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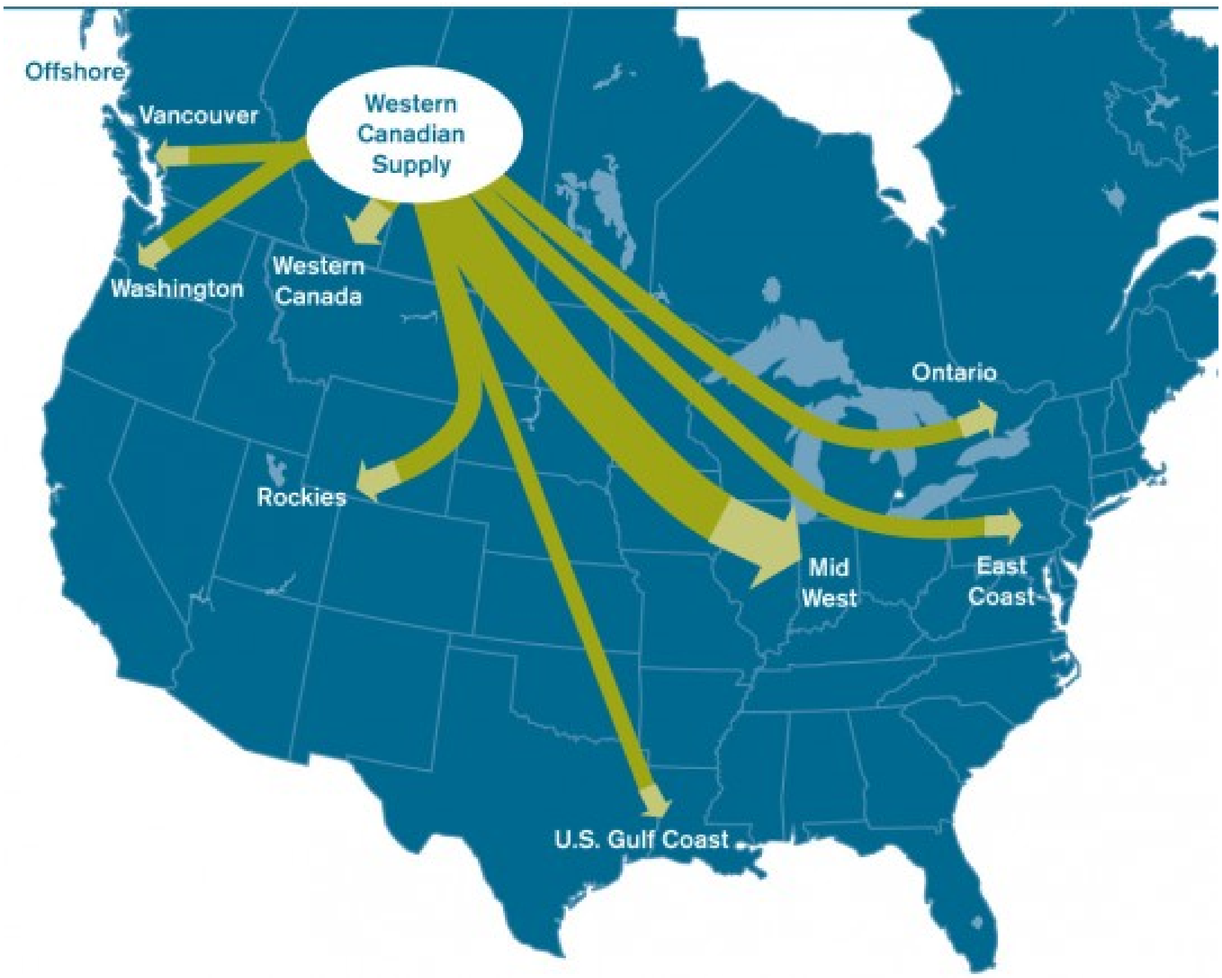
PACIFIC ACCESS:
PART III – ECONOMIC IMPACTS OF EXPORTING HORN RIVER NATURAL GAS TO ASIA AS LNG



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PACIFIC ACCESS

Part III – Economic Impacts of Exporting Horn River Natural Gas to Asia as LNG

Pacific Access: Part III – Economic Impacts of Exporting Horn River Natural Gas to Asia as LNG

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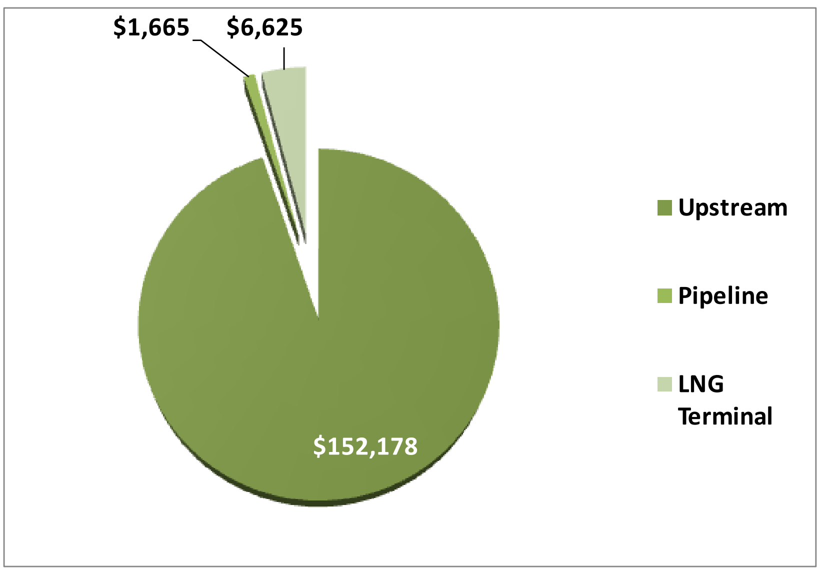
Executive Summary

This study continues the examination of the impacts of opening up the West Coast for energy transport. CERI's Regional I/O (RIO) model that was introduced in Part II of the Pacific Access series (Asia-Directed Oil Pathways and Their Economic Impacts) is used to calculate the impacts of developing wells in Horn River, transporting the gas to the Kitimat LNG Terminal and liquefying it.

The use of natural gas as a fuel of choice in Asia will continue to be a long-term potential market for shale gas production in Canada. The potential for revenues is substantial compared to current North America pricing and a potential netback of $5-$7/Mcf is foreseeable for Horn River producers if high demand for natural gas and Asian oil-linked pricing remain in the future.

Horn River has recently started to develop and the prospective impacts to British Columbia are substantial. The investment required to develop enough gas to fill LNG capacity has created multiple benefits for British Columbians. Figure E.1 shows the total GDP benefits to British Columbia.

Figure E.1: Total GDP Impacts for British Columbia



Source: CERI

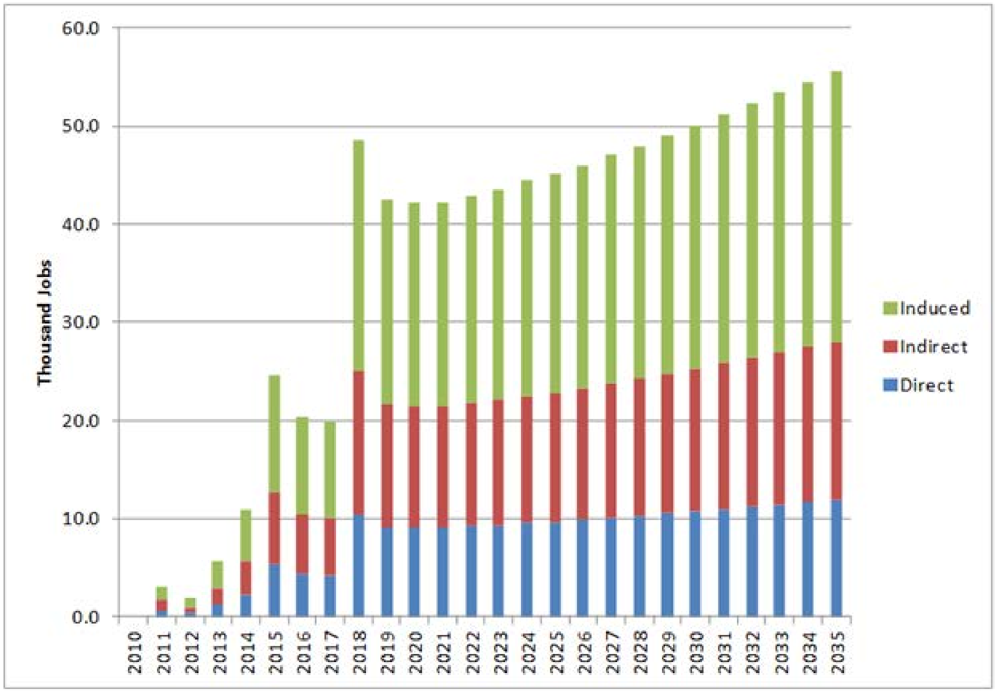
Horn River Impacts

The Horn River development to meet output of Kitimat LNG Terminal impacts for the period of 2010 to 2035 are as follows:

- A total of 944,500 jobs (person-years) will be generated in Canada of which 828,700 will be based in British Columbia. Figure E.2 shows the jobs generated on a year-by-year basis.
- GDP will be $161 billion of which the majority will be in British Columbia at $152.1 billion.

- Employee compensation in BC will be $39.4 billion and tax revenues will amount to $36.8 billion.

Figure E.2: Total Jobs Created in Canada for Horn River Upstream Development (thousand jobs)

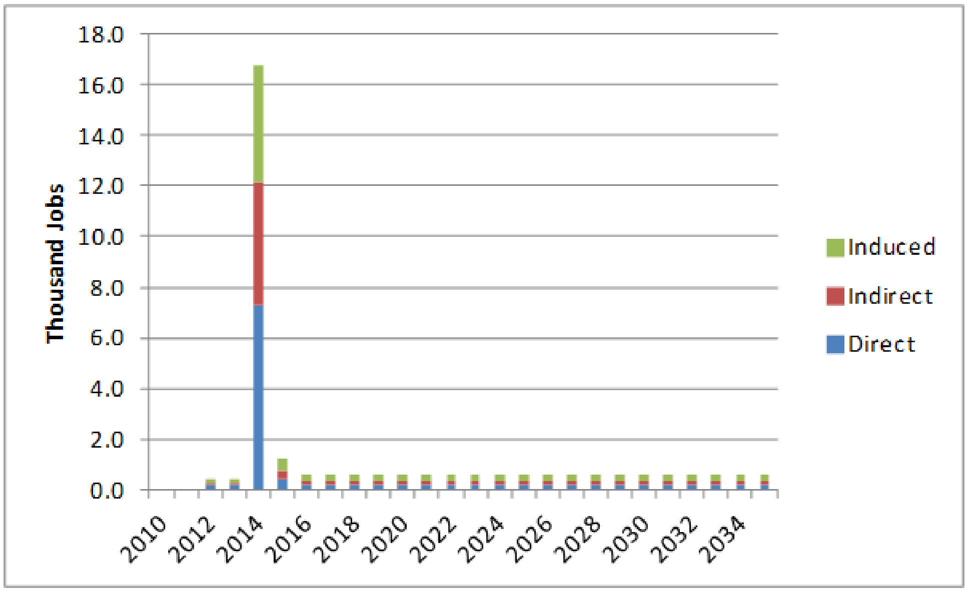


Source: CERI

Pacific Trail Pipeline Impacts

- A total of 31,000 jobs will be generated of which 24,700 jobs will be based in British Columbia. Figure E.3 shows the total national jobs created on a year-by-year basis.
- GDP will be $2.2 billion with $1.7 billion being generated in British Columbia.
- Employee compensation in BC will be $1.0 billion with $471 million in taxes payable.

Figure E.3: Total Jobs Created in Canada for the Building of the Pacific Trail Pipeline (thousand jobs)



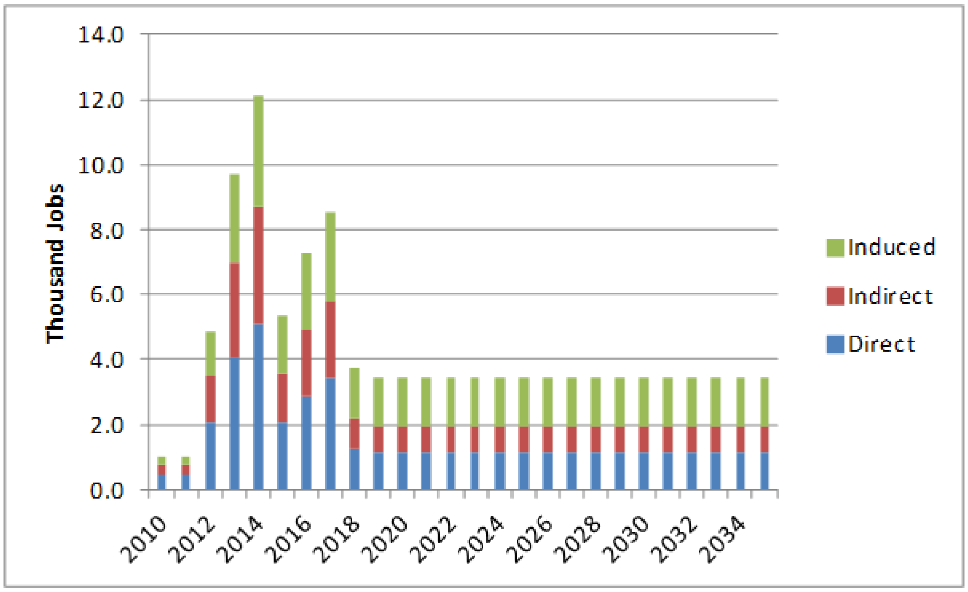
Source: CERI

Kitimat LNG Terminal

The construction and operation of the LNG terminal will generate the following:

- 112,000 jobs will be created in Canada with BC obtaining 97,000 of those jobs. Figure E.4 depicts the total jobs created in Canada on a year-by-year basis.
- There will be $7.8 billion in GDP generated with $6.6 billion based in BC.
- $4.6 billion in employee compensation will happen nationally with $2.2 billion in taxes generated.

Figure E.4: Total Jobs Created in Canada for the Building of the Kitimat LNG Terminal (thousand jobs)



Source: CERI

Ontario will get approximately $5.8 billion in GDP impacts from all 3 segments due to its extensive manufacturing base. Alberta will generate approximately $2.9 billion in GDP due partially to its close proximity and ability to manufacture some of the materials.

The opening of Pacific Access enhances Canada's ability to exploit its substantial energy resources.

Chapter 1: Introduction

This report shifts gears from Parts I and II of the Pacific Access report by focusing on the Horn River shale gas development and transport to the Kitimat LNG terminal.

Background

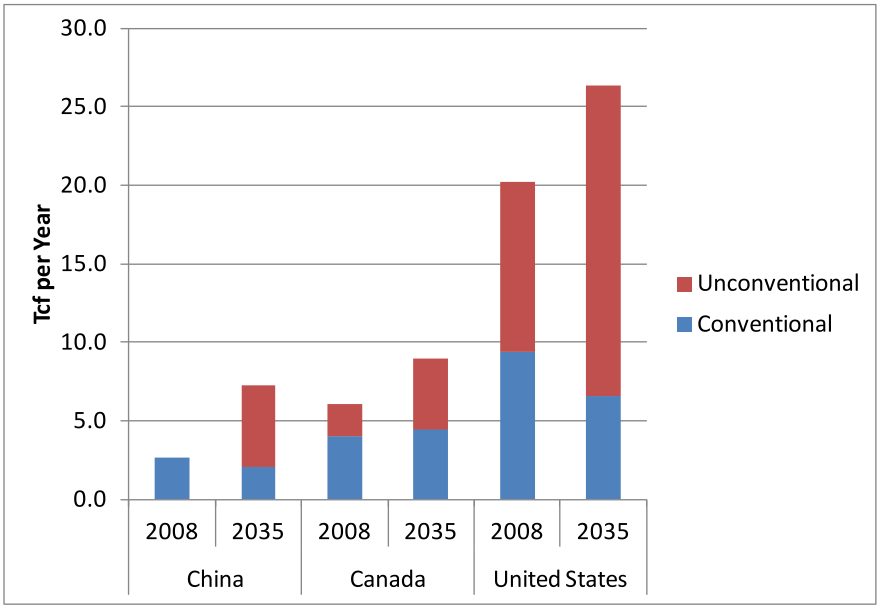
Unconventional natural gas production, particularly shale gas, has had a profound impact on global and North American natural gas markets. The vast potential of the Horn River Basin and the Montney have E&Ps abuzz with the prospect of exporting to growing Asian markets in the form of liquefied natural gas (LNG). Shale plays such as the Marcellus, Haynesville and Barnett have an advantage due to their proximity to consuming markets in the United States. LNG, however, confers a location advantage to the Horn River Basin and the Montney if natural gas is exported to energy hungry Asian markets, such as Japan, South Korea, China and Taiwan.

Unconventional Gas Production in North America and Natural Gas Demand

Shale gas is natural gas generated from and contained within dark-coloured, organic rich rocks. Shales can act as the source, reservoir, and seal for natural gas.[1] While shale formations have unique properties and characteristics, relatively recent advances in technology and science have made shale gas production economically feasible on a large-scale. The Energy Information Administration (EIA) estimates 5,760 trillion cubic feet (Tcf) of technically recoverable shale gas resources across 32 countries.[2] The Gas Technology Institute (GTI) estimates over 850 Tcf of gas in place in just the Western Canadian Sedimentary Basin (WCSB).[3] Marketable gas reserves in North America have grown substantially, especially in unconventional resources.[4] CERI Study 123, "North American Natural Gas Dynamics: Shale Gas Plays in North America – A Review" examined in more detail the natural gas dynamics and the shale basin plays in North America. The exploitation of this resource has resulted in an increased supply of natural gas. This is a trend that is expected to continue (see Figure 1.1), and without commensurate market growth producers are faced with low continental gas prices.

[1] Centre For Energy website, http://www.centreforenergy.com/AboutEnergy/ONG/ShaleGas/Overview.asp?page=1 (accessed on July 22, 2012)
[2] US Energy Information Administration website, Today In Energy, http://205.254.135.24/todayinenergy/detail.cfm?id=811 (accessed on June 5, 2012)
[3] Alberta Energy website, Shale Gas, http://www.energy.alberta.ca/NaturalGas/944.asp (accessed on November 17, 2010)
[4] Unconventional gas resources include tight gas, shale gas and coalbed methane.

Figure 1.1: 2011 Forecasted Natural Gas Production



Source: EIA[5]

Natural gas is becoming increasingly attractive as a substitute for other hydrocarbon based fuels. It is considered cleaner because it does not release substantial particulates, sulfur, nitrous oxides or mercury and on average emits about 30 percent less greenhouse gases (GHG). Furthermore, global natural gas demand growth is primarily driven by non-OECD countries.[6] In North America it is becoming an attractive fuel for electric companies because it has been cheap to acquire and meets stringent environmental fuel standards. However, future North American growth is dependent on how willing electric companies are to switch fuels and how fast existing coal plants will retire. Although there is an increasing fleet of natural gas vehicles, they are not expected to generate a significant demand for natural gas in the near future.[7] Since Non-OECD countries are expected to dominate future natural gas demand growth, Canadian producers find it attractive to ship to the West Coast rather than continue to sell gas in a depressed North America market.

Research and Report Organization

The purpose of this report is to use the Regional I/O model developed in Part II of the Pacific Access report to assess the impacts to each region due to the supply-chain of production from Horn River to the Kitimat LNG Terminal. Specifically, the economic impacts over the next 25 years for the construction and operation of the estimated wells required to fulfill the LNG terminal capacity, the building of the Pacific Trail Pipeline and the Kitimat LNG will be assessed. The economic effects will be measured on a regional, provincial and federal level.

---

[5] EIA, *International Energy Outlook 2011*. Report No: DOE/EIA-0484(2011)
[6] Ibid
[7] API. Natural Gas Supply and Demand. Accessed July 18th 2012 from http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/natural-gas/supply-and-demand.aspx

The estimated economic benefits at the provincial and federal levels are from CERI's Provincial I/O model with the detailed methodology and assumptions described in Appendix B. The Regional I/O concerns only British Columbia and Alberta as these are the provinces most affected by new oil and gas development. The regional categories are described below:

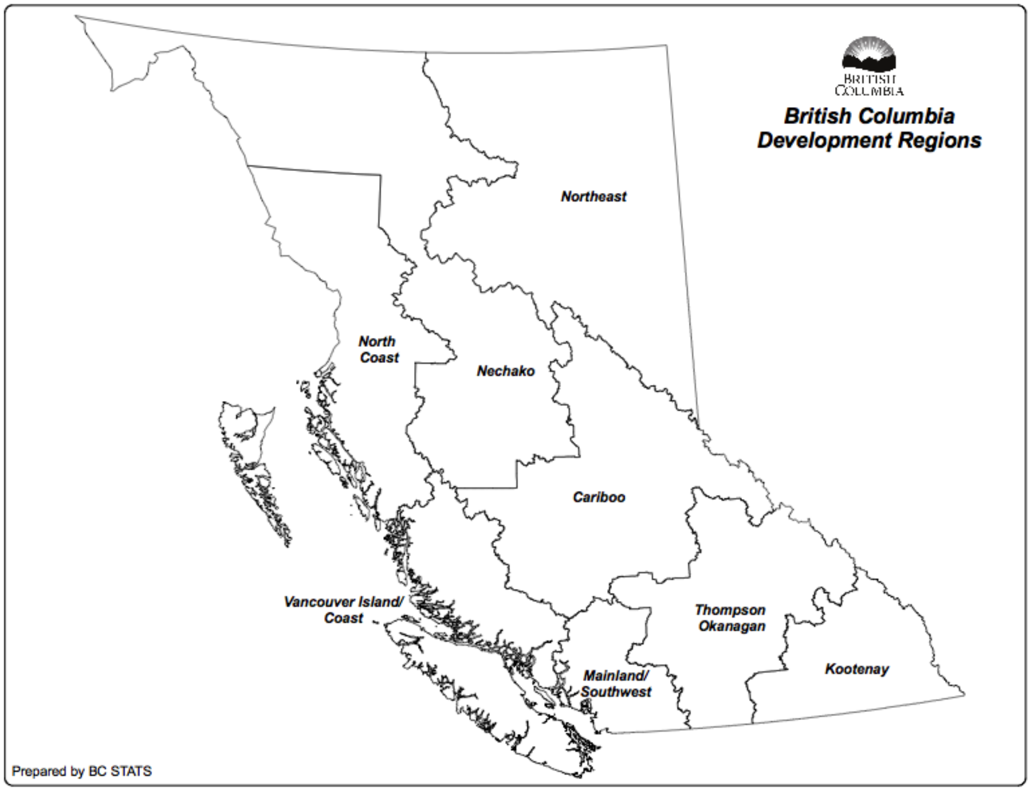
- **British Columbia:** Cariboo, Kootenay, Mainland/Southwest, Nechako, North Coast, Northeast, Thompson/Okanagan, Vancouver Island/Coast
- **Alberta:** Lower Peace, Lower Athabasca, Upper Peace, Upper Athabasca, North Saskatchewan, South Saskatchewan, and Red Deer.

Figure 1.2 and 1.3 show the areas of Alberta's Land-Use Framework regions and BC's Developmental Regions, respectively.

Figure 1.2: Alberta Land-Use Framework Regions

Source: North Saskatchewan Watershed Alliance

Figure 1.3: BC Developmental Regions



Source: BC Stats

The rest of the report is organized as follows:

- Chapter 2: Contains background information on Canadian Shale, BC Shale, Pacific Trail Pipeline and LNG
- Chapter 3: Describes the assumptions of the injections and the methodology of the Regional I/O model
- Chapter 4: Presents the results of the study
- Chapter 5: Draws key conclusions
- Appendix A: I/O results for the US
- Appendix B: Provincial I/O methodology
- Appendix C: Regional I/O methodology
- Appendix D: Additional LNG information

Chapter 2: Canadian Shale, Pipelines and LNG

Canadian Shale Plays

The National Energy Board (NEB) has highlighted the following shale plays in Canada as having significant potential. These shale plays are summarized in Table 2.1:

Table 2.1: Canadian Shale Plays

	Horn River	Montney	Colorado	Utica	Horton Bluff
Depth (m)	2,500-3,000	1,700-4,000	300	500-3,300	1,120-2000+
Thickness (m)	150	Up to 300	17 to 350	90 to 300	150+
Published estimates of natural gas (Tcf)*	144-600+	80-700	>100	>120	>130
Horizontal Well Cost, including fractures (million CDN $)	7 to 10	5 to 8	0.35 (vertical only)	5 to 9	Unknown

*Recoverable gas will be less

Source: NEB[1]

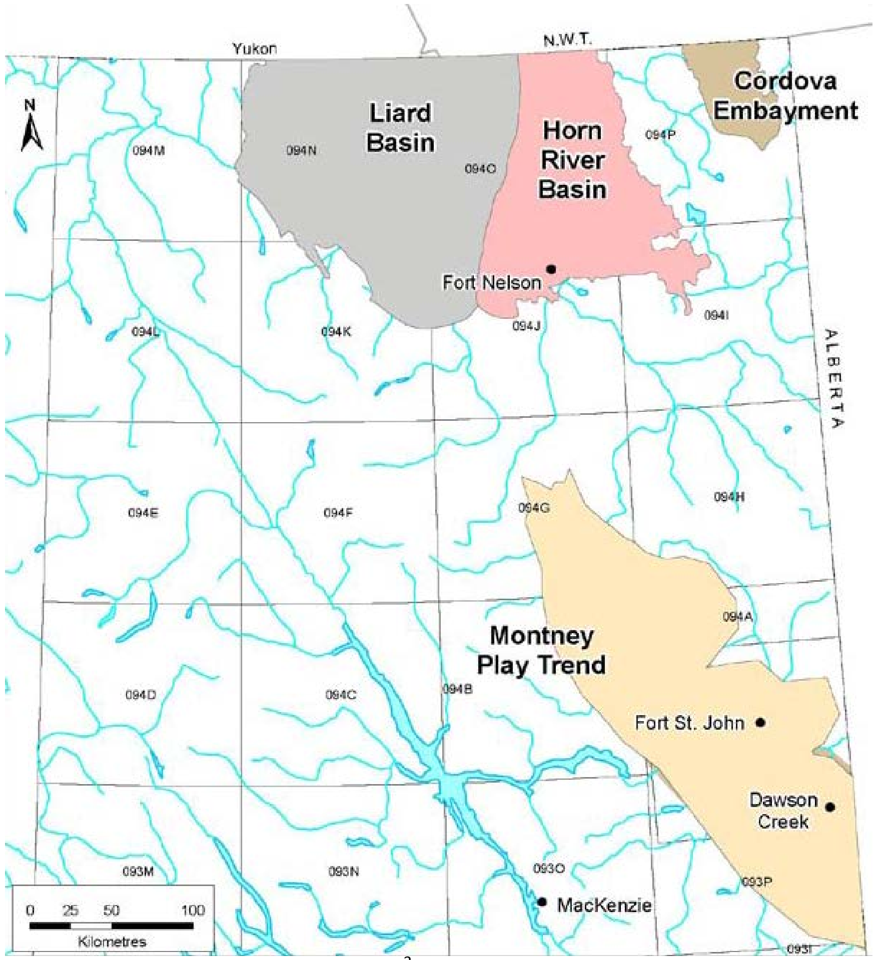
Horn River and the Montney have seen recent growth, which will be discussed in more detail later in this section. Currently, there has been increased attention on the Utica shale gas play in Quebec and to a lesser extent the Horton Bluff shale gas play in New Brunswick. The Colorado shale play is one of the oldest with more than 100 years of development but the nature of the formation enable only vertical wells to be drilled.[2] Together all of these shale plays contain a significant reserve of natural gas. However, despite the abundance of the resource, Canadian companies will only develop if it is profitable: for example, if the resource has a high liquids content such as the Montney or if there is potential to export it as LNG in order to take advantage of the higher overseas natural gas prices.

Shale Gas Development in British Columbia

While there are several intriguing shale plays in Western Canada, the two most promising are the Horn River Basin and the Montney Trend. Figure 2.1 illustrates the shale gas plays in British Columbia that are attracting attention.

[1] NEB. November 2009. *A Primer For Understanding Canadian Shale Gas – Energy Briefing Note.* ISSN 1917-506X.
[2] Ibid.

Figure 2.1: Shale Gas Plays in British Columbia



Source: British Columbia Ministry of Energy and Mines[3]
http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/C%20Adams.pdf (pp. 6)

Energy companies – spurred by shale gas discoveries – added C$220 million to British Columbia's land sale coffers in the September 2008 auction. According to the Ministry of Energy, Mines and Petroleum Resources, British Columbia closed out the 2008-09 fiscal year with an all-time high of C$2.4 billion from land sales – more than doubling the previous record set in 2007.[4] Bonuses paid for Petroleum and Natural Gas (PNG) Rights in British Columbia's shale gas regions were C$803 million in 2009, and have subsequently dropped to C$796 million

[3] British Columbia Ministry of Energy and Mines, "The Status of Exploration and Development Activities in the Montney Play Region of Northeast BC", Christopher Adams Presentation, April 2, 2012, http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/C%20Adams.pdf , (pp. 6)

[4] Marketwire, Press Release, "Government of British Columbia: Oil and Gas Produce Record-Breaking Fiscal Year". http://www.marketwire.com/press-release/government-of-british-columbia-oil-and-gas-produce-record-breaking-fiscal-year-966555.htm (accessed on July 22, 2012)

in 2010 and C$201 million in 2011.[5] They are, however, expected to increase with Apache Corporation's June 15, 2012 announcement of its new shale gas discovery in the Liard Basin.[6] Apache estimates that, based on its test wells there is approximately 48 Tcf of marketable gas on its Liard properties.[7]

The Horn River Basin

This section reviews the Horn River Basin, its geology and the major operating players in the basin.

