional risk to successful project execution from an investor's perspective; a risk not faced by other jurisdictions.

Additional specific taxation: a carbon tax and LNG income tax. An LNG project in British Columbia will have to pay two specific taxes which are not levied in other jurisdictions under consideration. Refer to the Government Incentives section for more detail on the recent package proposed by the BC government which could change these taxes.

First, a provincial carbon tax at the rate of CAD\$35 per tonne of CO₂eq as of 2018. As the federal government is planning to enact its carbon tax schedule, which will reach \$50 in 2022, the provincial tax is expected to increase in accordance with the national. The LNG plant uses energy in the form of electricity or natural gas which is burned at the plant as fuel. The energy obtained from the burning of natural gas will have an impact associated with the tax. The company can claim certain credits if its emissions per tonne of LNG plant are eligible for the Liquefied Natural Gas Environmental Incentive Program (discussed in more details below), but those credits do not fully offset the carbon tax. For the modelled facility, the carbon tax comprised 2% of the total supply cost or \$3.1 billion (nominal) if the LNG facility uses natural gas as fuel. This study assumes 8% of the gas intake is used for fuel.

It is important to note that for an LNG plant, which mostly uses electricity, the carbon tax burden will be lower. For instance, LNG Canada, used as a proxy, has a large portion of electricity in its

² CERI based on Financial Statements of the Annual Report of Cheniere.

fuel mix, which makes its emissions per tonne below the provincial benchmark of 0.16 t CO₂/t LNG. The expected annual emissions intensity of the project will constitute the best-in-class in the world at the time of the BC government assessment of the project (2015): “The average GHG intensity for the facilities used as a comparison is 0.35 t CO₂e/t LNG. The average of the lowest three emission intensities is 0.25 t CO₂e/t LNG, and the best-in-class facility at the time of the comparison was Snohvit LNG at 0.22 t CO₂e/t LNG” (BC EAO 2015). Under CERI’s study model, the Western LNG project emits 0.22 t of CO₂e per t of LNG, while the proxy project – LNG Canada – is configured to emit 0.15 t of CO₂e per t of LNG.

The second tax is specifically designed to levy against project operating income and net income. Before the project recovers its capital, a 1.5% tax on the net operating income is levied (even if the project has not reached a net income state). When a project reaches the post-payout of capital stage, it starts to pay 3.5% or 5% of its net income (5% from 2037 and further). The accumulated paid tax from the pre-payout stage is credited towards the post-payout stage. The ratio of the LNG income tax to total supply costs (discounted) for the Western Canada LNG is 1% or \$2.7 billion (nominal).

Proximity to Asian markets. One of the most significant advantages of the BC Coast-located projects is its proximity to the Asian markets – the centre of current and future growth of demand. It is also not constrained by the Panama or Suez Canal traffic and scheduling, which can cause delays, nor their transit charges. The comparative advantages for the jurisdictions will be discussed in more detail in Chapter 4.

Sourcing Natural Gas from AECO-C Hub

As an alternative to the integrated model, an LNG project may choose to source natural gas from major producers who could provide the project with a stable supply at AECO-C Hub-linked prices. While AECO-C hub prices are generally higher than a cost-effective upstream cost delivered at the hub (for the net margin of producers), in reality, this could be reversed from time to time. For instance, AECO-C prices in recent years were lower than typical production costs. In such periods, a large buyer of gas like an LNG plant would benefit from that market situation. As mentioned earlier, the LNG project may choose to structure feedstock supply as a specific portion of their upstream operations and the rest from the market. This strategy can help mitigate both market price and production cost risk.

Even though an LNG project can take advantage of the price downturns and improve their economics; such downturns cannot be relied on in the investment decision making since a negative market equilibrium price is not sustainable. Fundamentally, over the long term, the price equilibrium should reflect the marginal production cost including the return of, and on, capital. Hence, the cost of LNG based on AECO-C is expected to be higher than from upstream production controlled by the LNG plant owner.

The model shows that the difference between an integrated and merchant model will be \$1.5 per mmbtu or an 18% increase (total supply cost – \$9.85). The increase is driven by a change in

the gas feedstock (+\$1.16) and an increase in transportation from AECO-C compared to Montney (\$0.38).

Government LNG-focused Incentives

While there are several incentives (in the form of credits or allowances) for upstream or midstream activities of the LNG integrated project, they are out of the scope of this review. Rather, our focus is on the incentives available for the LNG plant.

Accelerated capital allowance. In 2015, the federal government announced changes to the tax treatment of LNG facilities. For capital assets acquired after February 19, 2015, and before 2025, equipment and structures used for natural gas liquefaction will be eligible for an accelerated capital cost allowance (CCA) rate of up to 30 percent (up from 8 percent). Non-residential buildings at LNG facilities will be eligible for a CCA rate up to 10 percent (up from 6 percent) (CAPP n.d.). CERI estimates that due to this change the weighted average capital allowance on the whole plant has increased from 7.6% to 25.5%. If the allowance were not introduced, the supply costs would be \$8.54 vs. \$8.35; thus, the incentive has decreased the cost by 2.3%.

BC LNG natural gas tax credit. A company can claim a tax credit towards the provincial income tax in the amount of 3% of the value of the natural gas feedstock provided that the total provincial tax does not drop below 8% (11% - 3%). The tax credit results in a reduction of approximately 5 cents per mmbtu of the supply cost. Note that this legislation has not yet been passed by the BC legislature. The approved version of the legislation may be different from what is assumed for the study. Also, the 11% corporate tax rate of 2017 is utilized for the study. BC enacted a 12% tax rate starting from January 2018.

Long-term project rule (Canada Revenue Agency n.d., 2016). Under the rule, the company may expedite depreciation of the asset. However, the rule is not essentially applicable to an LNG plant as the income stream from LNG starts to come after the full build-out period (on the sixth year after construction). The rule will be applicable if the government allows the start of depreciation of the capital costs (during the build-out period) against other revenue of the LNG proponent, e.g., the upstream gas revenues from the pre-drilled wells. For an integrated project, these wells are drilled ahead of the completion of plant construction to establish a significant gas production base for the LNG plant.

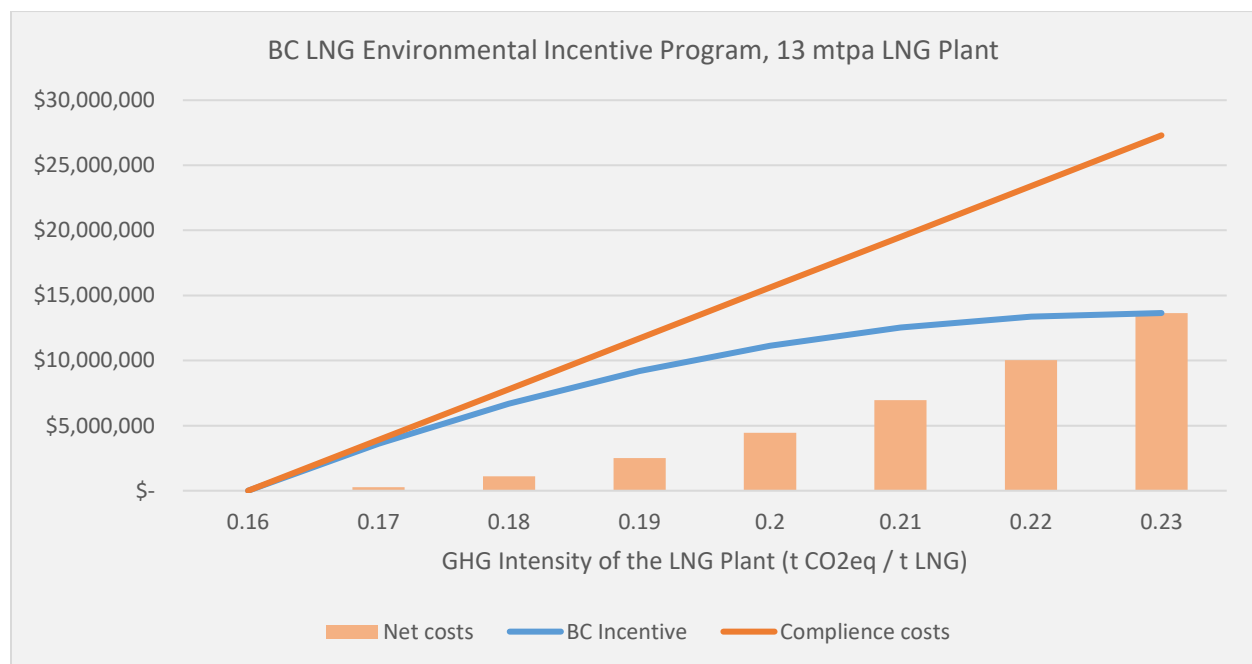
Liquefied Natural Gas Environmental Incentive Program (BC Government n.d.). This program provides an incentive for the LNG plants to strive to lower emissions per tonne of LNG output. “The Greenhouse Gas Industrial Reporting and Control Act” (GGIRCA) will require LNG operations to achieve a greenhouse gas emissions intensity benchmark of 0.16 metric tonnes of carbon dioxide equivalent per metric tonne of LNG produced (tCO₂e/t LNG). Note that as of 2015, this benchmark was lower than any other LNG export facility in the world, and 36% lower than the average of the lowest three emission intensities of existing LNG facilities (0.25 t CO₂e/t LNG).

Facilities which do not meet this benchmark directly will be able to achieve compliance with the benchmark through flexible options including purchasing “compliance units” under GGIRCA. If

the project emits between 0.16 to 0.23 tonne of CO₂eq per tonne of LNG, it can receive an environmental incentive which will offset part of the compliance costs. If the project reaches 0.16 or below, the incentive will offset all compliance cost. LNG facilities that perform better than the GHG performance benchmark of 0.16 t CO₂eq/t of LNG will receive earned credits at a rate of 1 credit per tonne of CO₂e below the benchmark per year. Earned credits are tradable and may be used by other operators of regulated operations similarly to offset units. If the plant emits more than 0.23 t CO₂eq/t of LNG, it is not eligible for the program.

Figure 3.4 illustrates compliance costs depending on the level of GHG intensity of a plant (CAD\$30 is assumed as a compliance cost).

Figure 3.4: BC LNG Environmental Incentive Program



Source: CERI

Natural Gas Development Framework. This is the most recent incentive package offered in March 2018 to the LNG industry in British Columbia. It is important to note that this package has not yet been approved by the legislature nor have specific tax or regulatory requirements been issued. For this reason, CERI regards it as a proposed measure rather than an existing measure and does not include it in the base cost (not reflected in \$8.35 per mmbtu LNG FOB supply cost).

The government originally established an electricity price higher than the standard industrial rate, an LNG income tax on top of the provincial corporate tax, and the treatment of LNG plants not as manufacturers with regard to PST payments. These conditions contributed to the lack of FID in the province (BC Government 2018). The government has advised LNG Canada that if it makes a positive Final Investment Decision by November 2018, British Columbia will (BC Government 2018):

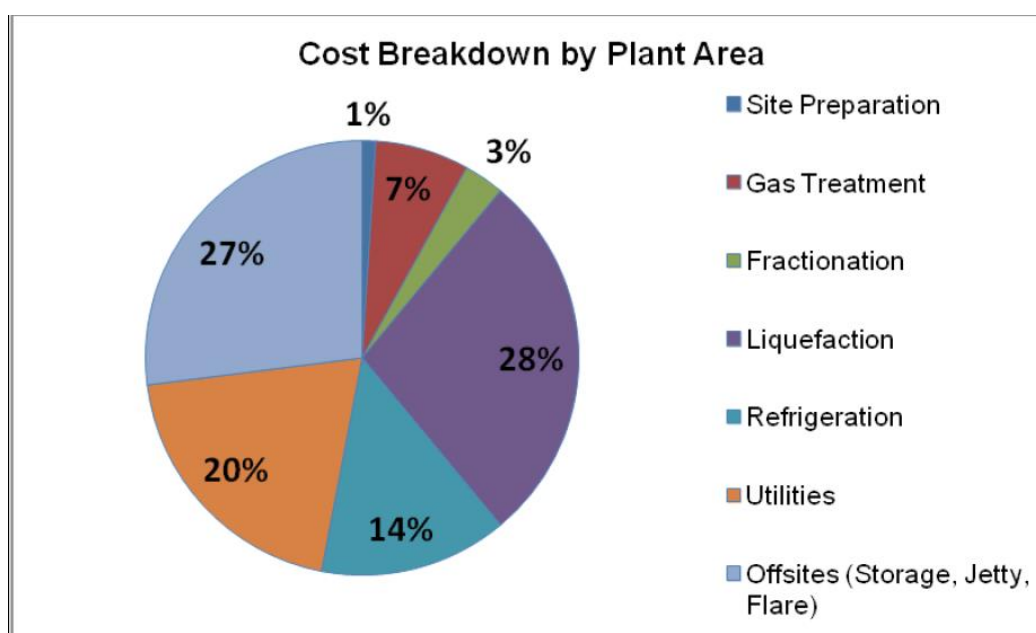
- Provide a PST exemption on construction costs of the LNG facility, as would apply to any manufacturing facility (however, the government will recapture foregone revenues once the project is operational).
- Provide a carbon tax treatment consistent with that provided to all large industry (capped at CAD\$30).
- Price electricity at the standard industrial rate.
- Repeal the LNG income tax.

The effect of this package is presented in Chapter 4, Path to Competitiveness.

Economies of Scale Effect

LNG plants have good potential for capturing an economy of scale effect. It is derived from the fact that the cost of the LNG train, as a rule, is approximately 50% of the total LNG plant costs (see Figure 3.5). Since much of the land is prepared, the storage, utilities, and jetty are constructed, and the main regulatory permits are obtained, the incremental train capacity costs are less per metric tonne of LNG than for the initial capacity. The same effect is captured if the plant is built at a larger scale from the outset (e.g., 26 mtpa compared to 13 mtpa reviewed below).

Figure 3.5: LNG Project Costs Breakdown



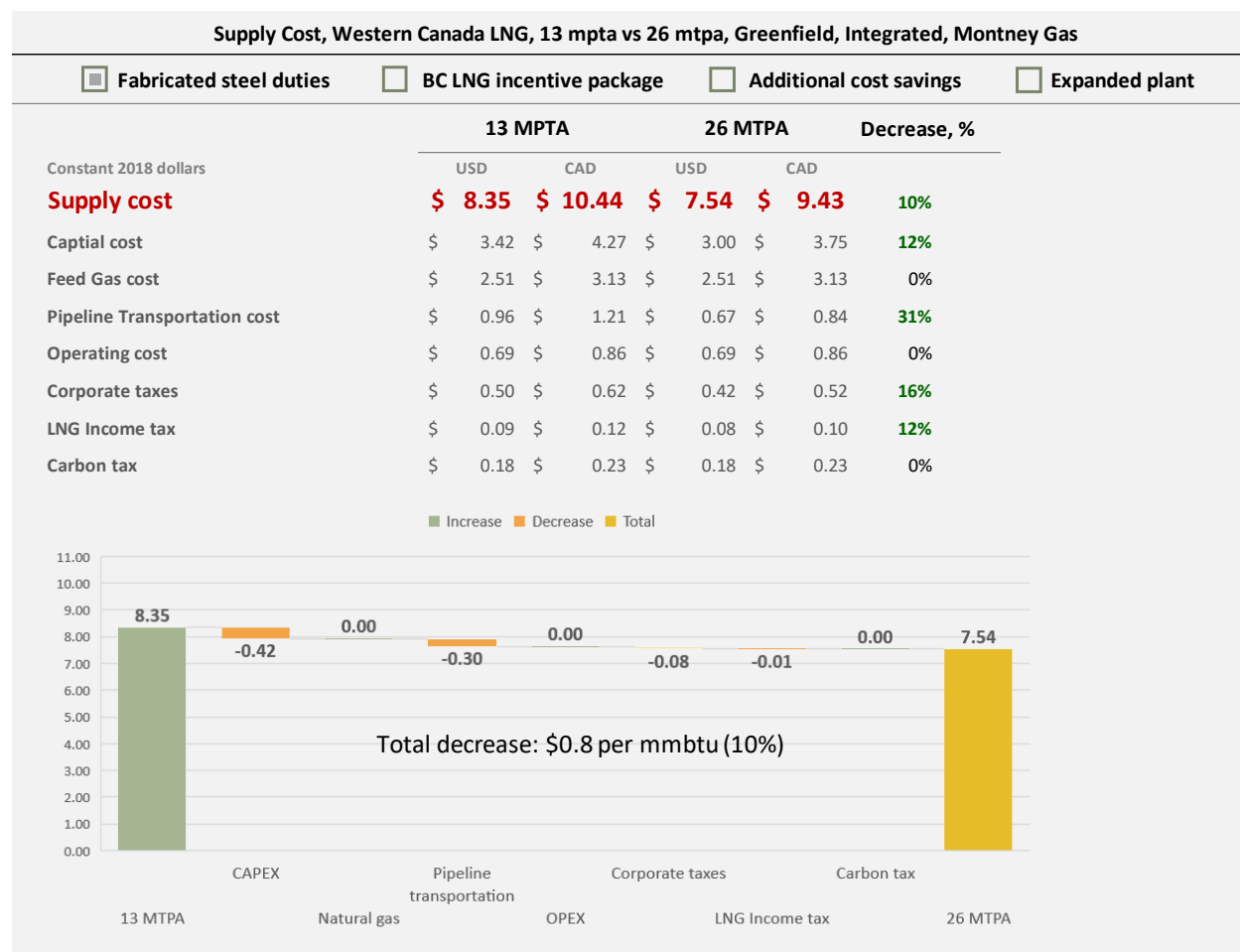
Source: (Oxford Institute for Energy Studies 2014)

To estimate this effect, CERI has modelled a 26 mtpa LNG plant. The major difference is the level of capital costs: \$28.2 billion (26 mtpa) compared to \$16.1 billion (13 mtpa) (fabricated steel duty is included). The increase in capital cost is 75%, while LNG output grows by 100%. The results are illustrated in Figure 3.6.

The supply cost of LNG per mmbtu falls by 10% from \$8.35 to \$7.54 (\$0.8). The largest drop comes from the capital costs (42 cents – as the output grows 1.25 times faster than costs – or 12%), followed by savings on transportation costs per mmbtu – (30 cents or 31%), and a decrease in corporate taxes (8 cents – 12%). Transportation costs are not halved as the initial throughput of 1.85 bcf/d requires just one compressor station with 3 compressor units, while doubling the capacity requires an additional two compressor stations with 4 units per station and an additional 3 units for the initial station. This results in some offsetting of the scale benefits of larger throughput due to the larger capital cost associated with expansion.

With regards to corporate taxes, while there is a drop in costs per unit of production, the absolute numbers in nominal dollars are of course higher for the 26 mtpa project – \$25 billion compared to \$5.7 billion for the 13 mtpa project.

Figure 3.6: LNG Economies of Scale Effect



Eastern Canada

The value chain of the Eastern Canada LNG project consists of similar components: upstream, transportation, and liquefaction. However, in two cases that CERI considered, upstream activities are not controlled by the project, as natural gas is obtained from the market at Hub-linked prices.

Securing natural gas supply for the projects in eastern Canada is more challenging than for the West due to lack of locally produced natural gas or lack of pipeline transportation options. The specifics for Quebec LNG projects differ slightly than for Nova Scotia, but overall, they are similar.

Quebec does not produce its own gas, yet it has shale potential from Macasty and Utica basins capable of sustaining output of 1 billion cubic feet per day at CAD\$3.72 (US\$2.98) (for details see CERI Study 154, “An Assessment of the Economic and Competitive Attributes of Oil and Natural Gas Developments in Quebec” 2015). The leading 11 mtpa GLN Quebec project includes building a 650-km pipeline that would connect it to the mainline gas distribution system in eastern Ontario (Énergie Saguenay n.d.).

Similarly, Nova Scotia and New Brunswick both have the potential for shale development. The recoverable resources are estimated at 13.4 TCF for New Brunswick and 7 TCF for Nova Scotia, not including CBM (for details see (CERI 2017)). To put this in perspective, the resources of both provinces are sufficient to source an LNG project of 8 mtpa for 50 years. However, more exploration and additional recoverable resources would be needed for several LNG projects. While both provinces are connected to the AGT Hub in Boston via the Northeast and Maritimes pipeline, its capacity of 0.55 bcf/d is not sufficient to transmit the needed 1.2 bcf/d for just one LNG project of 8 mtpa, let alone two projects (Bear Head LNG and Goldboro LNG). Moreover, the pipeline serves domestic demand. The local demand is around 0.2 bcf/d, leaving even less space to serve an LNG plant.

To supply a Nova Scotia-based LNG plant with natural gas, there are four viable options:

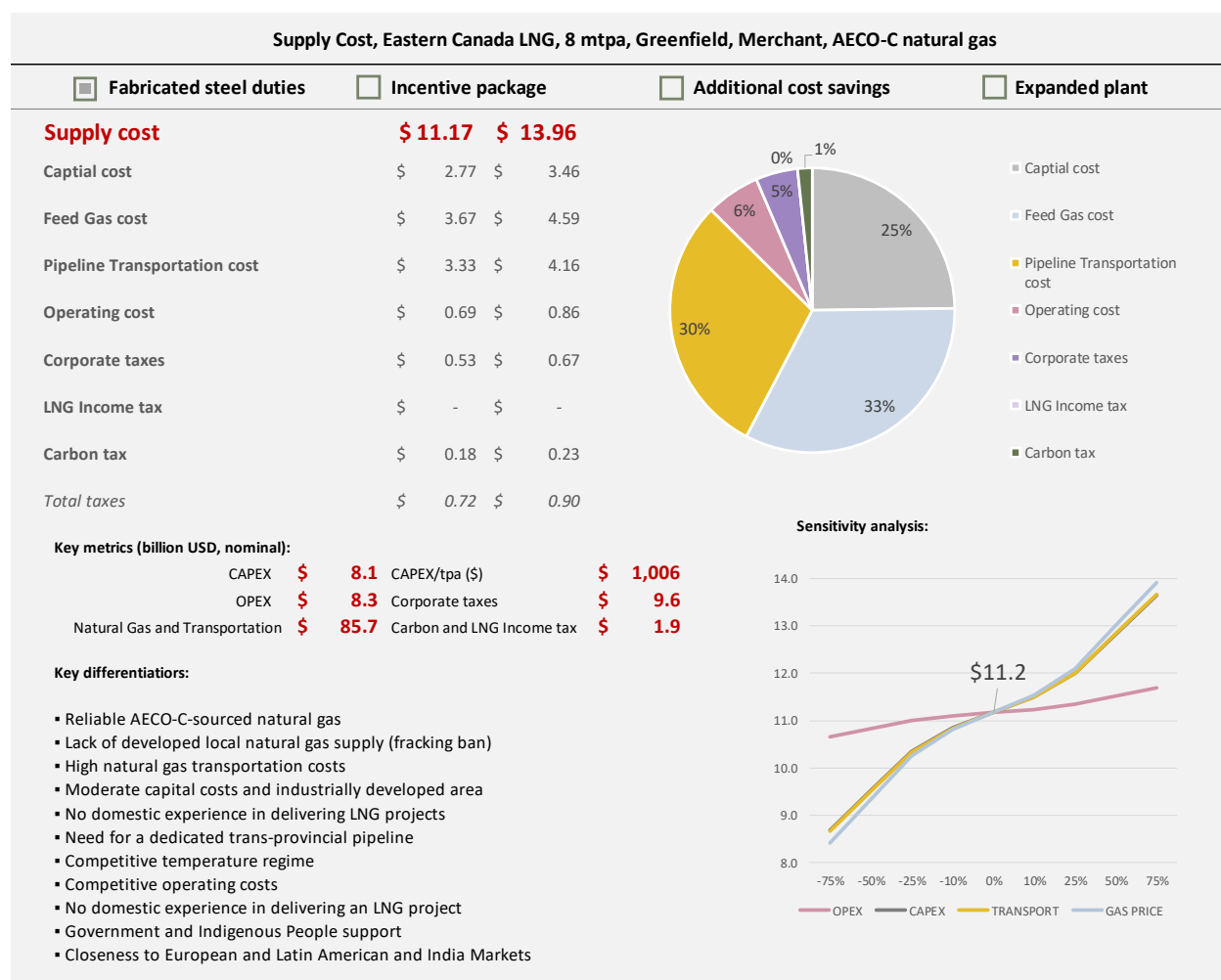
1. Source gas from Alberta – this will require a 1,600-kilometre pipeline from Dawn, ON to the LNG plant.
2. Source gas from Marcellus via Dawn, ON – the current export capacity from the US to Ontario is 4.9 bcf/d from the Midwest (includes Ohio – a Marcellus play state) and 2 bcf/d from the northeast (includes Pennsylvania and West Virginia – Marcellus play states). Additional pipeline capacity to Dawn would be required or operational changes to some existing pipelines are needed. Similarly, a new 1,600 km pipeline from Dawn to the LNG plant is needed.
3. Source gas from Marcellus via AGT hub (Boston) – twin and expand the MN&P pipeline adding compression.