The Horn River Basin is located in northeastern British Columbia and extends north to Fort Liard, southern Northwest Territories. The Horn River Basin area encompasses approximately 1.28 million hectares within the Fort Nelson/Northern Plains region of British Columbia.[8]

Figure 2.2 illustrates the location of the Horn River Basin. It lies adjacent to the Liard Basin on the west while on the east the Cordova Embayment extends from the northeastern corner of British Columbia into the Northwest Territories.

Figure 2.2: Location of the Horn River Basin

Source: http://www.ogfj.com/index/unconventional/horn-river-shale.html

[5] British Columbia Ministry of Energy and Mines, "Summary of Shale Gas Activity in Northeast British Columbia 2011", Oil and Gas Reports 2012-1, http://www.empr.gov.bc.ca/Mining/Geoscience/PublicationsCatalogue/OilGas/OGReports/Documents/2012/Summary%20of%20Shale%20Gas%20Activity%20in%20NEBC%202011%20Version%20HQ.pdf (pp. 8)
[6] Canada.com website, "Liard Basin find best reservoir on continent", http://www.canada.com/vancouversun/news/business/story.html?id=61a76f2d-048a-4fa6-ba89-02b51aea87e0 (accessed on July 22, 2012).
[7] ibid
[8] British Columbia Ministry of Energy and Mines, "Summary of Shale Gas Activity in Northeast British Columbia 2007", pp. 4.

The Horn River Basin is a Devonian-aged shale, and is, on occasion, referred to as the Ootla/Muskwa Shale. Horn River gas is dry with a high CO_2 content of 12 percent. It lies at a depth range of 7,800-13,300 ft. and is very comparable to the Haynesville Shale which lies at a depth of 10,500-13,500 ft. It is deeper than other shales such as the Fayetteville Shale, Woodford Shale and Barnett Shale. In terms of thickness and porosity, the Ootla/Muskwa Shale is 360-580 ft. and 4.0 percent, respectively.

Table 2.2 provides a summary of key geological characteristics of the Horn River Basin Shale.

Table 2.2: Horn River Basin Shale Geological Characteristics

Parameter	Horn River Basin Shale
Geological age	Devonian
Depth range (ft)	7,800-13,300
Shale thickness (ft), gross	360-580
GIP/sq mi (Bcf)	180-320
Porosity (%)	4.0
Total organic carbon (%)	3.0
Thermal maturity (Ro)	2.2-3.8*
Silica content (%)	45-68*
Pressure gradient (psi/ft)	n/a

Source: Deutsche Bank, 2008[9] and *Vero Energy, New Prospect Shale Gas, August 2010[10]

Table 2.3 provides the basin metrics for the Horn River Basin Shale. The geology of the Horn River Basin Shale is attractive. While it is a deep play, it is also a thick shale play (360-580 ft.) with an exceptionally low one-year decline rate (50 percent).[11] The Barnett Shale is considered low at 65 percent; many other shale plays hover between 80-90 percent.

[9] "From Shale to Shining Shale", Deutsche Bank, July 22, 2008, pp. 38.
[10] "New Prospect Cordova Embayment Shale Gas", Vero Energy (presentation), August 2010.
[11] Reuters website, "Encana says Horn River ranks high as shale-gas find", September 9, 2009, http://www.reuters.com/article/idUSN0933344420090909 (accessed on September 8, 2010)

Table 2.3: Basin Metrics for the Horn River Basin Shale

Parameter	Horn River Basin
Average Well Cost ($MM)	7.0-10.0
Depth range (ft)	7,800-13,300
IP Rate (MMcfpd)	5.0-12.0
EUR/Well (BCFE)	4.0-6.0
Threshold Price ($/MCFE)	n/a
Expected F&D Cost ($/MCFE)	2.0
Expected Recovery Factor (%)	20-30
Decline – Yr. 1 (%)	-50
Lateral lengths (ft)	4,600-8,200
Fracturing stages	6-12
Typical Well Spacing (acres/well)	40

Source: Deutsche Bank, 2008[12]

In early May 2008, Scotland-based Wood Mackenzie stated that the Horn River Basin could rival the prolific Barnett Shale located in East Texas, the latter accounting for 8.5 percent of the lower-48's total gas production.[13] With recoverable reserves in the region at 37 Tcf and easily rising to 50 Tcf or greater as drilling activity increases, the Horn River Basin certainly garnered attention for E&Ps across North America and Asia.[14] The Horn River Basin, according to Canadian Society for Unconventional Gas (CSUG) (now the Canadian Society for Unconventional Resources [CSUR]), may contain over 500 Tcf of original gas in place (OGIP).[15] This makes it the third largest North American natural gas accumulation discovered prior to 2010, ranking behind only the Marcellus Shale (Appalachia) and the Haynesville Shale (Louisiana). The Marcellus and Haynesville are established and commercially-producing plays and are often cited among North America's Big Five.

While the Horn River has positive geology and GDP potential, operators face several constraints. The key constraints faced by producers include low gas prices, a short drilling season, lack of existing infrastructure (pipelines and roadways), produced carbon dioxide (CO_2), and emerging water issues.[16] Although the remoteness and the distance of the Horn River Basin from large consuming markets in North America appear to be disadvantages, its proximity to Asian markets, via LNG, is breathing new life into shale gas in northeastern British Columbia. Not surprisingly, the geological potential of the Horn River Basin is attracting large independent

[12] "From Shale to Shining Shale", Deutsche Bank, July 22, 2008, pp. 38.
[13] Modern Shale Gas Development in the United States: A Primer, US Department of Energy, Office of Fossil Energy and the National Energy Technology Laboratory, April 2009, pp. 8.
[14] http://oilshalegas.com/hornrivershalebasin.html (accessed on September 8, 2010)
[15] Dawson, F M, "Shale Gas in North America: Emerging Supply Opportunities", Canadian Society for Unconventional Gas, October, 2008.
[16] "From Shale to Shining Shale", Deutsche Bank, July 22, 2008, pp. 38.

producers, as well as several mid-sized E&P companies. Figure 2.3 illustrates the landholdings within the Horn River Basin area. Currently, the top landholders in the region are Encana Corp., Apache Corp., EOG Resources and Nexen Inc., together holding exploration rights to over 760,000 net acres of Horn River land.

Other companies involved in the extraction of natural gas from the Horn River Shale include ExxonMobil/Imperial, Stone Mountain/Ramshorn Resources, Quicksilver Resources and Devon Energy. The aforementioned eight companies plus ConocoPhillips, Suncor Energy and Pengrowth Energy Trust, form the Horn River Basin Shale Producers Group. This group's mandate is to minimize the environmental footprint of the remote wilderness area and to facilitate cooperation between companies, First Nations and other key stakeholders.[17]

Figure 2.3: The Horn River Shale Region

Source: E&P Magazine[18]

[17] CAPP website, Collaboration – Horn River Basin Producers Group, http://www.capp.ca/ENERGYSUPPLY/INNOVATIONSTORIES/RELATIONSHIPSPARTNERS/Pages/Collaboration-HornRiverProducersGroup.aspx (accessed on July 22, 2012)

[18] E&P Magazine, "Horn River is a Play for the Ages", http://www.epmag.com/Production-Drilling/Horn-River-A-Play-The-Ages_82200 (accessed on July 22, 2012)

The following major players and their various mergers and acquisitions in the play are reviewed below: Encana, Apache, EOG Resources, and Nexen.

Encana began purchasing land in the Horn River Basin in 2003, and now holds 288,000 net acres in the Devonian shale;[19] including the total Greater Sierra area, which lies to the east and south, where the net acreage is approximately 1.8 million.[20] In the summer of 2006, Calgary-based Encana entered a 50/50 joint venture with Apache, as illustrated in Figure 2.3, in the Horn River.[21] Together Encana and Apache hold more than 430,000 net acres in the Horn River Basin.[22]

In 2008, the company drilled 11 wells, including 4 horizontal wells, using techniques similar to those used in the Texas Barnett.[23] Seven wells were completed in 2008, but this number increased in 2009 to 41 wells drilled, with 13 going online.[24] Encana's average production in 2010 was 29 million cubic feet per day (MMcfpd), up from 9 MMcfpd in 2009 and 4 MMcfpd in 2008.[25] Encana's daily net production averaged 24 MMcfpd in 2Q2010 in the Horn River, with 10 operating rigs.[26] Initial production rates for the first 30 days of production are reported to reach 8 MMcfpd, declining to 4 MMcfpd after one year.[27] Utilizing Debolt water processing, introduced in May 2010, for use in their frac'ing, Encana is achieving increases in drilling efficiencies.[28] In their 2Q2010 corporate update, Encana identified one well drilled in the Horn River to a total measured depth of just over 19,000 feet that is expected to have 28 fracture intervals when completed.[29]

[19] Encana website, Greater Sierra, http://www.encana.com/operations/canada/greater-sierra.html (accessed on July 22, 2012)
[20] Encana website, 2011 Key Resource Play Conference Call Series – Horn River, Calgary October 4, 2011, , http://www.encana.com/pdf/investors/presentations-events/100411-horn-river-conference-call.pdf (pp. 2) (accessed on July 22, 2012)
[21] Apache Corporation website, "Apache Canada takes the lead in shale gas production" (May 2008) http://www.apachecorp.com/explore/Browse_Archives/View_Article.aspx?Article.ItemID=595 (accessed on September 8, 2010)
[22] Kitimat LNG website, Natural Gas Supply, http://www.kitimatlngfacility.com/Supply/natural_gas_supply.aspx (accessed on July 22, 2012)
[23] ibid
[24] Encana website, 2011 Key Resource Play Conference Call Series – Horn River, Calgary October 4, 2011, , http://www.encana.com/pdf/investors/presentations-events/100411-horn-river-conference-call.pdf (pp. 9) (accessed on July 22, 2012)
[25] Ibid, pp. 2
[26] "Encana Q2 2010 Earnings Call Transcript" (July 27, 2010), http://seekingalpha.com/article/216690-encana-q2-2010-earnings-call-transcript (accessed on September 8, 2010)
[27] Oil Voice, "Encana Generates Third Quarter Cash Flow of US$2.8 billion" October 23, 2008, http://www.oilvoice.com/n/Encana_Generates_Third_Quarter_Cash_Flow_of_US28_billion/0fce3636.aspx, (accessed on July 22, 2012)
[28] Encana website, Debolt facility provides alternative to surface water sources, http://www.encana.com/news-stories/our-stories/environment-debolt-facility.html (accessed on July 22, 2012)
[29] Encana Q2 2010 Earning Call Transcript, July 27, 2010, http://seekingalpha.com/article/216690-encana-q2-2010-earnings-call-transcript?part=single (accessed on July 22, 2012)

Some of the acreage is attracting attention from other E&Ps eager to get into the Horn River Basin. Encana entered into a three-year agreement with Kogas Canada Ltd. (KOGAS); the latter is a subsidiary of Korea Gas Corporation, the world's largest importer of LNG, operating three LNG regasification terminals in South Korea.[30] KOGAS plans to invest C$565 million to earn a 50 percent interest in 154,000 net acres; 25,000 net acres are located in the Horn River while 129,000 net acres are in the Montney.[31] This agreement will enable Encana to accelerate E&P in the two highly prospective unconventional gas plays.[32]

At the 2011 Key Resource Play Conference in October 2011, Encana forecasted average production in 2011 to reach 266 MMcfpd.[33] In the same month, Encana agreed to sell its interest in the Cabin Gas Plant in the Horn River Basin.[34] The deal for approximately C$220 million is expected to help strengthen the company's balance sheet. Prolonged low natural gas prices have forced the company to refocus its 2012 capital program, allocating money into plays that have higher volumes of oil and natural gas liquids (NGLs).[35] The company is gearing its capital to liquids-rich plays, a decision that was announced in Encana's 4Q2011 Conference Call.

Encana's partner, Apache, holds approximately 207,000 net acres in the Horn River Basin area (and over 400,000 net acres total with Encana).[36] In a press release in April 2008, the company estimates that net gas resources on its acreage are between 9 and 16 Tcf.[37]

In April 2010, Apache completed frac'ing operations on the first well pad in the Horn River Basin.[38] This undertaking was nearly a decade in the making, after its first E&P activities commenced in the Ootla area of the Horn River Basin in 2001. Partnering up with Encana gave Apache access to knowledge and experience on unconventional gas development.[39]

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[30] Encana website, Encana generates third quarter cash flow of US$1.2 billion, or $1.57 per share, http://www.encana.com/news-stories/news-releases/details.html?release=627288 (accessed on July 22, 2012)
[31] ibid
[32] ibid
[33] Encana website, 2011 Key Resource Play Conference Call Series – Horn River, Calgary October 4, 2011, , http://www.encana.com/pdf/investors/presentations-events/100411-horn-river-conference-call.pdf (pp. 2) (accessed on July 22, 2012)
[34] Encana website, Encana agrees to sell interest in Horn River Cabin Gas Plant for approximately C$220 million, http://www.encana.com/news-stories/news-releases/details.html?release=615896, (accessed on July 22, 2012)
[35] Encana Management Discusses Q4 2011 Results, February 17, 2012, http://seekingalpha.com/article/375961-encana-management-discusses-q4-2011-results-earnings-call-transcript?part=single (accessed on July 22, 2012)
[36] Apache Corporation website, Region Overview, http://www.apachecorp.com/Operations/Canada/Region_overview/index.aspx (accessed on July 22, 2012)
[37] Stockhouse website, "Apache Canada takes the lead in shale gas production" (May 2008) http://www.stockhouse.com/Bullboards/MessageDetail.aspx?s=MOO&t=LIST&m=28560153&l=0&pd=0&r=0 (accessed on July 22, 2012)
[38] Apache Corporation website, "The Horn River Project" (July 2010), http://www.apachecorp.com/News/Articles/View_Article.aspx?Article.ItemID=1130 (accessed on July 22, 2012)
[39] ibid

Apache reported an 18 percent increase in production in 3Q2011, compared to a 2Q2011 average of 98 MMcfpd.[40] As of early 2012, the company reports that it has drilled, completed and began producing 69 horizontal wells.[41] Production peaked in September 2011 at a new rate of 149 MMcfpd.[42]

EOG Resources holds 157,500 net acres of Horn River land.[43] In an investor presentation in March 2009, EOG estimates that net gas resources on its acreage are approximately 6 Tcf, assuming a 25 percent recovery rate. Some analysts project that their potential reserves could be as high as 9 Tcf.[44] However, due to the regions limited pipeline infrastructure, EOG does not believe full scale production will be possible until 2012.[45] Like Encana, the company is maintaining a minimal drilling program after 2011.[46] The objective is currently to maintain its landholdings so that it can refocus its capital programs on oil and liquids-rich gas resources.[47] With operations across North America, Trinidad & Tobago, and Argentina, the company proposes to exploit existing assets and to explore opportunities that are focused on oil and wet gas (NGLs).[48]

It is important to note that the 3 aforementioned players (Encana, Apache and EOG) are partners in the approved Kitimat LNG facility, located at Bish Cove, near Kitimat, British Columbia. Apache currently owns a 40 percent stake in the planned project, while Encana and EOG Resources have 30 percent each. The mandate of the planned Kitimat LNG facility is to export natural gas from the Horn River Basin (and now the Liard Basin) to Asian markets, such as Japan, South Korea and China. This facility is discussed in much greater detail in the LNG section.

Nexen is another active player in the Horn River Basin and its position in the play is growing. Landholdings in the Horn River area expanded to over 300,000 net acres, up from 123,000 net

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[40] Oilshalegas.com website, Horn River Basin, http://oilshalegas.com/hornrivershalebasin.html (accessed on September 10, 2010)
[41] Apache website, British Columbia Operations, http://www.apachecorp.com/Operations/Canada/British_Columbia/index.aspx (accessed on July 22, 2012)
[42] ibid
[43] Oilshalegas.com website, Horn River Basin, http://oilshalegas.com/hornrivershalebasin.html (accessed on July 22, 2012)
[44] British Columbia Ministry of Energy and Mines, "The Status of Exploration and Development Activities in the Montney Play Region of Northeast BC", Christopher Adams Presentation, April 2, 2012, http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/2011Documents/C%20Adams.pdf (pp. 14)
[45] oilshalegas.com/hornriverbasin.html (accessed on July 22, 2012)
[46] British Columbia Ministry of Energy and Mines, "The Status of Exploration and Development Activities in the Montney Play Region of Northeast BC", Christopher Adams Presentation, April 2, 2012, http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalGas/Documents/2011Documents/C%20Adams.pdf (pp. 14)
[47] EOG Resources, A Hidden Gem in a Tumultuous Market, July 17, 2012, http://seekingalpha.com/article/725481-eog-resources-a-hidden-gem-in-a-tumultuous-market (accessed on July 22, 2012)
[48] ibid

acres, following a land sale in June 2010.[49] The company announced the potential for a net 3 to 6 Tcf of recoverable reserves in the Horn River Basin on its 123,000 net acres in the play.[50] Of this net acreage, 90,000 net acres are in the highly-touted Dilly Creek area. The company suggests that between 500 and 700 wells could be drilled in its land holdings[51] that extend into the Liard Basin and Cordova Embayment.[52] Some analysts suggest that there may be between 4 and 15 Tcf of recoverable natural gas on those holdings.[53] The company expects to increase its production capacity to 175 MMcfpd by end-2012.[54] The company has budgeted between C$50 million and C$75 million in net capital in 2012 to develop shale gas properties in northeastern British Columbia.[55]

Nexen entered a joint venture with INPEX Gas British Columbia, which is owned by INPEX Corporation and JGC Corporation.[56] Both Japanese companies have experience in LNG operations, in production and engineering.[57] Nexen is to receive C$700 million for a 40 percent interest in properties in the Horn River, Liard and the Cordova Embayment.[58] The joint venture with INPEX and JGC is expected to be complete in 2Q2012.[59] Recently, Nexen agreed to be acquired by the China National Offshore Oil Company (CNOOC) for approximately 15 billion dollars.[60]

On May 31, 2011, it was announced that Tokyo Gas, Osaka Gas, Chubu Electric and JOGMEC will be joining Mitsubishi in its Penn West joint venture.[61]

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[49] Nexen website, Nexen Announces Strong 2010 Results and Recaps Successful Year, February 16, 2011, http://www.nexeninc.com/en/AboutUs/MediaCentre/NewsReleases/News/Release.aspx?year=2011&release_id=118189 (accessed on July 22, 2012)

[50] Nexen Q12009 Earning Report, http://www.slideshare.net/earningreport/q1-2009-earning-report-of-nexen-inc (accessed on July 22, 2012)

[51] Nexen on the Hunt for Canada Shale Gas Partner, http://hornrivernews.com/tag/nexen-inc/ (accessed on July 22, 2012)

[52] Nexen website, Nexen Announces Strong 2010 Results and Recaps Successful Year, February 16, 2011, http://www.nexeninc.com/en/AboutUs/MediaCentre/NewsReleases/News/Release.aspx?year=2011&release_id=118189 (accessed on July 22, 2012)

[53] ibid

[54] Nexen website, Growth Plans, http://www.nexeninc.com/en/Operations/ShaleGas/GrowthPlans.aspx (accessed on July 22, 2012)

[55] Nexen and the Horn River Shale, December 5, 2011, http://www.investopedia.com/stock-analysis/2011/Nexen-And-The-Horn-River-Shale-NXY-TOT-APA-EOG-ECA1205.aspx#axzz2108c9vyd (accessed on July 22, 2012)

[56] ibid

[57] ibid

[58] ibid

[59] Nexen website, Nexen Announces First Quarter Results, April 25, 2012, http://www.nexeninc.com/en/AboutUs/MediaCentre/NewsReleases/News/Release.aspx?year=2012&release_id=127324 (accessed on July 22, 2012)

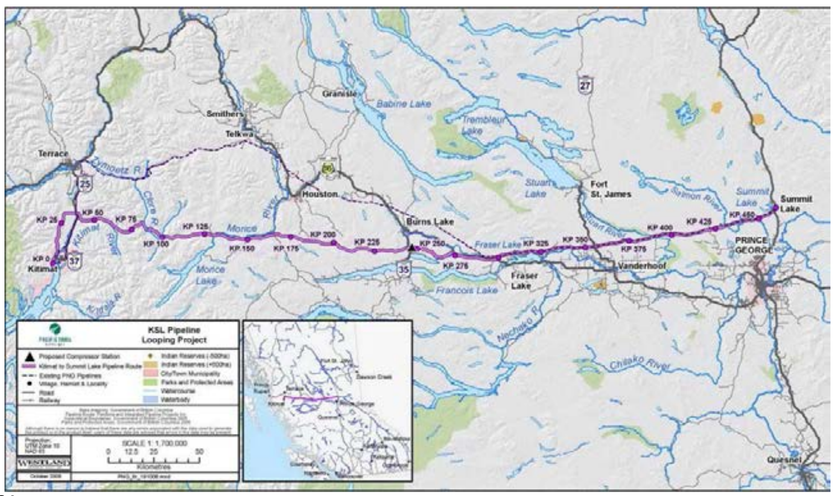
[60] China's CNOOC offers $15B for Calgary oil firm Nexen. *July 23rd 2012*. CBC news. (Accessed July 26th 2012 from http://www.cbc.ca/news/business/story/2012/07/23/20120723-nexen.html?cmp=rss)

[61] Canadian Shale Horn River Play Attracts Further Japanese Interest in Penn West JV, May 13, 2011, http://www.stockopedia.co.uk/content/canadian-shale-horn-river-play-attracts-further-japanese-interest-in-penn-west-jv-56508/

Pacific Trail Pipeline

The approved C$1 billion Pacific Trail Pipeline (PTP) will loop the existing Pacific Northern Gas pipeline, and will connect the Spectra Energy Transmission system at Summit Lake to the proposed Kitimat LNG terminal The pipeline received approval from Transport Canada and Fisheries and Oceans Canada. The Kitimat-to-Summit-Lake Pipeline Looping Project will be approximately 462 kilometers (287 miles) in length, and have a capacity of 1 Bcfpd. Pipeline construction is slated to be completed by 2015 and is illustrated in Figure 2.4.[62] Recently, the pipeline diameter was increased from 36" to 42". This increase allows for the doubling of the 1 Bcfpd capacity if needed[63].

Figure 2.4: Kitimat to Summit Lake Pipeline Looping Project



Source: BCTWA[64]

Liquefied Natural Gas

LNG is attracting a lot of interest in North America but for different reasons than a few years ago. This is particularly the case in British Columbia. In the early 2000s concerns of record high natural gas prices, increasing consumption, combined with the belief that North American natural gas resources were thought to have reached a plateau, spurring an interest in importing LNG to increase supply. Another factor fueling the considerable interest was rapid technological advance, which impacted the LNG value chain, decreasing the cost of liquefaction, shipping, re-gasification, and storing of LNG, making it an economically viable option. In spite of being the world's largest producer of natural gas, North America has traditionally been an importer of

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[62] Pacific Trail Pipelines, About, http://www.pacifictrailpipelines.com/project.aspx (accessed on July 22, 2012)

[63] Widening of gas pipeline to Kitimat wins approval: B.C. Terminal would ship fuel to Asia. *April 18th 2012*. Calgary Herald. (Accessed July 26th 2012 from http://www.calgaryherald.com/business/energy-resources/Kitimat%20LNG%20export%20terminal%20wins%20application%20to%20widen%20pipeline%20feeding%20it/6474618/story.html)

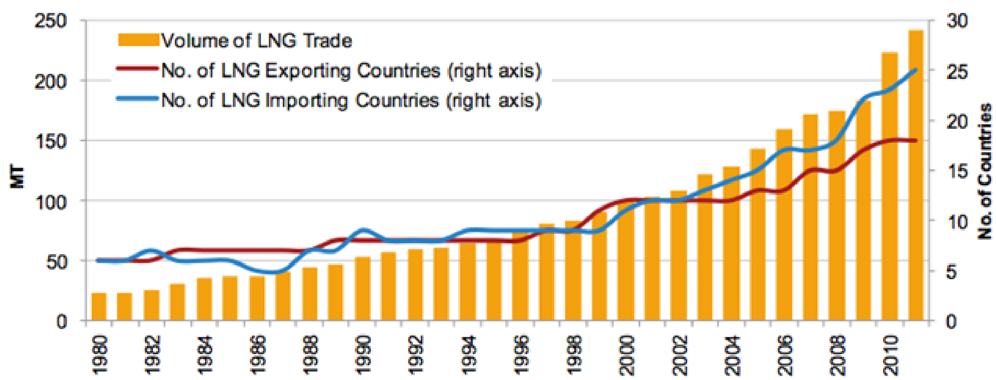
[64] BCTWA website, http://www.bctwa.org/FrkBC-KitimatChronlogy-Apr19-2011.pdf (accessed on July 22, 2012)

LNG.[65] Recently, depressed North American prices have shifted the focus to exporting rather than importing LNG.

Global LNG Trade

There has been substantial growth in world LNG trades with 20.7 megatonnes annually (MTA) in 2010 and 7.8 MTA added in 2011. Furthermore, numerous countries became importers of LNG. However, the International Gas Union (IGU) reports that a global gas market has not been established despite the increases in interregional trade. Figure 2.5 shows the changes in LNG imports and exports from 1980 to 2011. LNG trade volumes in 2011 are at 240.8 Mt, or approximately 530 million cubic meters.[66] This is an increase of 20.7 Mt or 9.4 percent over 2010 trade volumes.[67] Trade volumes were 140 Mt in 2005, 158 Mt in 2006 and 165 Mt in 2007.[68] Trade volumes are expected to reach nearly 300 Mt by 2012.

Figure 2.5: Global LNG Trade 1980-2011



Sources: Cedigaz, Waterborne LNG Reports, US Energy Information Agency (EIA), US Department of Energy (DOE), PFC Energy

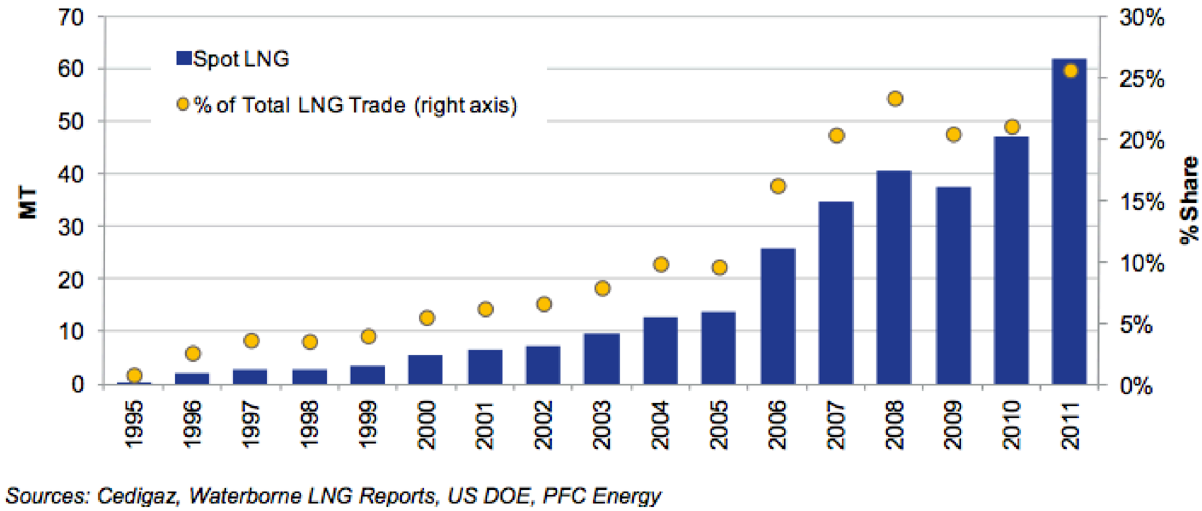
Source: International Gas Union[69]

Importers in Europe have faced decreasing demand because of increased utilization of alternative energy sources such as renewables. The exception is Germany because it will stop using nuclear and thus will need substantial natural gas supplies. In contrast, in many developing countries, natural gas has become a fuel of choice, so they have started to build regasification terminals to meet their energy demands. The increased interregional trade has resulted in a spot market that is increasingly taking a share of the market. However, the

[65] "Liquefied Natural Gas: A Canadian Perspective", National Energy Board, February 2009, pp. viii, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/lqfdntrlgscndnprspctv2009/lqfdntrlgscndnprspctv2009-eng.pdf
[66] IGU World LNG Report, 2011, pp. 5
[67] ibid
[68] IGU World LNG Report, 2011, pp. 7
[69] IGU. 2012. *World LNG Report 2011*.

majority of LNG shipments still occur under contracts between long-term sellers and buyers.[70] Figure 2.6 shows spot market trades from 1995 to 2011.

Figure 2.6: Spot Market Trade from 1995 to 2011



Source: IGU[71]

Despite increases in spot trading, most of the LNG contract prices are set by oil-linked price systems, especially in Asia. These oil-linked prices may be determined by numerous factors such as indexes, S-curves, and averaging mechanisms. Due to the high prices of oil globally these oil-linked natural gas prices make Asian markets attractive to Canadian gas producers. Table 2.4 gives an example of how gas pricing varies with oil prices.