- Source gas locally – this option requires the lifting of the hydraulic fracturing ban and the building of an approximately 340-400 km pipeline from the Horton Bluff Shale natural gas producing well to the LNG plant.

Supply Costs and Key Differentiators

The resulting supply cost for the AECO-C-based supply is depicted in Figure 3.7.

Figure 3.7: Eastern Canada LNG Project Supply Cost (AECO-C)



The largest drivers for supply cost are natural gas expenditures (33%), followed by pipeline transportation (30%), and capital costs (25%). Total taxes comprise 6%. The share of these drivers is illustrative of the main challenges for an LNG plant in this location described above. The gas travelling thousands of kilometres over the whole continent ultimately leaves its mark on the final FOB cost. For comparison, Western Canada LNG total natural gas and transportation equals 42% of supply cost versus 63% for Eastern Canada LNG.

The project supply cost is sensitive to natural gas price, transportation and capital costs almost in the same magnitude. For instance, capital cost overruns by 25% or equivalent transportation

cost changes will add \$0.83 to the required LNG costs to be recovered. Twenty-five percent higher gas costs will add \$0.9 to the total cost. Similarly, the reduction of costs in any element will bring similar savings.

Out of these three cost elements, in this business model, the capital and transportation costs could likely be influenced the most by the owners of a project. For capital costs, cost-effectiveness could be comprised of finding ways to produce a more efficient plant design/technology, employment of modular construction, competitive bidding and leveraging EPC contract terms, and efficient execution and project management.

The substantial transportation costs (\$3.33 per mmbtu) could also be potentially reduced, but the room for such a reduction is limited. First, the transportation costs to the Dawn hub in Ontario are estimated by CERI based on the existing TransCanada discounted CAD\$0.77/GJ 10-year toll from Empress to Dawn. CERI already assumes as an upside that such a discounted toll will be available to the LNG project for its life (note: the toll is inflated beginning in 2028). The normal toll for this distance is CAD\$1.8/GJ, and it is not certain if TransCanada is able to sustain a discounted toll for 30+ years. Second, the estimated capital costs of the new pipeline – CAD\$4.35 million/km (US\$3.5 million/km) are within the industrial average - CAD\$4.3 million per km (US\$3.41 million/km) which does not leave significant opportunity for cost reduction. In addition, the fact that the pipeline would be constructed across 4 provinces could cause delays, cost overruns and higher operating costs. A more viable option is if a pipeline operator would consider less than a 10% return (assumed by the study) – e.g., 8% - in a trade-off to gaining a 30-40 year long stable business. This option would decrease the toll by \$0.4 alone.

Lastly, the LNG project could seek better than AECO-C prices from local producers through long-term Gas Purchase Agreements, but it is problematic to estimate the success of this strategy and the level of the discount.

Nova Scotia, as any jurisdiction, has its advantages and disadvantages for LNG investors. Below is the summarization of key differentiators of the location which have a direct influence on the supply cost and landed cost.

Reliable AECO-sourced natural gas. AECO-C is a large liquid hub in Alberta, which provides clear pricing and access to producers and consumers. It is connected to the Central and Eastern Canada market via the TransCanada Mainline. As US imports of natural gas from Canada continue to fall (according to EIA Energy Outlook 2018) by 3% annually or from 2.94 trillion cubic feet a year (8.1 bcf/d) to 1.1 trillion cubic feet (3 bcf/d) in 2050 (EIA 2018), Alberta and British Columbia natural gas producers will be looking for new markets for their gas. These factors should allow a large LNG customer to consolidate the needed amount of 1.2 bcf/d or more and acquire natural gas supply and transportation to the east at competitive prices.

Lack of developed local natural gas supply (hydraulic fracturing ban). While local shale resources could be promising, there are bans on hydraulic fracturing in New Brunswick and Nova Scotia. Even if the exploration and production of the shale gas is permitted, it would likely take

more than 5 years to explore and test the new formation to delineate and prove the needed reserve amounts to warrant an LNG plant investment based on these reserves.

High natural gas transportation cost and need for a dedicated trans-provincial pipeline. As already mentioned, high transportation cost is derived from the long distance that the gas has to travel. Another factor which explains high cost per mmbtu is that the throughput of the feed gas is low compared to the capital costs of a new 42-48" pipeline. The economics could be improved if an LNG plant capacity were larger or if the pipeline was shared with other customers (discussed in more detail in Chapter 4, Path to Competitiveness).

Moderate capital costs and industrially developed area. The capital cost of \$1,006 per tonne of LNG is moderate in comparison to other high-cost LNG projects, e.g., offshore or onshore in Australia (Note: the costs include fabricated steel duties). As Nova Scotia projects are located close to existing industrial facilities – Sable Offshore Energy Project, Maritimes and Northeast Pipeline, Port Hawkesbury and Point Tupper, it would reduce the capital costs due to higher industrial activity in the area. Specifically, for the Bear Head project, the site is already prepared and equipped with roads, water and electricity. However, even with this advantage, the level of exposure to the construction industry, supplies, equipment and labour for the LNG construction cannot be fully comparable to the US Gulf of Mexico, which holds an advantage over any jurisdiction.

No domestic experience in delivering LNG projects. Similar to the Western Canada LNG project.

Competitive temperature regime. Similar to the Western Canada LNG project. The average temperature is 5.5 degrees Celsius.

Competitive operating costs. It is likely that overall operating costs will be similar to the Western Canada LNG project. The differences will be driven by the technology, fuel types and other location differences.

Government and Indigenous Peoples support. Similar to the BC Government, the Nova Scotia provincial government and municipal governments support LNG projects in the province. The Bear Head project, for instance, has already received many provincial and municipal permits. The local First Nations have also expressed their support of the LNG developments (Nova Scotia Government n.d.).

Proximity to European, Latin American and Indian Markets. The location of Nova Scotia's LNG projects is advantageous compared to the US Gulf of Mexico-based projects to access European, Latin American and Indian markets via the Suez Canal.

Marcellus-sourced Natural Gas Supply

The proximity of the prolific Marcellus/Utica play provides an attractive option for Eastern Canada LNG to realize transportation cost savings. The results show that the difference in supply cost is not large at 2% or \$0.22 per mmbtu (Figure 3.8). The closeness of the resources allows

saving 7% on the transportation, as it is estimated to be cheaper for the gas to reach Dawn, ON from Marcellus (\$0.51 per mmbtu) than from AECO-C (\$0.75 per mmbtu) even with discounted TransCanada tariffs.

Figure 3.8: Eastern Canada LNG Project Supply Costs (Marcellus vs AECO-C natural gas supply)

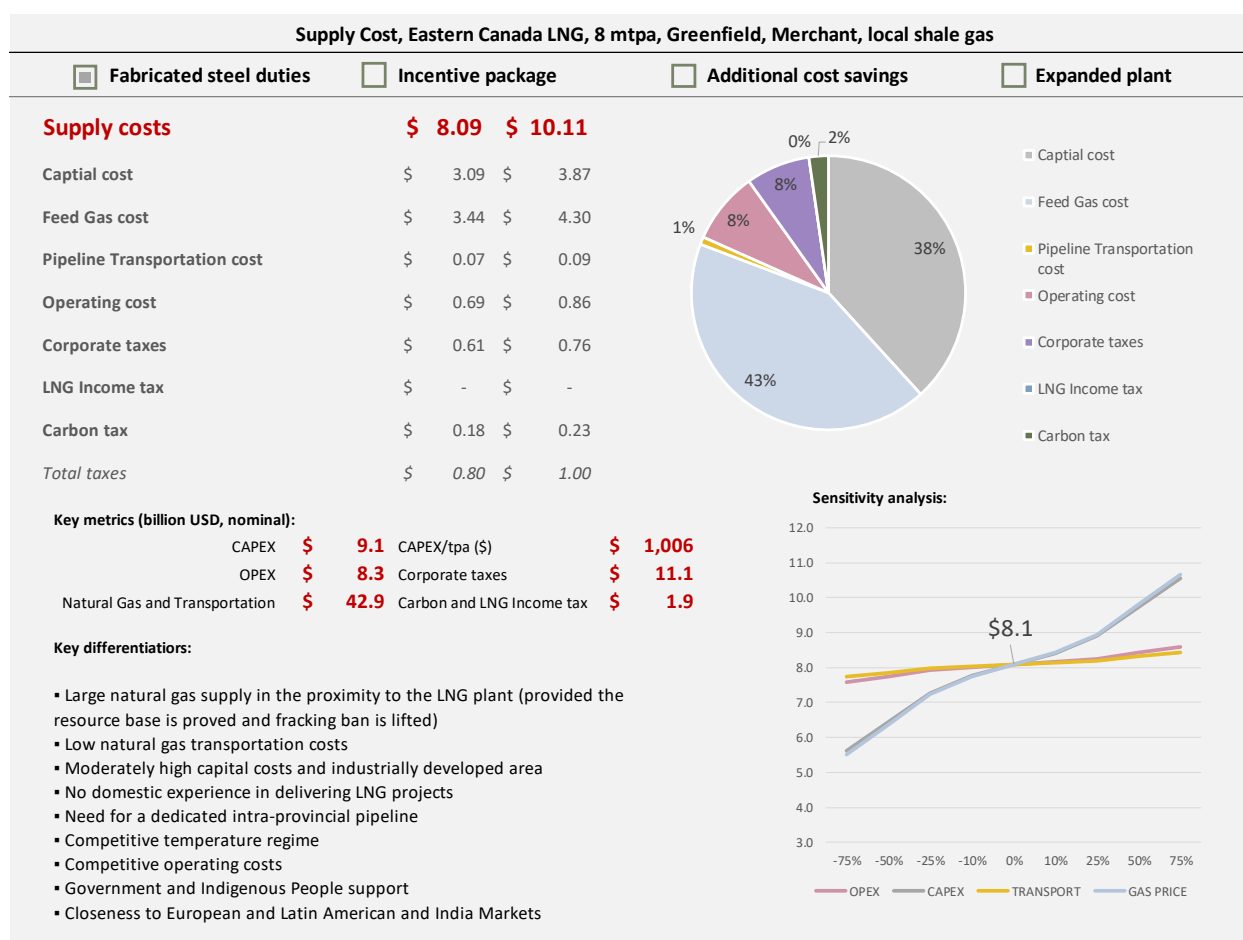
| Supply Cost, Eastern Canada LNG, (Marcellus vs AECO supply), Merchant | | | | | | |
|---|-----------------|-----------------|-----------------|-----------------|-------------|------------|
| Constant 2018 dollars | AECO, AB | | Marcellus, USA | | Increase, % | |
| | USD | CAD | USD | CAD | | |
| Supply costs | \$ 11.17 | \$ 13.96 | \$ 10.95 | \$ 13.69 | | -2% |
| Capital cost | \$ 2.77 | \$ 3.46 | \$ 2.77 | \$ 3.46 | | 0% |
| Feed Gas cost | \$ 3.67 | \$ 4.59 | \$ 3.69 | \$ 4.61 | | 0% |
| Pipeline Transportation cost | \$ 3.33 | \$ 4.16 | \$ 3.09 | \$ 3.86 | | -7% |
| Operating cost | \$ 0.69 | \$ 0.86 | \$ 0.69 | \$ 0.86 | | 0% |
| Corporate taxes | \$ 0.53 | \$ 0.67 | \$ 0.53 | \$ 0.67 | | 0% |
| LNG Income tax | \$ - | \$ - | \$ - | \$ - | | 0% |
| Carbon tax | \$ 0.18 | \$ 0.23 | \$ 0.18 | \$ 0.23 | | 0% |

Maritime Provinces-sourced Shale Natural Gas Supply

Locally-sourced gas from Nova Scotia and possibly from New Brunswick presents a much different picture and opportunity for not only LNG investors and producers but also domestic markets.

The supply costs are substantially lower than the AECO-hub based LNG project – \$3.9 per mmbtu or 28% (Figure 3.9). This is almost entirely due to cheaper transportation as the \$1 billion 340-km pipeline cost is easier to recover than a \$5.5 billion 1,600-km pipeline cost. Total transportation expenses are approximately \$0.4 per mmbtu (part of it sits in capital costs as the pipeline is modelled as part of LNG plant economics unlike the BC case); total savings on transportation are \$2.94 compared to the AECO-C case.

Local natural gas is also cheaper than the AECO-C and Dominion-hub (Marcellus) natural gas prices by \$0.32-0.34, but it is expected to be more expensive than from British Columbia (by 93 cents per mmbtu). This is primarily because the industry is not developed in Nova Scotia leading to higher costs of drilling, but also because of the characteristics of the Horton Bluff Shale formation. The cost of production in Nova Scotia and more detail about the formation can be found in CERI Study 165 “Economic Potential of Onshore Oil and Gas in New Brunswick and Nova Scotia.”

Figure 3.9: Eastern Canada LNG Project Supply Cost (local shale gas)

The largest driver of supply cost is the gas feedstock (43%) and capital expenditures (38%). The total tax burden is 10%.

The project supply costs are sensitive to capital and natural gas costs almost to the same magnitude. For instance, capital cost overruns by 25% will add an additional \$0.83 to the required LNG costs. If the natural gas price increases by 25%, the LNG costs per mmbtu increases by \$0.86. Cost reductions have similar impacts.

Government LNG-focused Incentives

CERI has not identified any specific financial or tax incentives related to Eastern Canada LNG projects beyond the advantages of the jurisdiction published on the Nova Scotia government website (Nova Scotia Government n.d.).

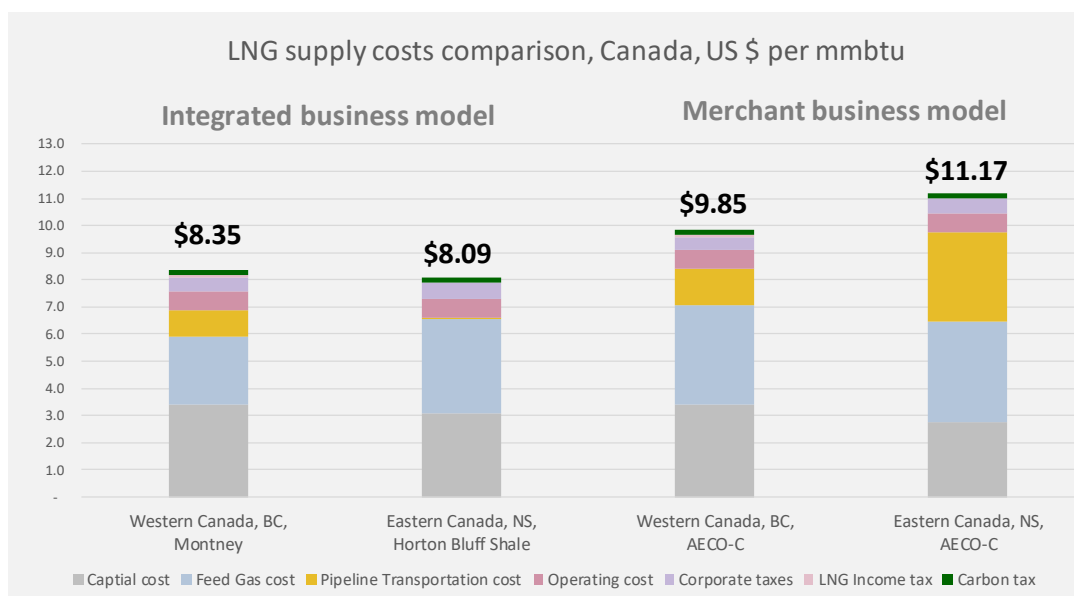
Canadian LNG Projects Supply Cost Comparison

Summing up the FOB cost of LNG in Canada, Figure 3.10 presents the supply cost of two integrated and two merchant business model projects on both coasts.

For integrated projects, the Eastern Canada LNG project holds a slight advantage of \$0.36 having an \$8.09 FOB cost per mmbtu over \$8.35 for the Western counterpart. The difference is explained by \$1.22 associated with total capital and transportation costs as the gas resource is half the distance from the facilities and the terrain is flat compared to the west. British Columbia's project, on the other hand, edges Nova Scotia's on natural gas cost by \$0.93.

If projects opt for the merchant model (both from AECO-C), the Western Canada LNG project gains a \$1.32 cost advantage over the Eastern counterpart due to its proximity to the AECO-C hub. The location advantage translates to cheaper gas transportation by almost \$2, while capital costs are better by \$0.65 in the east. If the gas is sourced from Marcellus for the Eastern project, British Columbia's LNG plant still has lower supply costs, though the difference is reduced to \$1.1 (a Marcellus gas-sourced project is \$10.95).

Figure 3.10: LNG Supply Costs Comparison, Canada



US Gulf of Mexico

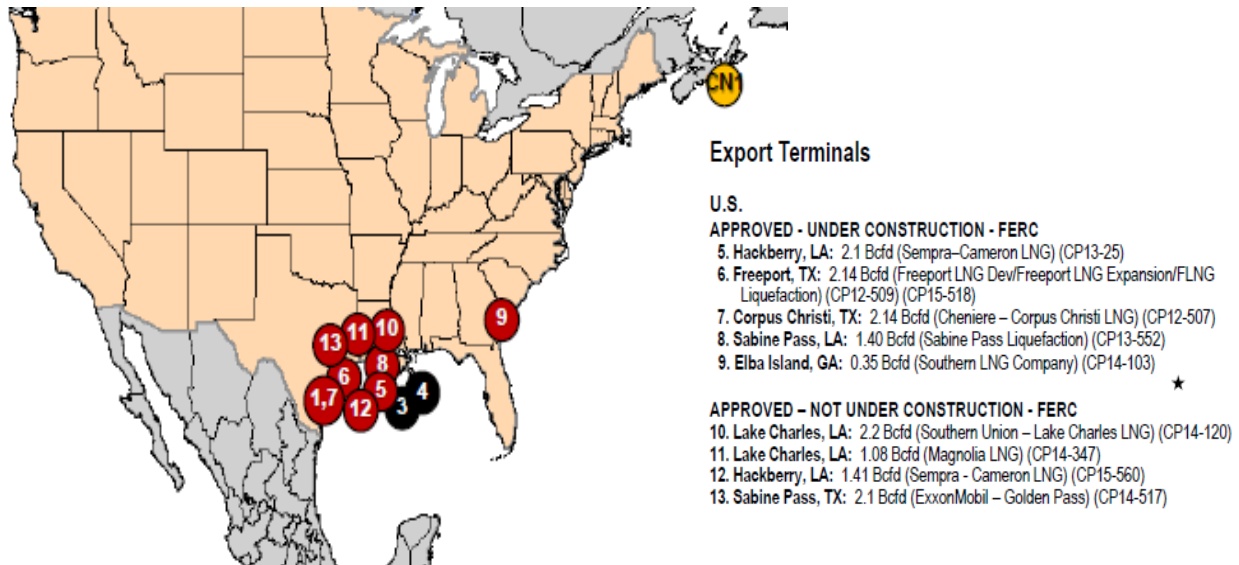
This section presents the results of the supply cost modelling for three US cases:

1. a liquefaction capacity added to an existing regasification plant (in Louisiana)
2. adding one train to an existing liquefaction facility (in Texas)
3. a greenfield project (in Texas)

The first case represents several projects such as Sabine Pass LNG, Freeport LNG, and Corpus Christi LNG. The second case is specific and refers to the situation when a project adds liquefaction to an existing liquefaction facility (e.g., an additional train in Sabine Pass). The results of these two cases are expected to be very similar. The third case represents a greenfield project in the Gulf, e.g., Cameron LNG (under construction) and Magnolia LNG.

Figure 3.11 shows all projects in the Gulf of Mexico – approved and under construction as of April 2018.

Figure 3.11: Status of LNG Export Terminals in the US Gulf of Mexico (April 2018)



Source: US FERC

The projects under construction already have long-term contracts on most of their output and will come onstream in the next several years, before Canadian LNG could be operational. This does not mean that Canadian projects will not compete with these facilities as there is a large and growing spot market (approximately 30% of trade volumes (IGU 2017)).

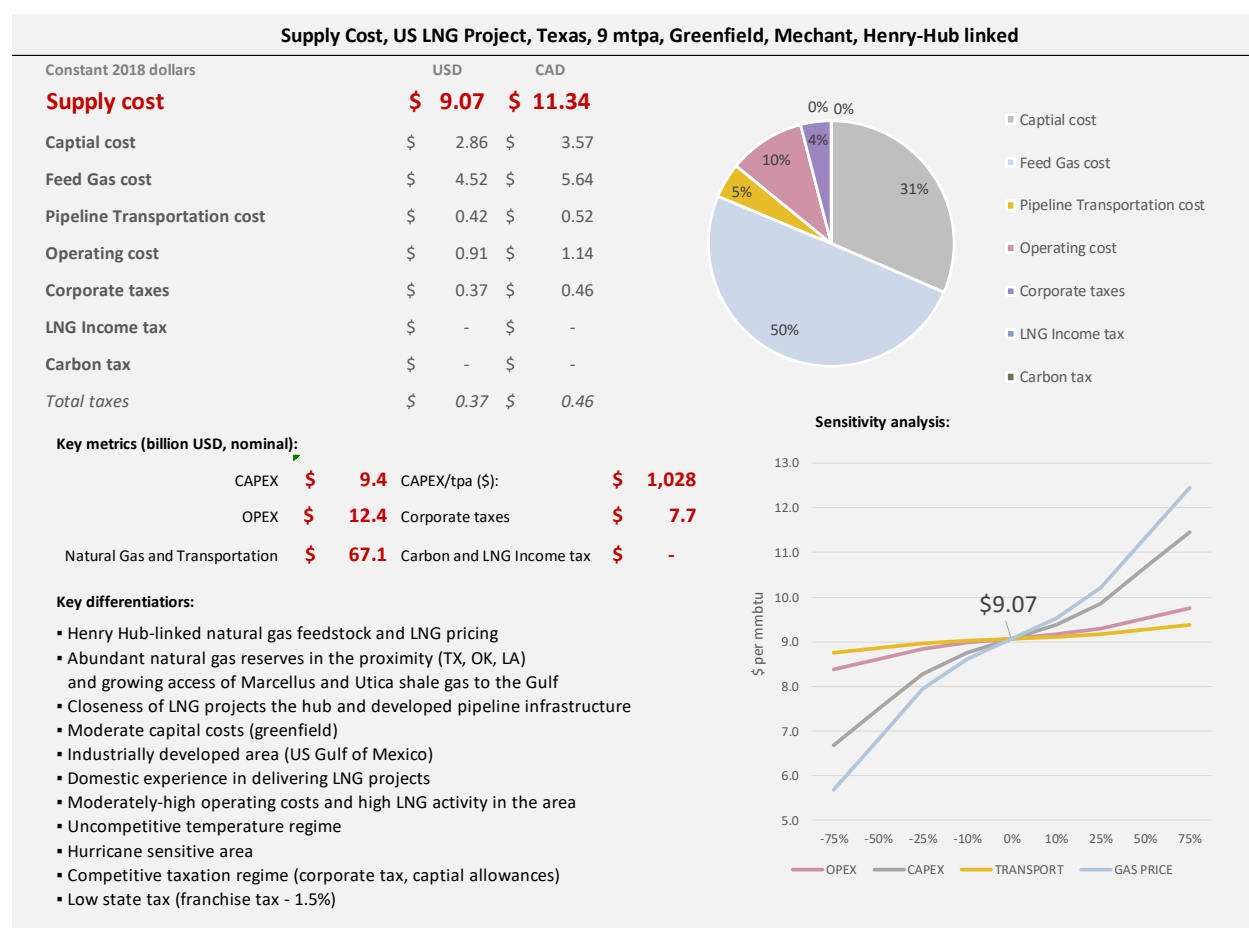
That said, the Canadian projects, which are also in need of long-term contracts to secure financing, will be largely competing with the facilities that come onstream in a similar time frame (2022-2024) and which are taking a FID in 2018-2020. In the US Gulf of Mexico, these will be predominantly greenfield facilities.

The rest of this section presents the supply costs for three cases in the US. The “new tax regime” denotes that the model has been run taking into consideration the changes to the federal corporate tax rate and capital allowances.

Greenfield LNG Project

The resulting supply cost for the greenfield LNG facility in Texas is shown in Figure 3.12.

Figure 3.12: US, Texas, Greenfield Project Supply Cost



The single largest driver of the supply cost is the natural gas feedstock (50%), followed by capital costs (31%). Total tax burden comprises 4%. The project supply cost is most sensitive to changes in capital expenses and gas price, while the change in the operating costs and especially natural gas transportation does not yield a substantial effect. Capital cost overruns by 25% will add \$0.8 to the required LNG costs to be recovered. Natural gas price increases of 25% will increase required LNG costs by \$1.1. Hence, projects in the US try to transfer natural gas price volatility fully on the customer using the formula of 115% of Henry Hub-price plus a constant. The constant generally represents liquefaction costs. As the “story” with Eastern Canada LNG was about transportation, the “story” in the US Gulf projects is about natural gas price.

Key differentiators for Gulf of Mexico projects:

Henry Hub-linked natural gas and LNG pricing. For Asian markets, LNG prices are dependent on the world oil market. The US Gulf of Mexico LNG projects are different in that they link to the US domestic gas market. This provides an opportunity for a cost-plus model with a transparent pricing formula: 115% of Henry Hub plus a constant for liquefaction (\$2.5-\$3.5 with small annual indexation). If the constant is properly estimated by the plant owner during the contractual

process and covers capital, operating costs and margin, the supplier is largely operating with minimum risks as it does not bear any risks associated with the natural gas price.

This formula sparked the interest of both Asian consumers and US investors in 2010-2015 as it would allow saving \$5-9 per mmbtu compared to spot and oil-linked contracts in times of high oil prices. In times of low oil prices and high Henry Hub Prices, e.g., in 2017, new oil-linked contracts and spot market prices in Asia were lower than FOB in the Gulf.

Abundant natural gas reserves in the proximity (TX, OK, LA) and growing access of Marcellus and Utica shale gas to the Gulf. Texas, Louisiana and Oklahoma combined produce almost 40% of US natural gas and are in proximity to the Gulf Coast projects (EIA n.d.). Marcellus and Utica shale gas from Pennsylvania (accounting for 20% of US domestic production) is also becoming more accessible in the Gulf. Companies are reversing pipelines (e.g., Northern Supply Access Project) and applying for bidirectional pipeline flows (e.g., Kinder Morgan Louisiana pipeline (KMPLP). The latter has applied for authorization to add a bidirectional 580 mcf/d capacity to send gas to the Sabine Pass LNG export terminal starting in 2019 when the fifth liquefaction train comes online (Argus Media 2016).

Proximity of LNG projects to the hub and developed pipeline infrastructure. Texas and Louisiana projects are in proximity to the Henry Hub and connected to a large network of pipelines from many providers. This allows LNG proponents to save on transportation costs investing largely into relatively short connection pipelines.

Moderate capital costs (greenfield and low capital costs for brownfields). The US Gulf Coast is intensely developed, and that activity contributes to competitive pricing. Capital costs are moderate for the greenfield projects (under \$1,100 per tonne of LNG). For brownfield projects, when liquefaction is added to regasification, the costs are within \$600-800 per tonne.

Domestic experience in delivering LNG projects. Compared to Canada, the US has experience in regasification and liquefaction projects across a number of states. That experience in the industry and government agencies facilitates the smooth management of projects by the proponents and government oversight agencies. This results in lower risks for planning and construction, which translates into lower FOB costs.

Moderately-high operating costs and high LNG activity in the area. CERI estimated operating costs for the GoM projects based on the actual expenses of the Sabine Pass LNG project in Texas in 2017 (\$0.92 per mmbtu). Cost savings could be realized in the future as 2016 operating costs were more than \$2. CERI is using \$0.7 per mmbtu for the long-term operating cost for the Gulf projects. This estimate incorporates further learning by LNG facility operators.³ Other factors may adversely impact the US GoM's operating costs. First, there is a greater probability of scheduling issues for shipping due to traffic through the Panama Canal. This could lead to lower utilization

³ Extending the LNG Boom: Improving Australian LNG productivity and competitiveness, McKinsey report, May 2013. The report estimated that Australia's LNG project operating costs are higher by 0.2 due to different climates. Canada and the US Gulf have almost identical temperature differences as Canada and Australia.

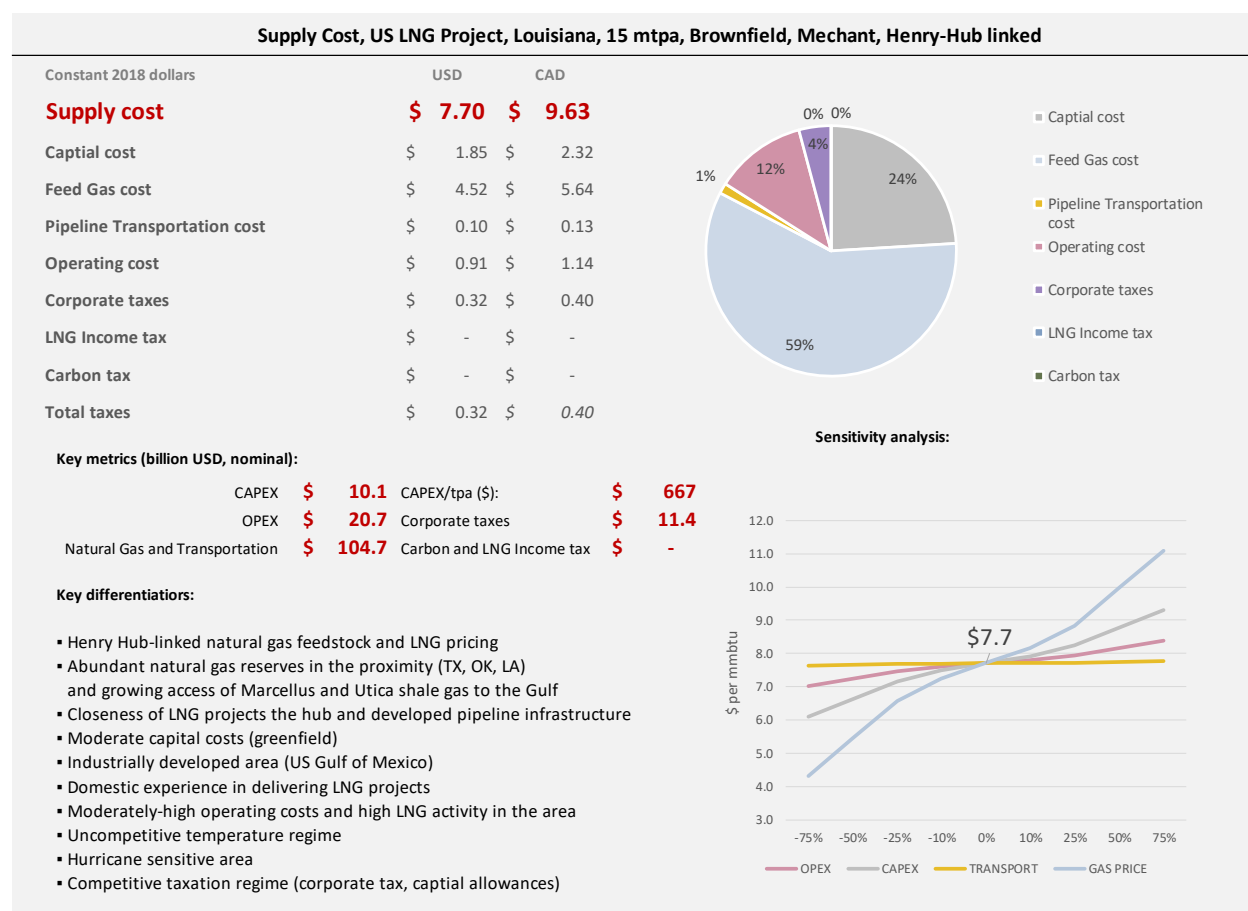
of the plant. Second, the GoM is a hurricane-prone area. These weather events could also influence utilization. Third, differences in labour cost between the US and Canada are higher due to the increased demand in the Gulf for LNG specialists while concurrent projects are underway.

Competitive taxation regime (corporate tax, capital allowances). A recent improvement in the economics of LNG facilities in the US has been realized from the reduction in corporate taxes. The federal corporate tax rate has changed from 35% to 21%, and companies are now allowed to claim 100% of investments under the capital cost allowance. In addition, the state of Texas franchise tax (a substitute for the corporate tax, applied conceptually on net sales) is low – 0.8%.

Brownfield LNG Project

The capital costs for brownfield projects is lower than greenfield options. If the liquefaction were added simultaneously or very shortly after the regasification facilities had been put in place, there would not be any advantage. The advantage comes from the fact that the regasification facilities had been depreciated for a number of years. For instance, the Cameron LNG commenced its commercial activity in 2009 and liquefaction is going to be added in 2019. The Sabine Pass LNG terminal started in 2008 with the first liquefaction constructed in 2015 (7 years later).

As brownfield and greenfield projects in the Gulf have the same price formula: $115\% + \text{the liquefaction constant}$, it means that brownfields can realize a higher margin. The resulting supply costs for the brownfield LNG facility in Texas are shown in Figure 3.13.

Figure 3.13: US, Louisiana, Brownfield LNG Supply Cost

As expected, the importance of capital cost as a share of overall supply cost has diminished – from 31% for greenfield, to 24% for the brownfield project. In dollar values, it has decreased more than \$1 per mmbtu. The role of the natural gas feedstock price increases to 59% in the total FOB LNG cost, followed by operating cost and taxes, which represent the same 4% of total supply costs.

Capital cost overruns by 25% will add \$0.5 to the required LNG costs to be recovered. A similar increase in natural gas prices increases total cost by \$1.1. However, since the price of the gas is passed through to customers, the main concern of the LNG owners in the Gulf would be controlling for capital costs and operating costs.

The key differentiators for Louisiana projects are similar to Texas. Between the two states, the main difference would be state income tax. In Louisiana, taxes on net income are 8%. Taxes on sales in Texas are 0.8%.

Addition of One Train

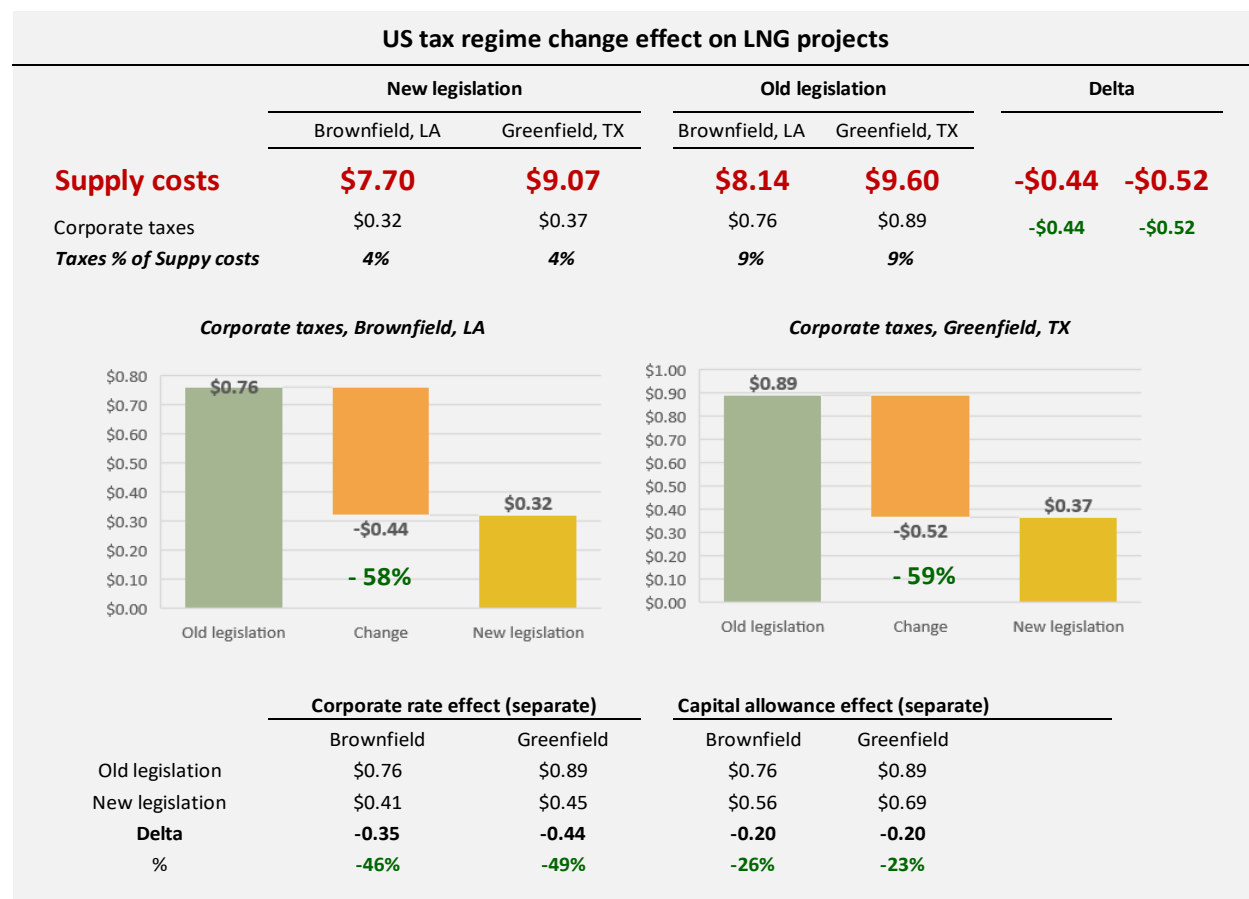
The case of adding one train to an existing liquefaction facility has yielded very similar results compared to the brownfield option. The supply cost of an additional train is \$7.64 per mmbtu compared to \$7.70 for the brownfield option. Due to similarity, this case will be dropped from further discussion in the study.

Effect of the New US Tax Regime

In late 2017, the United States passed legislation changing its taxation regime. This change led to increased discussion of the improved competitiveness of the US in comparison to Canada. Some argue that the comparison of corporate rates, for instance, is not the best approach, as both countries have a number of incentives and tax credits for companies, which change the effective tax rate.

While the study will touch upon the inter-jurisdictional comparison in Chapter 4, this section shows the effect of the legislation change on US LNG projects. The effects of the new legislation on LNG projects is illustrated in Figure 3.14.

Figure 3.14: US Tax Regime Change – Effect on LNG Projects

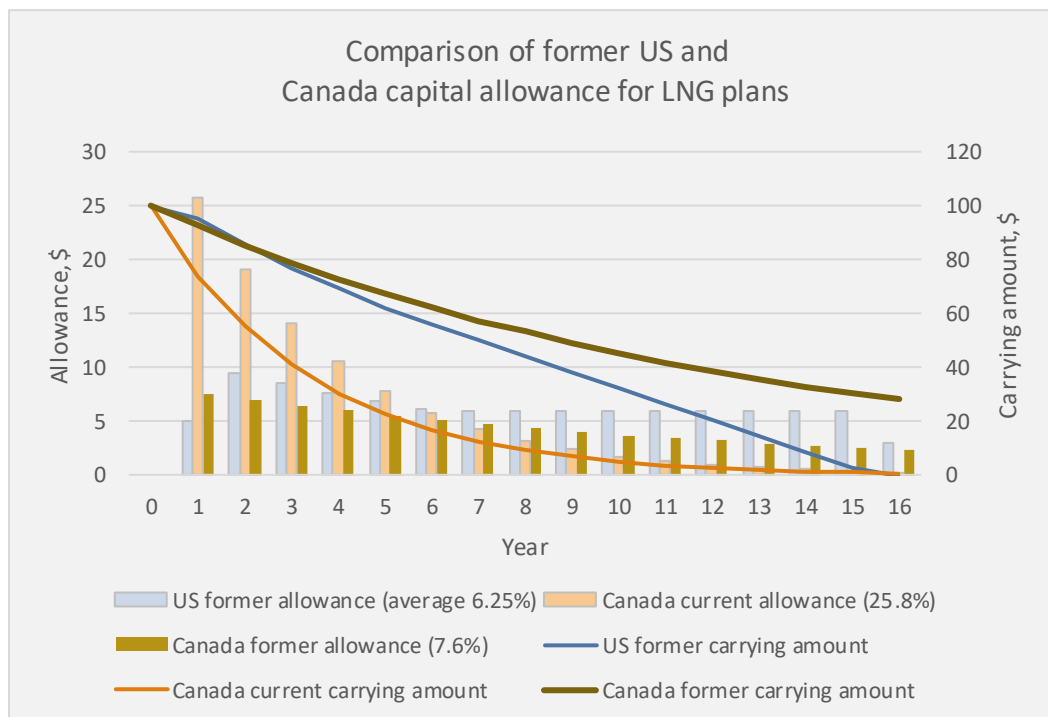


In sum, the legislation decreases supply costs by 5% by decreasing corporate taxes by 59% per mmbtu. The separate effect of expensing 100% of capital in the first year yields a benefit of \$0.20 per mmbtu (this effect is separate from the corporate tax effect; the corporate tax was fixed at the former rate of 35%). If the capital allowance did not change and only the corporate tax was adjusted, the effect would be a cost reduction of \$0.35-\$0.44.

The previous US capital allowance (average 6.25% annually) with regard to LNG projects was inferior to Canada's current rate (CERI calculated a 25.8% weighted average across the whole LNG plant), but better than Canada's former rate (7.6% as a weighted average across the LNG plant before the federal government introduced higher CCA rates for LNG plants).

Figure 3.15 shows an example when \$100 is depreciated using the former US capital allowance, and Canada's former and current capital allowances. Canada's carrying amount decreases much faster than under the former US system. The new US system is more advantageous as it allows expensing of 100% of the capital costs, especially when no ring-fencing is applied meaning that a project can use allowances from the LNG plant towards other income, e.g., generated from upstream gas production.

Figure 3.15: Comparison of Former US Capital Allowance and Canada's Current Capital Allowance for LNG plants



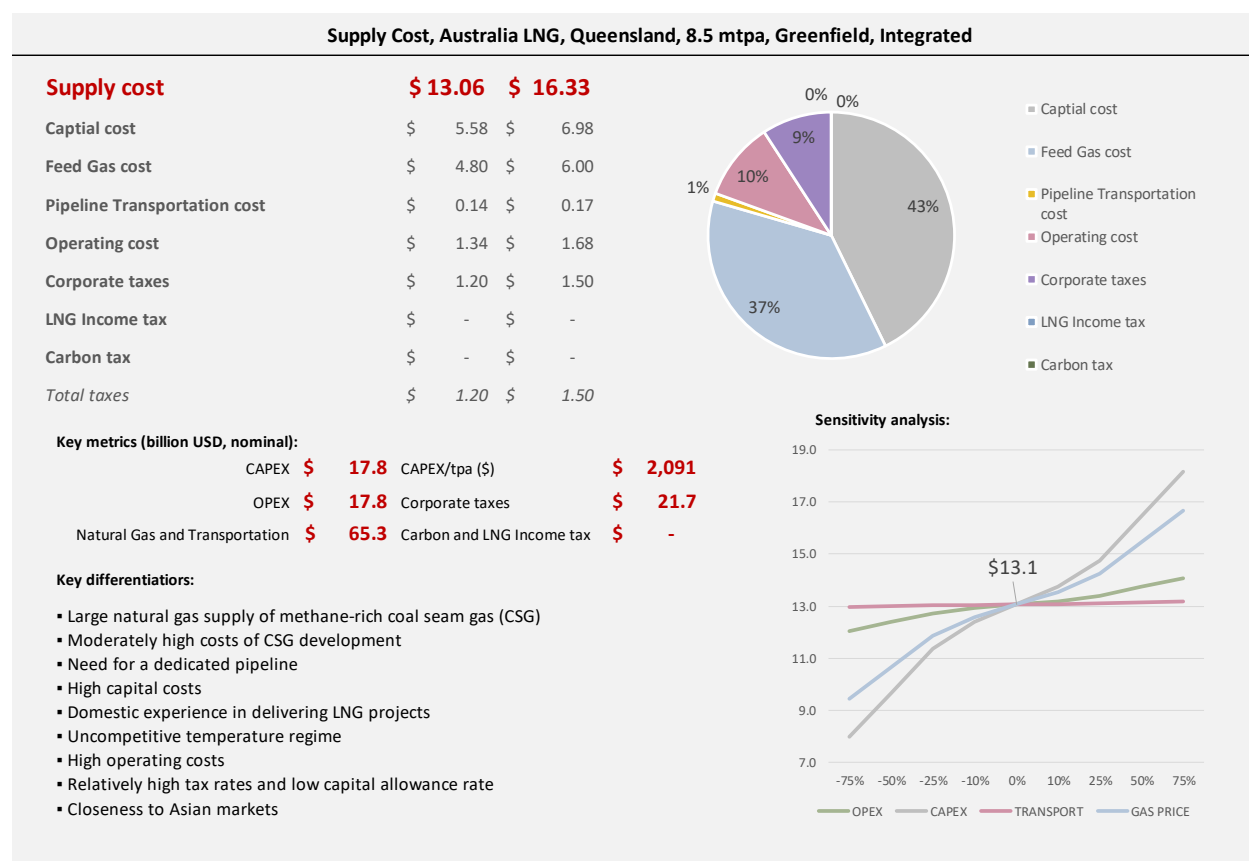
Australia

Australia has become a significant supplier of LNG to world markets with a 17.2% market share. It is also the closest in shipping distance to the growing Asia markets. Beginning in 1989, Australia has added seven projects to the market with 73.5 total mtpa; an additional 11.9 is coming onstream in 2018 (APPEA 2018).