Table 2.4: LNG Brent-Linked Prices with Varying Brent Oil Prices

Brent Oil Price $/bbl	Equivalent Brent-Linked LNG Price ($/MMBtu)
80	11.20
100	14.00
120	16.80
140	19.60
160	22.40

Source: Pehlivanova (Oil and Gas Journal) [72][73]

Furthermore, the Tsunami in Japan as well as stringent environmental standards emerging in Asia has created a demand for spot cargoes, which has caused the spot price to increase over

[70] Ibid
[71] Ibid.
[72] Pehlivanova, B. 2011. *North American LNG exports complicated by alternative markets, investment costs.* Oil and Gas Journal. 109(17):130-135.
[73] Ibid.

the last year. Lastly, prices for charters have been increasing as the amount of trade has increased and until more ships can be built the ability to transport will remain costly.[74]

LNG Terminals: Risks and Barriers

Recently Qatar has added substantial liquefaction capacity and Australia is rapidly trying to add capacity as well. Australia has started adding liquefaction capacity because there is currently a moratorium in Qatar on adding export capacity.[75] Table 2.5 shows the planned liquefaction additions for 2011.

Table 2.5: Planned Liquefaction Additions and Capacity

	Atlantic/Med.	Middle East	Pacific	Global Total
Decommissioned	0.9		8.3	9.2
Existing	77.8	100.3	100.6	278.7
Under Construction	14.4		69.6	84.0
Pre-FEED	12.3	3.2	29.4	44.9
In FEED	20.9		38.0	58.9
FEED Completed	55.6		13.1	68.7
Proposed without Announced Progress	101.8	7.0	160.4	269.1
Total	**283.6**	**110.5**	**419.4**	**813.5**

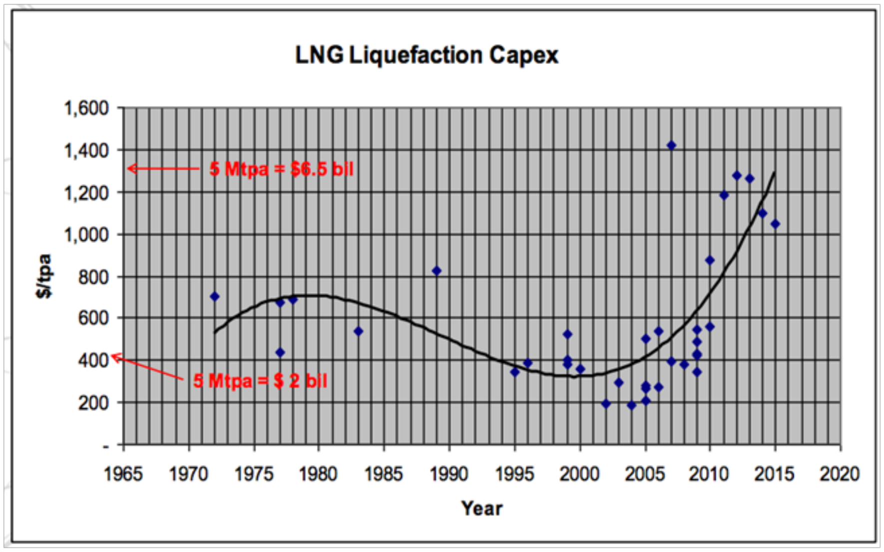
*Note: Under Construction does not have the 10.8 MTA announced in Iran

Source: IGU[76]

The capital-intensive nature of most liquefaction plants requires long-term contracts and high utilization rates in order to obtain a decent rate of return. As the technology has improved to build larger and larger liquefaction trains, the costs until 2003-2005 had been falling. Recently, with so many liquefaction plants proposed and being constructed the costs of building the plants have been increasing since the 2003-2005 period. For example, the Australian floating Ichthys liquefaction facility that is now slated to start in 2017 will now cost $34 billion as opposed to its 2008 estimate of $20 billion.[77,78] Figure 2.7 shows Wood Mackenzie's estimate of how capital costs for LNG plants may be affected over time.

74 IGU. 2012. *World LNG Report 2011*.
75 Ibid
76 IGU. 2012. *World LNG Report 2011*.
77 Wall Street Wire. January 13th 2012. *Australia LNG Project to Cost $34 Billion (Tot).* Accessed June 13th 2012 from http://247wallst.com/2012/01/13/australian-lng-project-to-cost-34-billion-tot/
78 It should be noted that this project will cost significantly more than the Kitimat LNG project because it includes a floating platform and various other infrastructure that would not be present for the Kitimat LNG project.

Figure 2.7: Liquefaction Capital Cost Projections



Source: Wood Mackenzie[79]

The escalation in capital costs for a liquefaction facility could substantially increase costs for Canadian producers attempting to enter the LNG market.

One of the main barriers in the development of new LNG receiving/shipping terminals is the location of terminals. It is becoming fundamentally difficult because numerous factors must converge to make a location suitable. LNG re-gasification and liquefaction facilities have to be located at tanker-friendly seaports near a major gas pipeline. Yet they need a lot of space for safety and security reasons, which further narrows the list of acceptable locations.

While FERC and Marad license proposed terminals in the United States, proposed LNG terminals in Canada are subject to stringent requirements and approvals by a number of federal and provincial organizations. Permitting seems to be a drawn-out process, as there is little experience with LNG facilities. On the federal level, an LNG facility must satisfy agencies such as the Canadian Environmental Assessment Agency, Transport Canada Marine Safety Navigable Waters, Transport Canada Environmental Affairs Environmental Programs, Transport Canada Marine Security, Transport Canada Marine Safety Compliance and Enforcement, Fisheries and Oceans Canada, Environment Canada and the NEB.[80] On the provincial level, an LNG facility must gain approval from provincial Utility Commissions and the provincial environmental assessment offices and transportation ministries.[81] In British Columbia, for example, an LNG proposal needs to pass through the British Columbia Utilities Commission (BCUC), British Columbia Environmental Assessment Office, Land and Water British Columbia, British Columbia

[79] Current State & Outlook for the LNG Industry. Rice Global E&C Forum: Engineering & Construction. Accessed March 20th 2012 from http://www.forum.rice.edu/wp-content/uploads/2011/06/RT_110909_Humphries.pdf
[80] NRCAN website, LNG Regulatory Requirements, http://www.nrcan.gc.ca/eneene/sources/natnat/regreg-eng.php (accessed on July 22, 2012)
[81] ibid

Oil and Gas Commission, British Columbia Ministry of Transportation and the local district where the facility is located (i.e., District of Kitimat).[82]

All LNG facilities must satisfy the Canadian Environmental Assessment Act (CEAA). In addition, any new or altered works in, on or over navigable water require approval from the Regional Superintendent of Navigable Waters Protection. Approval comes after, among other things, a positive environmental assessment (EA) from Transport Canada Environmental Affairs. For example, the Marine Transport Security Regulations (MTSR) requires that the LNG facility, port and ship have a security plan.[83] This plan must be approved by Transport Canada Marine Security.[84]

The regulations for operation of LNG terminals are rigorous and are centered on safety of the public and the employees of the terminal. The same is true for LNG receiving or shipping terminals. LNG terminals are designed to include spill containment systems, fire protection systems, multiple gas, flame, smoke and low- and high-temperature detectors and alarms, and automatic and manual shut-down systems.[85]

Despite the fact that the LNG industry has an exemplary safety record, many local concerns manifest themselves in “not-in-my-backyard” (NIMBY). And while issues of NIMBYism seem to be diminishing over time, or at least put in perspective, they are still a factor. In March 2004, voters in Harpswell, Maine, rejected plans to build a new US$350 million LNG terminal on a former Navy fuel depot site because it was considered too close to the residential area.[86] Residents argued that LNG terminals would harm the nearby fisheries in terms of trap loss from vessel traffic and displacement of fishing activity as a result of security exclusion zones around the terminal berths.[87] The project has been cancelled. The Québec Rabaska terminal that was to be located near Québec City was forced to find a new location at Lévis. The project faced strong local opposition in the old location. The project appears to be on hold. While WestPac’s terminal in British Columbia was the result of the changing natural gas business, the now-cancelled terminal faced considerable opposition from various environmental and First Nations groups.

Despite the stringent approval process, the situation with LNG applications in North America, and in particular British Columbia, remains fluid.

[82] ibid
[83] ibid
[84] ibid
[85] Center for Liquefied Natural Gas, Safety and Security Facts, http://www.lngfacts.org/resources/CLNG_Safe-Sec.pdf (pp. 2)
[86] Harpswell Rejects LNG, March 10, 2004, Dennis Hoey, http://www.pressherald.com/news/coast/040310harpswell.shtml
[87] ibid

According to FERC, as of May 24, 2012 there are 3 proposed/pending proposals in Canada: Kitimat LNG, BC LNG Export Co-operative (BC LNG) and LNG Canada.[88] All three are export terminals aiming to export shale gas from northeastern British Columbia. Both Kitimat LNG and BC LNG have received approval and are awaiting construction.

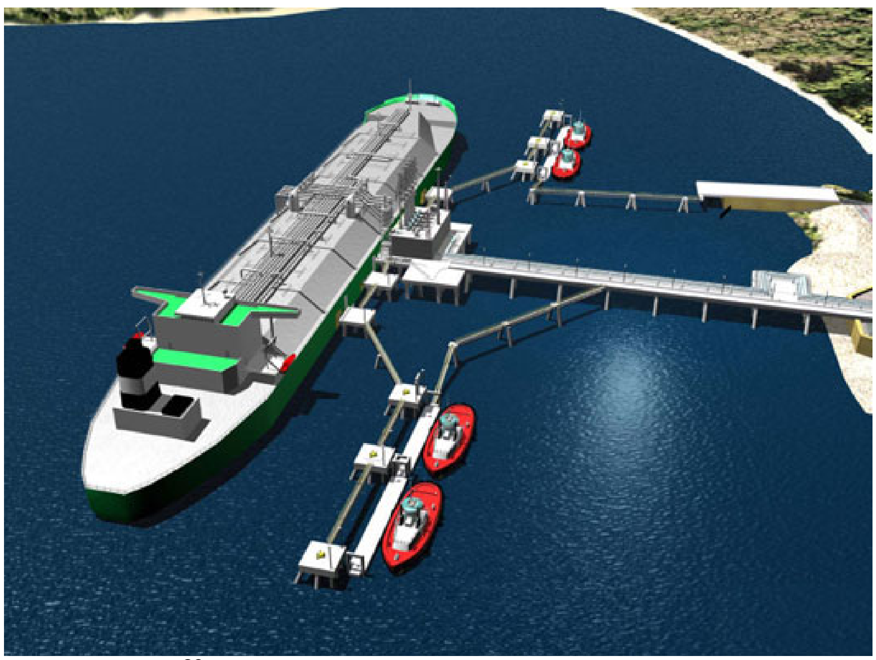
LNG in British Columbia

Kitimat LNG

Kitimat LNG is Canada's first proposed and approved LNG export terminal. The liquefaction terminal is located at Bish Cove, near the Port of Kitimat, and is a partnership among Apache, Encana and EOG Resources.

Figure 2.8 illustrates the Kitimat LNG terminal.

Figure 2.8: An Artist's Rendering of the Kitimat LNG Terminal Project



Source: Kitimat LNG website[89]

Kitimat LNG has an initial planned capacity of approximately 700 MMcfpd (or approximately 5 million metric tonnes of LNG per annum).[90] The capacity of the facility, however, can be

[88] FERC website, LNG Proposed/Pending LNG, http://ferc.gov/industries/gas/indus-act/lng/LNG-proposed-potential.pdf (accessed on July 22, 2012)
[89] Kitimat LNG website, Safety by design, http://www.kitimatlngfacility.com/Project/safety.aspx (accessed on July 22, 2012)
[90] Kitimat LNG website, Kitimat LNG Partners Announce Export License Approval By National Energy Board, http://mediacenter.kitimatlngfacility.com/Mediacenter/view_press_release.aspx?PressRelease.ItemID=2816 (accessed on July 22, 2012)

increased to approximately 1.4 Bcfpd, or 10 mmtpa.[91] The total cost of the project is approximately C$4.5 billion.

The planned LNG facility received provincial environmental assessment approval in January 2009 and received federal environmental assessment approval in December 2008.[92] The project was granted a construction deadline extension on May 12, 2011.[93] Announced at the end of May, the British Columbia Environmental Assessment Office granted a 4-year extension to complete a "substantial construction" by June 1, 2016.[94] The Kitimat LNG exporting terminal, of which Encana, Apache and EOG are partners, received approval for a 20-year export license to serve international markets in October 2011.[95]

BC LNG Export Co-operative (BC LNG)

BC LNG is the second LNG exporting proposal submitted to the NEB. Submitted on March 8, 2011, the smaller facility is also located in the Kitimat area and is targeting growing Asian markets for natural gas.[96] The project received a 20-year license to export LNG to international markets.[97] The project is undergoing an environmental assessment in accordance with the Canadian Environment Assessment Act (CEAA).[98] The facility is expected to export its first shipment in late 2013 or early 2014.[99]

At 0.250 Bcfpd, the BC LNG facility is much smaller than the Kitimat LNG.[100] The cost of the terminal is estimated to be in the range of C$360-450 million.[101] The application submitted to the NEB suggests that the Douglas Channel Energy Partnership (DCEP) will operate the facility.

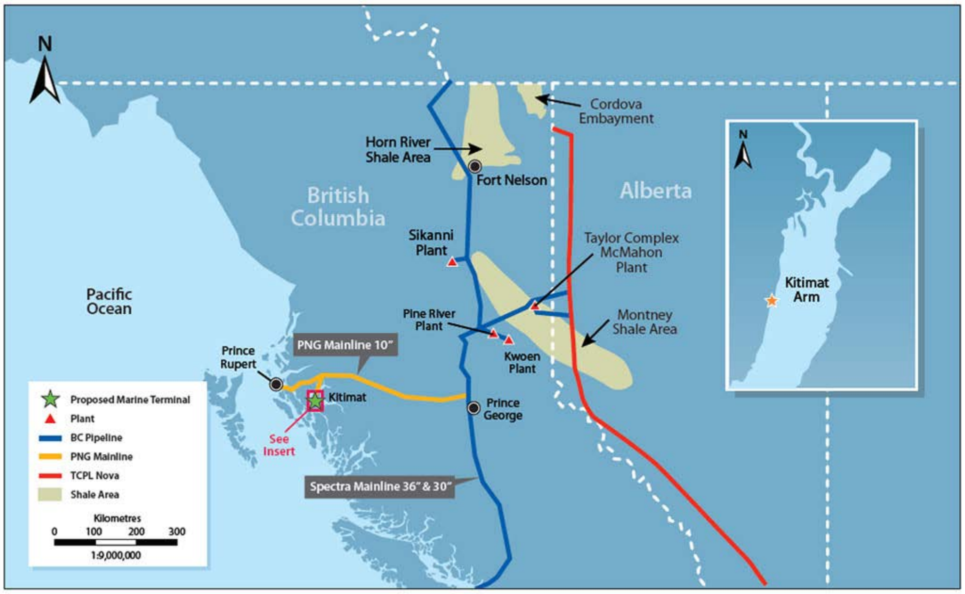
[91] ibid
[92] Kitimat LNG website, http://www.kitimatlngfacility.com/ (accessed on July 22, 2012)
[93] Energetic City website, LNG terminal construction deadline extension, May 30, 2011, http://www.energeticcity.ca/fortstjohn/news/05/30/11/lng-terminal-construction-deadline-extension (accessed on July 22, 2012)
[94] Kitimat LNG Project Granted Extension, May 30, 2011, http://www.opinion250.com/blog/view/20363/1/kitimat+lng+project+granted+extension (accessed on July 22, 2012)
[95] Kitimat LNG website, Kitimat LNG Partners Announce Export License Approval By National Energy Board, http://mediacenter.kitimatlngfacility.com/Mediacenter/view_press_release.aspx?PressRelease.ItemID=2816 (accessed on July 22, 2012)
[96] Pipeline News North, NEB Gets Another Application Proposing to Export LNG off BC Coast, March 16, 2011, http://www.pipelinenewsnorth.ca/article/20110316/PIPELINE0119/303169976/-1/pipeline/neb-gets-another-application-proposing-to-export-lng-off-bc-coast (accessed on July 22, 2012)
[97] NRCAN website, BC LNG Export License, http://www.nrcan.gc.ca/media-room/news-release/2012/44a/6142 (accessed on July 22, 2012)
[98] NRCAN website, Government of Canada Approves License to Export Liquefied Natural Gas, http://www.nrcan.gc.ca/media-room/news-release/2012/44/6140 (accessed on July 22, 2012)
[99] ibid
[100] Pipeline News North, NEB Gets Another Application Proposing to Export LNG off BC Coast, March 16, 2011,http://www.pipelinenewsnorth.ca/article/20110316/PIPELINE0119/303169976/-1/pipeline/neb-gets-another-application-proposing-to-export-lng-off-bc-coast (accessed on July 22, 2012)

While the Kitimat LNG proposal is led by three major energy companies, the BC LNG proposal is led by a partnership named BC LNG Export Cooperative LLC. The latter is a cooperative owned by the Haisla Nations Douglas Channel LNG LP and Houston-based LNG Partners LLC.[102] The arrangement is 50:50 with plans to export LNG from Douglas Island. And unlike the Kitimat LNG proposal, neither group in the Douglas Island LNG proposal has its own natural gas fields, but is strictly a conduit for those that are interested in exporting natural gas.[103] The founders of LNG Partners LLC were involved with Leviathan Gas Pipeline Partners LP, which was subsequently bought by El Paso Natural Gas Company for US$450 million in 1998.[104]

The project not only differs in size and scope from the Kitimat LNG proposal, it is unique in that it will utilize a barge-based LNG plant. The facility will also include an LNG carrier berth and other onshore facilities, such as storage containers.[105] The small-scale project is best described as utilizing an unused technique while using proven technology. Douglas Island's alternate plan is to build a land-based liquefaction plant on its site.[106] DECP plans to utilize excess natural gas pipeline capacity from Pacific Northern Gas (PNG) Mainline.[107] Figure 2.9 illustrates the proposed facility and its proximity to the PNG Mainline, as well as the Horn River Basin and the Montney.

[101] Another B.C. company jumps on LNG bandwagon, http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/another-bc-company-jumps-on-lng-bandwagon/article575746/ (accessed on July 22, 2012)
[102] Pipeline News North, NEB Gets Another Application Proposing to Export LNG off BC Coast, March 16, 2011,http://www.pipelinenewsnorth.ca/article/20110316/PIPELINE0119/303169976/-1/pipeline/neb-gets-another-application-proposing-to-export-lng-off-bc-coast (accessed on July 22, 2012)
[103] Northern Sentinel Website, LNG Co-op business plan outlined, April 29, 2011, http://www.bclocalnews.com/bc_north/northernsentinel/news/120631289.html?mobile=true (accessed on July 22, 2012)
[104] Another B.C. company jumps on LNG bandwagon, http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/another-bc-company-jumps-on-lng-bandwagon/article575746/ (accessed on July 22, 2012)
[105] Douglas Channel Energy website, http://douglaschannelenergy.com/ (accessed on July 22, 2012)
[106] Northern Sentinel, Another LNG project seeks export okay, April 1, 2011, http://www.bclocalnews.com/news/118850779.html?c=y&curSection=/greater_vancouver/bowenislandundercurrent&curTitle=BC+News&bc09=true (accessed on July 22, 2012)
[107] Douglas Channel Energy website, http://douglaschannelenergy.com/ (accessed on July 22, 2012)

Figure 2.9: Map of the BC LNG Facility and PNG Mainline



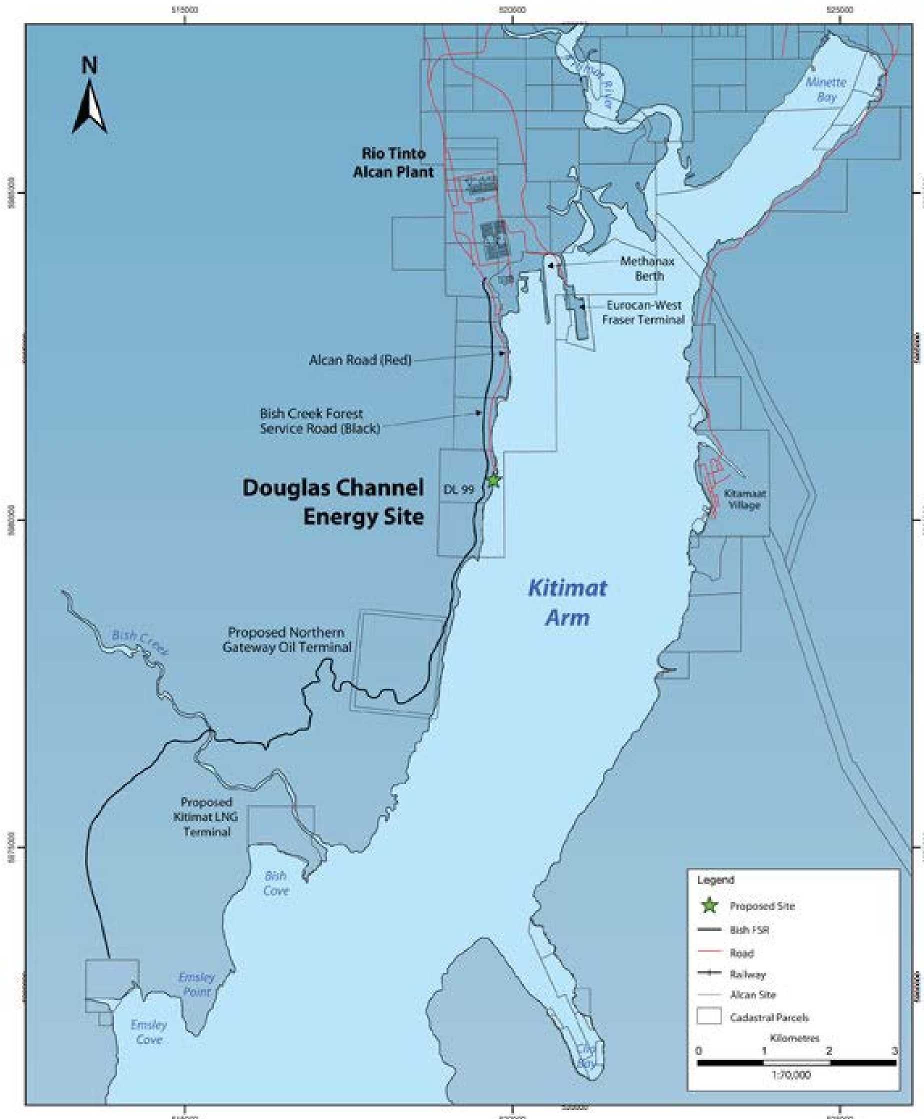
Source: DCEP website

The proposed terminal is located in the Kitimat Arm inlet and located close to the proposed Northern Gateway oil terminal and the much larger proposed Kitimat LNG.[108]

Figure 2.10 illustrates the proposed location of the BC LNG liquefaction facility. It is labeled as the Douglas Channel Energy Site. The map also shows the location of the proposed Kitimat LNG facility, as well as the location of Enbridge's proposed Northern Gateway oil terminal.

[108] Northern Sentinel, Another LNG project seeks export okay, April 1, 2011, http://www.bclocalnews.com/news/118850779.html?c=y&curSection=/greater_vancouver/bowenislandundercurrent&curTitle=BC+News&bc09=true

Figure 2.10: Location of the Proposed Douglas Island LNG Facility



Source: DCEP website

It is interesting to note that the location of BC LNG is across the inlet from Kitimat Village, the traditional home of the Haisla First Nations.[109] In spite of LNG NIMBYism in other parts of North America, including parts of British Columbia, it seems that First Nations in the Kitimat region generally support gas exports.[110] Beyond the BC LNG proposal, there seem to be few protests with other LNG proposals in the region. The same, however, cannot be said for the oil side of the energy business. Enbridge's Northern Gateway Pipeline proposal has encountered considerable resistance.

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[109] Kitimat District website, http://www.kitimat.ca/EN/main/visitors/regional-attractions/kitimaat-village.html (accessed on July 22, 2012)

[110] CTV News, Another B.C. company jumps on LNG bandwagon, Nathan Vanderklippe, http://www.ctv.ca/generic/generated/static/business/article1955836.html (accessed on July 22, 2012)

LNG Canada

Shell Canada and Nexen publicly supported exporting production from British Columbia's growing shale gas plays in 2010.[111] Both are players in British Columbia's shale gas. At the time, Kitimat LNG was the only proposed facility.[112]

Shell's new LNG project is now called LNG Canada, and is spearheaded by Shell Canada's parent company, Royal Dutch Shell. The facility is being planned in Kitimat. On May 15, 2012, Royal Dutch Shell announced that it plans to build a large export terminal, capable of shipping 2.0 Bcfpd.[113] As the largest terminal off the British Columbia coast, it is also the most expensive at C$12 billion.[114] Royal Dutch Shell will have a 40 percent stake while PetroChina, Mitsubishi and KOGAS will have 20 percent each.[115] The regulatory process is expected to commence late in 2012.

Other LNG Terminals in BC

One of the newest players in the Montney, PETRONAS, signed a US$1.1 billion deal with Alberta-based Progress Energy Resources Corporation in June 2011.[116] PETRONAS is Malaysia's national oil and gas company and is one of the largest LNG players in the world; Progress produces 75 MMcfpd from its Montney holdings, up from 10 MMcfpd last year.[117] PETRONAS clearly wanted to enter the North American shale game, solidifying its status as one of the global LNG leaders. Just over a year later, the Kuala Lumpur-based PETRONAS offered to take over Calgary-based Progress for C$5.5 billion.[118]

At the time of the initial deal, PETRONAS and Progress announced that they will launch a feasibility study to explore the possibility of constructing liquefaction on the west coast of British Columbia.[119] While the venture is 50:50 to develop the North Montney's Altares, Lily and Kahta properties, the potential LNG facility will be 80:20, with PETRONAS leading the way.[120]

[111] Petroleum Economist, Shell, Nexen back Canada LNG export plan, November 4, 2010, http://www.petroleum-economist.com/Article/2745956/Shell-Nexen-back-Canada-LNG-export-plan.html (accessed on July 22, 2012)
[112] ibid
[113] B.C. liquefied natural gas terminal planned, http://www.canadianbusiness.com/article/87311--b-c-liquefied-natural-gas-terminal-planned (accessed on July 22, 2012)
[114] ibid
[115] Shell moves closer to Kitimat LNG terminal, http://www.cbc.ca/news/business/story/2012/05/15/shell-lng-kitimat.html (accessed on July 22, 2012)
[116] Malaysia signs Canadian shale gas deal, June 3, 2011, http://www.upi.com/Business_News/Energy-Resources/2011/06/03/Malaysia-signs-Canadian-shale-gas-deal/UPI-30541307123832/ (accessed on July 22, 2012)
[117] ibid
[118] Canada's natural gas dreams closer to reality after Petronas moves, June 28, 2012, http://business.financialpost.com/2012/06/28/canadas-natural-gas-dreams-closer-to-reality-after-petronas-moves/ (accessed on July 22, 2012)
[119] Progress Energy website, North Montney Joint Venture, http://www.progressenergy.com/operations/north-montney-joint-venture (accessed on July 22, 2012)
[120] ibid

PETRONAS will be the operator of the facility, but both organizations would jointly market the LNG.[121]

One of the advantages of PETRONAS is the fact that it controls various aspects of the business, from the natural gas resources in British Columbia to the planned LNG facility in Prince Rupert, and has strong links to the Asian market.[122]

On June 28, 2012, the second largest LNG exporter in the world[123] announced it wants to export natural gas to Asia, via a planned export LNG terminal in Prince Rupert, British Columbia.[124] PETRONAS has not yet applied for a license but favours a particular site – Lelu Island, just south of Prince Rupert's Ridley Terminal.

[121] Progress Energy website, Progress Energy Announces Strategic Partnership with PETRONAS to Develop Montney Shale Assets, http://www.progressenergy.com/wp-content/uploads/2011/06/Progress-News-Release.pdf (accessed on July 22, 2012)
[122] Canada's natural gas dreams closer to reality after Petronas moves, June 28, 2012, http://business.financialpost.com/2012/06/28/canadas-natural-gas-dreams-closer-to-reality-after-petronas-moves/ (accessed on July 22, 2012)
[123] ibid
[124] Malaysia makes big bet on natural gas from Canada, http://www.theglobeandmail.com/globe-investor/malaysia-makes-big-bet-on-natural-gas-from-canada/article4376077/ (accessed on July 22, 2012)

Chapter 3: Methodology and Assumptions

This chapter explains the Regional I/O methodology and the capital costs assumptions on how the pipelines' investments and operations that feed into the model, are broken down by region within the boundaries of Alberta and British Columbia.

Provincial and Regional I/O Methodology

Input-output analysis addresses the way economic circumstances in one part of an economy can ripple through the rest of it. In particular, it is concerned with inter-industry relationships, notably the use output from one industry as an input into another industry's production process. The demand for such inputs is called *intermediate demand*, which is distinct from the *final demand* categories of personal consumption expenditures, government current expenditures, gross fixed capital formation (acquisition of machinery and equipment, construction of housing and other structures), net increases in inventories, and net exports. As these relationships are highly data-intensive, input-output analysis makes the following important simplifying assumptions:

- *Fixed proportions* – no scope for substitution among inputs: even if coal becomes cheaper relative to iron ore, for example, under fixed proportions one cannot take advantage of this price change by using more coal and less iron ore to make steel.
- *No economies or diseconomies of scale* – an increase or decrease in an industry's output entails proportionate increase or decrease to each of its inputs.

The following example requires the reader to have some knowledge of matrix algebra. Consider an economy with no external trade, no government, no need for transportation or wholesale/retail trade and therefore no resource cost in getting the product from producer to customer, and just three industries. Each of these industries satisfies both intermediate and final demands for its products. In this example, inputs and outputs could be measured in dollars or in physical units; in realistic cases physical units would be impractical. Given a set of final demands (f_1 for industry 1, f_2 for industry 2 and f_3 for industry 3) and a set of input coefficients (a_{12} , for example, is the fraction of a dollar's worth of input from industry 1 required to make a dollar's worth of industry 2's output), the objective is to find the total (gross) output from industries 1, 2 and 3 (labelled x_1, x_2 and x_3 respectively) required to satisfy both intermediate and final demands. The outputs to satisfy each of the final demands are specified in the following equations:

$$a_{11} x_1 + a_{12} x_2 + a_{13} x_3 + f_1 = x_1$$

$$a_{21} x_1 + a_{22} x_2 + a_{23} x_3 + f_2 = x_2$$

$$a_{31} x_1 + a_{32} x_2 + a_{33} x_3 + f_3 = x_3$$

Letting **x** and **f** respectively be vectors of total demand $\begin{pmatrix} x_1 \\ x_2 \\ x_3 \end{pmatrix}$ and final demand $\begin{pmatrix} f_1 \\ f_2 \\ f_3 \end{pmatrix}$;

and letting **A** be the matrix of input coefficients:

$$\begin{pmatrix} a_{11} & a_{12} & a_{13} \\ a_{21} & a_{22} & a_{23} \\ a_{31} & a_{32} & a_{33} \end{pmatrix}$$

We can write the foregoing set of equations as $\mathbf{A\,x + f = x}$.

According to the rules of matrix algebra, one may pre-multiply **x** by the identity matrix **I** (whose elements are ones along the diagonal and zeros elsewhere), giving

$$\mathbf{A\,x + f} = \mathbf{I\,x}, \text{ or}$$

$$\mathbf{f} = (\mathbf{I} - \mathbf{A})\,\mathbf{x}.$$

Pre-multiplying both sides of the equation by the inverse of **I** – **A** gives

$$(\mathbf{I} - \mathbf{A})^{-1}\,\mathbf{f} = (\mathbf{I} - \mathbf{A})^{-1}\,(\mathbf{I} - \mathbf{A})\,\mathbf{x} = \mathbf{x}$$

The term $(\mathbf{I} - \mathbf{A})^{-1}$ is called the *Leontief Inverse*, named after the economist who first formalized input-output analysis in computable form. The Leontief Inverse is the starting point for I-O multiplier analysis.

In general, a shock to an economic system in terms of a change to final demand can be written as Δ**f**, and in this example the change in gross outputs required to meet the change in final demand plus the associated changes in intermediate demand can be written

$$\Delta\mathbf{x} = (\mathbf{I} - \mathbf{A})^{-1}\,\Delta\mathbf{f}$$

One of the early applications of I-O was to explore ways of coping with the switch between wartime and peacetime economies, given that the war effort itself would make up a large part of final demand.

Real economies are more complicated than the example developed above. They have more industries, they engage in external trade, and they have governments that levy taxes and provide certain services. They also employ workers, who receive remuneration from which they finance personal consumption expenditures, taxes and savings; and capital, the returns to which, in an I-O framework, are not normally assumed to be spent. Real economies also have producer prices that are lower than the price paid by the purchaser because there are wholesale, retail and transportation “margins” to pay. Moreover, instead of a simple square I-O matrix like **A**, national statistical agencies more often resort to a rectangular matrix, in which outputs are from industries as before but inputs are classed as *commodities* that are more numerous than industries. For example, the agriculture industry produces both meat and crops. Unfortunately, only square matrices have inverses. In order to compute something comparable to a Leontief Inverse, one must first somehow transform a rectangular matrix into a square matrix. CERI employs a square industry-by-industry matrix similar to **A** above.

In place of the $(\mathbf{I} - \mathbf{A})^{-1} \Delta\mathbf{f}$, the CERI provincial I/O model (also known as UCMRIO2.0) computes direct plus indirect impacts on gross output as $(\mathbf{I} - \mathbf{C}\,\mathbf{A})^{-1}\,\mathbf{C}\,\Delta\mathbf{F}$ where **C** is the matrix of trade flows among pairs of provinces or territories, **F** is a matrix of shocks to final demand by region and industry, and **A** is now augmented with an extra row and column for households. Similarly, the provincial I-O model computes direct plus indirect plus induced impacts on gross output as $(\mathbf{I} - \mathbf{C}\,\mathbf{A} - \mathbf{C}\,\mathbf{P})^{-1}\,\mathbf{C}\,\Delta\mathbf{F}$, where **P** is a matrix containing the fraction of the output of each region and industry devoted to satisfying personal consumption expenditure. Impacts on GDP, wages & salaries, and employment are calculated on the basis that the ratio of any of the foregoing variables to the gross output of an industry within a province or territory remains constant. The entire United States is accommodated within UCMRIO2.0 as if it were a province or territory. The relationship between CERI's I/O models and the I/O tables of Statistics Canada and the US Bureau of Economic Analysis is described in Appendix D.

The regional I/O model takes impacts at the provincial level as determined by the interprovincial model and allocates them to eight different regions in British Columbia and seven in Alberta. These regions are shown in Figures 1.2 and 1.3. Direct impacts are assigned to the region in which they occur. Indirect and induced impacts to an industry at the provincial level are assigned to each of the regions in proportion to their respective shares of the industry's provincial output in the base year 2006. As there is no direct measure of output by region and industry, CERI had to rely largely on 2006 census division and subdivision data for experienced labour force by industry to impute a regional split of provincial output by industry. This procedure is described in more detail in Appendix C.

Input-output models were originally constructed for entire nations. Sub-national models have been developed in recognition of the fact that there are local peculiarities making a region different from the nation as a whole. For example, an increase in final demand for electricity in Saskatchewan or Alberta, that generate primarily using fossil fuels would have quite different impacts than at the national level where hydro predominates. Also, the smaller an economic area, the more prominent trade with "outside areas" becomes. At the other extreme, a model of the entire world economy would have no exports or imports. An interregional or multiregional I/O model looks at economic interactions among the various regions that it models. The emergence of regional science as a discipline distinct from geography has also fostered the development of regional and interregional I/O models, and pushed statistical agencies to collect and disseminate more of the relevant data.

One of the uses of the regional I/O model is to help regional jurisdictions and municipalities plan for socio-economic implications. This can aid in helping in physical and social services planning such as future requirements for hiring personal such as police, housing, hospitals, etc. and predict future loads on municipal services.

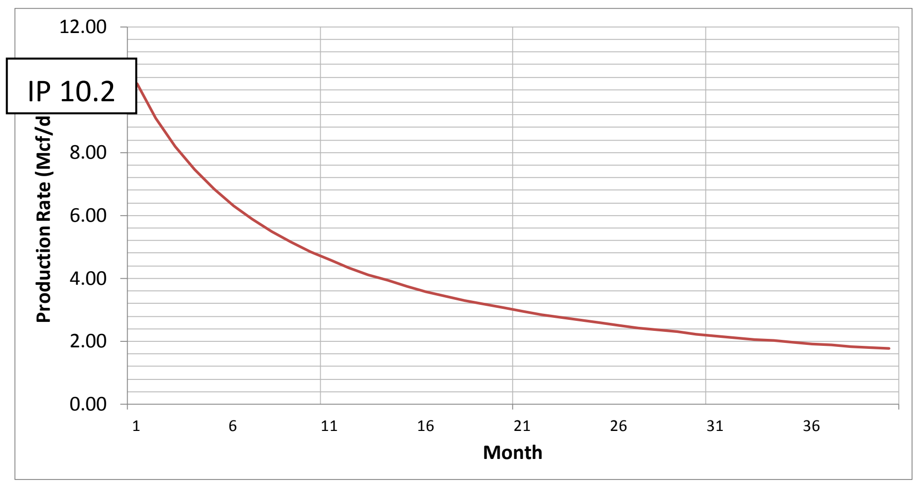
Capital Cost and Operation Investment Assumptions

A three component model was built to characterize the cost of producing, transporting and liquefying gas from Horn River to the Kitimat LNG terminal.

Component 1: Horn River Production and Processing

A well-development profile was generated to approximate the decline rate for a 12 frac stage well (see Figure 3.1).

Figure 3.1: Decline Curve of a 12 Stage Frac in the Horn River Region



Source: Encana, CERI

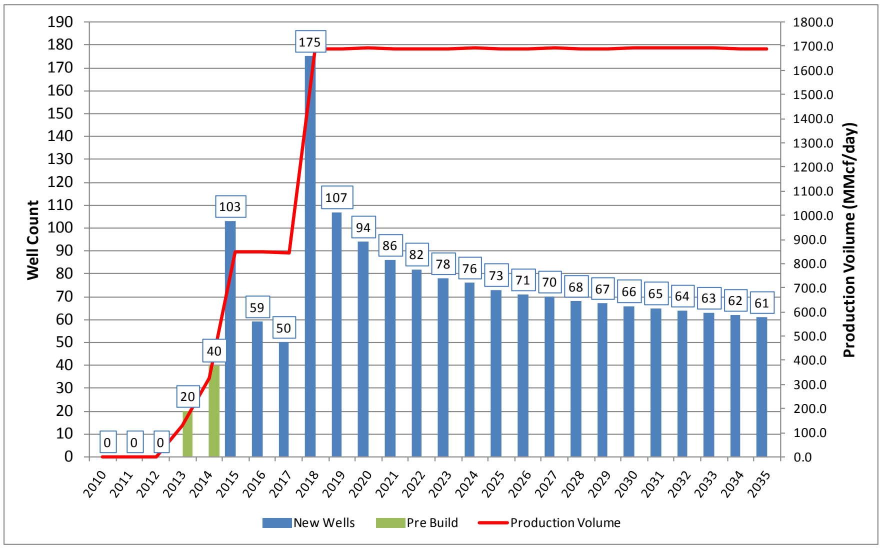
*Note: Initial Production Rate is 10.2 Mcfpd

It was assumed that all wells in the Horn River area will follow Figure 3.1's decline rate. CERI is aware that there is variability in the resource which could alter the total expected production from each well, as well as the initial rate of production. The total number of wells needed to sustain an approximate production of approximately 850 MMcfpd between the years 2015-2017 and then approximately 1,690 MMcfpd for the years 2018-2035 were calculated.[1] The first step was taking the average production rate for each year as an average of the 12 month production rates in the decline curve (i.e., the first year was the average of 1-12 months, the second year was 13-24 months, third year was 25-36 months, etc.). The number of wells for the first year was simply (850 MMcfpd – production from pre-drilled wells)/(average rate of production for the first year)

[1] The Kitimat LNG terminal and Pacific Northern Pipeline are capable of only 1,400 MMcfpd but it is assumed that shrinkage of magnitude 17% volume will occur during processing and transportation to the Kitimat LNG terminal.

This created the following well profile as shown in Figure 3.2. One can see the increase in the number of wells drilled as each phase of the Kitimat LNG project commences. The first peak is in 2015 which corresponds to the first phase of the Kitimat LNG and the second peak corresponds to the second phase of 2018.

Figure 3.2: Forecast of the Number of Wells and Expected Production in Horn River



Source: CERI

Total upstream capital costs were calculated by multiplying the forecast wells by the cost per well. Table 3.1 summarizes the total costs of different stage frac wells.

Table 3.1: Capital Costs per Well for Different Multi-Stage Fracs

Well Type	Total Capital Cost Per Well (2011 $CDN 2011)
3 Stage	$6,410,231
8 Stage	$10,392,843
10 Stage	$12,047,249
12 Stage	$13,701,655
24 Stage	$23,420,317

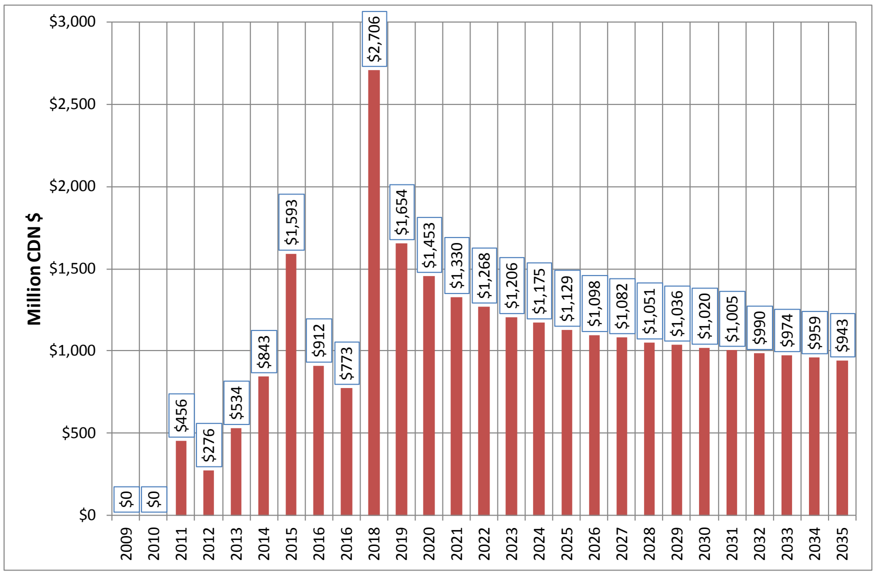
Source: PSAC[2]

Since Horn River gas has a very high CO_2 content (up to 12 percent), it was assumed that there would be a gathering line to take the gas to a processing plant before long distance transmission. The same production rate from the wells was assumed to be gathered and delivered to the plant (i.e., no shrinkage in the gathering system). The costs for the drilling

[2] Petroleum Services Association of Canada (PSAC), *2011 Well Cost Study: Upcoming Summer Costs Report* and *2011 Well Cost Study: Upcoming Winter Report*. PSAC.

segment of the model were calculated from PSAC data for a 12 stage well.[3] It was assumed that the Cabin Gas plant, and Spectra Processing plants would be built in addition to current regional processing capacity for a total of 1,050 MMcfpd additional capacity with approximately 1.2 billion in capital spent. The well and processing plant component make up the direct capital investment into the I/O model. Figure 3.3 showcases the total amount of capital investment that went into the North East region of Horn River.

Figure 3.3: Total Capital Costs for Well Drilling and Processing in Horn River



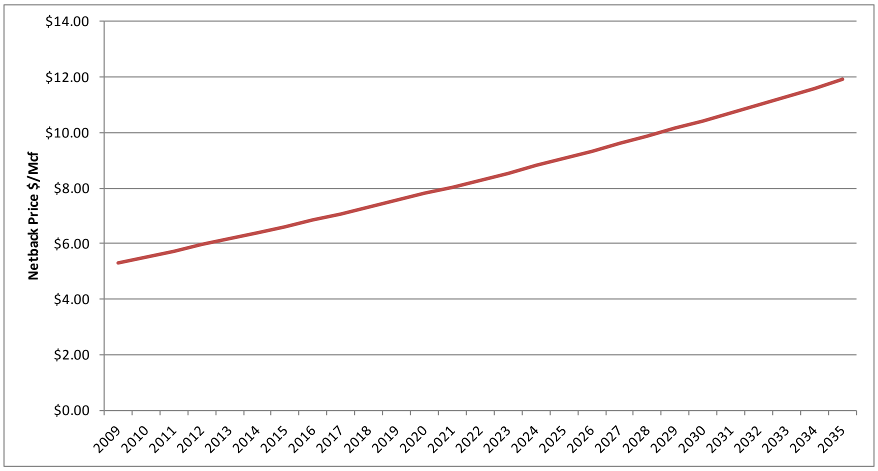
Source: CERI

*Note: The years 2011-2014 include the costs of building the processing plants.

In addition to the capital injections, the wellhead value of natural gas was calculated on a netback basis by taking the landed price of LNG in Japan and subtracting all transportation charges (including pipeline tolls) between gas plant gate and Japanese port. This enables subsequent calculations of upstream royalties and income taxes, and corresponds to the “gross output” of the upstream for input-output purposes. The tolls charged by pipelines, liquefaction plant and other downstream facilities corresponds as their “gross outputs” for input-output purposes, so that the sum of the gross outputs equals the export value of the liquefied natural gas. It is assumed that impacts such as income taxes, employment, compensation and GDP have the same relationship to gross output as they did in the base year of 2006. Because the impacts are not double counted in the base year it allows for an estimation of the GDP and employment during the operational phase. Figure 3.4 shows the forecasted netback pricing over the period of the I/O timeline and Table 3.2 shows the tolls for each segment of the netback.

[3] ibid

Figure 3.4: Wellhead Netback Price Forecast of Natural Gas in the Horn River Area of BC



Source: CERI

Table 3.2: Estimated Tolls in Netback Calculation for Horn River

Component	Toll ($/Mcf)
Regasification	0.50
Shipping	1.50
Liquefaction	6.00
Pacific Trail Toll	0.30
Spectra System Toll	0.30

Source: CERI

Netback Sensitivities and the Problem of Fixed Proportions

The problem with using a netback to calculate gross output from the upstream industry is that it becomes sensitive to the assumptions of price as well as the fixed proportions inherent within the model. For example, if Japan LNG prices doubled, the gross outputs would increase because the liquefaction costs and pipeline tolls are treated as constant. This would then proportionally end up with an increase in GDP, purchases from other industries and imports. It is not unreasonable to assume that there would be more impacts with increased netbacks as generally increasing netbacks result in increasing competition. This can increase activity and supply services which in turn generate impacts. Whether this relationship is proportionately the same as the model seems unlikely. Many more dynamic factors may influence this relationship than can be dealt with by the model. For instance, producers may attempt to ramp up gas production if their resources allow them to do so but they may also be faced with not having enough capital to take advantage of the higher prices. Lastly, since CERI is utilizing the base year of 2006 as an indicator of the relationships between different industries and final demand, some of the impacts may not be representative of activity in 2012.

Component 2: Pacific Trail Construction and Operation

It has been publicized that the Pacific Trail Pipeline will cost 1 billion dollars for a 36" pipe but the capital cost injection to the I/O model was approximately 1.2 billion dollars due to CERI's estimate of the cost of a 42" pipe. This capital was split by year and region based on assumptions of cost allocations. The operating costs were split according to estimated amount of pipe in each developmental region.

Table 3.3 and Figure 3.5 summarize these assumptions.

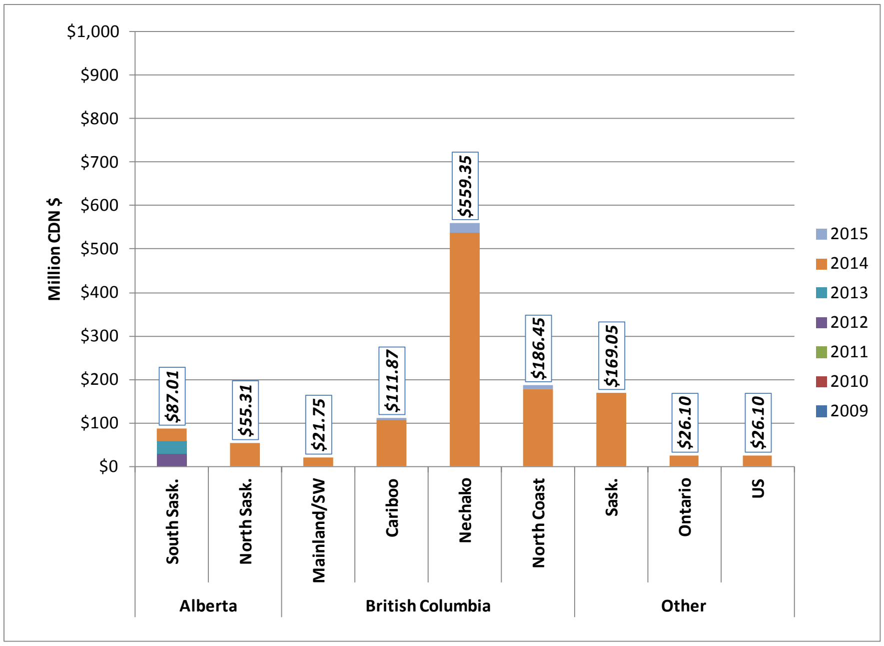
Table 3.3: Capital Cost and Operational Cost Assumptions for the Pacific Trail Pipeline

Pacific Trail Cost Components	
Total Estimated Expenditures	1.2 billion dollars
Capital Cost Allocation	%
Materials Pumps Labour Other Misc. Regulatory/Engineering	17 7 45 24 4
Pipeline Material Source (%) North Saskatchewan (in Alberta) Saskatchewan	 20 80
Pump Material Source (%) North Saskatchewan Mainland/Southwest BC Ontario United States	 15 25 30 30
Operating Cost	2.3% of Initial Capital Cost
Operating and Sust. Capital Regional Allocation (%) Cariboo Nechako North Coast	 13 65 22
Pacific Trail Flow Rates[4]	710 MMcfpd – 2015-2017 1420 Mcfpd – 2018-2035+

Source: Spectra, CERI

[4] 1% fuel loss in transportation.

Figure 3.5: Pacific Trail Pipeline Capital Cost Allocation



Source: CERI

Component 3: Kitimat LNG Terminal

The Kitimat LNG terminal capital costs were broken down into 2 trains to make a total capital cost of $4.5 billion. Three billion will go towards the building of the first train and 1.5 billion will go towards the building of the second train. The trains were slated to take approximately 36 months to complete and the construction phase was split annually as a proportion of the number of workers that had been required for another liquefaction terminal of similar size.[5] Liquefaction operating costs were assumed to be 3.67 percent of capital costs.[6] Table 3.4 has the summary of assumptions. Figure 3.6 shows the capital costs per year by region.

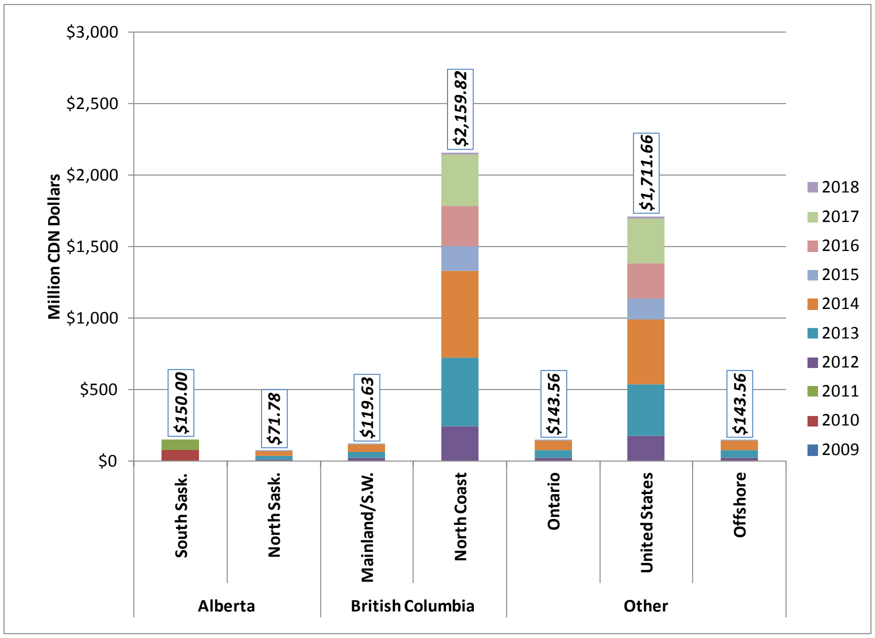
[5] http://www.laohamutuk.org/Oil/LNG/Refs/066Darwin10mtpaPublicEnvReport.pdf Accessed March 5th 2012.
[6] Attanasi, E.D. & Freeman, P.A. 2011. *A Survey of Stranded Gas Resources and Estimates of Development and Production Costs*. Society of Petroleum Engineers SPE130089

Table 3.4: Capital Cost and Operational Cost Assumptions for the Kitimat LNG Terminal

Component	Assumptions
Capital Cost Allocation Phase I[7]	%
Materials Liquefaction	23.3
Materials Tank	10.4
Marine Facilities	16.0
Construction & Other	45.3
Regulatory	5.0
Capital Cost Allocation Phase II	%
Materials Liquefaction	47
Construction Facilities	53
Heat Exchanger (Liquefaction Materials)	100% US Sourced
Tank Farm Materials	100% US Sourced
Marine Terminal (%) Sourced	
Ontario	30
Alberta	15
British Columbia	25
Offshore	30
Operating Cost	3.67% of Initial Capital Cost

[7] Splits based on information from http://www.kbr.com/Newsroom/Publications/technical-papers/LNG-Liquefaction-Not-All-Plants-Are-Created-Equal.pdf accessed May 29th 2012 and Emil D. Attanasi and Philip A. Freeman. 2010. *A Survey of Stranded Gas Resources and Estimates of Development and Production Costs*. U.S. Geological Survey: SPE Paper 130089.

Figure 3.6: Capital Cost Allocation for the Kitimat LNG Project by Year and Area of Injection



Source: CERI

Summary of Major Assumptions

Production and Processing

- All fracs in the Horn River area have the same initial production rate of 10.2 MMcfpd with the rate of termination at 0.02 MMcfpd.
- Shrinkage from the gathering system is minimal with the exception of processing which will account for 12 percent of the volume lost.
- The construction of processing plants will occur over a 16-24 month time span.

Transmission on Spectra and Pacific Trail System

- There will be no swapping at Station 2 and all gas originates from Horn River.
- There will be 4 percent shrinkage due to fuel loss on the Spectra system and shrinkage of 1 percent fuel loss on the Pacific Trail system due to fuel usage at compressor stations.
- The Pacific Trail system will be built over a period of 2 years with the completion date in 2015.
- Even though Spectra tolls are slated to increase by 3 percent each year, it was assumed that the real dollars for the toll will remain approximately the same for each year as 3 percent is close to the rate of inflation.

Kitimat LNG Terminal

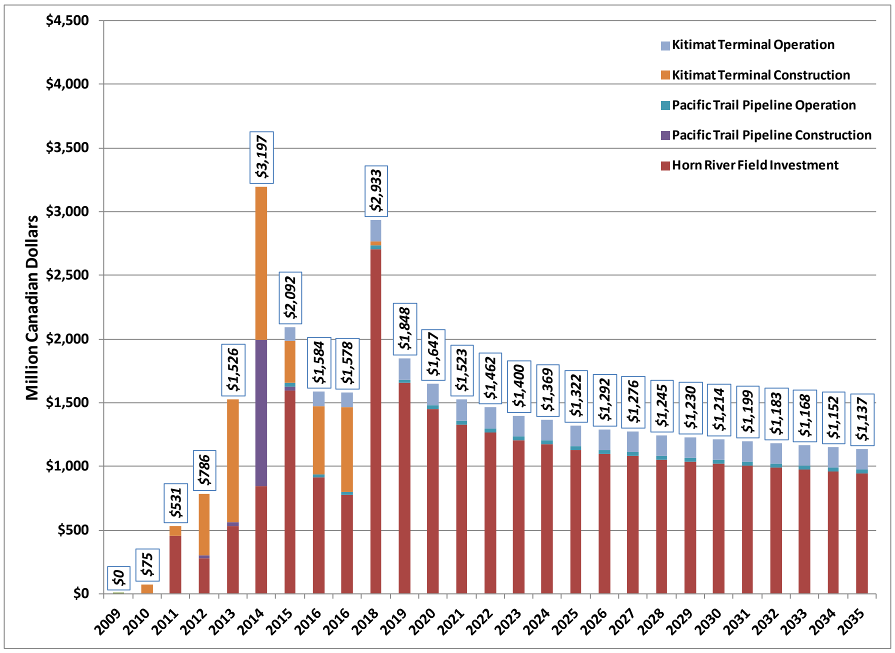
- The Kitimat LNG terminal is assumed to operate at contracted capacity as stated from their NEB permit.
- There is no shrinkage in liquefaction due to the use of electric compressor stations that may operate from a fuel source other than natural gas.

- Construction will take approximately 36 months to complete with expenditures split per year by the % of workers for each year.

Overnight construction is assumed for everything with no financing of debt in the capital cost numbers.

Figure 3.7 summarizes all of the capital cost and operational costs for CERI's I/O models:

Figure 3.7: Total Costs



Source: CERI

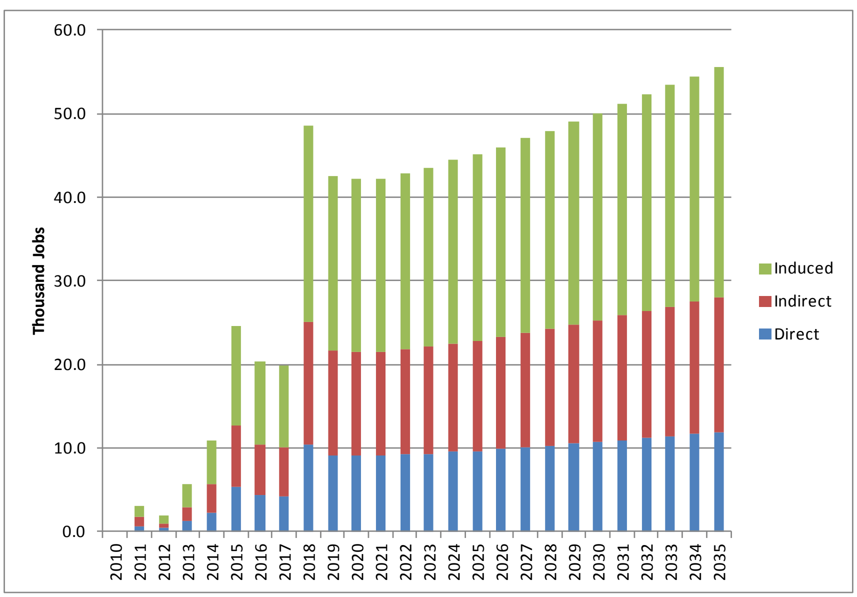
Chapter 4: I/O Results

This chapter describes economic impacts derived from expenditures on the Horn River shale gas project and associated natural gas production as described in Chapter 2. It also incorporates the corresponding information on the associated pipelines and LNG facility. These impacts were estimated using CERI's I/O model, as described in Appendix B. Economic impacts other than employment are expressed in dollars of year 2010 purchasing power. These economic impacts consist of GDP, employee compensation and person-years of employment associated with natural gas production and processing in the Horn River area over the period 2010-2035.