The Australian LNG projects have also been known for their high capital costs which translates into high supply costs. It is beyond the scope of the study to consider the details of these cost overruns. There are some publications in the public domain which delve into those Australian LNG project cases in greater detail. In this study, CERI focuses on examining the onshore projects on the eastern coast, their supply costs, and location key differentiators.

The supply cost of a representative coal seam gas-sourced onshore project is illustrated in Figure 3.16.

Figure 3.16: Australia LNG Supply Costs, Queensland



The largest drivers for supply costs are capital costs (43%) and natural gas costs (37%), followed by operating costs (10%) and taxes (9%). The project supply cost is mostly sensitive to capital and natural gas costs. For instance, capital cost overruns by 25% will add \$1.7 to the LNG costs.

Similar increases in natural gas costs will add \$1.2 to the FOB LNG cost. Conversely, the drop in costs in either element will bring similar savings effect.

The key differentiators of the Australian projects (onshore, Queensland):

Large natural gas supply of methane-rich coal seam gas (CSG). The natural gas resource base in Australia is 257 TCF (reserves and contingent), of which 75 TCF is in coal seam gas (43 TCF reserves; 32 are contingent) (Geoscience Australia 2014). To put it into perspective, 43 TCF is enough to supply three LNG projects in the east for approximately 30 years. The methane content in the CSG is around 97-98%, while shale plays usually have 84-95%, which positions it better for a leaner LNG.

Moderately high costs of CSG development. Coal seam gas is produced from coal beds typically 200-1000 meters below the surface. This is shallower than unconventional gas typical for North America plays. It also requires less fracturing (roughly 40% of the time) than for shale gas. However, the number of wells to sustain production is high – 1,000-2,000 a year (Brian Towler et al. 2016). There are other technical issues associated with CSG development such as high levels of produced saline water, slugging, wellbore pressure profile, relative permeability, and geological variability.

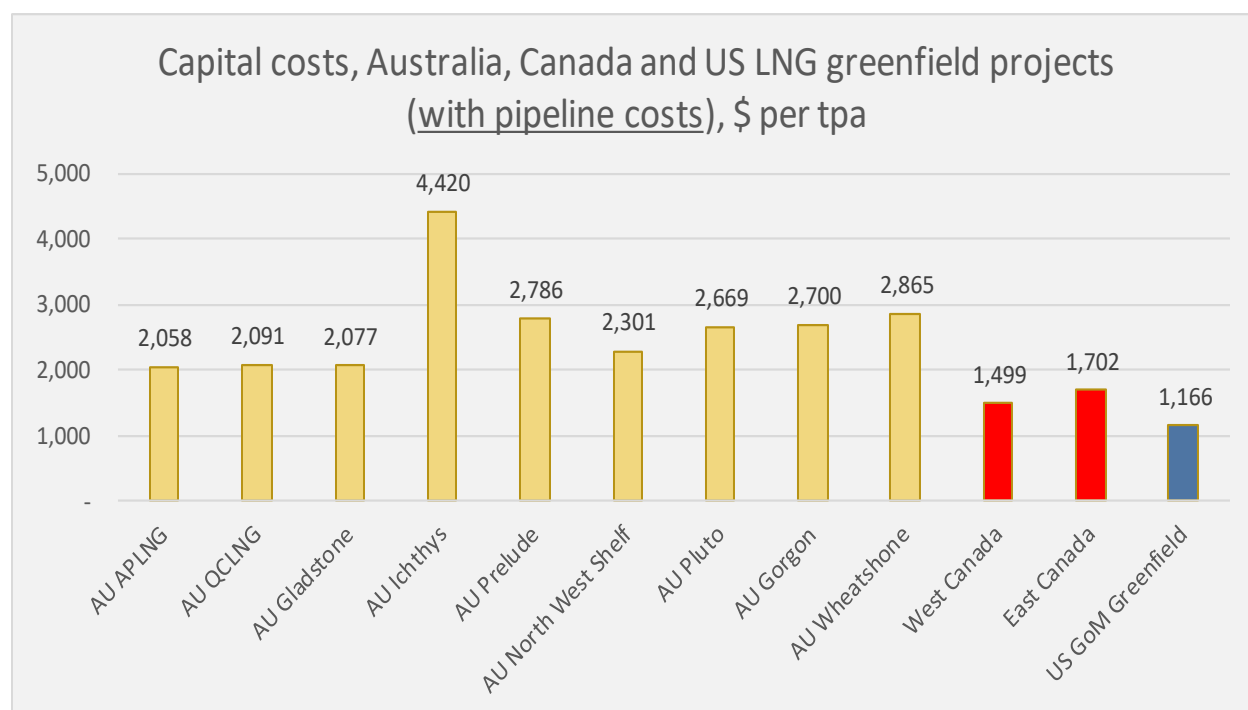
The costs of CSG development vary from A\$3.81 to A\$5.51 per GJ or US\$2.7-\$3.9 per mmbtu (CERI based on (CORE Energy Group 2016)). The weighted average that CERI used in this study (weighted across several resource plays) is \$3.4 per mmbtu inflated 2% annually. The costs are comparable to current Henry Hub prices. For comparison, Montney-sourced gas is half the cost – \$1.73 per mmbtu (2018, US dollars).

Need for a dedicated pipeline and high costs of construction. Similar to other jurisdictions, the feedstock needs to travel large distances to get to the coast. In the case of eastern Australian projects, it is approximately 540-km across flat terrain. The pipeline construction costs are estimated at \$9.3 million/km (2014 US dollars) which is 2.7 times higher than the industry average. The cost of the pipeline is derived from the QCLNG (proxy project) sale of the built pipeline to feed the LNG project to APA Group for US\$5 billion.

High capital costs. The projects in Australia, both onshore and offshore, have been substantially more expensive than in other jurisdictions. Many projects ran significant cost overruns. The overruns varied from 17% to 58%, with the average being 37%.⁴ If the modelled project were on budget (-37% lower in CAPEX) compared to actual costs, the supply costs would be \$10.5 or 20% lower compared to the modelled cost of \$13.09.

Figure 3.17 shows all Australian project capital costs as well as Canadian and US greenfield estimates used for the study for comparison.

⁴ CERI estimate based on various resources which included original and final costs of the projects

Figure 3.17: Capital Costs, Australia, Canada, US Greenfield LNG Projects

Source: CERI, (APPEA 2018)

Domestic experience in delivering LNG projects. One of the important advantages of Australia is the experience and lessons learnt in how to deliver an LNG project and, more importantly, a portfolio of concurrent LNG projects in the country. This experience can be leveraged if a new project is built.

Uncompetitive temperature regime. The average annual temperature of 22.7 degrees Celsius (Gladstone) positions LNG plants in Australia at a disadvantage compared to Canada.

Relatively high operating costs. Australian projects have a number of factors which translate to higher capital and operating costs, including higher labour, materials and freight costs, more onerous equipment and infrastructure specifications, and climate-related plant efficiency (McKinsey 2013). All of this could contribute to \$0.5 per mmbtu of additional costs (McKinsey 2013).

Relatively high tax rates and low capital allowance rate. The stability of the tax system is an important factor for long-term projects like LNG. Australia has been offering this value and vast gas reserves located close to markets in order to attract investors. Since the early 2000s, the government decreased the effective life of LNG assets from 30 to 15 years, allowing for accelerated depreciation. The incentive was done not only for the LNG sector but by and large for the whole oil and gas sector. It covered assets involved in manufacturing condensate, crude oil, domestic gas, or liquid petroleum gas, including gas transmission and distribution and excluded refineries. In 2001, the government further streamlined the capital allowances with the

New Business Tax System (Capital Allowance) Act 2001. Starting in 2006, the declining balance method was set to use 200% base, instead of 150%, which further improved capital allowances. Overall, annual capital allowance rates changed from 5% (150%/30) to 13.3% (200%/15). If the old rate was not changed, the supply costs would have been higher by \$0.50 or 3.8%. At the same time, the rate of 13.3% is a disadvantage for Canada (~28%) and the US (100%), where the project can expense capital in the first year.

The corporate tax rate is slightly higher than in British Columbia (30% versus a combined federal and provincial 27% in British Columbia), higher than Louisiana (28% federal and state combined), but lower than in Nova Scotia (31%).

Proximity to Asian markets. One of the clear advantages of the Australia projects is their short distance to the markets in Asia – China, Japan, Korea, India. The distances are shorter and there are no canals to pass through compared to the US projects.

Chapter 4: LNG Competitive Analysis

This chapter is divided into four parts. The first outlines the shipping distances and costs from LNG producing jurisdictions to Asian and European markets. The second part presents major advantages for Canadian LNG projects which could lay a path forward for increased cost-competitiveness. The third part presents the comparative perspective of the projects in five jurisdictions. The fourth part concludes with the review of economic impacts and cooperation with Indigenous Peoples on LNG developments.

LNG Shipping Advantages and Costs

In Asia, Australia holds distance and LNG transportation cost advantages over Canadian and US projects. However, shipping costs from Canada are very close to Australia's (8 cents per mmbtu more to Japan) and (14 cents per mmbtu more to China). The advantage of Canadian projects over the US Gulf of Mexico is approximately \$1.

Australia also holds a shipping cost advantage of \$0.43 per mmbtu in the India market over Eastern Canada LNG projects and \$0.5 over Western Canada LNG. At the same time, Eastern Canada LNG holds a cost advantage over GoM LNG by \$0.6 per mmbtu.

In the European LNG market, Eastern Canada LNG leads by \$0.33 per mmbtu over GoM-based projects. Western Canada LNG is close in transportation costs to GoM – \$1.38.

Figure 4.1: LNG Shipping Costs



In sum, Canadian projects hold first or second place in the ranking of transportation costs to major demand markets. In many cases (except for the Indian market) the difference compared to the cheapest jurisdiction is marginal.

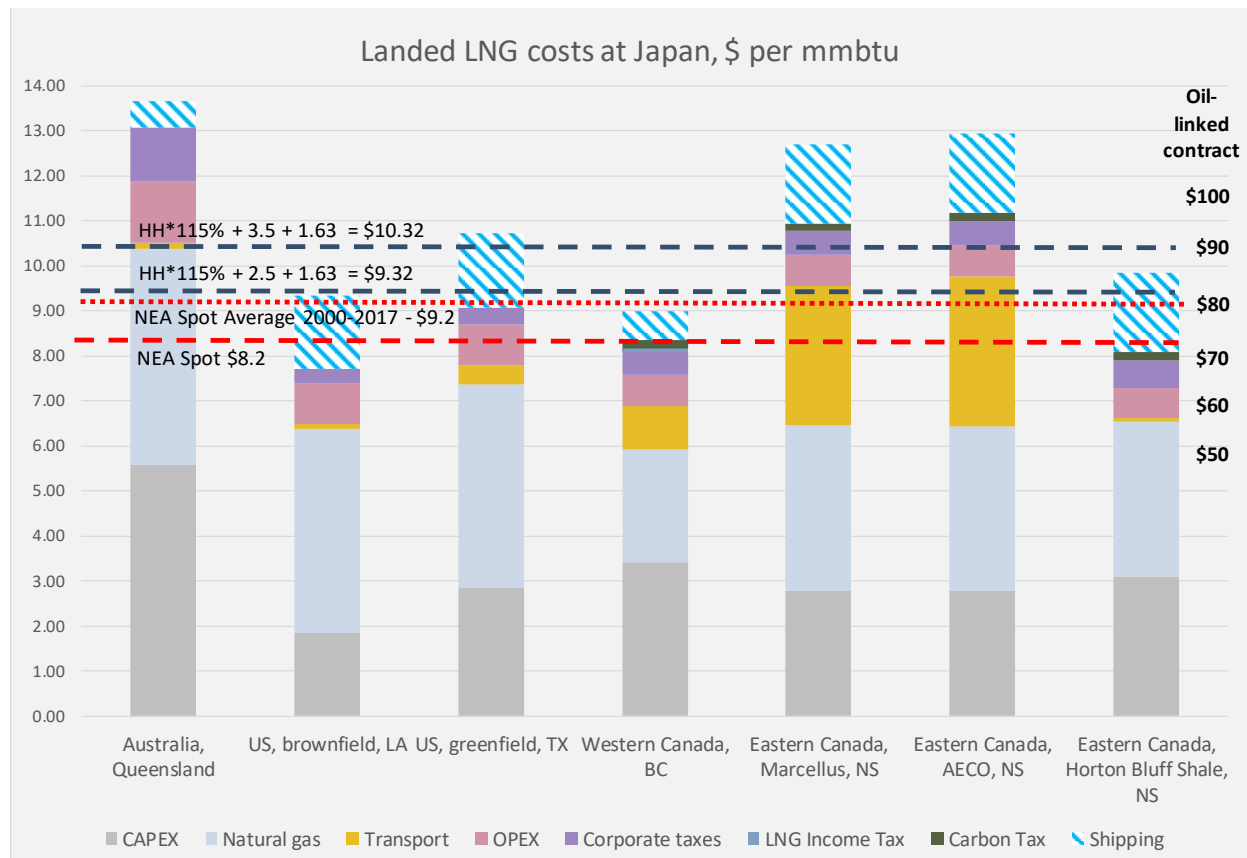
Path to Competitiveness

The cost competitiveness of an LNG plant is in relation to the destination markets. A project with certain supply costs and transportation costs needs to ensure that the price offered at the destination market over 20-years will cover those costs. Otherwise, the LNG owners risk a loss. In this section, the landed costs of LNG in Canada and competing jurisdictions are compared with prices at the destination markets. Further, the section presents ways to improve cost-competitiveness for Canadian projects.

Western Canada LNG and Asian Market

The landed costs at Japan are shown in Figure 4.2, as well as the current spot price of LNG (\$8.2 – May 2018), the average spot price for 2000-2017 (\$9.2), Henry Hub-linked price of LNG at Japan, and oil-linked contract price levels (11.5% of Brent). The comparison is made at Japan; however, the results apply to the entire northeast Asia market.

Figure 4.2: Landed LNG Cost at Japan



Key observations:

1. **Western Canada and Eastern Canada LNG landed costs are more expensive than the current spot price in Japan** (for Eastern Canada LNG, northeast Asia is not a priority market). The difference between Western Canada LNG landed costs and spot price is \$0.80 at the time of writing (May 2018).
2. **Under an oil-linked contract, a Western Canada LNG project will need an oil price of approximately \$80 or higher over the life of the project to break-even** (contract price is assumed at 11.5% of Brent contract; break-even costs include a return to investors).
3. **The total liquefaction costs of Western Canada LNG (all costs except for natural gas) are higher than for the US GoM-based project.** *Note: this comparison is made for equal LNG output, capital size, and gas feedstock volume to control for the effects from these variables on the corporate taxes.*

Figure 4.3: Total Liquefaction Costs Comparison for Western Canada

| Total liquefaction costs (all costs except natural gas feedstock), \$ / mmbtu | | | |
|--|--------------------------|---|------------------------|
| Generic project comparison | | | |
| All projects are 13 mtpa \$1,237 / tpa CAPEX | | | |
| US, GoM, greenfield | | Western Canada, BC, greenfield | |
| Louisiana | Texas | | |
| \$5.04 | \$5.17 | | \$5.84 |
| Comparison of Western Canada LNG to US Greenfield LNG: | | | |
| Compared to Louisiana (per mmbtu): | | Compared to Texas (per mmbtu): | |
| Capital cost: | - | Capital costs: | - |
| Pipeline transport: | + \$0.86 | Pipeline transport: | + \$0.56 |
| Taxes: | + \$0.18* | Taxes: | + \$0.35* |
| Operating cost: | - <u>\$0.23</u> | Operating cost: | - <u>\$0.23</u> |
| Total: | + \$0.80 (+15.8%) | Total: | + \$0.68 (+13%) |
| * - \$0.1 on Corporate taxes, + \$0.09 LNG Income tax, + \$0.18 Carbon tax | | * + \$0.07 on Corporate taxes, + \$0.09 LNG Income tax, + \$0.18 Carbon tax | |

The Louisiana-based project can deliver LNG at \$0.8/mmbtu less than a British Columbia-based project, while Texas can deliver at \$0.68 less. Note that BC edges Louisiana on corporate taxes by 10 cents per mmbtu, while at a disadvantage to Texas at 7 cents per mmbtu.

4. **Western Canada LNG gains an advantage over US GoM projects due to cheaper shipping (by \$1) and cheaper natural gas from the LNG project's own upstream production (by \$2).**

5. US greenfield projects are almost break-even at the market with a liquefaction constant of \$3.5 over the long term. Note that a greenfield Corpus Christi project executed 20-year contracts with a \$3.5 constant. However, these projects cannot match current pricing at the Asian spot market. Under oil-linked contracts (which Asia customers favour), the project will need a price over \$90 to break-even.
6. US brownfield projects are break-even with Henry Hub pricing and a liquefaction constant of \$2.5. Note that Sabine Pass' 20-year contracts have a constant of \$2.75 (weighted by volume). Even with the capital cost advantage, these projects cannot match current LNG pricing in Asia. Under oil-linked contracts, the project will need a price slightly more than \$80 to break-even.
7. Australian CSG projects would need an oil price over \$100 to break-even under the recent oil-linked formula and around \$90 under the old (14.5% of Brent + \$0.5).

Australian projects, as well as brownfield GoM supply costs, are based on either finished facilities' actual capital expenditures or announced EPC contract values. Their capital cost data has higher precision and certainty translated into more reliable supply costs obtained in the study. Australian supply costs reflect the actual cost overruns the project had. Ideally, to mitigate estimated cost risks in Canada, a project's landed cost should be below the long-term market price. Therefore, even the average historical NEA price of US\$9.2 which is higher than Western Canada LNG landed costs may not be sufficient for investors to make a FID.

Another important consideration is what future oil price is needed for the project to break-even in Asia. The findings suggest \$80 or higher over the life of the facility. The recent fundamental change in the oil market and prices under \$50, has sent LNG prices below levels many projects can absorb. This resulted in fewer FIDs in 2016-2017.

Simultaneously, the argument that oil will not play a significant role in the LNG market in the future is not supported as oil-linked long-term contracts still constitute a prevailing share in LNG sales. It is true that the spot market has been growing, creating an alternative to the oil-linked pricing. However, it is not certain if the spot market is going to reach much more than its existing trade volume share of 30%. In fact, the share of non-long-term trade has flattened and has fallen slightly since 2013.

The fundamental supports for the long-term projects are still in place because an LNG facility, as a rule, requires external financing warranted by the existence of executed contracts, rather than bets on the spot market. It is highly likely that the oil-linked contracts in Asia will remain an important factor in investment decision-making. Thus, the required oil price level of \$80 or above may be taken with caution by investors in the LNG market, especially when major oil-producing countries like Saudi Arabia and Russia suggest that \$60 is a reasonable and fair price.

What are the possible ways to bring the supply costs and delivered costs down or gain better value for the product for West Coast LNG projects? CERI has considered the following options:

1. Government

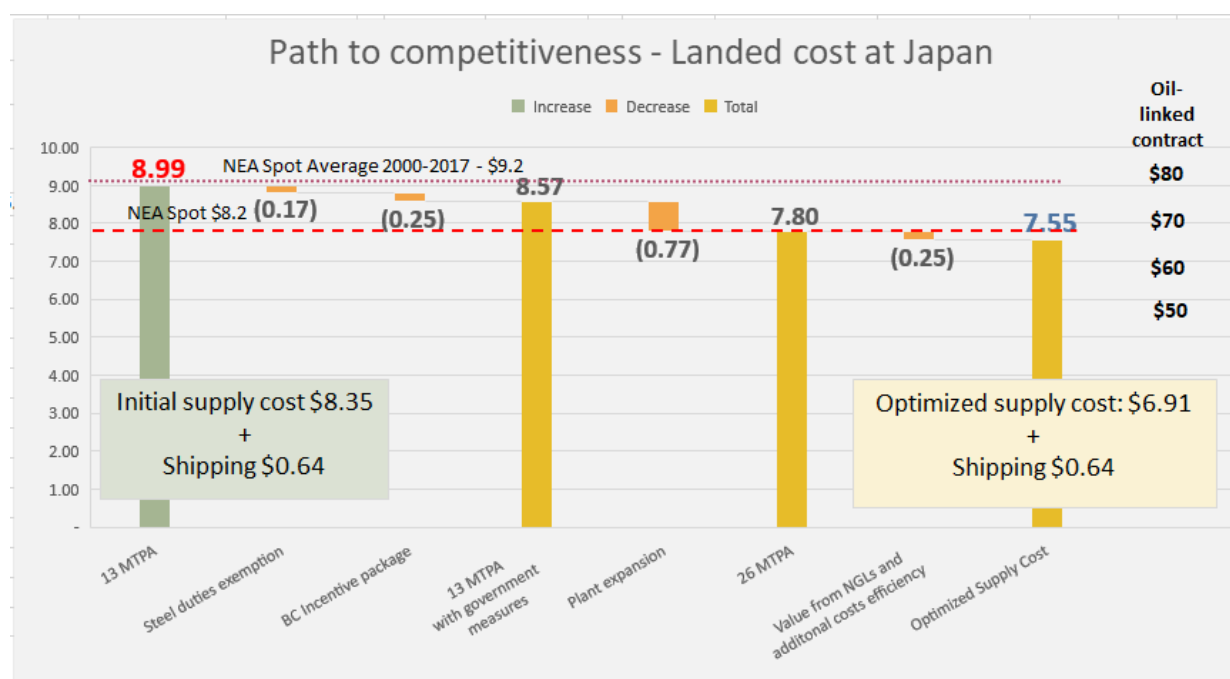
- Exempt LNG projects from fabricated steel duties and countervailing duties on imported LNG modules
- Introduce additional incentives such as an increase in the capital cost allowance

2. LNG Project Proponents

- Expand the plant capacity to exploit economies of scale
- Explore additional value from NGLs
- Seek better LNG sales contract options

The effects of some of these measures are illustrated in Figure 4.4.