The Upstream: Development, Production and Processing of Horn River Gas

The temporal pattern of upstream impacts, depicted in Figure 4.1, is distinctly different from those of pipelines and LNG facilities in that the latter have high employment during the construction phase and lower but steady employment over the operating life. As production from the original wells declines, new wells must be drilled in order to sustain production. Thus capital spending continues on a large scale in the upstream, whereas sustaining capital is relatively modest in pipelines and LNG facilities.

Figure 4.1: Horn River Upstream Investment and Operations, 2010-2035 (thousand jobs)

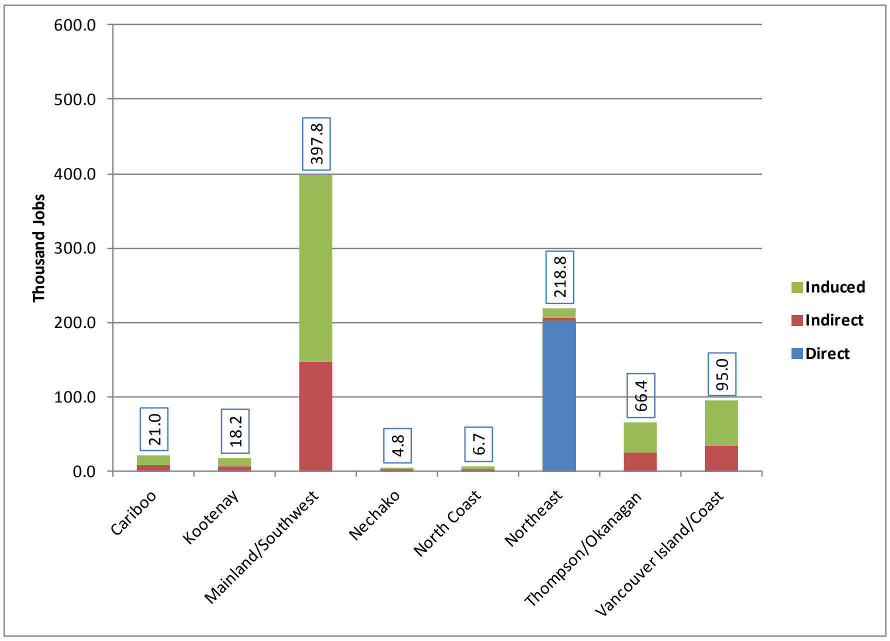


Source: CERI

The national employment impact of the upstream development over the 25-year period is 944,500 person-years, of which the majority will be in British Columbia (828,700), while neighbouring Alberta, where major oil and natural gas producers' head offices are located, will capture 24,600. Territories and other provinces are projected to capture 91,200 person-years of employment, largely in Canada's manufacturing heartland: Ontario and Quebec.

Figure 4.2 identifies the Development Region with the largest employment impact as the Mainland/Southwest that encompasses the Vancouver and Abbotsford metropolitan areas, followed by the Northeast where all the upstream facilities will be located.

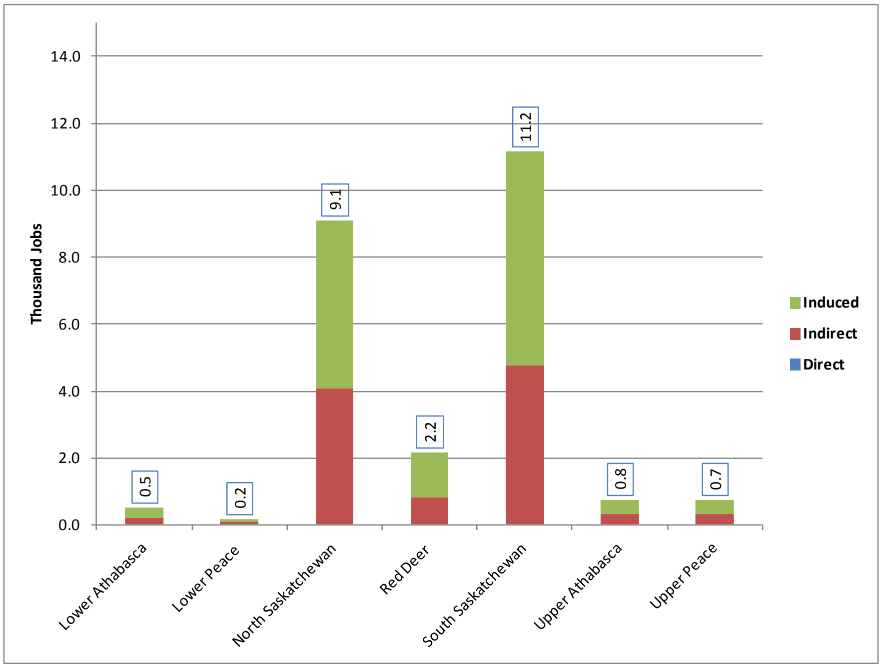
Figure 4.2: British Columbia Upstream Investment and Operations Regional Employment Impacts, 2010-2035 (thousand jobs)



Source: CERI

Figure 4.3 portrays the regional breakdown of Alberta employment impacts. The greatest employment impact is in the South Saskatchewan region, followed rather closely by the North Saskatchewan region. These regions incorporate the metropolitan areas of Calgary and Edmonton, respectively.

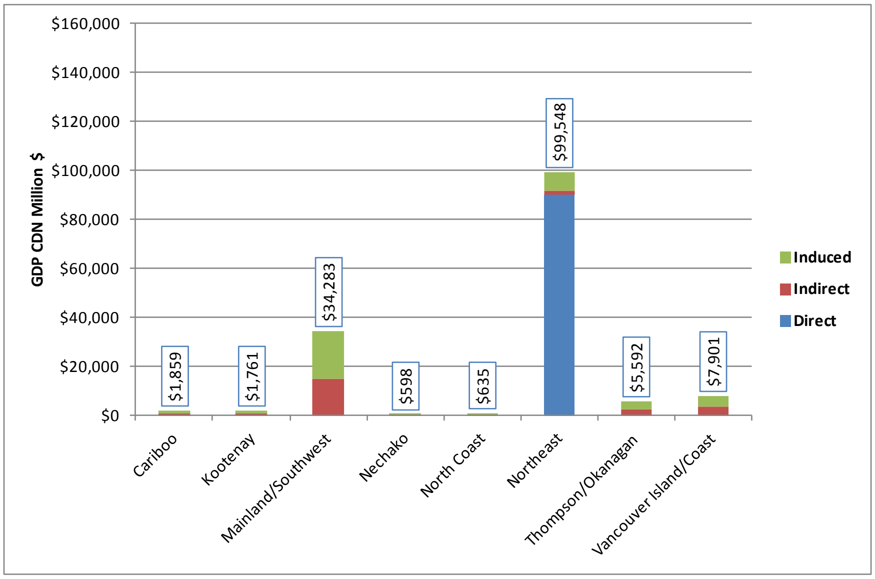
Figure 4.3: Alberta Upstream Investment and Operations Regional Employment Impacts, 2010-2035 (thousand jobs)



Source: CERI

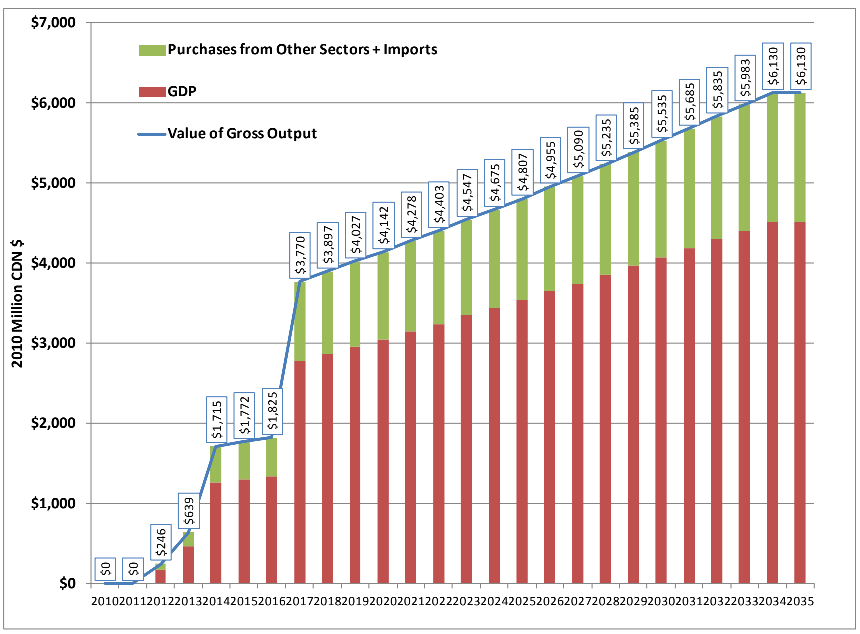
The provincial and regional distribution of GDP impacts is broadly the same as employment impacts, except that they are even more concentrated in British Columbia ($152.1 billion out of $161 billion nationally), captured regionally in Figure 4.4. The netback mentioned in Chapter 2 to calculate the gross value output and then calculate GDP and employment from gross output is shown in Figure 4.5. Note how GDP makes up a larger contribution of gross output than purchases from other industries and imports. Alberta GDP impact of $2.3 billion, shown regionally in Figure 4.6, is smaller than the Ontario impact of $5.1 billion, shown in Figure 4.7. The sum of provincial/territorial GDP impacts presented in the latter figure is $6.8 billion.

Figure 4.4: British Columbia Upstream Investment and Operations Regional GDP Impacts 2010-2035 (2010 million CDN $)



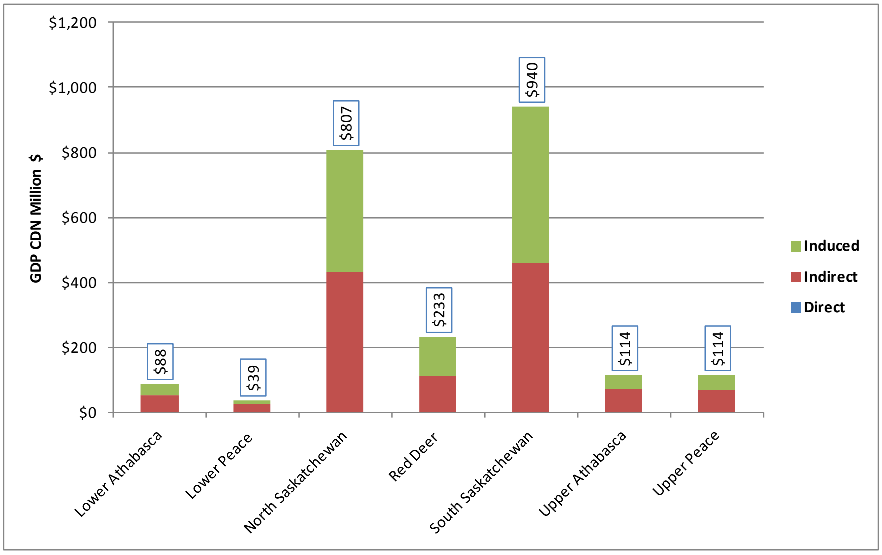
Source: CERI

Figure 4.5: Breakdown of Gross Output as GDP and Employee Compensation



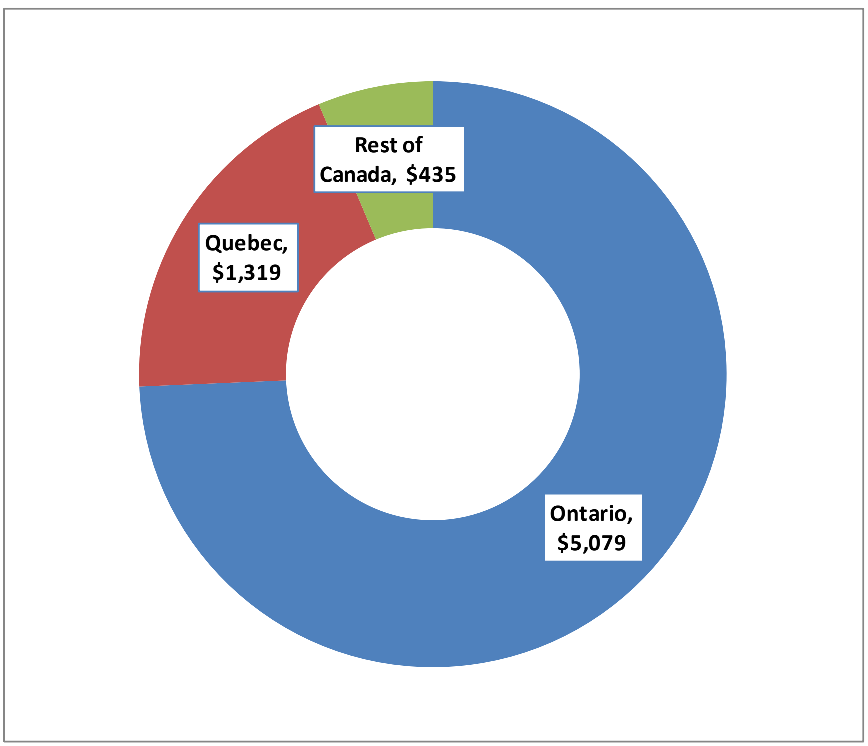
Source: CERI

Figure 4.6: Alberta Upstream Regional GDP Impacts



Source: CERI

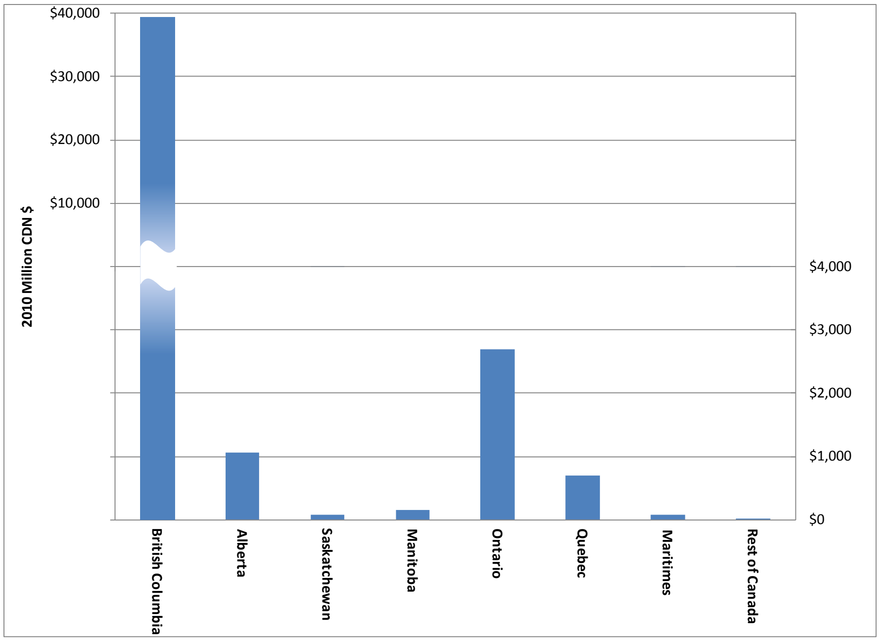
Figure 4.7: Horn River Upstream GDP Impacts (2010 million CDN $)



Source: CERI

Not surprisingly, the impact of the Horn River upstream on employee wages and salaries is strongest in British Columbia at $39.4 billion. Impacts on employee compensation in other provinces are summarized in Figure 4.8, with Ontario in second place at $2.7 billion and Alberta in third place at just over $1 billion.

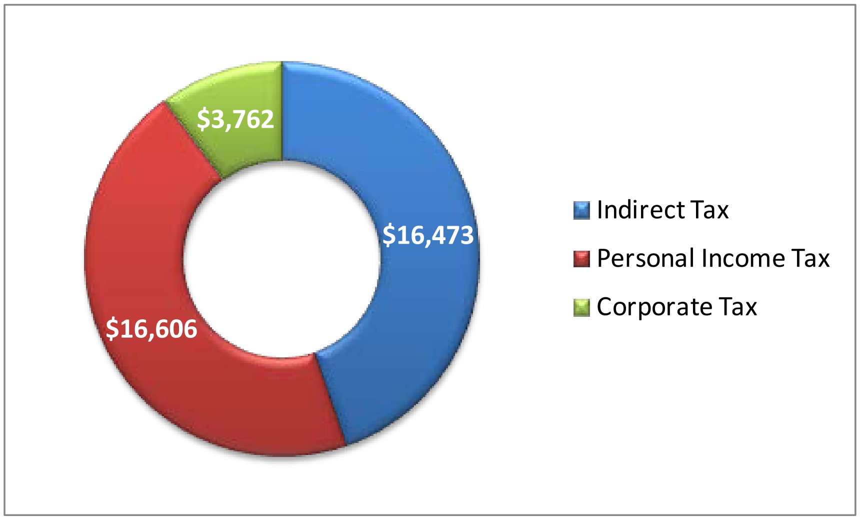
Figure 4.8: Horn River Employee Compensation Impacts: Selected Provinces



Source: CERI

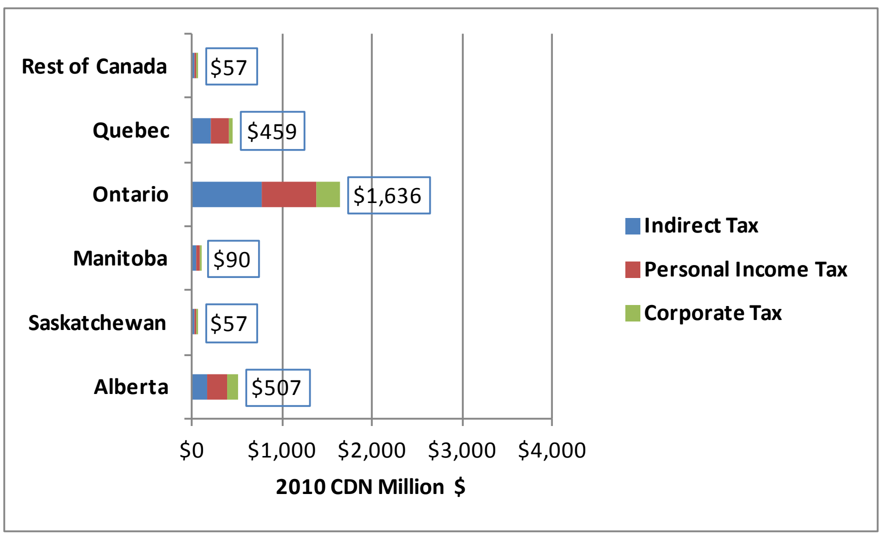
The incomes generated by the Horn River upstream will cause additional tax revenues to flow into the coffers of various governments. These tax revenues, with respect to British Columbia, will total an estimated $36.8 billion, identified by broad tax category in Figure 4.9. Figure 4.10 summarizes a projection of impacts on taxes payable in other provinces totaling $2.8 billion, led by Ontario at $1.6 billion.

Figure 4.9: Horn River Upstream Investment and Operations Impact on BC Total Taxes Payable, 2010-2035 (2010 million CDN $)



Source: CERI

Figure 4.10: Horn River Upstream Investment and Operations Total Tax Impact – Other Provinces and Territories. 2010-2035 (2010 million CDN $)

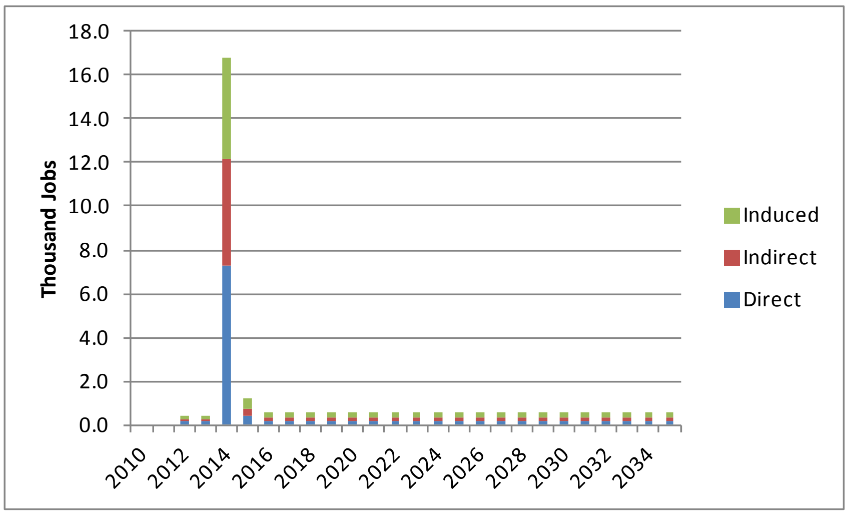


Source: CERI

Pipeline Construction and Operation

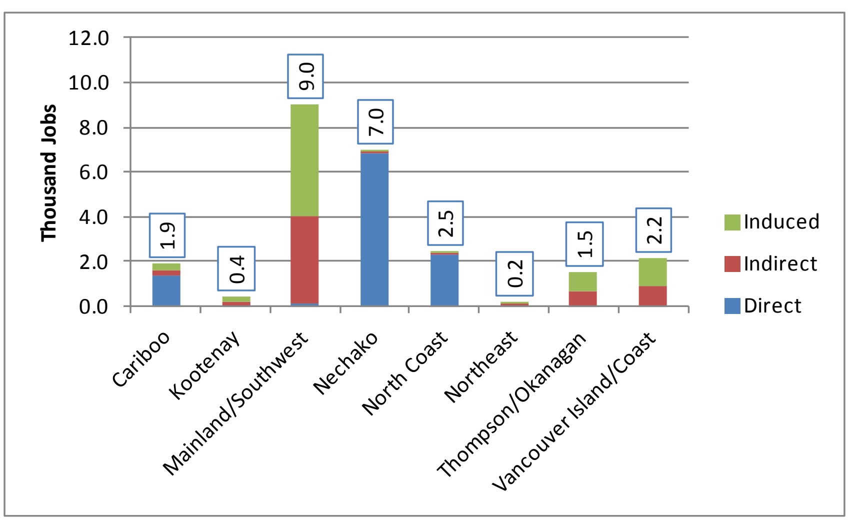
In contrast to the upstream, where employment is largely sustained throughout the forecast period, pipeline employment impacts are strongly centered on the construction year 2014. Pipeline operations are not a major source of employment. Nationally, as shown in Figure 4.11, 7,000 direct jobs in 2014 are accompanied by an additional 9,000 indirect and induced jobs. The direct, indirect and induced national employment generated by the natural gas pipeline portion of the Horn River project is 30,700 person-years, of which 24,700 will be in British Columbia as shown regionally in Figure 4.12, and 2,100 in Alberta as shown regionally in Figure 4.13.

Figure 4.11: Pipeline-Related Direct, Indirect and Induced Employment Impacts in Canada 2010-2035 (thousand jobs)



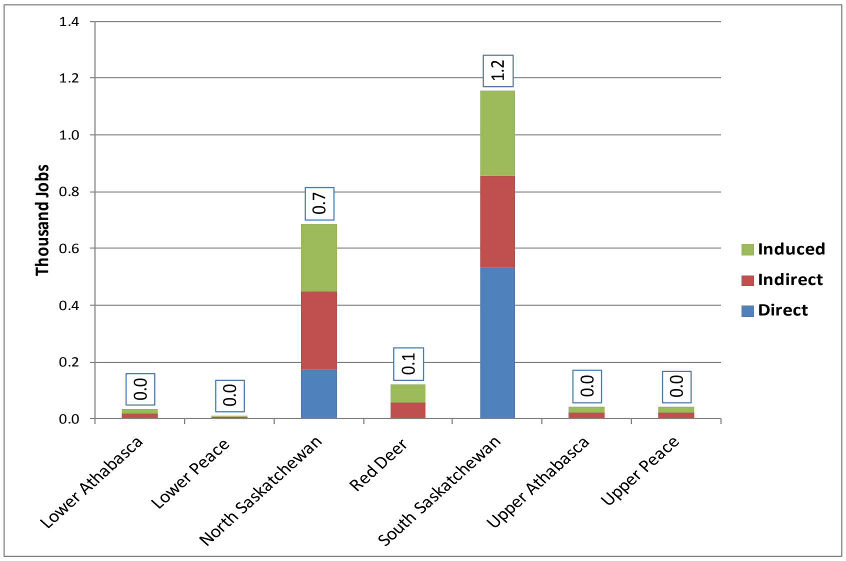
Source: CERI

Figure 4.12: Regional Pipeline-Related Employment Impacts in BC, 2010-2035 (thousand jobs)



Source: CERI

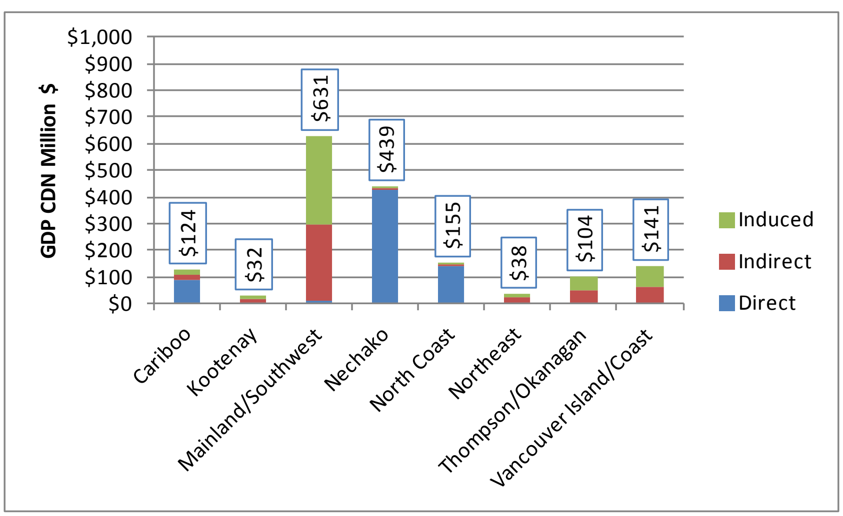
Figure 4.13: Regional Pipeline-Related Employment Impacts in Alberta 2010-2035 (thousand jobs)



Source: CERI

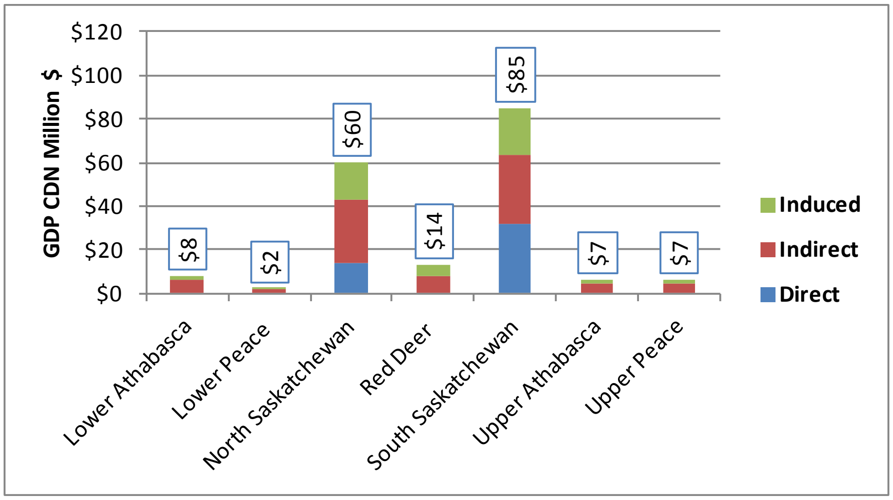
National pipeline GDP impacts of $2.0 billion will be felt primarily in British Columbia, depicted regionally in Figure 4.14, and amounting to $1.7 billion. In second place are Alberta impacts of $0.2 billion, depicted regionally in Figure 4.15. Impacts elsewhere in the country total $0.3 billion, primarily in Ontario and Saskatchewan as shown in Figure 4.16. Within BC, the Mainland/Southwest region will experience the largest GDP impact even though it experiences no direct impact as the pipeline does not pass through it, followed by the Nechako region that has the longest portion of the pipeline's total length. In Alberta, the South Saskatchewan region will be most impacted, followed by the North Saskatchewan region. GDP impacts in other Alberta regions are found to be much lower.