Figure 4.4: Path to Competitiveness for Western Canada LNG



Overall, if all measures are applied, an LNG project's landed costs to Japan could decrease from \$8.99 to \$7.55 per mmbtu, or by 16%. The resulting landed cost can be recovered by an LNG project with a market Brent crude oil price under \$65.

Fabricated steel duties exemption. The federal government decision to exempt LNG projects in Canada from the fabricated industrial steel components duties and countervailing duties levied onto the imported LNG modules' steel structures, could allow a project to decrease capital costs by 4.2% and save \$683 million in duties. The value of the steel frames is estimated at US\$1.16 billion.

A sample module is shown in Figure 4.5. The duty is levied onto the steel frames in which the LNG equipment is contained. LNG projects gain capital cost efficiency using the modular approach from producing modules at one geographical place. The internal LNG equipment, which is the main value of the module, is attached to the frame in production, making it a single unit designed to be easily attached to other modules at the plant location. The steel frames are the constructive elements to hold the equipment and do not have a value to an LNG plant alone if produced separately from the LNG equipment.

Figure 4.5: LNG Modules



CERI's modelling shows that such an exemption by the federal government would equal \$0.17 per mmbtu in additional cost competitiveness for an LNG plant.

Additional provincial incentives. CERI has estimated three out of four incentives which were proposed by the BC government in the Natural Gas Development Framework (all except electricity rates as all projects were assumed to use natural gas). This incentive is in addition to the Natural Gas Tax Credit, which is implemented in the initial supply cost (\$8.35 FOB cost or \$8.99 landed cost in Japan). The effect of the new incentive package is a \$0.25 per mmbtu improvement in competitiveness.

British Columbia corporate tax is competitive (26% tax rate - 15% federal tax and 11% provincial), compared to Louisiana (29%), Texas (21% + 0.8% on the net sales), Australia (30%) or Nova Scotia (31%). With the BC Natural Gas Credit, the effective tax rate could drop to 23%, but this depends on the volume of gas consumed. For instance, in the 13 mtpa model, the average effective tax rate was 24.1%.

Additional federal incentives. Beyond regulating import duties, the federal government could improve the capital allowance for the LNG industry. The federal government has already increased the capital allowance for LNG projects aimed to accelerate the capital payback. That changed the weighted average of the capital allowance from 7.6% to 25.8%. At the same time, the recent change in the US tax legislation gives US jurisdictions an advantage, as they can claim 100% capital allowance in the first year and carry forward the unused amount. Canadian projects can also benefit from higher capital allowance, especially if ring-fencing is removed.

Expansion of the plant. Project proponents may decide to expand the liquefaction plant to benefit from economies of scale. Such economies per mmbtu of the LNG will be driven from supporting infrastructure – jetty, land, storage, pipeline, utilities, permitting, administrative and other cost elements which would be divided across the larger export volume. The expected effect on per mmbtu basis is \$0.77 and is a significant incentive that drives LNG expansion projects all over the world.

However, it is not likely to expect an LNG project to gain such a cost advantage until 5-7 years after the initial plant is built. Nor is it guaranteed that a project would expand due to possible factors deterring an expansion FID including negative macroeconomics, slowing demand, lack of financial resources, or operating or permitting challenges at the location. This means that it is prudent to expect that the initial capacity should be competitive on its own.

Practically, many LNG plants are expanding gradually over time, rather than building an expanded 20-30 mtpa project all at once. This is done for a number of reasons. First, it is more difficult to secure contracts with customers for a 16 mtpa project before the FID, rather than for an 8 mtpa project. Modern contracts tend to be not only shorter but also smaller in volume. For instance, Sabine Pass' 19.8 mtpa has been contracted to six customers with an average 3.3 mtpa per customer, while the more recent project of Cheniere's Corpus Christi has seven customers for its 8.5 mtpa with an average of 1.2 mtpa per customer. Putting together a portfolio of customers for a large plant becomes problematic. Second, it is more challenging for companies to secure financing for a larger plant rather than a smaller one. Finally, delivering two trains, rather than a 4 or 5 train project, is more manageable for a project management team. The scale and scope of a mega project may be beyond the management capacity of a company and result in budget overruns.

Consequently, even though the prize of additional cost-effectiveness is attractive, it is not likely to be relied on during the initial FID.

Additional value from NGL and cost savings. Another way that an integrated project may reduce its supply costs is focusing on the liquids-rich natural gas plays and monetizing those natural gas liquids in excess of what an LNG plant needs. As mentioned in Chapter 3, the Montney play has on average 16.2 barrels of NGLs per mmcf, which many E&P companies are targeting; especially when in the first 4-5 years the ratio of condensate can reach over 100 barrels per mmcf.

As gas composition gets richer in ethane, butane and propane, it will have lower methane volumes, while the latter is the most important part of the LNG output. Thus, going after C2+ rich compositions will require more volumes of natural gas to satisfy LNG methane specifications. It is expected that the NGL revenues will offset additional costs of stripping the NGL in the Montney area or at the LNG plant and sending NGLs back to domestic markets, most likely to Alberta. CERI estimates that the additional revenue from NGLs (primarily condensate) will help reduce natural gas feedstock cost by 10%.

The higher heating value of the Montney gas could also be considered an advantage over lean gas (e.g., from Australia and the US GoM) as Asia traditionally prefers richer gas content LNG. Although this advantage has diminished over time as regasification plants have been configuring for leaner gas, it is still an opportunity to increase revenues.

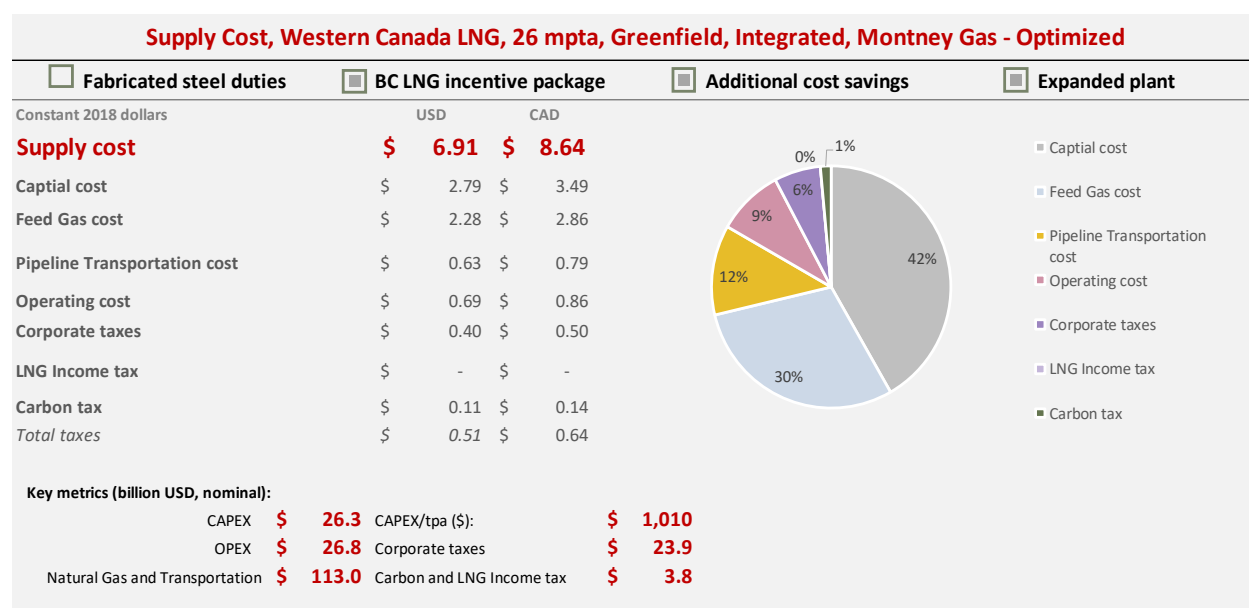
Lastly, the LNG proponent has a significant incentive to save on capital, operating costs, natural gas feedstock and transportation costs. Each project has its specific areas for improving efficiency as well as areas with the greatest risk of cost overruns. For simplicity, CERI has assumed a possible decrease in transportation costs by 5% due to, e.g., a decreased toll by a midstream company reached through negotiations.

The effect of these measures is estimated at \$0.25 per mmbtu in increased cost-competitiveness.

Seek better LNG sales contract options. Finally, the proponents could strive to execute a contract at a better oil-linked formula than 11.5% of Brent. It is difficult to estimate the chances of such a success especially as the market is oversupplied (IGU 2017).

The average formula has changed from 14.2% of Brent + \$0.5 in 2011 to 11.5% of Brent + \$0 in 2017. CERI has used the latter for the study, which represents the strictest test for LNG competitiveness. If a project could secure better terms, it gains competitiveness. For instance, if the contract is signed at the rate of 12.5%, the needed oil price is already \$65 for a project to break-even, not \$70 under the 11.5% rate. The optimized supply cost is illustrated in Figure 4.6.

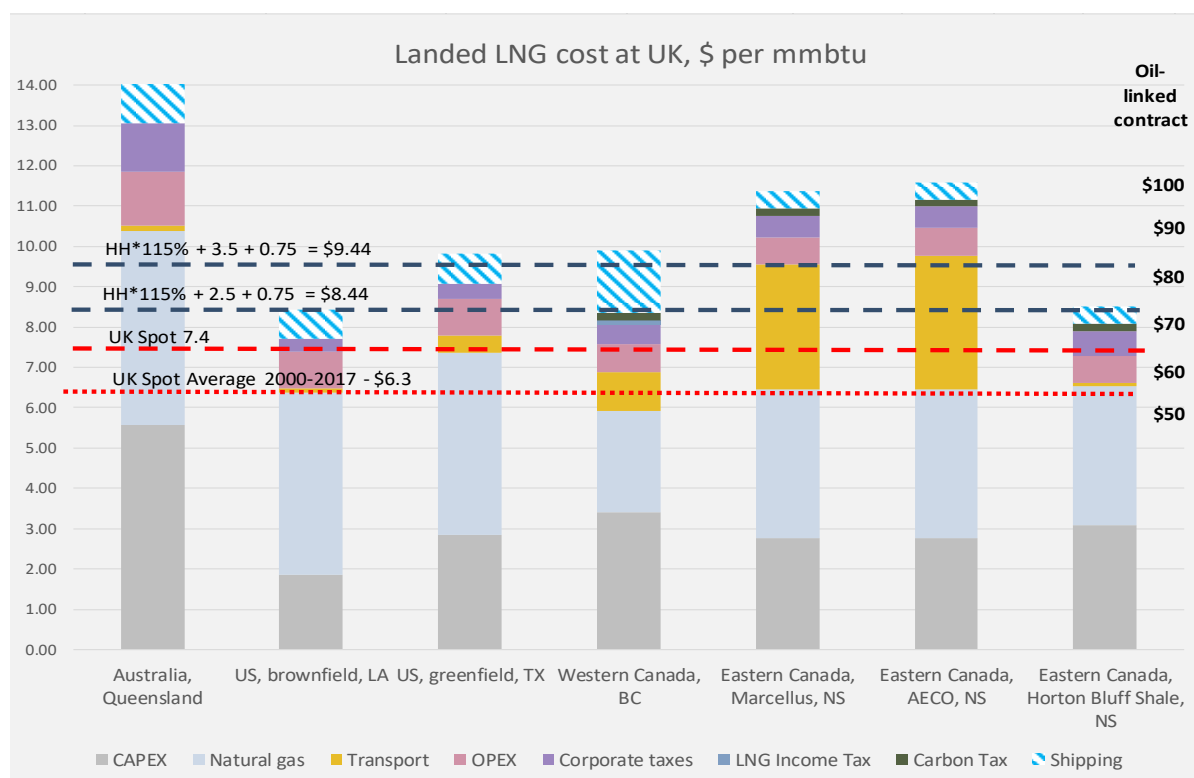
Figure 4.6: Optimized Supply Cost, Western Canada LNG



Eastern Canada LNG and European Market

The landed costs in the UK are shown in Figure 4.7, as well as the current spot price of LNG (\$7.4 – May 2018), average spot price for 2000-2017 (\$6.3), the Henry Hub-linked price of LNG in the UK, and for the reference oil-linked contract price levels (11.5% of Brent).

Figure 4.7: Landed LNG Cost in the UK



Key observations:

1. **Eastern Canada and Western Canada LNG landed costs are more expensive than the current spot price in the UK.** The difference between Western Canada LNG and the spot price is \$2.5 per mmbtu, while for Eastern Canada LNG with Marcellus and AECO-sourced gas it is \$4-\$4.2, respectively. The closest supply cost to the market price is local gas-sourced case with a \$1.1 difference to the market. Even though a Western Canada LNG project's delivered cost is lower than hub-based models of Eastern Canada LNG, this section will focus on the Eastern Canada LNG since Europe is the primary market. From the previous section, it is seen that Western Canada LNG can potentially reach optimized supply cost of \$6.91; added transportation to the UK of \$1.56 makes the optimized landed cost at \$8.5, \$1.1 higher than the current spot price.
2. **The Eastern Canada LNG project will need an oil price of approximately \$100 over the life of the project to break-even** (contract price is assumed at 11.5% of Brent contract).
3. **The total liquefaction costs of Eastern Canada LNG (all costs except for natural gas) are higher than the US GoM-based project.** *Note: this comparison is made for equal LNG output, capital size, and gas feedstock volume to control the effects these variables have on corporate taxes.*

Figure 4.8: Total Liquefaction Costs Comparison for Eastern Canada LNG

| Total liquefaction costs (all costs except natural gas feedstock), \$ / mmbtu | | | |
|--|------------------------|--|--------------------------|
| Generic project comparison | | | |
| All projects are 8 mtpa \$1,006 / tpa CAPEX | | | |
| US, GoM, greenfield | | Eastern Canada, NS, greenfield (Marcellus) | |
| Louisiana | Texas | | |
| \$4.26 | \$4.46 | \$7.26 | |
| Comparison of Western Canada LNG to US Greenfield LNG: | | | |
| Compared to Louisiana (per mmbtu): | | Compared to Texas (per mmbtu): | |
| Capital cost: | - | Capital costs: | - |
| Pipeline transport: | + \$2.99 | Pipeline transport: | + \$2.67 |
| Taxes: | + \$0.24* | Taxes: | + \$0.36* |
| Operating cost: | - \$0.23 | Operating cost: | - \$0.23 |
| Total: | + \$3.00 (+41%) | Total: | + \$2.80 (+38.6%) |
| * + \$0.05 on Corporate taxes, + \$0.19 Carbon tax | | * + \$0.17 on Corporate taxes, + \$0.19 Carbon tax | |

The Louisiana-based project can deliver a mmbtu of LNG at \$3.00 less than a Nova Scotia-based project, while Texas can deliver at \$2.8 less. Note that Nova Scotia's corporate tax is higher by 5-17 cents per mmbtu than in the US, as the combined provincial and federal tax rate is 31%. This is higher than in any jurisdiction reviewed in the study.

4. **An Eastern Canada LNG project based on local gas is cost-competitive compared to brownfield and edges greenfield projects in the US by \$1.3 per mmbtu.**
5. US greenfield projects are almost break-even at the market with the liquefaction constant at \$3.5 over the long term. However, these projects cannot match current pricing at the UK spot market.
6. A brownfield US project is breakeven under a Henry-Hub pricing model (landed cost at \$8.4 matches exactly the formula-based price of \$8.4), but not competitive at the current spot market price.

The gap between the supply costs of viable LNG options in Nova Scotia is substantial – from \$4 (Marcellus gas) to \$4.2 (AECO-C gas). The European market has been less attractive for LNG shipments than the Asia market due to lower prices. The difference between costs in the UK compared to Japan were \$4-\$8 in 2009-2014, shrinking to \$2.25 in 2016, and \$0.8 in May 2018. The differential is volatile, but in all cases the European market is at a discount to the Asian market, partly due to access to cheaper Norwegian and Russian pipeline natural gas. This puts a project on the East coast at a comparative cost disadvantage.

What are the possible ways to bring the supply costs and delivered costs down or gain better value for the product for East Coast LNG projects? CERI has considered the following:

1. Government

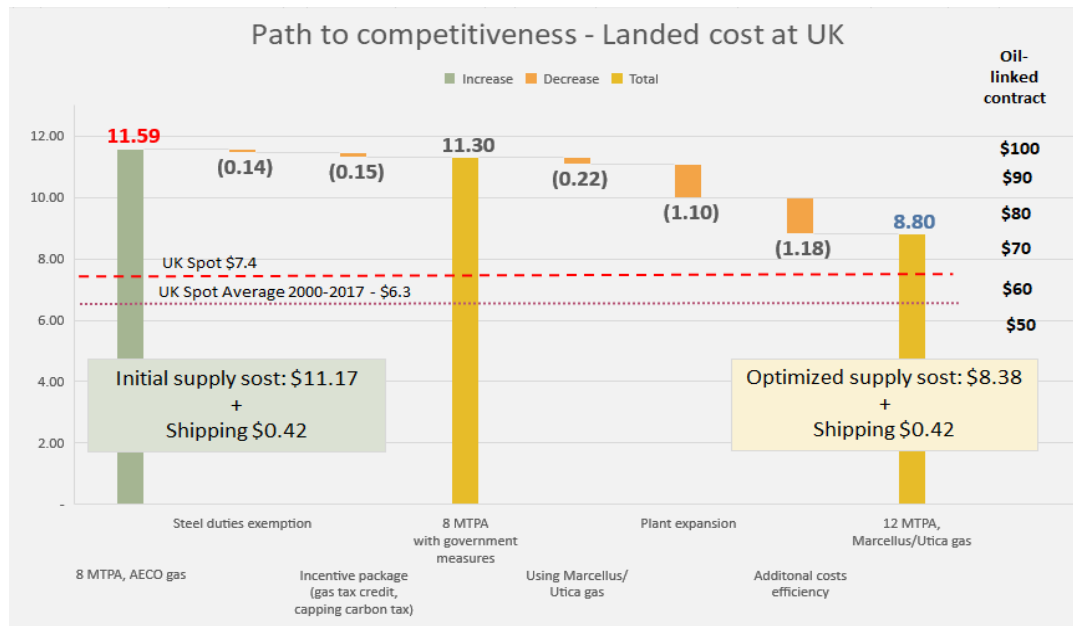
- a. Exempt LNG projects from fabricated steel duties and countervailing duties on the imported LNG modules (similar to Western Canada LNG)
- b. Introduce additional incentives

2. LNG project

- a. Expand the plant to exploit economies of scale
- b. Seek additional savings in the transportation and natural gas costs
- c. Seek better LNG sales contract options

The effects of some of these measures are illustrated in Figure 4.9.

Figure 4.9: Path to Competitiveness for Eastern Canada LNG



Overall, if all measures are applied, an LNG project landed costs to the UK could be decreased from \$11.59 to \$8.8 per mmbtu delivered cost, or by 25%. The resulting cost is recovered by an LNG project under an oil-linked Brent price of \$77/barrel. The resulting delivered cost is still higher than the spot price at the time of writing, but it is \$2 lower than the maximum observed in the UK (in 2008).

Fabricated steel duties. The federal government decision to exempt LNG projects in Canada from the fabricated steel duties and countervailing duties onto the imported LNG modules steel structure could allow a project to decrease capital costs by 4.4% and save \$358.7 million in duties. The value of the frames onto which the fabricated steel duty is levied is estimated at US\$0.58 billion.

CERI modelling shows that the exemption by the federal government would equal \$0.14 per mmbtu in additional cost competitiveness.

Additional provincial incentives. Nova Scotia incentives are assumed to be built similar to those in BC. Specifically, the provincial tax credit in the amount of 3% (similar in nature to the BC Natural Gas Tax Credit) and capping carbon tax at \$30 for the life of the project. The effect of these measures is \$0.15 per mmbtu.

Additional federal incentives. CERI has analyzed the impact on the supply cost if the capital allowance was increased to 100% (similar to the current US approach). The result was found to be minimal – around 1 cent per mmbtu. This is explained by the fact that capital allowance of 25.8% used in the study grows the depreciation pool faster than the growth of operating income

offset. Thus, if the 100% rate is used, the effect is almost the same as for 25.8%. With 100%, the project starts to pay corporate tax one year later, which has a minimal effect.¹

This conclusion holds true only if ring-fencing is applied to an LNG project. It means that a proponent cannot use an allowance generated from LNG capital costs towards other income. If ring-fencing is removed, the higher rate of the allowance is better for project economics. This exemption can be of significance to make a project more cost-competitive.

It should be noted that an LNG project can take a long time to build and first revenues are not generally seen until the 6th year after the project construction start, and could be more than 10+ years after the project start. Thus, using these capital allowances against other income earlier than the end of construction can improve the supply cost of a project. For an integrated project, such revenue can come from the natural gas from a pool of pre-drilled gas wells to supply LNG (it is not feasible to drill all wells one year before the LNG commissioning).

As the revenues from upstream have not been modelled for the study, CERI has not measured the effect of removing ring-fencing on the project economics.

Using US Marcellus/Utica gas. Being closer to Nova Scotia, sourcing gas from Marcellus and Utica shale gas saves project costs. The total effect of using US gas rather than AECO is \$0.22 per mmbtu; it comes from a shorter distance.

Plant expansion. Similar to the projects in British Columbia, a larger upside in economics is usually sought through the expansion of an LNG plant. In the case of Eastern Canada LNG, we assume an expansion from 8 to 12 mtpa (50%), while capital cost increases by 31.5%. The effect of such an expansion is \$1.11 per mmbtu in improved cost-competitiveness. It comes from savings on capital costs per mmbtu (\$0.3) and corporate taxes (\$0.05); the largest savings is driven by the more efficient use of the pipeline due to increased throughput (\$0.73).

Additional cost efficiency. Each project has its specific areas for improving efficiency as well as areas where most risks of going overbudget come from. Since natural gas and transportation costs are the largest components of the supply cost (64%), CERI has assumed that a project located in Nova Scotia could increase efficiencies in these areas.

Natural gas price is modelled to decrease by 5% based on the assumption that a project is successful in executing contracts with gas suppliers realizing a price discount for a large volume.

At the same time, if more than one LNG project uses a dedicated pipeline, then a toll is split between the customers across a larger volume. In addition to a pipeline capacity of 1.7 bcf/d used for a 12 mtpa project, another 0.7 bcf/d is assumed to be transmitted for another LNG

¹ For the US, the change of the previous system to 100% allowance has a larger effect – up to 20 cents per mmbtu, as shown in Chapter 3. This is because the former US system was closer to a straight-line method than to a declining balance.

project, and the toll is split proportionally to the throughput. Transportation costs are assumed to decrease by 10%.

Overall, these three measures could reduce supply cost by another \$1.18 (84% of the decrease is due to transportation).

Seek better LNG sales contract options. European natural gas and LNG prices are set by reference to oil, oil products and other alternative fuels. For contract-based supply, the weighting factors and prices are, as a rule, multiplied by the original negotiated price. Most European contracts do not have S-curves, but many have floor prices. If an LNG plant is successful in negotiating a better initial price and floor price, it can influence its profitability in a positive way.

Optimized Supply Costs for Locally-sourced Gas

Application of similar measures (except for pipeline sharing and cost of transportation) to the project with locally-sourced gas reduces landed costs from \$8.5 to \$7.35, making such an option viable under current spot prices, while still short of the historical average of \$6.3.

Comparative Perspective and Other Important Factors

This section provides a comparative perspective of key findings, assumptions, and actual data.

Table 4.1: Comparative Perspective on LNG Projects

| | Western Canada, BC | Eastern Canada, NS | Eastern Canada, NS | GoM, Louisiana, Brownfield | GoM, Texas, Greenfield | Australia, Queensland |
|--|------------------------|-------------------------------|---------------------------|----------------------------------|-------------------------------|--------------------------|
| Project specific | Initial / Optimized | Initial / Optimized | Initial / Optimized | | | |
| MTPA | 13 / 26 | 8 / 12 | 8 / 12 | 15 | 9 | 8.5 |
| Source of gas: | Montney, BC | AECO / Marcellus, Utica | Horton Bluff Shale, NS | Henry Hub-linked | Henry Hub-linked | CSG |
| Capital cost, \$ / tpa | 1,204 / 1,010 | 1,006 / 844 | 1,006 / 844 | 667 | 1,028 | 2,091 |
| Total supply cost | 8.35 / 6.91 | 11.17 / 8.38 | 8.09 / 6.93 | 7.7 | 9.07 | 13.06 |
| Cost of gas, \$ / mmbtu | 2.51 / 2.28 | 3.67 / 3.5 | 3.44 / 3.27 | 4.52 | 4.52 | 4.8 |
| Landed costs, \$ / mmbtu | Asia: 8.99 / 7.55 | Europe: 11.59 / 8.8 | 8.5 / 7.35 | Europe: 8.4 Asia: 9.33 | Europe: 9.8 Asia: 10.71 | Asia: 13.6 |
| Spot price, early May 2018 | Asia: 8.2 | Europe: 7.4 | Europe: 7.4 | Europe: 7.4 Asia: 8.2 | Europe: 7.4 Asia: 8.2 | Asia: 8.2 |
| Needed oil price under 11.5% of Brent contract to break-even (optimized) | \$65 | 77\$ | \$64 | - | - | - |
| Region specific | | | | | | |
| Area | Remote | Industrial | Industrial | Industrial | Industrial | Remote |
| Need for a dedicated pipeline | Yes | Yes | Yes | No | No | Yes |
| Liquids rich gas | Yes | No | No | No | No | No |
| Domestic experience in LNG | No | No | No | Yes | Yes | Yes |
| Shipping to Europe (UK), \$/mmbtu | 1.56 | 0.42 | 0.42 | 0.75 | 0.73 | 1.84 |
| Shipping to Asia (Japan) | 0.64 | 1.76 | 1.76 | 1.64 | 1.63 | 0.58 |
| Fiscal and incentives | | | | | | |
| Total taxes, \$ (% of supply cost) | 9% | 6% | 6% | 4% | 4% | 9% |

| | | | | | | |
|---|---|---|---|---|---|-------|
| Corporate taxes | 26% (with gas tax credit – up to 23%) (27% from 2018) | 31% / 28% | 31% / 28 % | 21% | 29% | 30% |
| Capital cost allowance | 25.8% | 25.8% | 25.8% | 100% | 100% | 13.3% |
| Other specific taxation | Carbon tax LNG Income Tax (removed) | Carbon tax | Carbon tax | 0.8% Franchise tax | | |
| Effect of selected incentives on corporate taxes | -0.25/ mmbtu (BC Package) Exemption from steel duties - 0.17/mmbtu | Exemption from steel duties - 0.14/mmbtu | Exemption from steel duties - 0.14/mmbtu | -0.52/ Mmbtu (tax law change effective 2018) | -0.44/ mmbtu (tax law change effective 2018) | |

Potential Economic Impacts of LNG Projects

LNG projects are capital-intensive projects which have long value chains starting from upstream drilling and processing of natural gas, midstream transportation, liquefying natural gas and exporting. All these activities include large-scale construction during the build-up phase as well as operation and maintenance for 30+ years of plant life. Drilling of wells which support a plant is usually ongoing for the entire life of a project.

As such, the LNG projects have significant impacts on a country's GDP, taxes and employment. The scale of these impacts is dependent on many variables including the scale of the project (capital costs), the scope of construction, the volume of materials, services and labour attracted domestically and abroad, level operating costs, taxation regime and others.

The summary of the economic benefits (based on (BC EAO 2015)) that would be generated from a proposed project in BC is based on capital expenditures between \$10.4 and \$16.6 billion in Canada, representing 46% of total capital costs, of which up to \$7.1 billion would be spent in BC. The contribution to BC GDP varies from \$3.7 to \$6 billion dollars.

For the initial 13 mtpa project, the proponent estimates that construction to full build-out would directly create 16,686 person-years (PYs) of employment in Canada, while the expanded variant would require 29,200 PYs of employment in Canada, including 10,950 PYs of work for BC residents. According to the company, 10% of the direct construction workforce would be hired locally, 20% from other parts of BC, 50% from other parts of Canada and 20% from abroad.

During operations, an LNG facility would require 705 total direct jobs, while the expanded plant would require 1,342 direct jobs. Total direct, indirect and induced full-time equivalent jobs range from 19.6 thousand to 38.5 thousand people across Canada for initial and full build-out, respectively.

It should be noted that the estimate of induced labour impacts is uncertain as is the concept. The ability to attach benefits to the general economy of individual projects amidst all other activities is problematic.

In Nova Scotia, our reference case LNG plant has the potential to provide significant economic benefits including (based on (Nova Scotia Environment 2009):

- 45 to 70 permanent direct jobs (during operation)
- 175 permanent indirect jobs
- 600 to 700 construction jobs

For Canada, the total contribution to GDP is estimated at \$4.2 billion, with the majority in Nova Scotia (\$3.06 billion).

Cooperation with Indigenous Peoples on LNG Developments

This section presents a review of the current state of the relationship between the province of British Columbia, proponents of large energy projects (including LNG and natural gas transmission projects) and Indigenous Peoples. The section is based on information from CERI Study 161 “Risk Analysis of British Columbia Natural Gas Projects: Environmental and Indigenous Peoples Issues.” All information presented below is current as of November 2016 unless otherwise stated.

Understanding of Aboriginal and treaty legal rights issues is fundamental to the potential success of a proposed natural gas pipeline and LNG projects in British Columbia. A failure to understand these issues can affect the progress or even the regulatory approval of a natural gas pipeline or LNG project.

Consultation with Indigenous Peoples is not intended to prove or reject claimed Aboriginal rights or title since they can only be declared by the courts or agreed to in a government-to-government document like a treaty. The courts have repeatedly encouraged the resolution of Indigenous issues by negotiation rather than litigation, which is a costlier, adversarial and time-consuming way to address outstanding Indigenous issues.

While the duty to consult Indigenous Groups rests with the Crown, the Crown, as represented by the regulatory authorities, can assign certain procedural aspects of consultation to proponents. Industry must contact, involve and reach agreements with Indigenous Peoples prior to commencing any operations in their traditional lands. The engagement of Indigenous Peoples by proponents needs to start as early as possible, prior to the exploration phase and continue

throughout the lifecycle of the project, including construction, operations, decommissioning and abandonment.

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.

However, by entering into impact benefit agreements, Indigenous Groups are not waiving their right to review, comment and approve, any environmental studies, permit applications or environmental monitoring regimes related to the project.

The importance of achieving and maintaining positive relationships with Indigenous Groups potentially affected by a proposed project cannot be stressed enough. Effective consultation and engagement with Indigenous Groups are one of the most critical factors for the success of the project.

Treaties and other agreements can be considered as important tools for Indigenous Peoples to build sustainable, healthy and resilient communities. The agreements can help establish effective relationships with Indigenous Peoples, address concerns associated with developments in their traditional territories, or resolve conflicts. Types of agreements with Indigenous Groups negotiated within the Province to date are as follows (BC MARR 2016a):

- Treaties (including Final Agreements, Agreements-in-Principle and Incremental Treaty Agreements);
- Reconciliation Agreements (including Accords and MOUs);
- Strategic Engagement Agreements;
- Off-Reserve Action Plans;
- Cut-off Claims;
- Economic and Community Development Agreements;
- Atmospheric Benefit Sharing Agreements;
- Revenue Sharing Agreements (including the First Nations Clean Energy Business Fund Revenue Sharing Agreements, Forest Consultation and Revenue Sharing Agreements, etc.);
- Natural Gas Pipeline Benefits Agreements.

Examples of agreements with Indigenous Peoples specific to the natural gas and LNG industry are discussed in detail below.

LNG Environmental Stewardship Initiative

The Liquefied Natural Gas Environmental Stewardship Initiative (LNGESI) is a new form of collaboration between the Province, Indigenous Peoples and the LNG sector that was established in May 2014. As of July 2015, 32 First Nations, the Province and the industry have been working together on the LNGESI. The Initiative is not designed to change or alter the current regulatory

process, but rather to complement the regulatory process. The goal of the LNGESI is to ensure the balance between the environment and economic growth, establish strong environmental legacies related to LNG development and produce high quality, trusted and accessible environmental information. Four key areas included in the scope of the LNGESI are 1) ecosystem assessment and monitoring; 2) ecosystem restoration and enhancement; 3) ecosystem research and knowledge exchange; and 4) stewardship education and training (BC MARR 2014, 2015b, 2016b).

Capacity Building Initiatives

In addition to the LNGESI, the Province is working with Indigenous Peoples on all aspects of LNG opportunities in British Columbia that include skills training, employment, consultation and accommodation work in regulatory decision making, and economic benefits sharing. In 2015, the Province launched a new Aboriginal Skills Training Development Fund that is an investment of up to \$30 million over the next three years for new Aboriginal skills-training projects and partnerships. Up to \$10 million annually in this new funding is intended to support community-based training programs focused mainly on Indigenous Groups that will benefit from the growth of the LNG industry. The overall goal of this program is adding 15,000 more Indigenous workers to the Province's workforce within 10 years (BC MARR 2015a, 2015c). As of June 2016, more than 1,000 Indigenous Peoples have already benefited from the training programs, with 85% graduating and finding a job (Pynn 2016).

Proponents of natural gas pipeline and LNG projects also have the potential to provide important economic opportunities for Indigenous Peoples, including capacity-building initiatives to support employment, contracting and business development. Examples of these initiatives have been specified by the proponents on a number of the reviewed projects and may include the following (BC EAO 2014; BC MARR 2015a, 2015c):

- Building Aboriginal business capacity during pre-construction and construction of proposed projects by designating services to qualified Aboriginal businesses and individuals;
- Providing capacity funding to optimize employment and contracting opportunities;
- Supporting workforce readiness programs focused on transferable skills with various post-secondary institutions including Aboriginal Skills and Employment Training organizations and local colleges;
- Supporting education legacy programs focused on long-term capacity building for Aboriginal and non-Aboriginal communities;
- Partnering with local non-profit organizations to enhance the quality of life in local communities, including training to address barriers to Aboriginal training and employment;
- Providing capacity funding to support meaningful participation in consultation activities with the proponents and the regulatory process.

It is worthwhile noting that there is no legal obligation for proponents to provide capacity funding to Indigenous Groups as part of the consultation process. Nevertheless, proponents often chose to provide funding to help inform the consultation process and to avoid potential impacts on Aboriginal interests from the proposed project. The provincial regulator (BC EAO) encourages proponents to have early discussions with Indigenous Groups and to establish capacity funding agreements. Capacity funding agreements assist Indigenous Groups in participating in the environmental assessment (EA) process in an effective and timely way. These types of agreements should not be confused with any economic benefit agreements (BC EAO 2013).

Economic Benefit Agreements

Natural Gas Pipeline Benefits Agreements (NGPBAs) are agreements between the Government of BC and Indigenous Peoples and are part of the Province's comprehensive approach to partnering with Indigenous Peoples on LNG opportunities (which also includes development skills training and environmental stewardship projects discussed earlier). The purpose of the NGPBAs is to provide financial benefits to the participating Indigenous Groups and to secure their support regarding the proposed natural gas pipeline projects (BC MARR 2016c).

Economic benefit agreements are not legally required and must be kept separate and distinct from the duty to consult. The fact that Indigenous Peoples may have signed an Impact Benefit Agreement (IBA) for a project does not relieve the Crown of its duty to consult and accommodate Aboriginal interests. By entering into IBAs, Indigenous Peoples are not waiving their right to review, comment and approve, any environmental studies, permit applications or environmental monitoring regimes related to the project (McCarthy Tétrault LLP 2016; McMillan LLP 2011).

According to the BC MARR, as of June 2016, approximately 90% of the Indigenous Groups with proposed natural gas pipelines through their traditional territories have indicated their support through one or more pipeline benefit agreements. Throughout British Columbia, 62 NGPBAs have been reached with 29 of 32 eligible First Nations for four proposed natural gas pipelines – the Prince Rupert Gas Transmission, Coastal GasLink, Westcoast Connector Gas Transmission, and Pacific Trail Pipeline. According to the Province, 16 out of 19 Indigenous Groups that must be consulted along the Prince Rupert Gas Transmission Project route have signed benefit agreements; the Province has been in discussions with the three remaining Indigenous Groups (Hoekstra 2016). For the Pacific Trail Pipeline Project, all 16 Indigenous Groups located along the proposed pipeline route have indicated their support for the project (BC MARR 2015c; Pynn 2016).

Natural Gas Pipeline Benefit Agreements

Analysis of 24 NGPBAs for the Coastal GasLink Pipeline, Prince Rupert Gas Transmission and Westcoast Connector Gas Transmission Projects publicly available on the BC MARR's website shows that the Province will share financial benefits associated with the development of the proposed natural gas pipeline projects with the potentially impacted Indigenous Groups, including the following types of payment for each individual agreement:

- 1) Project payments specific for each individual NGPBA that will be provided by the Province to the participating First Nations in two installments, including:
 - a) an initial payment within 90 days of the material commencement of the natural gas pipeline project construction, and
 - b) a final payment within 90 days after the in-service date of the natural gas pipeline project.
- 2) Additional payments are specific to each individual NGPBA that usually represent 10%, 15% or 20% of the project payment. They will be provided to the participating First Nations within 90 days after the effective date of the agreement.
- 3) Ongoing benefits that are not project- or agreement-specific. The Province will provide the ongoing benefits of \$10,000,000 per year for each of the three major natural gas pipeline projects, commencing on the first anniversary of the in-service date for the natural gas pipeline project and continuing annually for as long as the project is making natural gas deliveries to an LNG facility. The ongoing benefits will be shared between eligible First Nations that should attempt to reach unanimous agreement on the allocation of the ongoing benefits.

Details of the reviewed NGPBAs are presented in Table 4.2.

First Nations Limited Partnership Agreement

The First Nations Limited Partnership (FNLP) Agreement announced February 26, 2013, is a benefit agreement between Chevron, Woodside (as the Apache successor) and all 16 First Nation bands whose territories are located along the proposed route of the Pacific Trail Pipeline Project from Summit Lake to Kitimat. This agreement is unique among any pipelines in Western Canada since the Pacific Trail Pipeline Project is the first proposed natural gas pipeline related to LNG in British Columbia with the support of all directly affected First Nations (BC MARR 2015c; Chevron Canada 2016).

The FNLP Agreement includes up to \$550 million in commercial benefits (up to \$200 million in direct financial benefits) over the life of the Pacific Trail Pipeline Project, including a recently enhanced benefit of \$10 million a year operating life of the project from the Province of BC. In addition, the agreement will also provide substantial business and training opportunities for the involved First Nations.

To date, over 1,600 FNLP members receive skills training through the Pacific Trail Pipeline's Aboriginal Skills to Employment Partnership; over 900 of these trainees have found jobs. First Nations employment currently accounts for 64% of all early works construction workforce hours on this project. To date, FNLP members have also been awarded over \$245 million in the Pacific Trail Pipeline's construction contracts, and over 65% of construction contract expenditures have been made to member First Nation businesses (Chevron Canada 2016; Rowland 2015).

Coastal First Nations Liquefied Natural Gas Benefits Agreement

The purpose of the Coastal First Nations Liquefied Natural Gas Benefits Agreement (LNGBA) signed in January 2016 is to enable the Province, the Great Bear Initiative (GBI) Society and GBI Member Nations to share in the benefits associated with the development of an LNG industry on the north coast of British Columbia. As stated in the Agreement, it applies to all LNG projects within the Coastal First Nations territory, and currently includes 10 proposed LNG projects. The Province will make payments to the GBI on behalf of GBI Member Nations (there are currently 9 GBI Member Nations – signatories of the LNGBA) as follows (BC MARR and GBI Society 2016):

1) Base funding, including:

- Initial base payment in the amount of \$4,500,000;
- Ongoing base funding consisting of a one-time payment of \$750,000 and ongoing annual payments of \$1,500,000 that will be provided by the Province if the proponent of an LNG project makes a final investment decision (FID) before March 31, 2018;
- The obligation to provide base funding is only triggered on a one-time basis, and it is not provided for each LNG project.

2) Incremental project funding, including:

- FID payments for each LNG project where an FID has been announced that will be provided by the Province to the GBI annually until the in-service date is reached, in an amount that depends on *estimated* LNG production;
- In-service payments for each LNG project that is commissioned and begins producing LNG that will be provided by the Province to the GBI annually in an amount that depends on *actual* LNG production;
- LNG expansion payments (if an LNG project expands its LNG production capacity) that will be added by the Province to each annual in-service payment, until the LNG project expansion date is reached, in an amount that depends on estimated *additional* LNG production. The Province will not continue to provide LNG expansion payments for an LNG project once the LNG project expansion for that project is reached.

Table 4.2: Summary of Financial Benefits from Natural Gas Pipeline Benefit Agreements Between the Government of British Columbia and Indigenous Groups Potentially Impacted by the Proposed Natural Gas Pipeline Projects

| Indigenous Group - Participant of Natural Gas Pipeline Benefits Agreement | Indigenous Group Population | Coastal GasLink Pipeline Project | | Prince Rupert Gas Transmission Project | | Westcoast Connector Gas Transmission Project | |
|---|-----------------------------|----------------------------------|------------------------|--|------------------------|--|------------------------|
| | | Project Payment, \$ | Additional Payment, \$ | Project Payment, \$ | Additional Payment, \$ | Project Payment, \$ | Additional Payment, \$ |
| Doig River First Nation | 303 | \$1,170,000 | 175,500 | 1,120,000 ^a | 168,000 | – | – |
| Gitanyow Nation | 846 | – | – | 1,150,000 ^a | 230,000 | 1,130,000 ^b | 226,000 |
| Gitxaala Nation | 1,916 | – | – | 1,540,000 | 308,000 | 1,640,000 ^b | 328,000 |
| Halfway River First Nation | 277 | 2,030,000 | 406,000 | 1,680,000 ^a | 336,000 | – | – |
| Kitselas First Nation | 655 | 1,150,000 | 230,000 | 1,760,000 ^a | 352,000 | 1,590,000 ^b | 318,000 |
| Lake Babine Nation | 2,488 | – | – | 3,240,000 | 324,000 | – | – |
| Lheidli T'enneh | 419 | 1,240,000 | 248,000 | – | – | – | – |
| McLeod Lake Indian Band | 551 | 3,380,000 | 338,000 | 2,950,000 ^a | 295,000 | – | – |
| Metlakatla First Nation | 905 | – | – | 2,150,000 ^a | 430,000 | 1,950,000 ^b | 390,000 |
| Moricietown Band | 2,039 | 4,990,000 | 998,000 | – | – | – | – |
| Nee-Tahi-Buhn Indian Band | 149 | 2,100,000 ^c | 420,000 | – | – | – | – |
| Nisga'a Nation | 6,034 | – | – | 5,070,000 | 1,014,000 | – | – |
| Skin Tyee First Nation | 182 | 2,330,000 ^c | 466,000 | – | – | – | – |
| Tl'azt'en Nation | 1,777 | – | – | 2,160,000 | 324,000 | – | – |
| West Moberly First Nations | 290 | 2,010,000 | 201,000 | – | – | – | – |
| Wet'suwet'en First Nation | 246 | 2,320,000 ^c | 464,000 | – | – | – | – |
| Yekooche First Nation | 235 | 390,000 | 78,000 | 390,000 | 78,000 | – | – |
| Total Payment (Per Project), \$: | | 23,110,000 | 4,024,500 | 23,210,000 | 3,859,000 | 6,310,000 | 1,262,000 |

Data Sources: (BC MARR 2016c; BC MARR and Doig River First Nation 2015a, 2015b, BC MARR and Gitanyow Nation 2015a, 2015b, BC MARR and Gitxaala Nation 2015a, 2015b, BC MARR and Halfway River First Nation 2014a, 2014b; BC MARR and Kitselas First Nation 2014; BC MARR and Lake Babine Nation 2015; BC MARR and Lheidli T'enneh 2014; BC MARR and McLeod Lake Indian Band 2015a, 2015b, BC MARR and Metlakatla First Nation 2014a, 2014b; BC MARR and Moricietown Band 2015; BC MARR and Nee-Tahi-Buhn Indian Band 2014; BC MARR and Nisga'a Nation 2014; BC MARR and Skin Tyee First Nation 2014; BC MARR and Tl'azt'en Nation 2015; BC MARR and West Moberly First Nations 2015; BC MARR and Wet'suwet'en First Nation 2014; BC MARR and Yekooche First Nation 2014a, 2014b; BC MARR n.d.). Table created by CERL.

Notes:

^a Where a portion of the Prince Rupert Gas Transmission Project is constructed within 70 m of the centreline of the Westcoast Connector Gas Transmission Project, the Province at its sole discretion may reduce the project payment. For details, please refer to (BC MARR and Doig River First Nation 2015b; BC MARR and Gitanyow Nation 2015a; BC MARR and Halfway River First Nation 2014b; BC MARR and Kitselas First Nation 2014; BC MARR and McLeod Lake Indian Band 2015b; BC MARR and Metlakatla First Nation 2014a).

^b Where a portion of the Westcoast Connector Gas Transmission Project is constructed within 70 m of the centreline of the Prince Rupert Gas Transmission Project, the Province at its sole discretion may reduce the project payment. For details, please refer to (BC MARR and Gitanyow Nation 2015b; BC MARR and Gitxaala Nation 2015b; BC MARR and Kitselas First Nation 2014; BC MARR and Metlakatla First Nation 2014b).