Figure 4.14: Regional Pipeline-Related GDP Impacts in British Columbia (million CDN $)



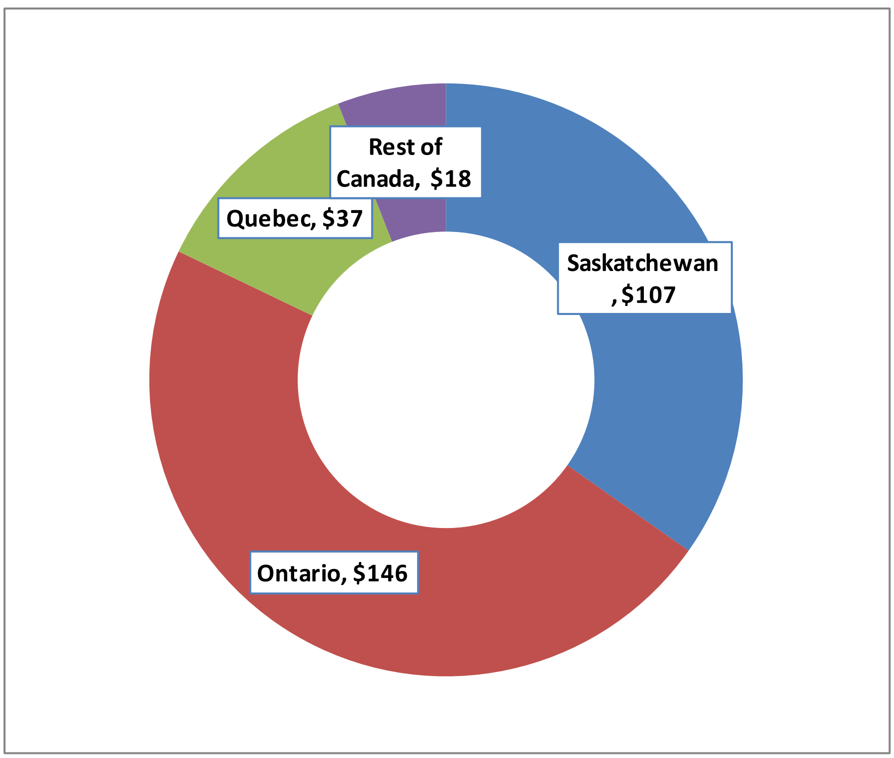
Source: CERI

Figure 4.15: Regional Pipeline-Related GDP Impacts in Alberta, 2010-2035 (2010 million CDN $)



Source: CERI

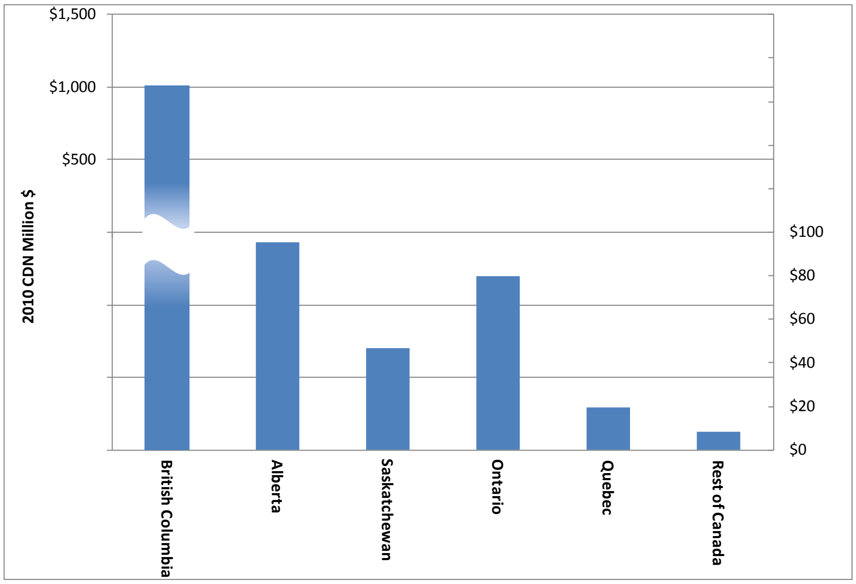
Figure 4.16: Pipeline-Related GDP Impacts – Other Provinces and Territories, 2010-2035 (2010 million CDN $)



Source: CERI

As a result of pipeline construction and operation of the Pacific Trail Pipeline wage and salary impacts are overwhelmingly in BC at approximately $1.0 billion, with no other province as high as $100 million (see Figure 4.17).

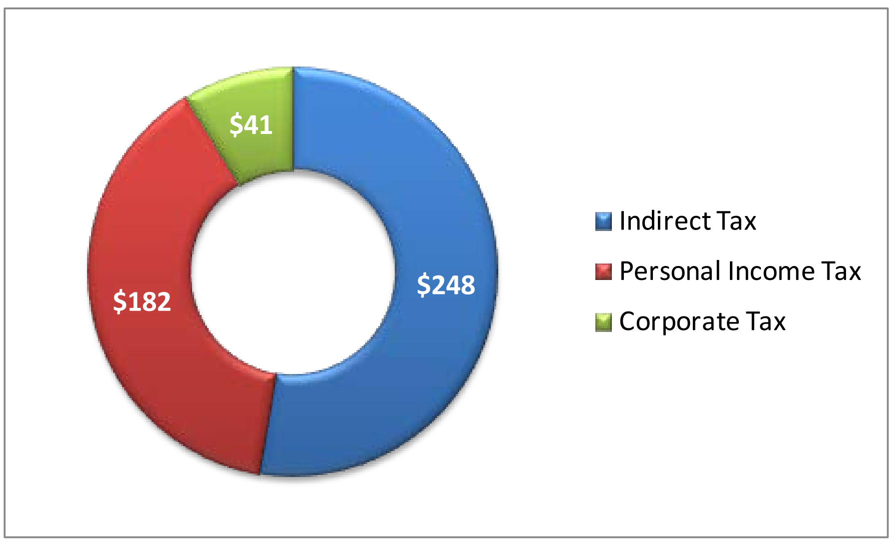
Figure 4.17: Pipeline-Related Employment Compensation Impacts, 2010-2035 (2010 million CDN)



Source: CERI

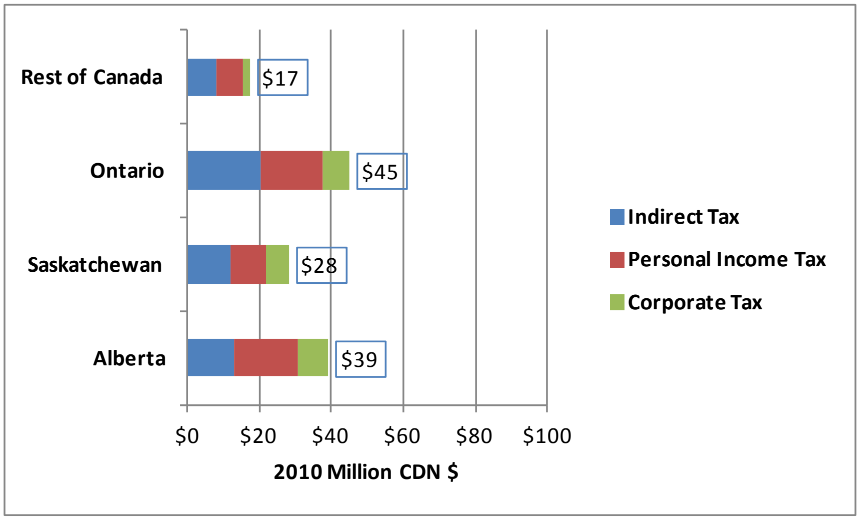
Pipeline-related impacts on taxes payable in Canada consist of $471 million payable by British Columbia taxpayers for the years 2010 to 2035 as shown in Figure 4.18, followed by $45 million by Ontario taxpayers and $39 million payable by Alberta taxpayers as shown in Figure 4.19.

Figure 4.18: Pipeline-Related Impacts on Taxes Payable – British Columbia, 2010-2035 (2010 million CDN $)



Source: CERI

Figure 4.19: Pipeline-Related Impacts on Taxes Payable – Selected Provinces, 2010-2035 (million CDN $)



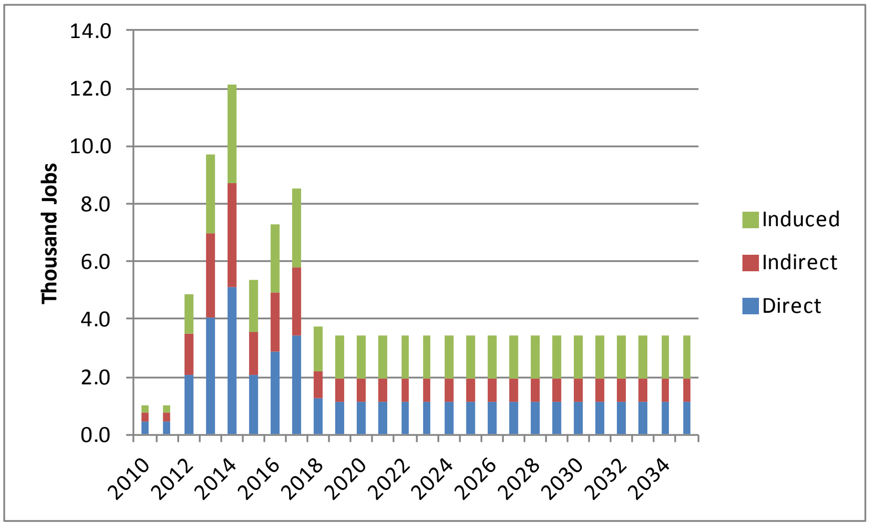
Source: CERI

Construction and Operation of LNG Terminal

Employment impacts associated with the LNG terminal are highest during the multi-year construction period, as shown in Figure 4.20. A total of 112,000 person-years of employment would occur nationally, including 97,000 in BC (shown regionally in Figure 4.21), 5,000 in Alberta (shown regionally in Figure 4.22) and 10,000 in the rest of the country.

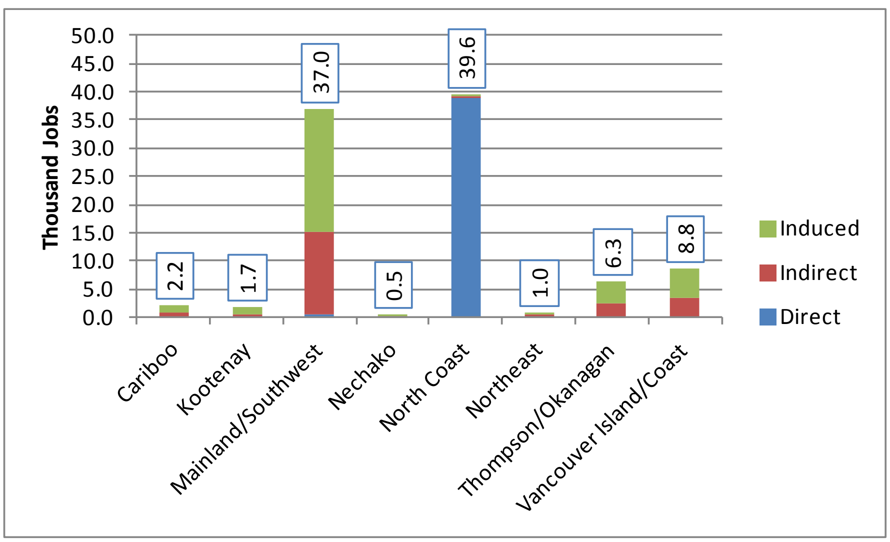
Within BC, two regions dominate, North Coast where the terminal will be situated, and Mainland/Southwest where most of BC's population and industrial base are located. Figure 4.21 shows that employment impacts in these two regions are virtually equal. Employment impacts in Alberta's regions are much smaller, as shown in Figure 4.22, with South Saskatchewan leading and North Saskatchewan in second place.

Figure 4.20: Direct, Indirect and Induced Employment in Canada LNG Terminal, 2010-2035 (thousand jobs)



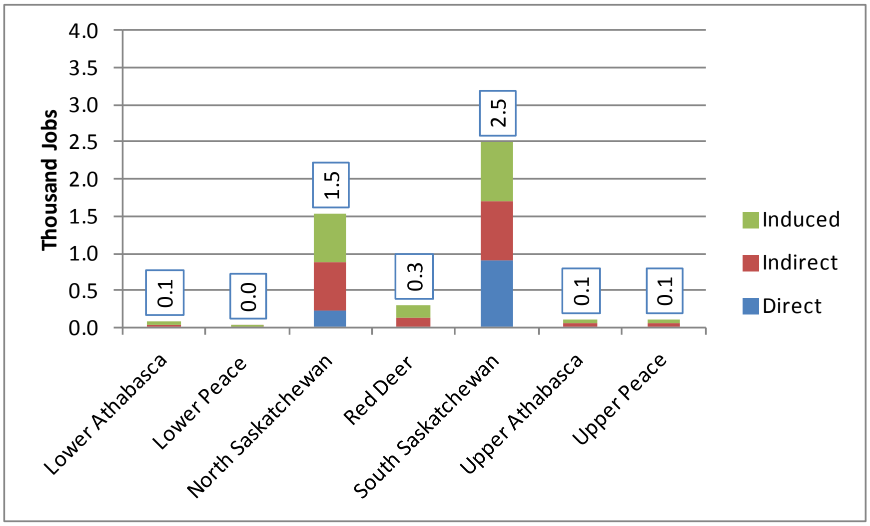
Source: CERI

Figure 4.21: British Columbia Regional Employment Impacts – LNG Terminal, 2010-2035 (thousand jobs)



Source: CERI

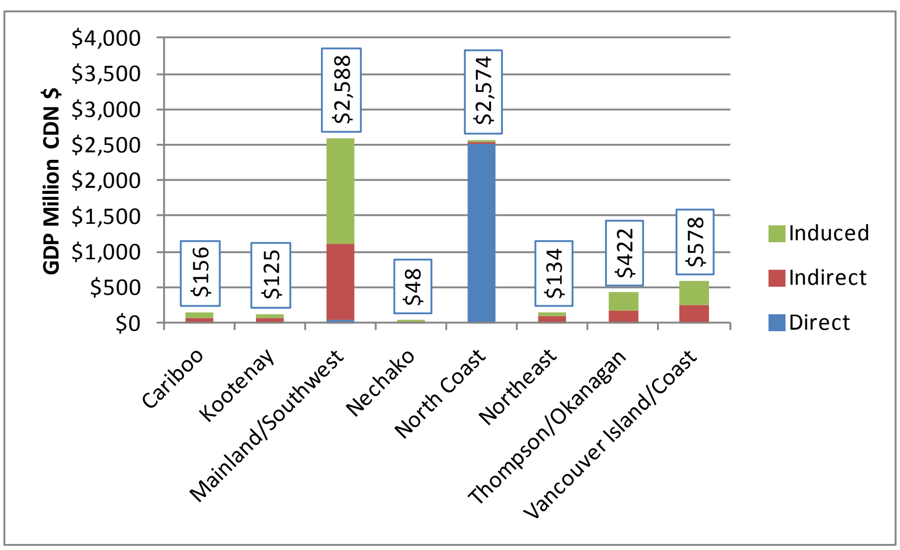
Figure 4.22: Alberta Regional Employment Impacts - LNG Terminal, 2010-2035 (thousand jobs)



Source: CERI

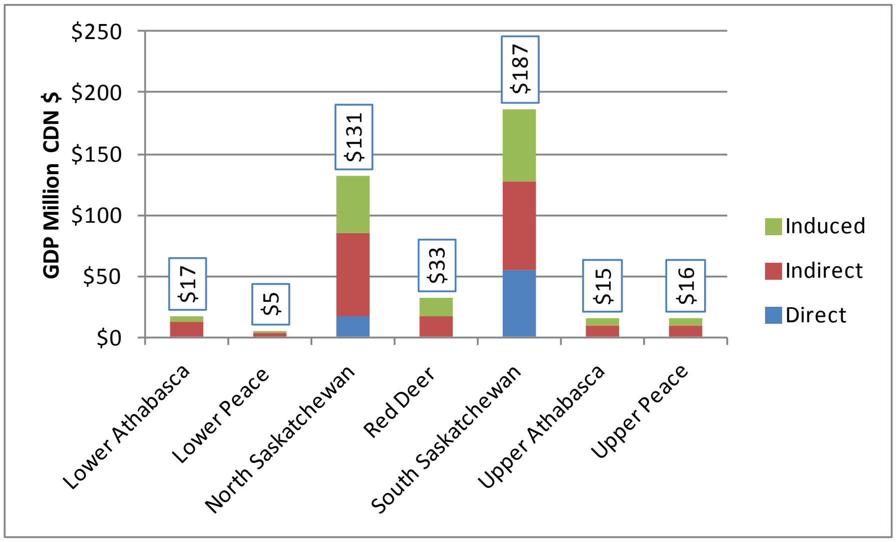
The geographical distribution of the terminal's GDP impacts as depicted in Figures 4.23, 4.24 and 4.25 is very similar to that of employment impacts. Of the national GDP impact of $7.8 billion, the largest share is in BC with a $6.6 billion impact and once again a virtual tie between the Mainland/Southwest and North Coast regions. The second-highest GDP impact is in Ontario at $0.6 billion, followed by Alberta with $0.4 billion. As with employment, GDP impacts are concentrated in two Alberta regions, with South Saskatchewan leading and North Saskatchewan in second place.

Figure 4.23: British Columbia Regional GDP Impacts - LNG Terminal, 2010-2035 (2010 million CDN $)



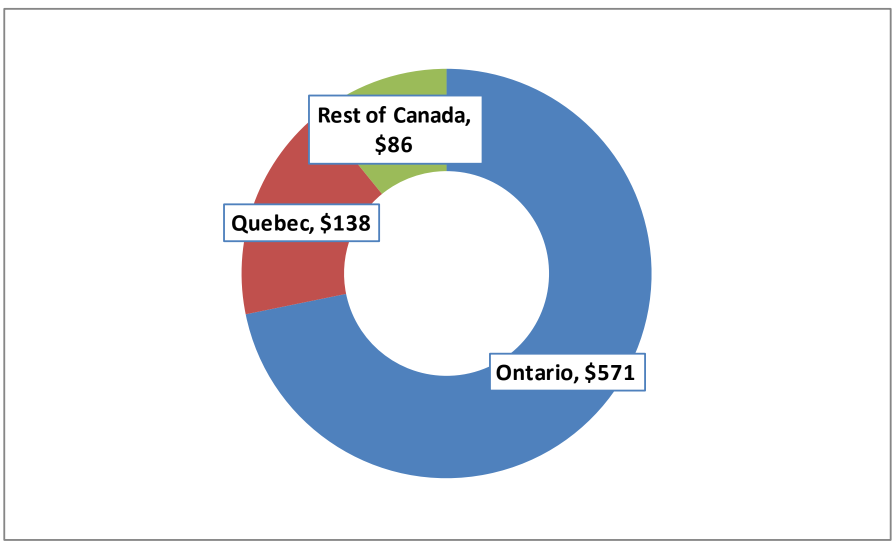
Source: CERI

Figure 4.24: Alberta Regional GDP Impacts - LNG Terminal, 2010-2035 (2010 million CDN $)



Source: CERI

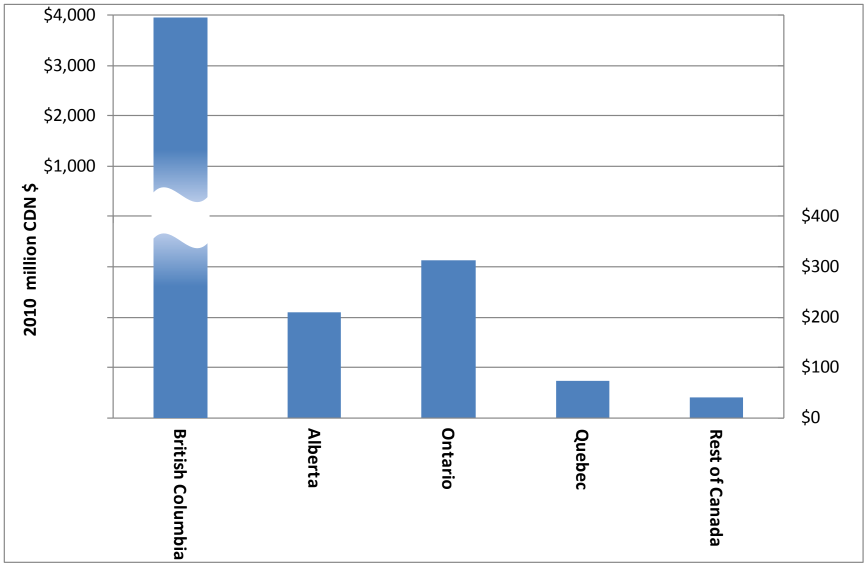
Figure 4.25: GDP Impacts of LNG Terminal – Selected Provinces (2010 million CDN $)



Source: CERI

The LNG terminal's construction and operation will generate impacts on wages and salaries of $4.6 billion and will be experienced mainly in BC at $3.9 billion. Impacts in other provinces, shown in Figure 4.26 include Ontario at $0.3 billion and Alberta at $0.2 billion.

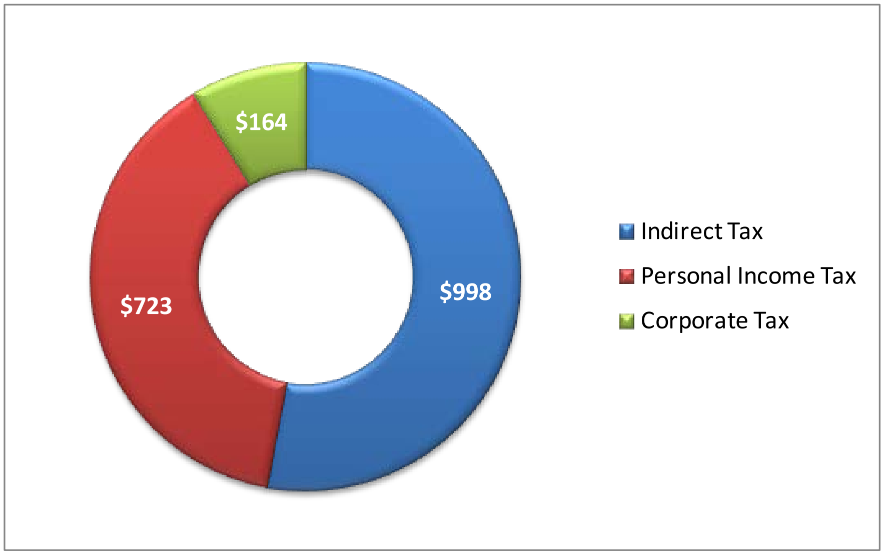
Figure 4.26: Impacts of LNG Terminal on Employee Compensation, 2010-2035 (2010 million CDN $)



Source: CERI

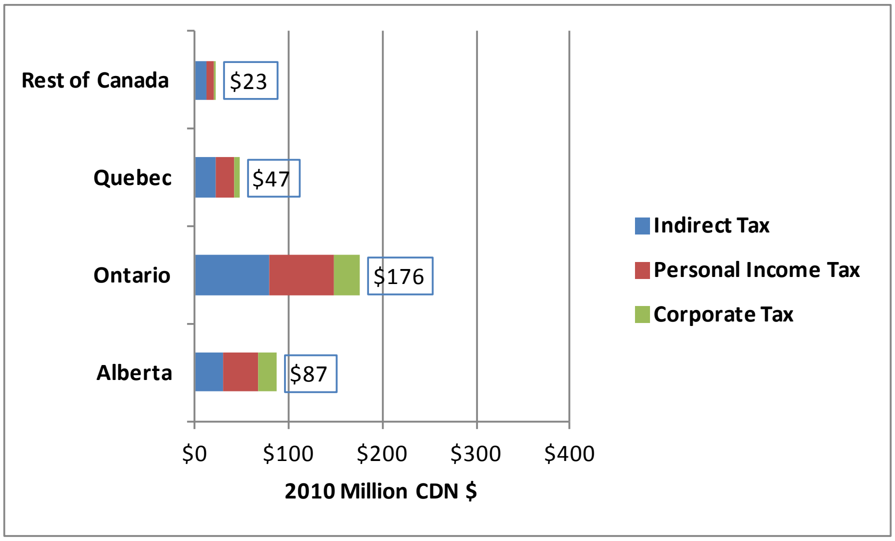
Of the LNG terminal's total impact of $2.2 billion on taxes payable nationally, $1.9 billion would be from BC taxpayers as shown in Figure 4.27. Other provinces' taxpayers would experience much lower impacts on their tax bills as shown in Figure 4.28, Ontario being in second place at $0.2 billion and Alberta third at $0.1 billion.

Figure 4.27: LNG Terminal's Impact on Taxes Payable – British Columbia, 2010-2035 (2010 million CDN $)



Source: CERI

Figure 4.28: LNG Terminal's Impact on Taxes Payable – Selected Provinces, 2010-2035 (2010 million CDN $)

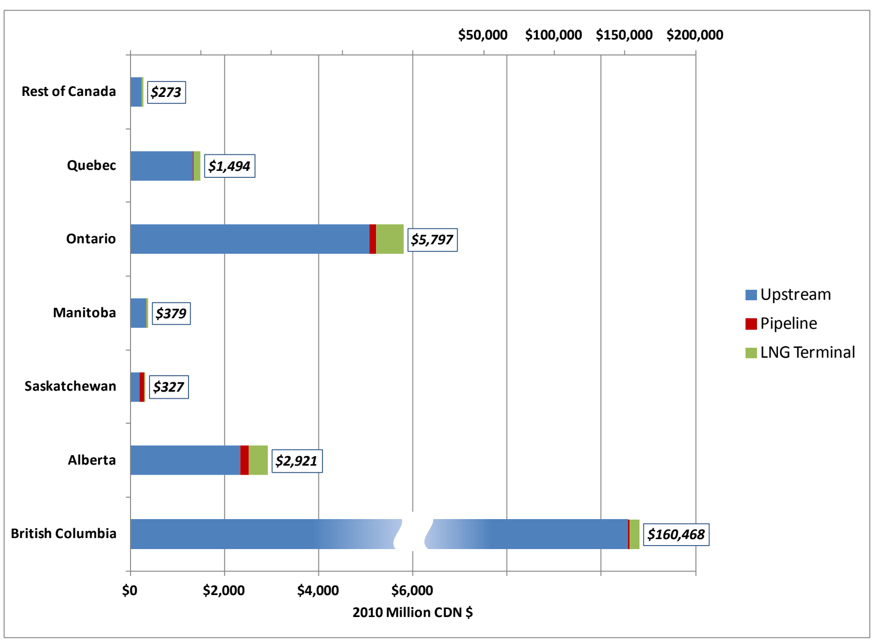


Source: CERI

Combined Impacts of Upstream Activities, Pipelines and LNG Terminal

Figure 4.29 is provided to show the contributions of each phase of the project for every province except British Columbia.

Figure 4.29: Combined GDP Impacts of Supply Chain, 2010-2035 (2010 Million CDN $)



Source: CERI

Ontario has a significant contribution because of upstream impacts associated with Ontario's manufacturing sector. Alberta comes in second because some of the equipment is being manufactured in Alberta plus its close proximity to development. British Columbia's GDP impacts are substantial, with $160 billion generated during the period 2010-2035 for all 3 segments.

Conclusions

The impacts of constructing the LNG terminal and relevant infrastructure (i.e., the pipeline and wells) has significant benefits to British Columbians who generally amass the majority of benefits. There are benefits to the rest of Canada but they are usually indirect with mostly manufacturing requirements making up a majority of the benefits. Nonetheless the surplus of natural gas supply in North America does suggest that alternative Pacific markets will give Horn River producers the best value for their gas and generate substantial revenues for both themselves and the province of British Columbia.

Chapter 5: Conclusions

Like Part II of the Pacific Access Report, East Asia (especially Japan) stands out as an ideal market in light of depressed continental prices. Furthermore, the demand in Asia for natural gas has been outpacing supply which has further increased prices. Producers can expect to get a higher netback price for selling liquefied natural gas in Asia than in North America even if liquefaction plants are capital intensive. Furthermore, unlike the Part II scenario there is really no alternative for Horn River natural gas in the North American market as the entire continent has low gas prices in comparison to the rest of the world.

The majority of the economic impacts from upstream activity, pipeline construction and operation, and the Kitimat LNG terminal lie within British Columbia because this is where all the development is located. Alberta, Ontario and Quebec will also receive economic benefits due to their manufacturing base as well as, in the case of Alberta, their proximity to British Columbia.

Within British Columbia the regions that tend to benefit the most are the Mainland/Southwest, Northeast and North Coast developmental regions. In the case of the Northeast and North Coast regions the impacts are due to the direct capital investments in the building of well-heads and the LNG terminal, respectively. The Mainland/Southwest gets impacts because of its manufacturing base as well as being the most populated region in British Columbia.

Like Part II, the regional impacts may aid in enabling municipal governments and other institutions to assess what is needed to accommodate the anticipated influx of personnel required in the construction and operating of such projects.

Appendix A: US I/O Results

Component 1: Upstream Horn River Developments

Table A.1: I/O Impacts at US PADD Level

2010-2035	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
PADD I	3,367	1,706	39
PADD II	3,302	1,719	41
PADD III	1,005	429	12
PADD IV	294	141	4
PADD V	2,380	1,176	26
Total US	10,348	5,170	122

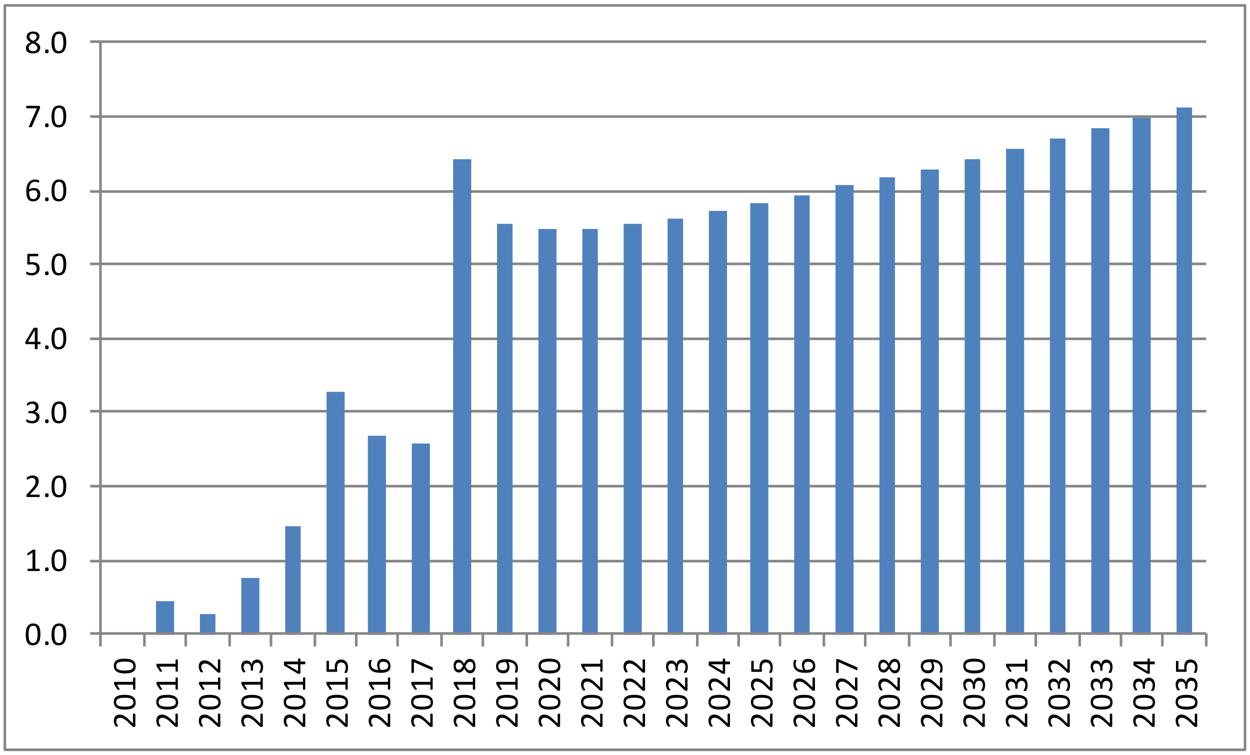
Source: CERI

Table A.2: I/O Impacts at US State Level

	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alabama	88	44	1
Alaska	26	7	0
Arizona	129	62	2
Arkansas	51	24	1
California	1,407	687	15
Colorado	125	60	2
Connecticut	283	147	3
Delaware	30	11	0
District of Columbia	33	20	0
Florida	372	176	5
Georgia	194	99	3
Hawaii	28	13	0
Idaho	61	31	1
Illinois	561	292	6
Indiana	331	174	4
Iowa	187	94	2
Kansas	60	30	1
Kentucky	83	42	1
Louisiana	121	40	1
Maine	61	32	1
Maryland	124	62	2
Massachusetts	461	250	5
Michigan	482	258	6
Minnesota	424	225	5
Mississippi	45	22	1
Missouri	119	63	2
Montana	37	18	1
Nebraska	42	20	1
Nevada	66	31	1
New Hampshire	70	37	1
New Jersey	232	113	2
New Mexico	40	16	1
New York	622	316	6
North Carolina	209	97	3
North Dakota	40	20	1
Ohio	274	143	4
Oklahoma	82	36	1
Oregon	291	151	3
Pennsylvania	274	140	4
Rhode Island	98	51	1
South Carolina	81	42	1
South Dakota	60	30	1
Tennessee	135	69	2
Texas	661	282	7
Utah	52	25	1
Vermont	20	10	0
Virginia	177	88	2
Washington	434	226	5
West Virginia	26	13	0
Wisconsin	422	225	5
Wyoming	19	5	0
Total US	**10,348**	**5,170**	**122**

Source: CERI

Figure A.1: US Employment in Thousand Jobs from 2010-2035



Source: CERI

Component 2: I/O Impacts in the US for the Pacific Trail Pipeline

Table A.3: I/O Impacts at the US PADD Level for the Pacific Trail Pipeline

2010-2035	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
PADD I	115	59	1
PADD II	120	64	1
PADD III	45	20	1
PADD IV	11	5	0
PADD V	77	38	1
Total US	368	186	4

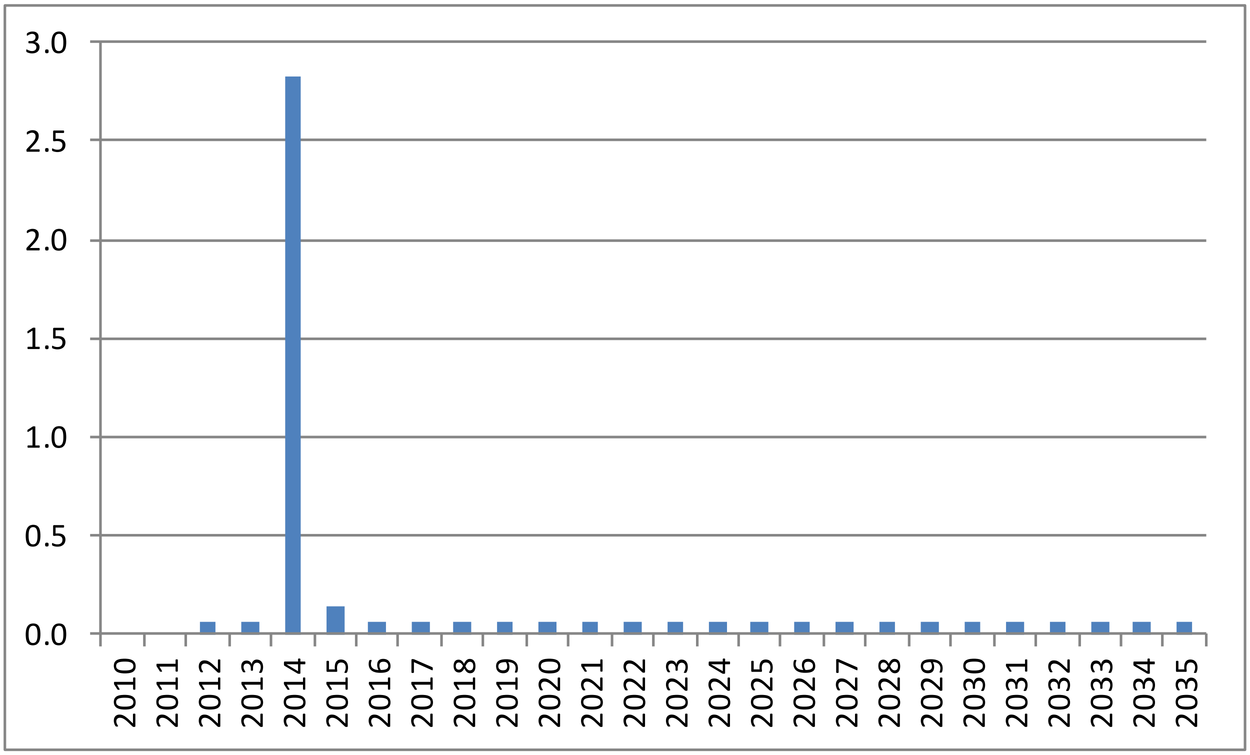
Source: CERI

Table A.4: I/O Impacts at the US State Level for the Pacific Trail Pipeline

	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alabama	4	2	0
Alaska	1	0	0
Arizona	5	3	0
Arkansas	2	1	0
California	49	24	1
Colorado	5	2	0
Connecticut	7	4	0
Delaware	1	0	0
District of Columbia	1	1	0
Florida	14	7	0
Georgia	7	4	0
Hawaii	1	0	0
Idaho	2	1	0
Illinois	18	10	0
Indiana	20	11	0
Iowa	5	3	0
Kansas	3	1	0
Kentucky	4	2	0
Louisiana	5	2	0
Maine	1	1	0
Maryland	5	2	0
Massachusetts	12	6	0
Michigan	16	9	0
Minnesota	10	5	0
Mississippi	2	1	0
Missouri	5	3	0
Montana	1	0	0
Nebraska	2	1	0
Nevada	2	1	0
New Hampshire	2	1	0
New Jersey	8	4	0
New Mexico	2	1	0
New York	21	11	0
North Carolina	9	5	0
North Dakota	1	1	0
Ohio	14	7	0
Oklahoma	4	2	0
Oregon	10	5	0
Pennsylvania	12	6	0
Rhode Island	2	1	0
South Carolina	4	2	0
South Dakota	1	1	0
Tennessee	7	3	0
Texas	30	14	0
Utah	2	1	0
Vermont	1	0	0
Virginia	7	3	0
Washington	9	5	0
West Virginia	1	0	0
Wisconsin	11	6	0
Wyoming	1	0	0
Total US	**368**	**186**	**4**

Source: CERI

Figure A.2: US Employment in Thousand Jobs Due to the Pacific Trail Pipeline



Source: CERI

Component 3: I/O Impacts in the US for the Kitimat LNG Terminal

Table A.5: I/O Impacts for Each US PADD for the Kitimat LNG Terminal

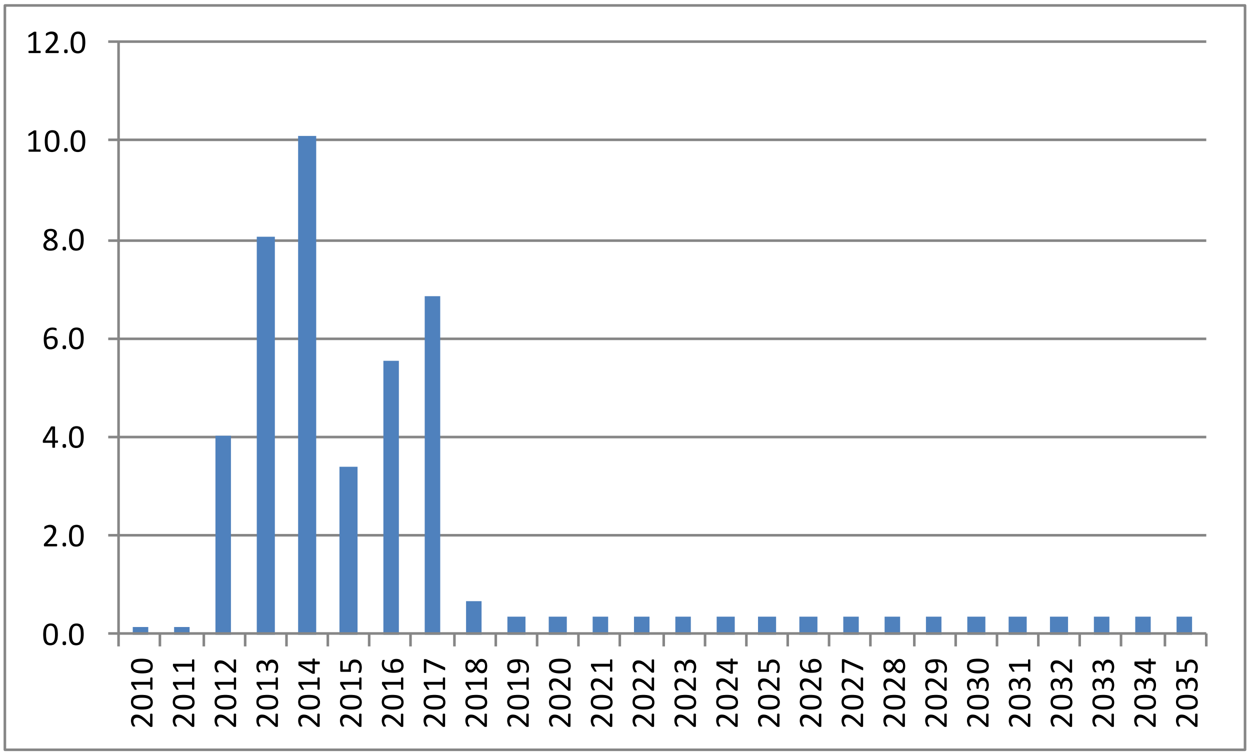
2010-2035	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
PADD I	1,034	527	12
PADD II	1,577	887	19
PADD III	407	190	5
PADD IV	94	46	1
PADD V	682	337	8
Total US	3,793	1,987	45

Table A.6: I/O Impacts at the US State Level for the Kitimat LNG Terminal

	$CAD Million		Thousand Person Years
	GDP	Compensation of Employees	Employment
Alabama	39	20	1
Alaska	7	2	0
Arizona	51	26	1
Arkansas	20	10	0
California	438	215	5
Colorado	46	23	1
Connecticut	56	29	1
Delaware	10	4	0
District of Columbia	9	6	0
Florida	128	62	2
Georgia	67	35	1
Hawaii	8	4	0
Idaho	17	9	0
Illinois	164	85	2
Indiana	676	418	7
Iowa	44	22	1
Kansas	23	12	0
Kentucky	38	20	1
Louisiana	40	15	0
Maine	11	6	0
Maryland	45	23	1
Massachusetts	99	54	1
Michigan	146	78	2
Minnesota	79	42	1
Mississippi	18	9	0
Missouri	48	25	1
Montana	6	3	0
Nebraska	17	8	0
Nevada	18	9	0
New Hampshire	18	10	0
New Jersey	78	39	1
New Mexico	16	7	0
New York	192	98	2
North Carolina	90	44	1
North Dakota	9	4	0
Ohio	135	71	2
Oklahoma	35	17	0
Oregon	86	45	1
Pennsylvania	108	56	1
Rhode Island	13	7	0
South Carolina	36	19	1
South Dakota	11	5	0
Tennessee	63	33	1
Texas	275	129	3
Utah	20	10	0
Vermont	6	3	0
Virginia	61	31	1
Washington	73	37	1
West Virginia	9	4	0
Wisconsin	89	47	1
Wyoming	5	1	0
Total US	3,793	1,987	45

Source: CERI

Figure A.3: US Employment in Thousand Jobs Due to the Kitimat LNG Terminal



Source: CERI

Appendix B: Provincial I/O

What is an Economic Input-Output Model?

W. Leontief [1937] describes the Input-Output (I/O) model as a computable version of Walras General Equilibrium; this model is more often linked to classical theories, such as those of Quesnay's Tableau Économique and Marx's reproduction equations. The focus on the entire economy gives I/O analysis a macroeconomic flavour, but its technique and foundations are more microeconomic. The production and consumption functions are derived from microeconomic analysis. Therefore, some people argue that I/O is at the interface of the two and categorize it as "mesoeconomics".[1]

In Canada, the first national I/O table was published in 1969 for the reference year 1961. After 1996 Statistics Canada improved the provincial and economic statistics by using sub-national surveys and other improved sources and methods. The reliability of the tables was improved beginning with the reference year 1997. Since 1997, the Input-Output and the interprovincial trade flow tables have been compiled and published annually for each province and territory in Canada. The national level I/O table is the simple aggregation of the provincial and territorial tables. After 1996, industries in the I/O tables were classified using the North American Industry Classification System (NAICS).

I/O accounts consist of three tables: Make (output), Use (input), and Final Demand. They are available at four different levels:

- **W**orksheet level: includes 299 industries, 170 final demand categories, and 725 commodities
- **L**ink level: includes 113 industries, 120 final demand categories, and 476 commodities
- **M**edium level: includes 64 industries, 37 final demand categories, and 109 commodities
- **S**mall level: includes 25 industries, 13 final demand categories, and 57 commodities

At the **W**, **L,** and **M** levels of detail, some of the entries in national matrices are confidential. Consequently, data are provided to users after suppressing the confidential information at the **S** level.

The Final Demand table shows transactions in goods and services for final use in the economy, as well as for all exports (irrespective of whether those exports are reserved for final demand elsewhere). A transaction is considered to be for final use if the good or service is exported or purchased for final consumption or capital investment. While purchases by households (other than housing itself) are considered to be final use, businesses, government, and other entities purchase services and commodities both for final and intermediate uses. Their intermediate purchase is reflected in the Use table and their final use appears in the Final Demand table.

[1] The term is a combination of "meso" which means "middle" and "economics".

The Use table presents the intermediate purchases by industries for production of their goods and services. Such purchases are non-capital expenditures of the industries, and include property tax, indirect taxes, wages and salaries, and subsidies.

The Make table records the values of production of goods and services in each industry. The term industry covers all entities in the economy except for households.

The following simple equation illustrates the relationship between the products in the I/O matrices:

Products in Make matrix = Products in Use matrix + Products in Final Demand matrix

Impact Analysis Modeling

Any activity that leads to increased production capacity in an economy has two components: construction (or development) of the capacity, and operation of the capacity to generate outputs. The first component is referred to as investment, while the second is either production or operation. Both activities affect the economy through purchases of goods and services, as well as labour. Figure B.1 illustrates the overall approach CERI uses to assess economic impacts resulting from these activities.

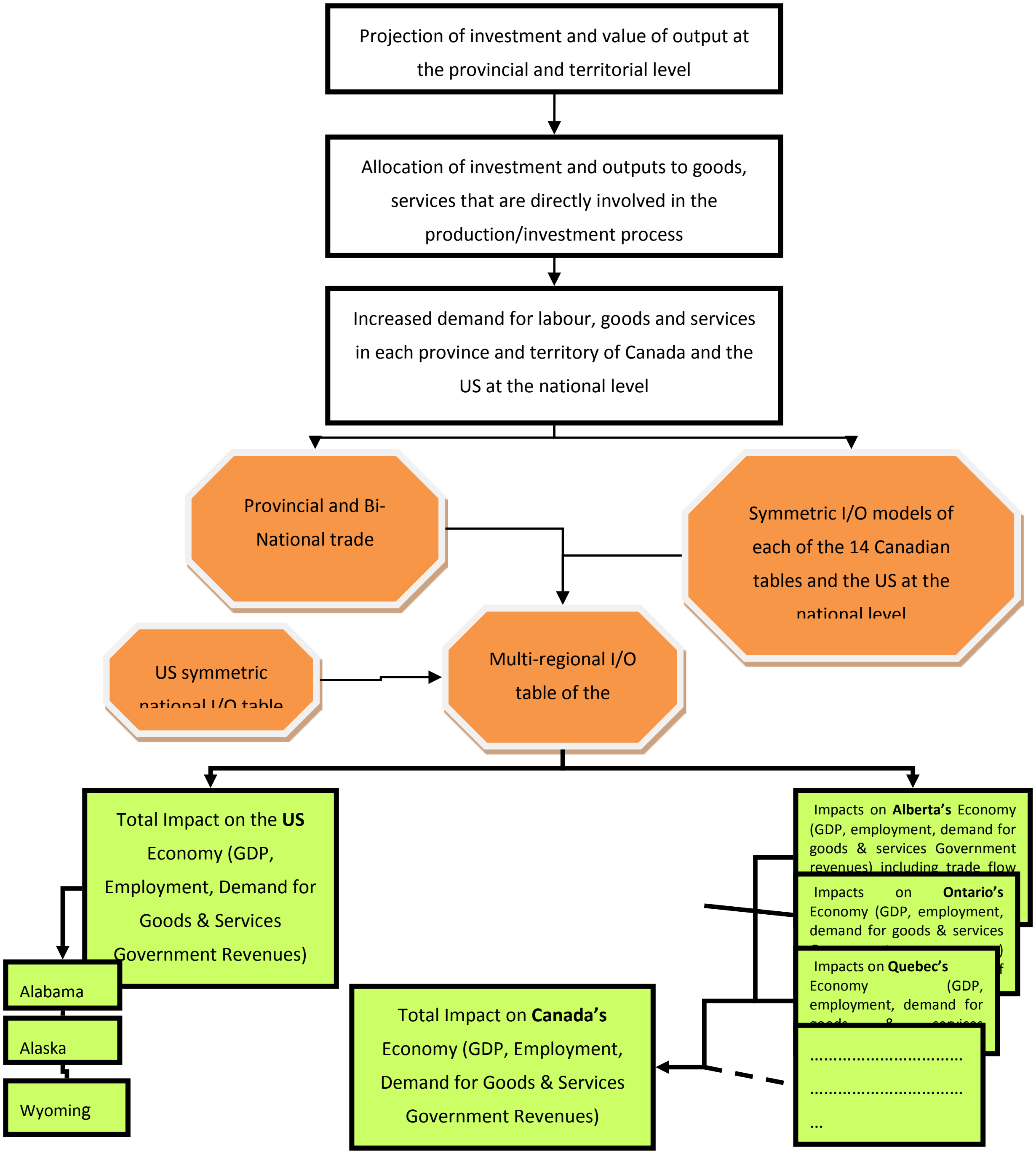
The first step is to estimate and forecast the value of investment (i.e., construction or development expenditure) and production (sales). The total investment or development expenditures are then disaggregated into purchases of various goods and services directly involved in the production process (i.e., manufacturing, fuel, business services, etc.) as well as labour required, using the expenditure shares. Similarly, the value of total production (output or sales) from a production activity (i.e., conventional oil production, petroleum refinery, etc.) is allocated to the purchase of goods and services, payment of wages, payments to government (i.e., royalty and taxes), and other operating surplus (profits, depreciation, etc.).

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

The estimated bi-national trade flow tables, developed by CERI, are used to derive import or export of each type of good and service for all 13 provinces and territories in Canada plus Government Abroad and the United States (US) at the national level. The value of goods and services used by a particular industry and produced in a different province or territory in Canada (or a state in the US) can then be calculated. This method captures the trade supply chains among all trading partners in Canada and the US, as well as their feedback effects. The latter are changes in production in one region that result from changes in intermediate and final demand in another region, which are in turn brought about by demand changes in the first region.

In this exercise, the investment and operation dollars are initially determined on a project basis. For example, in the case of the oil sands industry, the dollars are allocated to Mining and Extraction, In Situ, Integrated Mining and Upgrading, and the Stand-Alone Upgrading categories. Investment and operations spending stimulate Alberta's economy in various sectors simultaneously, including the Oil Sands, Construction, Refinery, and Manufacturing sectors. The relationship between the oil sands and the pipeline and refining industries is captured in the base economy, and thus inducement on the supply side results in impacts on these industries. Investment in Alberta also impacts the US economy; these impacts can be identified at the sector level. The US Bureau of Economic Analysis (USBEA) data is used to link these impacts at both the state and industry levels in the US. Thus, refinery upgrades required in order to handle heavier oil sand crudes are not reflected in the model, but generic refinery upgrades are implicitly accounted for in the indirect impact of investment in oil sands development upon activity in the refinery sector (both in Canada and the US). No direct shocks are made to the US sectors.

Figure B.1: Overall Bi-National Multi-Regional I/O Modeling Approach



CERI's US-Canada Multi-Regional I/O Model (*UCMRIO 2.0*)

This section discusses the multi-stage process to build the *UCMRIO 2.0* model. An earlier version of the model was developed in 2008, as a Multi-regional I/O model for the US and Canada for examining the economic impacts of the Canadian petroleum industry on Canada's provinces and territories. CERI's *UCMRIO 2.0* model builds on the Multi-regional I/O model for Canada. The models' structures are defined in the System of National Accounts (SNA) terminology as industry-by-industry, or "industry technology", and share the following advantages:

- Compatibility with economic theory;
- Recognition of the institutional characteristics in each industry;
- Preservation of a high degree of micro-macro link;
- Maximization of the use of detailed information from the Supply (Make) and Use Tables (SUTs);
- Comparability with other types of statistics; and
- Transparency of compilation method, resource efficiency, support for a wider and more frequent compilation of input-output tables internationally.

Further, the *UCMRIO 2.0* is different from its predecessor in the following aspects:

- The I/O tables have been updated to the most recent available base year of 2006; the previous update was from 2003 data. In particular, the oil and oil sands industries have been adjusted to represent more current conditions. In the new model, the manual method of constructing I/O tables was replaced by using the *balanced symmetrical I/O* tables from StatsCan. This provides consistency between provincial I/O tables and interprovincial trade flow matrix. The ultimate source of all *UCMRIO 2.0* input-output tables and trade flow matrix is StatsCan.
- The new model also includes a new provincial table, labelled as Government Abroad,[2] which accounts for the impacts of Canadian military bases, commercial offices, and embassies abroad, on the Canadian economy.
- The trade flow matrix has been enhanced, thus allowing for more accurate mapping of the trade relations between Canadian provinces and the US. For instance, the oil sands industry, which is one of the industries in the Canadian I/O tables, does not exist in the US tables. Therefore, during mapping of the trade flow matrix, it was verified that Alberta's exports of oil sands were delivered to refineries in the US, rather than to a non-existent US oil sands industry. Mapping the trade flow represents a significant improvement in the model and it is an important contribution to ensure that the appropriate provinces/states and industries are impacted. Better mapping of the energy industry trade flows creates better mapping of the impacted sectors and regions in Canada and the US.

[2] Government Abroad includes activities that are part of the Canadian economy but do not have a natural and unambiguous spatial boundary. They are classified as a fourteenth region, for purposes of provincial and territorial input-output tables. Examples include activities of Canadian embassies, the armed forces stationed abroad, and activities relating to offshore oil and gas extraction. These activities form a part of Canadian GDP, but are not assigned to any of the 13 provinces and territories.

Overall, the model formulation and approach have been enhanced to capture the relations among various sectors and local economies of different regions with increased precision. This set of procedures is well documented, frequently cited, and commonly practiced in I/O literature. The new model's structure is similar to the old version, however this latest edition of CERI's I/O model allows for more flexibility, representing a more accurate picture and improved final results.

Building the Model

The following steps show how the bi-national *UCMRIO 2.0* has been developed, and how one can trace direct, indirect, and induced effects of the Canadian energy sector on the Canadian and US economies. The model provides insights at the provincial level for Canada and at the state level for the US.

Compilation of the bi-national *UCMRIO 2.0* has the following steps:

- StatsCan provides S level Symmetrical I/O tables (SIOTs) and Final Demand tables for 13 provinces and territories plus Government Abroad. Therefore, there are 14 regional tables for Canada plus one national table. Provincial data are only available at the S level due to confidentiality of more disaggregated data for some sectors in various provinces. The I/O tables used are at *producer's prices*. CERI did not construct symmetrical tables from the Use and Make tables this time as the compiled tables were available. The base year for the I/O tables is 2006.[3]
- SIOTs are balanced, so the use of inputs in the economy is equal to the production of outputs.
- The US national Use and Make tables (2006) were sourced from the USBEA. These tables are at *producer's price*, and consist of 67 sectors and 13 final demand categories. CERI compiled the US SIOT table and carefully combined industry sectors in order to arrive at 29 industry sectors, consistent with Canadian S-level aggregation.

- The intermediate and final demand parts of the US SIOT table are constructed as follows:

$$B=V(\mathrm{diag}(q-m))^{-1}U \quad \text{and} \quad F=V(\mathrm{diag}(q-m))^{-1}Y$$

- Where,

  - **B**: Intermediate part of Use table transformed to symmetric I/O table format
  - **F**: Final demand part of Use table transformed to symmetric I/O table format
  - **V**: Transpose of Make table excluding imports
  - **U**: Intermediate demand part of Use table
  - **Y**: Final demand part of Use table
  - **q**: Vector of total supply of products

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

- **m**: Vector of imports by products
- **diag(q-m)**: Matrix with q-m on the diagonal

- By using these equations, the rectangular commodity by industry Use and Make tables are transformed to a symmetrical square I/O table and its corresponding final demand matrix.
- In order to highlight the energy sectors in the US and Canadian provincial SIOTs, CERI disaggregated the "Mining and Oil and Gas Extraction'' industry to five subsectors including: Conventional Oil, Oil Sands, Natural Gas and LNG, Coal, and Other Mining. In the same fashion, the Manufacturing industry is broken into Refinery, Petrochemical, and Other Manufacturing.
- Whereas the trade flow between Canadian provinces and territories was provided by StatsCan, the trade flow pattern between the individual provinces and the US was not. The data was gathered from a variety of sources and compiled by CERI into a trade flow pattern between the two countries. CERI is confident that the developed mapping portrays an accurate trade flow pattern, which is crucial for generating a credible impact analysis for the US in particular.
- In the *UCMRIO 2.0*, an exchange rate is needed in order to link data from US and Canada to a common monetary basis. We use the average exchange rate between the US and Canadian dollar for the base year 2006 to convert the trade flow matrix to Canadian dollars. However, parity is assumed for the exchange rate projection (see section on Exchange Rates in Chapter 2).
- We combine 15 SIOTs (13 provincial tables, 1 for Government Abroad and 1 for the US at the national level) to compile one bi-national I/O matrix. The bi-national matrix is then merged with the trade flow matrix, and inverted to generate direct, indirect, and induced effect multipliers (see section on Multipliers).

Industries in the UCMRIO 2.0

The classification of industries in both the US and Canada is identical. Table B.1 provides a brief description of these sectors or commodities.

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

Serial No.	Sector or Commodity	Examples of activities under the sector or commodity
1	Crop and Animal Production	Farming of wheat, corn, rice, soybean, tobacco, cotton, hay, vegetables and fruits; greenhouse, nursery, and floriculture production; cattle ranching and farming; dairy, egg and meat production; animal aquaculture
2	Forestry and Logging	Timber tract operations; forestry products: logs, bolts, poles and other wood in the rough; pulpwood; custom forestry; forest nurseries and gathering of forest products; logging.
3	Fishing, Hunting and Trapping	Fish and seafood: fresh, chilled, or frozen; animal aquaculture products: fresh, chilled or frozen; hunting and trapping products
4	Support Activities for Agriculture and Forestry	Support activities for crop, animal and forestry productions; services incidental to agriculture and forestry including crop and animal production, e.g., veterinary fees, tree pruning, and surgery services, animal (pet) training, grooming, and boarding services
5	Conventional Oil[4]	Conventional oil, all activities e.g., extraction and services incidental to conventional oil
6	Oil Sands	Oil sands, all activities e.g., extraction and services incidental to oil sands
7	Natural Gas and NGL	Natural gas, NGL, all activities e.g., extraction and services incidental to natural gas and NGL
8	Coal	Coal mining, activities and services incidental to coal mining
9	Other Mining	Mining and beneficiating of metal ores; iron, uranium, aluminum, gold and silver ores; copper, nickel, lead, and zinc ore. Mining; non-metallic mineral mining and quarrying; sand, gravel, clay, ceramic and refractory, limestone, granite mineral mining and quarrying; potash, soda, borate and phosphate mining; all related support activities
10	Refinery	Petroleum and coal products; motor gasoline and other fuel oils; tar and pitch, LPG, asphalt, petrochemical feed stocks, coke; petroleum refineries
11	Petrochemical	Chemicals and polymers: resin, rubber, plastics, fibres and filaments; pesticides and fertilizers; etc.