^c Where a portion of the Coastal GasLink Pipeline is constructed within 70 m of the centreline of the Pacific Trails Pipeline Project, the Province at its sole discretion may reduce the project payment. For details, please refer to (BC MARR and Nee-Tahi-Buhn Indian Band 2014; BC MARR and Skin Tyee First Nation 2014; BC MARR and Wet'suwet'en First Nation 2014).

Other Examples of Economic Benefit Agreements

The LNG Canada Export Terminal and Kitimat LNG Terminal projects have also obtained the support of the Haisla Nation, whose traditional territory LNG terminals would be built on (Hoekstra 2016).

There is also ongoing engagement and negotiation on natural gas exploration, development and production between the Province and the Treaty 8 First Nations. As of April 2014, four economic benefit agreements were completed, and others were being worked on (Province of BC 2014).

Revenue Sharing Agreements

The Government of BC is working with Indigenous Groups to provide benefit-sharing opportunities in regard to land and resource management. The revenue sharing agreements with Lax Kw'alaams and Metlakatla First Nations signed in 2014 share a portion of Provincial Government revenues from sole proponent agreements related to the Grassy Point lands and the proponents Aurora LNG (Aurora LNG Digby Island Project) and Woodside Energy (Grassy Point LNG Project). The sole proponent agreements give the proponents the exclusive right to proceed with activities to inform planning for LNG development (Province of BC 2014).

By signing these revenue sharing agreements, Lax Kw'alaams and Metlakatla First Nations demonstrate their support for prospective LNG development at Grassy Point. These two reconciliation agreements are the fifth and sixth of the ten new non-treaty agreements that the Province has committed to reaching within two years. They are also the 23rd and 24th economic benefit agreements reached with Indigenous Peoples since 2011 when the BC Jobs Plan was launched (Province of BC 2014).

Chapter 5: Conclusion

Global natural gas consumption is positioned to grow by 45% over the next 25 years. Developing countries in Asia, Africa, Latin America, and the Middle East account for 80% of the increase in global consumption.

In 2016, total global natural gas pipeline trade was 737.5 bcm while LNG trade was 346.6 bcm. LNG accounts for 32 percent of globally traded gas and this number is expected to grow. According to BP, global LNG is growing seven times faster than pipeline gas trade and, by 2035, half of all globally traded gas will be LNG; 60% by 2040.

Canada has world-class proven low-cost natural gas reserves sufficient for domestic demand and export. It also has 15+ projects on both coasts, four of which have received export licenses and environmental approvals and are close to FID (in addition to 0.3 bcf/d Woodfibre LNG, which has already taken a FID).

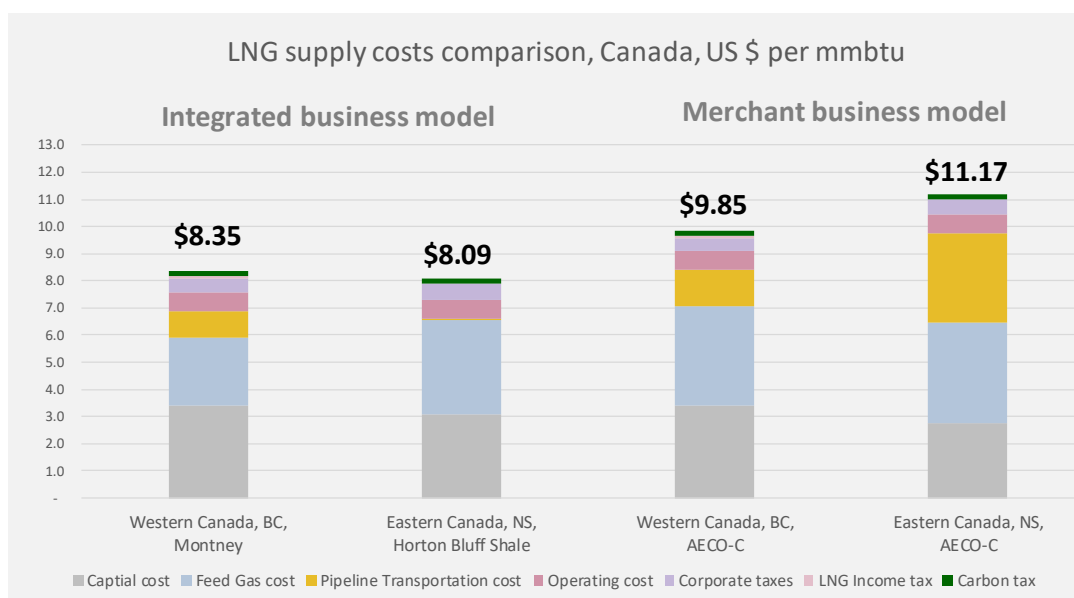
Will Canada play a role in satisfying natural gas demand growth in the world and join the cohort of 18 export countries?

The study focused on examining Western and Eastern Canada LNG supply costs and competitiveness factors in comparison with the US Gulf of Mexico and Australia. The study assessed key elements of supply costs and competitiveness of LNG projects. The elements included capital costs, operating costs, taxes (including a carbon tax), natural gas costs and gas transportation costs to LNG plants as well as cost drivers and specifics of each jurisdiction, e.g., temperature, need for a dedicated pipeline, and experience in delivering LNG projects. Further, the paper presents ways to improve cost-competitiveness of Canadian LNG projects and compares LNG landed costs at European and Asian markets with current and historical market prices.

Below are the five questions and the findings that the study revealed. **Note that the answers to the first four questions show non-optimized supply costs, meaning that these FOB costs should be expected if no additional actions are taken by governments or proponents to improve costs. The conclusions based on the improved competitiveness are shown in the last question.**

- **What are the supply costs of greenfield Canadian LNG projects on the East and West Coasts?**

The FOB supply costs of projects are shown in Figure 5.1. Note that these are unoptimized supply costs. Such improvements are modelled by CERI and reviewed in the last question.

Figure 5.1: Canadian LNG Project Costs

For integrated projects, Eastern Canada projects hold a slight advantage of \$0.36 having an \$8.09 FOB cost per mmbtu compared to over \$8.35 for Western Canada. The difference is explained by \$1.22 associated with total capital and transportation costs as the gas resource is half the distance to the project and the terrain is flat compared to the west. British Columbia's project, on the other hand, edges Nova Scotia's on natural gas cost by \$0.93.

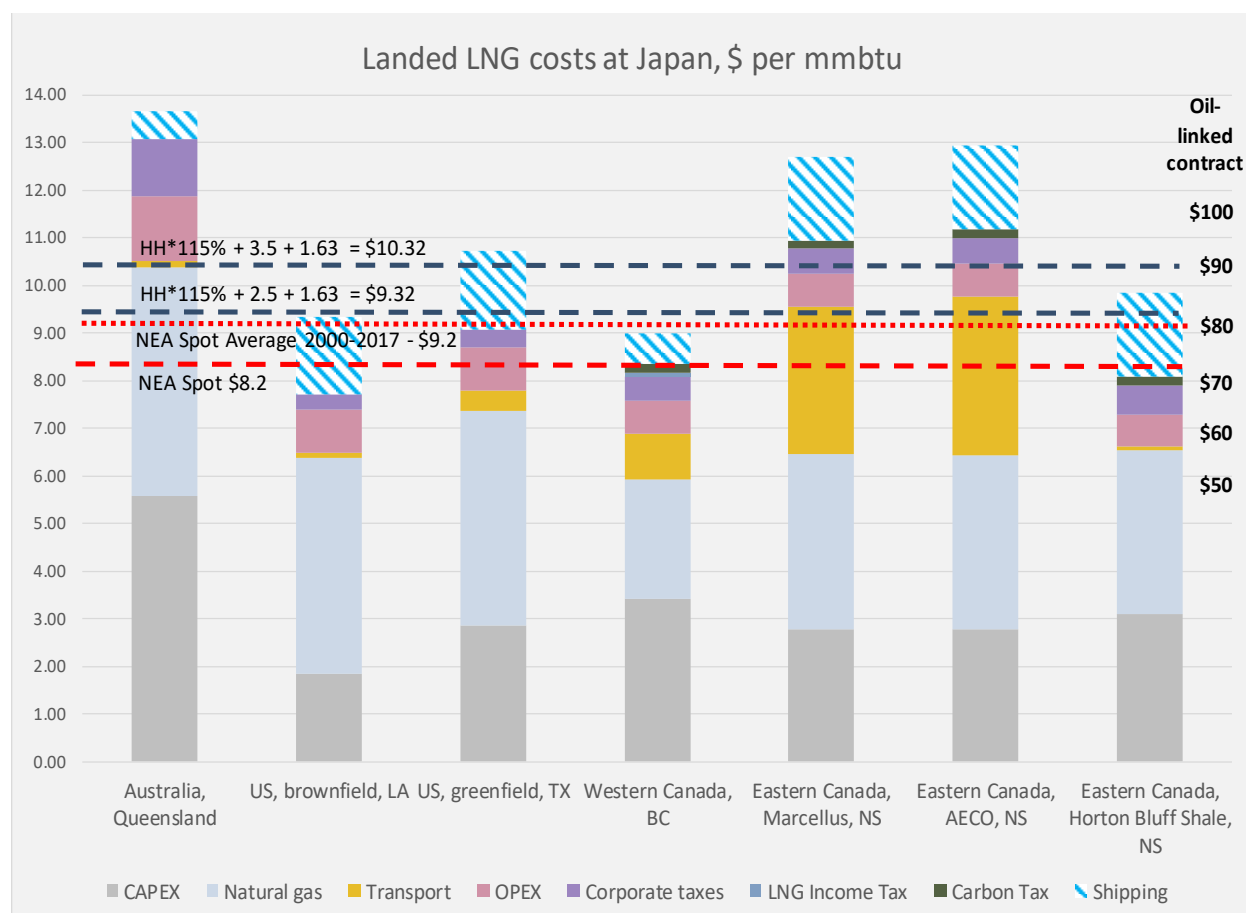
If a merchant model is used (sourced from AECO-C), the Western Canada LNG gains \$1.32 total advantage over the Eastern counterpart due to its proximity to AECO-C hub. Location advantage translates to cheaper gas transportation by almost \$2, while capital costs are better by \$0.65 in the east. If the gas is sourced from Marcellus for the Eastern project, British Columbia's LNG plant still has cheaper supply costs, though the difference reduces to \$1.1 (Marcellus gas-sourced project is \$10.95).

- How cost-competitive are greenfield Canadian LNG projects compared to greenfield and brownfield projects in the US Gulf of Mexico and Australia at European and Asian markets?

Asian Markets

Figure 5.2 shows the landed costs at Japan, the current spot price of LNG (\$8.2 – early May 2018), the average spot price for 2000-2017 (\$9.2), Henry Hub-linked price of LNG at Japan, and oil-linked contract price levels (11.5% of Brent). The comparison is made in Japan. However, the results apply to the entire northeast Asia market.

Figure 5.2: Cost Competitive Analysis Landed at Japan

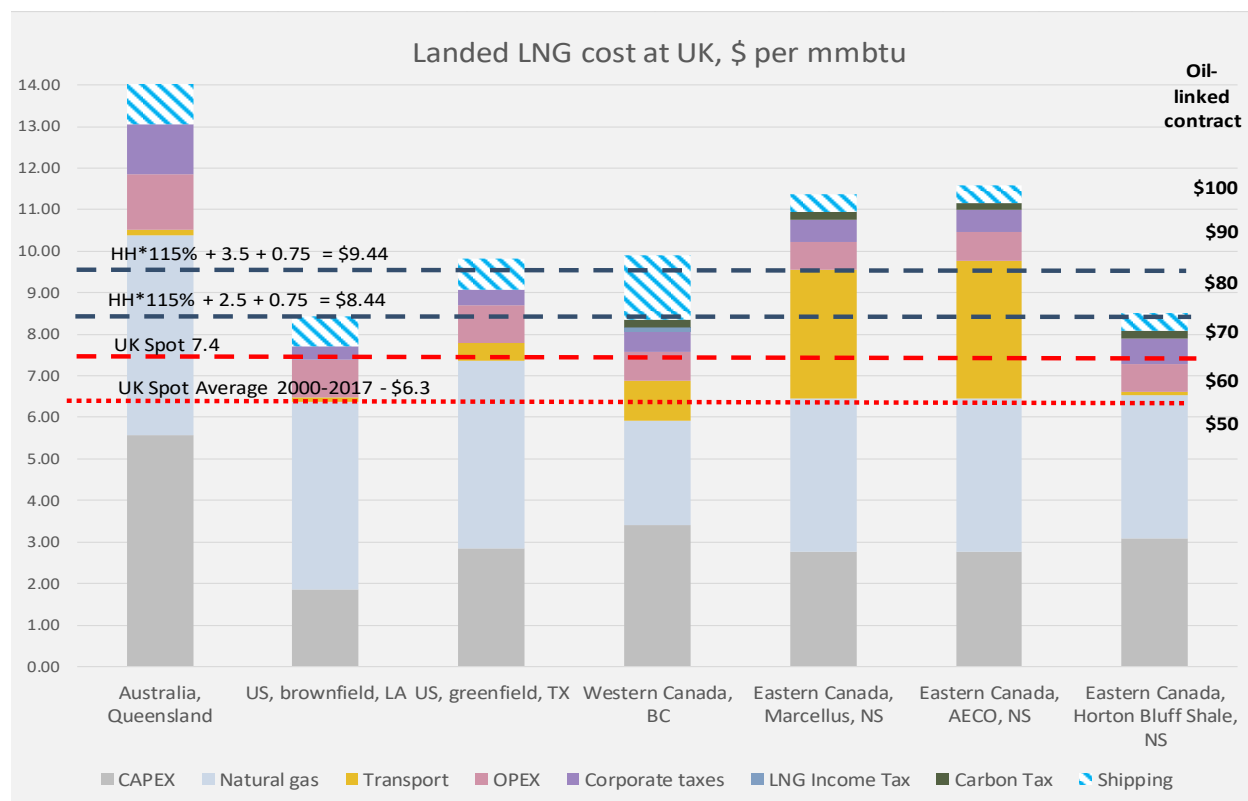


1. **Without additional efforts to decrease supply costs, Western Canada and Eastern Canada LNG landed costs are more expensive than the current spot price in Japan.** The difference between Western Canada LNG landed costs and spot price is \$0.80 at the time of writing. At the same time, the landed cost is below the historical average of \$9.2. Also, a Western Canada LNG project will need an oil price of approximately \$80 or higher over the life of the project to break-even under long-term LNG contracts.
2. **Western Canada LNG has an overall landed cost advantage over US GoM projects by \$1.7 (US greenfield) and by \$0.3 (US brownfield) due to cheaper shipping (by \$1) and cheaper natural gas from the LNG project's own upstream production (by \$2).** At the same time, **total liquefaction costs (except for natural gas) are better by \$0.7-\$0.8 for the GoM than for Western Canada**, meaning that it is more expensive to conduct LNG business in Canada than in the US.
3. While US projects are not competitive at the spot market with current prices, they break-even under the Henry Hub formula LNG pricing contracts.

European Markets

Figure 5.3 shows the landed costs in the UK, the current spot price of LNG (\$7.4 – early May 2018), the average spot price for 2000-2017 (\$6.3), the Henry Hub-linked price of LNG in the UK, and for the reference oil-linked contract price levels (11.5% of Brent).

Figure 5.3: Cost Competitiveness Analysis Landed at the UK



1. **Without additional efforts to decrease supply costs, Eastern Canada and Western Canada LNG landed costs are more expensive than the current spot price in the UK.** The difference between Western Canada LNG and spot price is \$2.5 per mmbtu, while for Eastern Canada LNG with Marcellus and AECO-sourced gas is \$4-\$4.2, respectively. The closest supply cost to the market price is a local gas-sourced case with a \$1.1 differential to the market. An Eastern Canada LNG project will need an oil price of approximately \$100 over the life of the project to break-even under long-term oil-linked LNG contracts
2. **US GoM projects hold a landed cost advantage over Marcellus gas-sourced Eastern Canada LNG at the European market by \$1.5 (US greenfield) and by \$2.9 (US brownfield)** primarily due to cheaper gas pipeline transportation and lower taxes. **Total liquefaction costs (except for natural gas) are better by \$2.8-\$3.0 for the GoM than for Eastern Canada,** meaning that it is more expensive to conduct LNG business in Canada than in the GoM.

3. While US projects are not competitive at the spot market with current prices, they break-even under the Henry Hub formula LNG pricing contracts.

With regard to Australia, both Western and Eastern Canada LNG projects are more competitive than coal seam gas-sourced LNG plants. Eastern Canada LNG edges Australia by \$3.9 per mmbtu in the European market, while Western Canada LNG is better than Australia by \$4.7 per mmbtu in the Asia market.

- **What should the LNG price be in Asian and European markets for LNG projects in Canada to break-even and how does the required price correspond with existing market realities?**

Without additional efforts to decrease supply costs, the Western Canada LNG will need over the life of the project:

- A market price of \$8.99 per mmbtu or higher at northeast Asia to break-even at spot market (historical average for the last two years is \$9.2).
- An oil price of approximately \$80 or higher to break-even under long-term LNG contracts.

Without additional efforts to decrease supply costs, the Eastern Canada LNG will need over the life of the project:

- A market price of \$11.6 (AECO-C gas) or \$11.4 (Marcellus gas) per mmbtu or higher in the European market to break-even in the spot market (historical average for the last two years in the UK is \$6.3).
 - An oil price of approximately \$100 or higher to break-even under long-term LNG contracts.
- **What are the advantages and disadvantages of Canadian jurisdictions in comparison to the US Gulf of Mexico and Australia jurisdictions?**

The comparative perspective of the jurisdictions with a focus on costs is presented in Table 5.1. The two least cost options are marked in green, and the others are shown as an increased % of the least cost value. The same comparison in dollar amounts can be found in Appendix D.

Table 5.1: Jurisdictional Comparison of Non-Optimized LNG Supply Cost (\$ per mmbtu)

| | Western Canada | Eastern Canada AECO-C/local gas | US GoM (greenfield) | Australia |
|--|-----------------------|--|--------------------------------|------------------|
| Supply cost (non-optimized) | \$8.35 | \$11.17 / \$8.09 | \$9.07 | \$13.06 |
| Natural gas cost | \$2.51 | +47% / +37% | +80% | +92% |
| Capital cost / tpa | +23% | \$2.77 / +12% | +3% | +102% |
| Operating cost | \$0.69 | \$0.69 | +33% | +96% |
| Natural gas transportation cost *** | \$0.96 | \$3.33 / \$0.07** | \$0.42 | 0.14** |
| Shipping to Europe | +270% | \$0.42 | +79% | +338% |
| Shipping to Asia | +9% | +201% | +181% | \$0.58 |
| Tax burden | +112% | +96% / +118% | \$0.37 | +228% |
| Capital allowances | 25.8%* | 25.8%* | 100% | 13.3% |

* A 25.8% yield produces an almost identical result as a 100% allowance if ring-fencing is not removed; if ring-fencing is removed, the capital allowance rate of US GoM becomes superior compared to Canada.

** These costs represent only operating costs of transportation, unlike for other jurisdictions.

*** Natural gas transportation costs are only shown in absolute dollar amounts as for some cases they represent only operating transmission costs (because a pipeline is part of the LNG project), while in other cases they represent full gas transportation cost (toll).

The major advantages for Canada and specifically British Columbia are low-cost natural gas, competitive operating costs, competitive capital allowance legislation, and a short distance to the Asia markets. Disadvantages include the remote area which translates into higher capital cost plus additional taxes (carbon tax and LNG Income tax). However, the recent incentive package by the BC Government will lower the tax disadvantage; the effect is included in the last question.

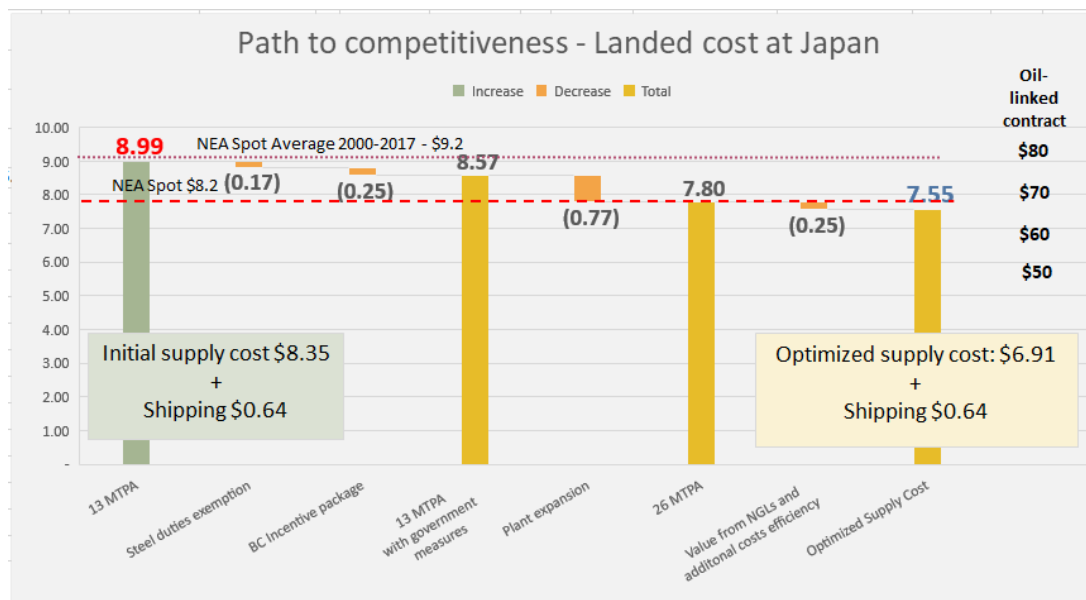
The major advantages for Canada and specifically Nova Scotia are competitive operating costs, competitive capital allowance legislation, industry average capital costs for a greenfield project, and a short distance to European markets. Disadvantages include the higher cost of natural gas and transportation and high taxes primarily due to the corporate tax (31%).

▪ What are the paths to make Canadian projects more cost-competitive?

Provided that specific actions are taken by governments and proponents (see the Path to Competitiveness section in Chapter 4), the total landed costs for Western Canada LNG project

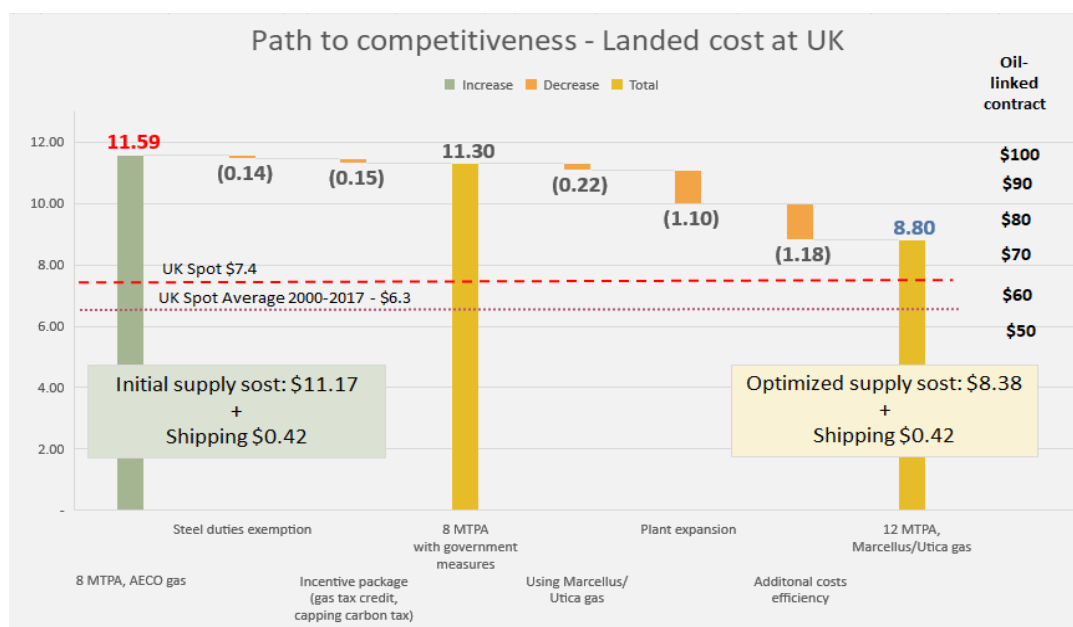
could be reduced to \$7.55 per mmbtu, which is lower than current and average historical prices. The resulting landed cost is recovered by an LNG project under \$65 of Brent oil price (compared to an initial \$80 price) (see Figure 5.4).

Figure 5.4: Optimized Canadian LNG Project Costs



CERI has not found a viable path to reduce an Eastern Canada project landed cost below the European market price if the project sources gas from AECO-C or Marcellus. The final optimized landed cost is \$8.8 (see Figure 5.5), while the market price is \$7.4, and the historical average is \$6.3. In order to make these projects cost-competitive, more solutions than those modelled are required. Further savings should be sought on the capital cost and transportation cost side.

Figure 5.5: Optimized Eastern Canada LNG Costs



At the same time, if local shale gas were available in Nova Scotia, the optimized cost for such a case would reduce the landed costs from \$8.5 to \$7.35, making such an option viable under current spot prices, while still short of the historical average of \$6.3.

The incentives made available by the Canadian and provincial governments are an important part in making projects more competitive and attracting investors to Canada. An increase of capital allowance in the past for the LNG industry has allowed cost reductions of 21 cents per mmbtu for Canadian projects. The recent BC government Natural Gas Development Framework (often referred to as the BC Incentive package in the study) removes an additional 25 cents. The Natural Gas Tax Credit removes 5 cents, totalling 51 cents for all three measures.

Still, even with these measures, a US greenfield project has 27.5% lower taxes per mmbtu than for a large 26 mtpa project in Canada with optimized supply costs. LNG costs in the US are also 13-41% lower per mmbtu of output LNG than in Canada, if natural gas cost is not taken into consideration.

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Appendix A: Supply Cost Assumptions

General Assumptions for All Liquefaction Plants

- 5-year construction period except for the Sabine Pass additional train project (4 years).
- 30 years in production
- Exchange rate: CAD/USD – 0.8
- Exchange rate: AUD/USD – the average of 2016-2017 is taken – 0.75
- All costs, including per mmbtu/mmcf figures, are in US dollars unless otherwise specified
- 1 mtpa = 0.131 bcf/d
- 1 mmbtu = 1 mcf
- Discount rate - 10%
- LNG price annual inflation – 2%
- Feedstock natural gas price annual inflation - 2%
- Henry Hub price forecast was modelled by taking 2017 actual price and inflated by 2% annually
- OPEX inflation – 2%
- Shrinkage of gas at the facility – Western Canada 1.3%, Eastern Canada 1.5%, US projects 1.5%, Australia 2%
- Facility annual utilization rate – 80% (1st year of production), 90% (2nd year of production), 95% (3rd and all following years of production)
- CAPEX allocation across 5 years build-out: 3%, 10%, 29%, 29%, 30%; Sabine Pass additional train 4 years CAPEX allocation – 10%, 30%, 30%, 30%.
- Not included in the models:
 - Capital borrowing and interest payments
 - Property taxes
 - Fuel tax (BC Fuel tax)

Project-specific Assumptions

Western Canada

| | Western Canada | Source/Notes |
|--|---|---|
| Capacity, mtpa | 13 (greenfield) | LNG Canada Project Description, 2013, BC Oil and Gas Commission |
| Total natural gas input, mmcf/d | 1,850 (including for power generation) | |
| Natural gas for power generation, mmscf/d | 136 (8% of gas intake) | |
| Trains | 2 x 6.5 mtpa | |
| CAPEX, \$ billion | \$15,396 (75% of High Cost, 25% of Low Cost), brought to 2018 dollars | LNG Canada Export Terminal Project Assessment Report, BC Environmental Assessment Office, 2015 |
| CAPEX, \$ per tpa | \$1,237 (with fabricated steel duty), \$1,184 (without duty) | Total CAPEX divided by capacity |
| OPEX, \$ per mmbtu | \$0.52 of facility output, inflated (non-natural gas operating costs divided by natural gas intake for sales for 2 trains brought to 2018 dollars) 75% of High-Cost estimate plus 25% of the Low-Cost estimate | CERI estimate based on LNG Canada Export Terminal Project Assessment Report, BC Environmental Assessment Office, 2015 |
| Federal income tax, % | 15% | |
| Provincial income tax, % | 11% 11% corporate tax rate is utilized for the study effective 2017, while BC has enacted 12% beginning January 2018. The difference in supply costs due to the change is provided in the study | |
| Carbon Tax, \$ | In accordance with federal legislation (\$50 CAD from 2022) | |
| BC LNG Emissions Benchmark | 0.16 t CO ₂ eq. / t of LNG | Liquefied Natural Gas (LNG) Regulation in British Columbia, McCarthy Tétrault |
| Project LNG Emissions Intensity | 0.152 t CO ₂ eq. / t of LNG (total emissions of 3,957,728 t CO eq per year divided by 26 mtpa) | LNG Canada Export Terminal Project Assessment Report, BC Environmental Assessment Office, 2015 |
| LNG Income Tax | In accordance with current BC legislation | BC Government |
| Capital Costs Allowance (CCA) | 25.8% - weighted average of CCA's for capital cost components | CERI Estimate |
| 1) fabricated steel duties and countervailing duties | Duty: Capital cost * 54% (share of foreign CAPEX) * 13.9% (value of fabricated steel) * 45.8% = \$533.1 million Countervailing duties 6,185 tonnes of fabricated steel per mtpa * CAD 2,333 * 13 mtpa – 150 million Total duties: 683.1 million | CERI estimate |

Eastern Canada

For Eastern Canada, three supply costs are estimated based on the source of natural gas. The other input variables are kept the same. The source of feedstock also impacts transportation options and costs.

| | Eastern Canada | Source/Notes |
|---|--|---|
| Capacity, mtpa | 8 (greenfield) | CERI Estimate |
| Total natural gas input, mmcf/d | 1,137 (including for power generation) | |
| Natural gas for power generation, mmscf/d | 84.2 (8% of the natural gas intake) | |
| Trains | 2 x 4 mtpa | |
| CAPEX, \$ billion | \$7.7 billion (\$9.06 2014 CAD brought to 2018 US dollars) | Bear Head LNG Environmental Impact Assessment Application |
| CAPEX, \$ per tpa | \$1,006 (with fabricated steel duty), \$962 (without duty) | Total CAPEX divided by capacity |
| OPEX, \$ per mmbtu | \$0.52, inflated (assumed the same as for BC) | CERI estimate; the same as for BC project |
| Federal income tax, % | 15% | |
| Provincial income tax, % | 16% | |
| Carbon Tax | In accordance with federal legislation (\$50 CAD from 2022) | |
| Capital Costs Allowance (CCA) | 25.8% - weighted average of CCA's for capital costs components | CERI Estimate |

US, Louisiana, Brownfield

| | US, Louisiana | Source/Notes |
|---|--|---|
| Capacity, mtpa | 15 | CERI Estimate |
| Total natural gas input, mmscf/d | 2,132 (including gas for power generation) | |
| Natural gas for power generation, mmscf/d | 157.9 (8% of the natural gas intake) | |
| Trains | 3 x 5 mtpa | |
| CAPEX, \$ billion | \$10 billion | Cameron LNG website |
| CAPEX, \$ per tpa | \$667 | Total CAPEX divided by capacity |
| OPEX, \$ per mmbtu | \$0.7 per mmbtu of facility output, inflated | CERI estimate based on the Cheniere 2017 report. Total LNG output 734 bcf, OPEX \$712 million (\$4.2 billion total OPEX – \$3.1 billion COGS – \$0.35 Depreciation - \$0.006 Restructuring – \$0.019 Impairment); LNG revenues in total revenue stream – 95%. |
| Natural gas transportation | \$0.07 per mmbtu (transportation costs from Henry Hub), inflated A connecting pipeline, 23 miles; total CAPEX \$110 million integrated into the project | CERI Estimate based on a proxy of similar distance for the TransCanada pipeline in the US Gulf; CERI Estimate |
| Federal income tax, % | 21% | |
| State income tax, % | 8% | |
| Depreciation | GDS MARCS, Table A-1, 15-year recovery period for the former legislation 100% capital allowance for 2018 tax legislation | Publication 946, US IRS |

US, Texas, Greenfield

| | US, Texas | Source/Notes |
|--|---|---|
| Capacity, mtpa | 9 (greenfield) | CERI Estimate |
| Total natural gas input, mmscf/d | 1,279 (including gas for power generation) | |
| Natural gas for power generation, mmcf/d | 94.8 (300 mmcf/d for 26 mtpa) | |
| Trains | 2 x 4.5 mtpa | |
| CAPEX, \$ billion | \$9.3 billion (company estimate that the project would cost \$9-10 billion). 75% of High Estimate and 25% of Low Estimate | Cheniere Annual Report, Corpus Christi project section, 2017 |
| CAPEX, \$ per tpa | \$1,028 | Total CAPEX divided by capacity |
| OPEX, \$ per mmbtu | \$0.7, inflated (the same approach as for US, Louisiana) | CERI estimate |
| Natural gas transportation | \$0.29 per mmbtu (transportation costs from Henry Hub), inflated plus, a connecting pipeline, 23 miles; total CAPEX \$110 million integrated into the project | CERI estimate based on a proxy of similar distance for the TransCanada pipeline in the US Gulf; CERI Estimate |
| Federal income tax, % | 21% | |
| State income tax, % | Franchise tax - 0.8% multiplied for whichever is lower of Revenue minus COGs and 70% of Revenue | US Texas tax law |
| Depreciation | GDS MARCS, Table A-1, 15-year recovery period for the former legislation 100% capital allowance for 2018 tax legislation | Publication 946, US IRS |

US, Texas (additional train)

| | US, Texas | Source/Notes |
|---|---|--|
| Capacity, mtpa | 5 (additional train) | CERI Estimate |
| Total natural gas input, mmscf/d | 711 (including gas for power generation) | |
| Natural gas for power generation, mmscf/d | 52.6 (8% of natural gas intake) | |
| Trains | 1 x 5 mtpa | |
| CAPEX, \$ billion | \$3.55 billion (CERI estimate based on the EPC costs provided for each train and total costs provided for all 5 trains) | Cheniere Annual Report, Sabine Pass project section, 2017 |
| CAPEX, \$ per tpa | \$709 | Total CAPEX divided by capacity |
| OPEX, \$ per mmbtu | \$0.7, inflated (the same approach as for US, Louisiana) | CERI estimate |
| Natural gas price, \$ per mmbtu | Henry Hub forecast | CERI estimate |
| Natural gas transportation, \$ per mmbtu | \$0.07 (transportation costs from Henry Hub), inflated plus, a connecting pipeline, 23-mile; total CAPEX \$110 million integrated into the project | CERI estimate based on a proxy of similar distance for the TransCanada pipeline in the US Gulf; CERI Estimate |
| Federal income tax, % | 21% | |
| State income tax, % | Franchise tax - 0.8% multiplied for whichever is lower of Revenue minus COGs and 70% of Revenue | US Texas tax law |
| Depreciation | GDS MARCS, Table A-1, 15-year recovery period for the former legislation 100% capital allowance for 2018 tax legislation | Publication 946, US IRS |

Australia

| | Australia, East Coast | Source/Notes |
|--|---|--|
| Capacity, mtpa | 8.5 | CERI Estimate |
| Total natural gas input, mmscf/d | 1,208 (including gas for power generation) | |
| Natural gas for power generation, mmscf/d | 52.6 (8% of the natural gas intake) | |
| Trains | 2 x 4.25 mtpa | |
| CAPEX, \$ million | \$17.8 billion | APPEA, Australia (QCLNG) |
| CAPEX, \$ per tpa | \$2,091 | Total CAPEX divided by capacity |
| OPEX, \$ per mmbtu | \$1.02 per mmbtu of facility output, inflated | CERI estimate OPEX for the Australian projects is assumed to be equal to BC (0.52) with the addition of the following adjusting elements: Climate-related plant efficiency (\$ 0.2/mmbtu), labour productivity (\$0.2/mmbtu), Service market maturity (\$0.1/mmbtu). Estimates are based on 2013 McKinsey & Company report: Extending the LNG boom: improving Australian LNG productivity and competitiveness |
| Natural gas transportation OPEX for the pipeline integrated into the project, \$ per mmbtu | \$0.10 per mmbtu | Cooper-Eromanga Basin Outlook, 2016. Indicative tariff for the QGP pipeline \$0.05 assumed for the Nova Scotia pipeline multiplied by the ratio of LNG OPEX in Canada and Australia (1.96) |
| Federal income tax, % | 30% | Government of Australia |
| State income tax, % | - | |
| Depreciation | Declining method, 200%/effective life, 15 years | Government of Australia |

Appendix B: Pipeline Supply Cost Model

The pipeline supply cost model for the Western Canadian LNG plant uses the following assumptions:

- 3 years to construct a pipeline
- Time in operation – 30 years
- Diameter: 48", pipeline length – 650 km
- Throughput – 1.85 bcf/d (or 3.7 bcf/d for the 4 trains case)
- CAPEX - \$4.8 billion CAD (Coastal GasLink website) or \$3.8 billion; \$5.91 million / km; \$5.8 billion CAD for 3.7 bcf/d
- OPEX – \$30.2 million per year for 1.85 bcf/d, \$141 million for 3.7 bcf/d case. Inflated annually.
- Carbon emissions in tonnes – 1% of throughput gas multiplied by 0.053 (t CO₂eq per mcf)
- CCA on pipeline – 8% (Class 49), CCA on compressors – 15% (Class 7); applied to the previous year balance
- OPEX and toll annual increase – 2% (2% for the toll was established based on the average annual growth of tolls of the following pipelines – Alliance Pipeline (2005-2017), TransCanada Mainline (2007-2019), Northeast and Maritimes Pipeline (2006-2017), TQM (2009-2017), NGTL (2009-2017).
- Toll annual increase – 2%
- Discount rate - 10%

The pipeline supply costs for the Eastern Canadian LNG plant uses the following assumptions:

- 3 years to construct a pipeline
- Time in operation – 30 years
- Diameter: 48", pipeline length – 1,600 km plus 62.5 km to Bear Head LNG location
- Throughput – 1.14 mmcf/d (or 1.85 mmcf/d for the pipeline costs sharing option)
- CAPEX – US \$5.5 billion (CERI estimate based on Oil & Gas Journal (2016), \$3.35 million / km
- OPEX – \$74 million. Inflated annually.
- Carbon emissions in tonnes – 1% of throughput gas multiplied by 0.053 (t CO₂eq per mcf)
- CCA on pipeline – 15% (Class 7), CCA on compressors – 8% (Class 49); full depreciation for 15 years
- Discount rate - 10%
- Toll annual increase – 2% (similar to above)

In the case when local Horton Bluff Shale gas is used, a 337-km 48" pipeline is modelled as part of the LNG project. Total CAPEX of the pipeline is \$1 billion (\$3.76 per km), OPEX – \$0.05 per mcf.

Appendix C: Shipping Costs

- Vessel size - 160,000 cubic meters of LNG
- Vessel capacity - 98%
- Laden Voyage Boil-Off Factor - 0.12% per day
- Ballast Voyage Boil-Off Factor - 0.09% per day
- Bunker Fuel IMO 380 – 100 mt/day
- Time in operation – 30 years
- Vessel speed - 17 nautical miles per hour
- Suez Canal Cost – \$0.15 per mmbtu (roundtrip)
- Panama Canal Costs – \$0.2 per mmbtu (roundtrip)
- Charter rate – \$65,000 per day
- Shipping utilization is assumed at 100% for simplicity

| Load Port | Load Country | Offtake Port | Offtake Country | Nautical Miles | Total Trip Days (includes time for loading and offloading) | Cost of Shipment |
|------------------------|--------------|--------------|-----------------|----------------|---|------------------|
| Port of Corpus Christi | US | Osaka | Japan | 9,932 | 52 Panama | 1.64 |
| Port of Corpus Christi | US | Ningbo | China | 10,529 | 55 Panama | 1.73 |
| Port of Corpus Christi | US | Incheon | South Korea | 10,072 | 52 Panama | 1.66 |
| Port of Corpus Christi | US | Kaohsiung | Taiwan | 10,694 | 55 Panama | 1.75 |
| Port of Corpus Christi | US | Fos-Sur-Mer | France | 5,676 | 31 | 0.82 |
| Port of Corpus Christi | US | Barcelona | Spain | 5,431 | 30 | 0.79 |
| Port of Corpus Christi | US | Thamesport | UK | 5,257 | 29 | 0.75 |
| Port of Corpus Christi | US | Hazira | India | 10,033 | 54 Suez | 1.66 |
| Port Arthur | US | Osaka | Japan | 9,858 | 51 Panama | 1.63 |
| Port Arthur | US | Ningbo | China | 10,455 | 54 Panama | 1.72 |
| Port Arthur | US | Incheon | South Korea | 10,070 | 52 Panama | 1.66 |
| Port Arthur | US | Kaohsiung | Taiwan | 10,620 | 55 Panama | 1.74 |
| Port Arthur | US | Fos-Sur-Mer | France | 5,579 | 30 | 0.81 |
| Port Arthur | US | Barcelona | Spain | 5,330 | 29 | 0.77 |
| Port Arthur | US | Thamesport | UK | 5,041 | 28 | 0.73 |
| Port Arthur | US | Hazira | India | 9,895 | 54 Suez | 1.64 |
| Sabine Pass | US | Osaka | Japan | 9,825 | 51 Panama | 1.63 |
| Sabine Pass | US | Ningbo | China | 10,414 | 54 Panama | 1.71 |
| Sabine Pass | US | Incheon | South Korea | 10,058 | 52 Panama | 1.66 |
| Sabine Pass | US | Kaohsiung | Taiwan | 10,587 | 55 Panama | 1.74 |

| Load Port | Load Country | Offtake Port | Offtake Country | Nautical Miles | Total Trip Days (includes time for loading and offloading) | Cost of Shipment |
|--------------|--------------|--------------|-----------------|----------------|---|------------------|
| Sabine Pass | US | Fos-Sur-Mer | France | 5,558 | 30 | 0.80 |
| Sabine Pass | US | Barcelona | Spain | 5,309 | 29 | 0.77 |
| Sabine Pass | US | Thamesport | UK | 5,206 | 29 | 0.75 |
| Sabine Pass | US | Hazira | India | 11,754 | 63 Suez | 1.91 |
| Kitimat | Canada | Osaka | Japan | 4,217 | 24 | 0.64 |
| Kitimat | Canada | Ningbo | China | 4,905 | 27 | 0.73 |
| Kitimat | Canada | Incheon | South Korea | 4,680 | 26 | 0.70 |
| Kitimat | Canada | Kaohsiung | Taiwan | 5,228 | 29 | 0.78 |
| Kitimat | Canada | Fos-Sur-Mer | France | 9,622 | 50 Panama | 1.56 |
| Kitimat | Canada | Barcelona | Spain | 9,602 | 50 Panama | 1.56 |
| Kitimat | Canada | Thamesport | UK | 9,708 | 51 Panama | 1.56 |
| Kitimat | Canada | Hazira | India | 9,574 | 50 | 1.38 |
| Point Tupper | Canada | Osaka | Japan | 10,761 | 56 Panama | 1.76 |
| Point Tupper | Canada | Ningbo | China | 11,358 | 59 Panama | 1.85 |
| Point Tupper | Canada | Incheon | South Korea | 10,965 | 57 Panama | 1.79 |
| Point Tupper | Canada | Kaohsiung | Taiwan | 11,528 | 60 Panama | 1.87 |
| Point Tupper | Canada | Fos-Sur-Mer | France | 3,702 | 21 | 0.56 |
| Point Tupper | Canada | Barcelona | Spain | 3,517 | 20 | 0.53 |
| Point Tupper | Canada | Thamesport | United Kingdom | 2,713 | 16 | 0.42 |
| Point Tupper | Canada | Hazira | India | 7,633 | 42 Suez | 1.31 |
| Gladstone | Australia | Osaka | Japan | 3,806 | 22 | 0.58 |
| Gladstone | Australia | Ningbo | China | 3,880 | 22 | 0.59 |
| Gladstone | Australia | Incheon | South Korea | 4,188 | 24 | 0.64 |
| Gladstone | Australia | Thamesport | United Kingdom | 11,687 | 62 Suez | 1.84 |
| Gladstone | Australia | Kaohsiung | Taiwan | 3,655 | 21 | 0.56 |
| Gladstone | Australia | Hazira | India | 6,150 | 33 | 0.88 |

Appendix D: Jurisdictional Comparison of Non-optimized LNG Supply Costs

All costs are in US dollars per mmbtu.

| | Western Canada | Eastern Canada AECO-C/local gas | US GoM (greenfield) | Australia |
|-------------------------------------|----------------|------------------------------------|------------------------|---------------|
| Supply cost (non-optimized) | 8.35 | 11.17 / 8.09 | 9.07 | 13.06 |
| Natural gas cost | 2.51 | 3.67 / 3.44 | 4.52 | 4.80 |
| Capital cost / tpa | 3.42 | 2.77 / 3.09 | 2.86 | 5.58 |
| Operating cost | 0.69 | 0.69 | 0.91 | 1.34 |
| Natural gas transportation cost *** | 0.96 | 3.33 / 0.07** | 0.42 | 0.14** |
| Shipping to Europe | 1.56 | 0.42 | 0.75 | 1.84 |
| Shipping to Asia | 0.64 | 1.76 | 1.64 | 0.58 |
| Tax burden | 0.78 | 0.72 / 0.80 | 0.37 | 1.20 |
| Capital allowances | 25.8%* | 25.8%* | 100% | 13.3% |

* 25.8% yields an almost identical result as 100% allowance if ring-fencing is not removed; if it is removed, the capital allowance rate of the US becomes superior compared to Canada's. See additional federal incentives in the Path to Competitiveness section of Chapter 4 for more detail.

** These costs represent only operating costs of transportation, unlike other jurisdictions.