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

Serial No.	Sector or Commodity	Examples of activities under the sector or commodity
12	Other Manufacturing	Food, beverage and tobacco; textile and apparel; leather and footwear; wood products; furniture and fixtures; pulp and paper; printing; pharmaceuticals and medicine; non-metallic mineral, lime, glass, clay and cement; primary metal, iron, aluminum and other metals; fabricated metal, machinery and equipment, electrical, electronic and transportation equipment, etc.
13	Construction	Construction of residential, commercial and industrial buildings; highways, streets, and bridges; gas and oil engineering; water and sewer system; electric power and communication lines; repair construction
14	Transportation and Warehousing	Roads, railways; air, water & pipeline transportation services; postal service, couriers and messengers; warehousing and storage; information and communication; sightseeing & support activities
15	Transportation Margins	Transportation margins
16	Utilities	Electric power generation, transmission, and distribution; natural gas distribution; water & sewage
17	Wholesale Trade	Wholesaling services and margins
18	Retail Trade	Retailing services and margins
19	Information and Cultural Industries	Motion picture and sound recording; radio, TV broadcasting and telecommunications; publishing; information and data processing services
20	Finance, Insurance, Real Estate and Rental and Leasing	Insurance carriers; monetary authorities; banking and credit intermediaries; lessors of real estate; renting and leasing services
21	Professional, Scientific and Technical Services	Advertising and related services; legal, accounting and architectural; engineering and related services; computer system design
22	Administrative and Support, Waste Management and Remediation	Travel arrangements and reservation services; investigation and security services; services to buildings and dwellings; waste management services
23	Educational Services	Universities; elementary and secondary schools; community colleges and educational support services
24	Health Care and Social Assistance	Hospitals; offices of physicians and dentists; misc. ambulatory health care services; nursing and residential care facilities; medical laboratories; child and senior care services
25	Arts, Entertainment and Recreation	Performing arts; spectator sports and related industries; heritage institutions; gambling, amusement, and recreation industries
26	Accommodation and Food Services	Traveler accommodation, recreational vehicle (RV) parks and recreational camps; rooming and boarding houses; food services and drinking establishments

Serial No.	Sector or Commodity	Examples of activities under the sector or commodity
27	Other Services (Except Public Administration)	Repair and maintenance services; religious, grant-making, civic, and professional organizations; personal and laundry services; private households
28	Operating, Office, Cafeteria and Laboratory Supplies	Operating supplies; office supplies; cafeteria supplies; laboratory supplies
29	Travel, Entertainment, Advertising and Promotion	Travel and entertainment; advertising and promotion
30	Non-Profit Institutions Serving Households	Religious organizations; non-profit welfare organizations; non-profit sports and recreation clubs; non-profit education services and institutions
31	Government Sector	Hospitals and government nursing and residential care facilities; universities and government education services; other municipal government services; other provincial and territorial government services; other federal government services including defence

US-Canada Trade Table and Model Structure

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

The following is a brief discussion of the modeling.

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

$$AX+FD = X \rightarrow (I-A) \times X=FD \rightarrow \quad X= (I-A)^{-1} \times FD \rightarrow \quad X= L \times FD$$

Where; **A** is the matrix of input coefficients (n×n), **I** is identity matrix (n×n) and **L** is the Leontief inverse matrix (n×n). This is the core formula of the Leontief quantity model. This relationship estimates direct and indirect impacts for a single economy (i.e. no trade flow). We can expand this model to include induced effects by endogenising the most important component of local final demand, namely private consumption. This captures the economic impact of increased consumption due to earned wages from new jobs. After endogenising the private consumption expenditure we arrive at the following relationship:

$$X= (I-A-PCE)^{-1} \times FD^*$$

We use **PCE** for private consumption expenditure matrix and **FD*** for the exogenous part of the final demand.

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

$$X = (I - C \times A - C \times PCE)^{-1} \times C \times FD^{*}$$

In order for the above equation to have a finite solution, (I-C × A-C × PCE) must be a nonsingular matrix.[5] As is the case for standard I/O models, the impact of an industry, such as the oil sands industry, is calculated by modeling the relationship between total gross outputs and final demand as follows:

$$\Delta X = (I - C \times A - C \times PCE)^{-1} \times C \times \Delta FD^{*} \qquad \text{(Equation 1)}$$

Where:

ΔX -- Changes (or increases) in total gross outputs of the US and all provinces and territories, at the sectoral level, due to construction and operation of projects (i.e., oil sands). Dimension n=465 so this vector is a 465×1 vector.

I – is a 465×465 identity matrix, unity for diagonal elements and zero for off-diagonal elements.

A – is a 465×465 block diagonal matrix of technical coefficients at the sectoral level for the US and Canada. It is composed of 15 blocks so that each block is a 31×31 matrix corresponding to the US and each province's (or territory`s) input technical coefficient matrix.[6] An element of such a matrix is derived by dividing the value of a commodity used in a sector by the total output of that sector. The element represents requirements of a commodity in a sector in order to produce one unit of output from that sector.

PCE – is a 465×1 vector at the sectoral level for Canada and the US. Each of its elements measures the private consumption expenditure share of a sector's total gross output by jurisdiction (province, territory or the US).

C – is a 465×465 transposed matrix of multiregional trade coefficients. It includes import and export shares of a sector's total output in the US and each province or territory. Each element on the row of this matrix measures the share of export to a particular sector in the US or a province/territory from a given sector in another province/territory or the US.[7]

ΔFD* – is a 465×1 vector of changes (or increases) in the exogenous part of final demand at the sectoral level. Outputs from Canada and the US resulted from any change in the final demand components in the US or any province or territory, including commodities directly demanded (or purchased) for the construction and development of any sector are captured in **ΔX**.

[5]For further information on Interregional I/O analysis please see Hertwich and Peters (2010), Miller and Blair (2009), CERI Study No. 120 (2009), Oosterhaven and Stelder (2008), and Sim, Secretario, and Suan (2007).
[6]In other words, one can say all 14 Canadian tables (13 provinces and 1 Government abroad) and one US input technical coefficients matrices are stacked together in construction of a diagonal block matrix at the national level.
[7]In particular, this matrix is a bridge matrix which connects the US, or any province, to other provinces through import and export coefficients. See Miller and Blair (2009).

The calculation of total impact is based on the multiplication of direct impact and the inverted matrix. Based on the direct impact on a sector, Equation 1 above is used to estimate all the direct, indirect, and induced effects on all sectors in all provinces, particularly in terms of changes in consumption, imports, exports, production, employment, and net taxes. The direct impact is referred to as **∆FD*** in Equation 1. The change in final demand (**∆FD***) consists of various types of investment expenditures, changes in inventories, and government expenditures. In the current model, the personal expenditures are not part of the final demand and have been endogenised to accommodate the induced impact.

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

Direct, indirect, and induced impacts:

$$\Delta X = (I - C \times A - C \times PCE)^{-1} \times C \times \Delta FD^{*} \qquad \text{(Equation 2)}$$

Direct and indirect impacts:

$$\Delta X = (I - C \times A)^{-1} \times C \times \Delta FD \qquad \text{(Equation 3)}$$

The difference between Equation 2 and 3 is referred to as the induced impact of any changes in final demand components.

Once the impact on output (change in total gross outputs) is calculated, the calculation of impacts on GDP, household income, employment, taxes, and so forth, are straightforward. In particular, as previously mentioned, the base year for the I/O tables used in this report is 2006. CERI utilizes the tax information derived from these tables and federal and provincial tax information from the *Finances of the Nation*, where these numbers reflect the tax structure of the Canadian economy in the year 2006.[8] CERI acknowledges that there have been changes, notably to the corporate income tax structure and the goods and services sales tax (GST) since 2006. The new tax regime will result in changes in tax impacts as business responds to the new incentives. Therefore tax estimates should be interpreted on a 2006 basis.

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

[8] Canadian Tax Foundation; Finances of the Nation; 2006, 2007 and 2008.

Disaggregation of National Results for the US

To report the US economic impacts down to the state level, CERI constructed a series of disaggregating coefficients. This process allows CERI to illustrate the economic impacts of the oil sands developments in Canada, on each US state's economy.

The USBEA publishes detailed information on the sectoral GDP, employment, and compensation of employees for the US states.[9] **CERI used the base year data (year 2006)** to establish a series of coefficients to disaggregate the national figures to state levels. For instance, to disaggregate national agricultural GDP among all states, CERI uses a set of 51 share coefficients, one for each state and the District of Columbia, in order to disaggregate the national numbers. It is evident that the sum of these coefficients is equal to unity and they depict the share of each state in the GDP of the US economy.

This approach, which has been used in *UCMRIO 1.0,* is not without its flaws. The main concern was that the model splits the impact of the Canadian Energy Industry (Oil Sands, Conventional Oil, and Natural Gas) among the US states based on only the size of their economies. As a result, large economies such as California, Texas, New York, and Florida will be affected more than the rest of the states, and impacts on states like Illinois, Michigan, Ohio and Washington, which are smaller but have a larger share of total US-Canada energy trade, will be understated. CERI was able to address this problem in the new *UCMRIO 2.0.*

In *UCMRIO 2.0,* we employed a disaggregation method, which provides impacts for the states with the strongest ties to the Canadian energy sector through identifying who are the main Canadian partners among the US states. In particular, we map the supply of capital goods and services from the US states to the Canadian energy industry, as well as demand for Canadian natural gas and oil by state. As a result, CERI was able to disaggregate the indirect impacts of the Canadian energy sector on the US economy. For the induced effects in the US, we assume that the income earned by US employees who work for businesses that are involved with the Canadian oil and gas industry will be spent on commodities that will be produced uniformly throughout the US. Following this procedure, we use the relevant share coefficients to estimate the sectoral employment, and compensation of employees.

Interpretation of the US Impacts

The impacts of the Canadian Energy Sector on the US economy consist of the amount of GDP, employment, government revenue, household income, and export volumes that is generated in the US as a result of new spending, or export in the Canadian energy sector. For example, one additional dollar in Canadian oil sands production which will be consumed in Canada or the US requires inputs from other linked industries and primary input sources like labor and capital. These input sources and linked industries are either in Canada or the US.[10] The linked industries in the US also require inputs from other linked industries in Canada and the US in order to produce goods and services that were demanded in the first place. There will be further subsequent rounds of spending, and this will continue with the amount of money circulating

[9] See http://www.bea.gov/regional/gsp and http://ww.bea.gov/regional/spi.

[10] We do not study impacts on Rest of the World (ROW), because it is exogenous according to our assumption.

getting smaller at each successive round of activity as money leaks out of the economy in the form of savings and imports, until the amount of money circulating in the economy as a result of the initial energy spending becomes negligible. However, during this process, jobs will be created in the US, and income earned from these jobs will be spent on all sorts of commodities. As a result, the impact on the US economy is the result of the initial one dollar of gross output in Canada.

The model assumes that a fraction of the new Canadian oil sands production will be imported by US refiners. Thus, newly produced Canadian barrels either displace a fraction of the US import of crude oil from the rest of the world or constitute a supply that prevents US refining capacity from having to lie idle. In the latter case, the imported barrels from Canadian oil sands will create and/or support part of the GDP, jobs, etc., currently supported by the imported oil from other origins. This replacement support is not captured by the conventional I/O analysis to the full extent. The fixed economic structure of I/O tables in base year 2006 constrains the magnitude of impact. It implies that the marginal response of the US industries as a result of oil sands production in Alberta is equivalent to the average relationship observed in the base year. CERI finds that Canadian oil sands could essentially replace US imports of oil from offshore sources. This enhances oil trade between Canada and the US, and implies a different trade flow pattern in the future compared to the base year. As a result, CERI utilizes a procedure to capture this "upper bound support effect", which recognizes the economic impacts of the Canadian oil sands industry if all new bitumen/SCO barrels were exported to the US. This estimation only provides an upper limit for the impacts on US.

UCMRIO 2.0 Multipliers

Table B.2 summarizes the I/O multipliers, which have been employed to investigate the impacts of the oil and gas industry on the US and Canadian economies. *UCMRIO 2.0* multipliers are consistent with *StatsCan*, *RIMS II* and *IMPLAN*.[11] Note that the *UCMRIO 2.0* is a bi-national multiregional model, so it is capable of estimating the cross border spillover impacts. Therefore, we report two types of multipliers for our model. The *UCMRIO 2.0* multipliers indicate that most of the economic impact from a new shock stays in the country of origin. One dollar investment in oil sands in Alberta has a relatively higher impact on the economy in the US compared to the impact on the Canadian economy of $1 investment in the US oil industry (i.e. 0.24 vs. 0.05). Almost 90 percent of the impact stays in Canada when the oil industry in Canada is stimulated; this compares to 98 percent of impacts remaining in the US when the oil industry in the US is shocked. This finding is consistent with existing literature. For Instance, Japan's Ministry of Economy, Trade and Industry (METI) compiled a US-Japan I/O table in 2005 in order to analyze interdependence among various industries in both countries. One of their findings was that, on average, 98 percent of total economic impact of a change in final demand stays in the country of origin.[12]

[11]For more information on Regional Input-Output Modeling System (RIMS II) see https://www.bea.gov/regional/rims/. For Impact Analysis for Planning (IMPLAN) see http://implan.com/V4/Index.php.
[12]See http://www.meti.go.jp/english/statistics/tyo/kokusio/index.html

Table B.2: Oil and Gas I/O Multipliers for Canada and the US

Country/State of the Original Shock	Output	Value Added (GDP)	Source
Alabama (Offshore Oil and Gas)	1.5		Joseph R. Mason - RIMS II
Kansas (Oil and Gas)	1.5		Timothy R. Carr - RIMS II
Louisiana (Offshore Oil and Gas)	1.79		Joseph R. Mason - RIMS II
Mississippi (Offshore Oil and Gas)	1.53		Joseph R. Mason - RIMS II
Ohio (Oil and Gas)	1.97		Kleinheinz & Associates
Oklahoma (Oil and Gas production)	1.61	1.03 (est.)	Mark C. Snead - IMPLAN
Pennsylvania (Oil and Gas)	1.56		Pennsylvania Economy League - IMPLAN
Texas (Offshore Oil and Gas)	2.07		Joseph R. Mason - RIMS II
PADD II- United States (Oil and Gas)	2.12	1.16	BEA-RIMS II
United States (Offshore Oil and Gas)	2.39		Joseph R. Mason - RIMS II
Canada (Mining , Oil and Gas)	1.52	1.04	Statistics Canada
United States (Oil) - US national impact - Canada impact	2.78 0.05	1.5 0.03	CERI-*UCMRIO 2.0*
Canada (Oil/Oil Sands) - Canada impact - US national impact	1.77 0.24	1.00 0.11	CERI-*UCMRIO 2.0*

All multipliers are Type II, according to RIMS II definition and with respect to initial outlay.

Data Sources

This section briefly reviews data sources used to compile data for Canada and the US. As previously mentioned, the annual US I/O tables are available through the USBEA. The *Make, Use, and Final Demand* tables are quite detailed at the industry level and have been available since 1947. The 85-industry, 365-industry, and 596-indusry are just a few examples of table formats issued by the USBEA. Statistics are in compliance with the definitions of the 1997 North American Industrial Classification System (NAICS).

The *Use* table shows the inputs to industry production and the commodities that are consumed by final users. The *Make* table, on the other hand, depicts the commodities that are produced by each industry. In this report we use the *Make and Use* table to construct the US symmetric I/O table consistent with the Canadian Multi-provincial I/O tables developed by CERI.

The National Accounts and I/O tables in Canada were also developed at the end of the Second World War. Tables in the present format, however, were first published in 1969 for the base year 1961. The I/O accounts are one of four main accounts that are published by Canada's System of National Economic Accounts (CSNEA), the others being income and expenditure accounts, financial and wealth accounts, and balance of payments accounts.

The I/O accounts are calculated at the national, provincial, and territorial level on an annual basis only.[13] These tables are available at different levels of aggregation[14] on the Canadian Socio-Economic Information Management System (CANSIM) Tables 381-0009 to 381-0014. Provincial I/O data are also available on an occasional basis.

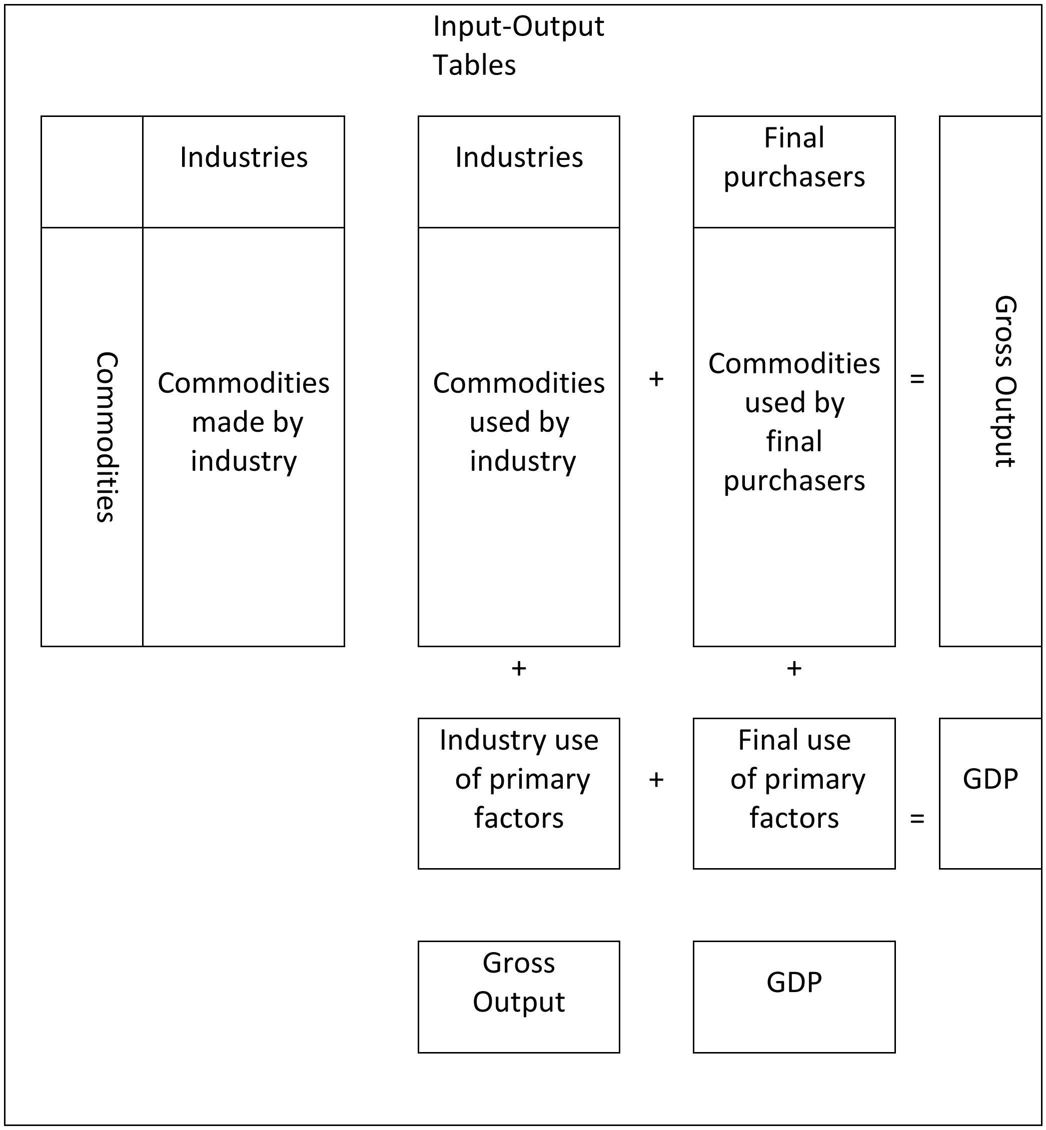
The framework of both the US and the Canadian I/O system is complementary and consists of the following three basic tables:

- Gross output of commodities (goods and services) by producing industries;
- Industry use of commodities and primary inputs (the factors of production, labour and capital, plus other charges against production, such as net indirect taxes); and
- Final consumption and investment, plus any direct purchases of primary inputs by final demand sectors.

Figure B.2 is a schematic of the I/O system, and combines features of both the US and Canadian system and the more traditional single matrix presentation.

[13]The I/O tables and models, published annually by Statistics Canada, are entitled "The Input-Output Structure of the Canadian Economy". This document covers the basic concepts related to the I/O tables. Each year, two years of data are reported; the latest year is considered preliminary and the previous one is considered final. There are also many documents which are available on request from the I/O division.
[14]The I/O Tables of this publication are stored in CANSIM at the Small (S) level, Medium (M) level and Link (L) level of aggregation.

Figure B.2: Schematic of the Input-Output System



Source: A User Guide to the Canadian System of National Accounts, Statistics Canada, Catalogue No. 13-589E, November 1989.

Assumptions and Limitations

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

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

Although the I/O approach has been widely used around the world for economic impact assessment, there are certain limitations that should be noted. I/O matrices are limited to the estimation effect on demand, rather than supply. Therefore, they do not take into account important objectives such as lasting effects on productive potential. Most effects on supply, which are likely to lead to a sustainable increase in the growth rate of assisted sectors (or provinces/states) and enable them to catch up with more developed sectors (or provinces), are completely disregarded. Some of these overlooked points include: the creation of new productive capacity, improvement of the training and education of the workforce, construction of infrastructure, productivity gains throughout the economy, spread of technological progress, and intensity of high-tech activities in the productive sector. All these effects on supply can transform productive capacity in a lasting and irreversible manner. These cannot be estimated using this multi-regional I/O tool.

In particular, several other well-known limitations of the I/O approach are discussed below:

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

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

Since these attributes cannot be incorporated in a static I/O model, these models are primarily used over a short-run time horizon, where relative prices and productivity are expected to remain relatively constant. Hence, over a longer period, static I/O models are not the best tools for economic impact analysis. GE models or macroeconomic models accounting for the factors mentioned above could be more appropriate. Moreover, I/O models and other static macroeconomic models and general equilibrium models do not account for sectoral dynamics and adjustment in an economy.

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

Lack of capacity to capture price, investment, and production interactions. An I/O model is incapable of representing the feedback mechanism among price change, investment, and production. For example, an increase in oil price provides a signal to investors to increase investment. The increase in investment would add productive capacity (more drilling) and also the production. However, this type of interaction cannot be modeled in a simple I/O model.

Appendix C: Regional I/O

CERI's Regional I/O model divides Alberta into seven regions and British Columbia into eight. The eight in BC are called Development Regions by the British Columbia government and Economic Regions by Statistics Canada (StatsCan). They contain whole census divisions. Alberta's seven regions were set forth in the province's recently-published Land Use Framework; their boundaries were unknown at the time of the 2006 census of population, and in many cases they contain parts of census divisions. It was necessary to aggregate information at the census subdivision level to derive census data for each of the seven Alberta regions. An extra step was required to transform Alberta census division data into regional data by applying the percentage split of each census division's population among the regions that it belongs to.

Information by census division in E-stat's *cumulative profiles* for each province from the 2006 census in respect of population, employment, unemployment rate, and experienced labour force by industry, among other things, is given in somewhat finer detail than in StatsCan's *community profiles* on the latter's public website. Experienced labour force is identified in community profiles for the following categories of industries: agriculture and other resource-based industries, construction, manufacturing, wholesale trade, retail trade, finance and real estate, health care and social services, educational services, business services, and other services. The experienced labour force information by industry on E-stat's cumulative profiles, in contrast, conforms more closely to the format of CERI's Regional I/O model as it also includes utilities, transportation and warehousing, information and cultural industries, professional scientific and technical services, management of companies and enterprises, administrative and support, arts, entertainment and recreation, accommodation and food services, other services (except public administration), and public administration.

The corresponding information for gross output, GDP, and wages and salaries was not available by census division from the 2006 census, and therefore had to be estimated by assuming that the percentage split among regions would mirror that of an experienced labour force. CERI's Regional I/O model requires that resource-based industries be broken down into crop and animal production, forestry, fishing/hunting/trapping, oil, oil sands, natural gas and liquids, coal, and other mining. It also requires that "manufacturing" be broken down into petrochemicals, oil refining, and other manufacturing. Information on other industrial categories separately identified in CERI's Regional I/O model is available from Statistics Canada at provincial levels but not in community profiles. CANSIM matrix 282-0008 contains provincial labour force information, and has the additional virtue that it separately identifies agriculture, fishing, and hunting/trapping. CANSIM matrix 281-2003 contains the corresponding provincial information on employment; matrix 397-0026, on GDP; and matrix 381-0016, on gross output.

Even at a provincial level, statistics on refining and petrochemicals are lacking for British Columbia because it has only two oil refineries and no sizeable petrochemical facility. (A methanol plant and an ammonia plant at Kitimat were shut down in 2005 and have been almost completely dismantled. They are slated to be shipped to China.) Similarly, the Atlantic Provinces have three refineries, each located in a different province. Statistics Canada keeps information on individual facilities confidential in order to avoid disclosing it to potential competitors, so it will publish aggregate information only if it encompasses at least three reporting entities. The only information CERI could find on a facility-by-facility basis is emissions data available through Environment Canada, and even that database excludes small facilities whose emissions are below a threshold number. Refinery GDP, employment, labour income and gross output were allocated among the provinces in proportion to physical output of refined petroleum products (RPPs). Saskatchewan and British Columbia RPP output data were combined due to the residual disclosure problem, so a further allocation of GDP, employment, labour income and gross output was done among the three refineries in those two provinces in proportion to capacity. The Prince George refinery owned by Husky is located in the Cariboo Region; the Burnaby refinery owned by Chevron is located in the Mainland/Southwest Region. All operating refineries in Alberta are located in the North Saskatchewan Region. (The idle refinery at Bowden is in the Red Deer Region.) Economic activity in all forms for the petrochemical industry of British Columbia was taken to be 1 percent of manufacturing, and was assigned to the Mainland/Southwest Region; economic activity by region for "petrochemicals" (excluding fertilizer) was estimated by apportioning the corresponding Alberta provincial number based on Environment Canada's greenhouse gas emissions data by facility, aggregated by region; economic activity by region for "fertilizers excluding potash" was estimated by apportioning the corresponding Alberta provincial number based on published ammonia capacity by plant, aggregated by region. There are no fertilizer manufacturing plants in British Columbia.

Farm revenue figures by census division for agriculture and forestry were obtained from the 2006 Census of Agriculture. Provincial totals for employment, labour income, GDP and gross output for agriculture and for forestry were allocated regionally based on each region's percentage of provincial farm agricultural revenue and farm forestry revenue. In Alberta, an additional step was required because a few census divisions' farm forestry revenues were not disclosed. The sum of their farm forestry revenues (obtained residually) was allocated among them in proportion to the number of farms in each. British Columbia's fishing/trapping gross output, GDP, labour income and employment were allocated among its three coastal regions on a per capita basis. The commercial fishing/trapping industry in Alberta is minute. Based on a casual review of the literature, the assumption was made that 65 percent of the industry is located in the North Saskatchewan Region, 20 percent in the South Saskatchewan Region, and the remaining 15 percent in the Red Deer Region.

Appendix D: LNG Information and Statistics

Liquefaction and Regasification

Liquefaction is the process in which natural gas is cooled to the point (-256° Fahrenheit) where it condenses into its liquid state. In its liquid state, natural gas occupies only 1/600 of its gaseous volume, making it economical to transport between continents and over long distances in specially-designed LNG tankers.

LNG is a clear, colourless, odourless liquid that weighs slightly less than half as much as water. As a result, it floats on fresh or salt water. Facilities that export LNG, where LNG is loaded onto specially-designed double–hulled tankers, are liquefaction facilities. These tankers and their cargo are greeted by regasification plants, or import terminals. To return LNG to a gaseous state, it is fed into a re-gasification plant. At the receiving terminal in its liquid state, LNG is pumped first to a double-walled storage tank, similar to those used in the liquefaction plant, at atmospheric pressure, then pumped at high pressure through various terminal components where 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.

LNG provides a medium for moving natural gas long distances by ship where pipeline transportation is not feasible. The shale plays in northeastern British Columbia, like much of the world's gas resource base, are located a great distance from the continent's largest consuming markets.

Whether the terminal is a liquefaction or regasification facility, storage plays an important role. Access to large amounts of storage, beyond the storage capacity on the ship, is a 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. The problem can be resolved with storage.

As of end-2007, LNG was exported by 15 countries and was imported by 18 countries, but these numbers have changed in the past few years.[1] Nations that export LNG include: Algeria, Australia, Brunei, Egypt, Equatorial Guinea, Indonesia, Libya, Malaysia, Nigeria, Norway, Oman, Qatar, Trinidad and Tobago, United Arab Emirates and the United States.[2] Within the last couple of years, Yemen, Russia and Peru have joined the list bringing the total to 18 nations.[3] This number is expected to change further over the next few years as there are export facilities

[1] California Energy Commission website, LNG Worldwide, http://www.energy.ca.gov/lng/international.html (accessed on July 22, 2012)
[2] ibid
[3] GIIGNL, The LNG Industry in 2011, http://www.giignl.org/fileadmin/user_upload/pdf/A_PUBLIC_INFORMATION/LNG_Industry/GIIGNL_The_LNG_Industry_2011.pdf (pp.8)

being either planned or under construction in nearly a dozen countries, including Angola, Cameroon, Mozambique, Papua New Guinea, Tanzania, Iran, Israel, Colombia, Canada, Venezuela, Brazil and Russia.[4] It is interesting to note that as of April 2012, there are 13 plants under construction: Australia (8), Algeria (2), Indonesia (1), Angola (1) and Papua New Guinea (1).[5] Australia currently has 4 operating export facilities, and will soon exceed Qatar, the world's largest LNG exporter, which currently has 11 export plants.[6] Other large players, in terms of facilities include Nigeria and Algeria, currently at 4 each.[7] Many of the largest players exporting LNG have stranded gas, or gas that is in remote areas and difficult to transport with pipelines and vehicles. Table D.1 illustrates LNG exporting countries for 2011.

Table D.1: LNG Exporting Countries for 2011 as Reported by the IGU

Exporter	MT
Qatar	75.5
Malaysia	25.0
Indonesia	21.4
Australia	19.2
Nigeria	18.7
Trinidad	13.9
Algeria	12.6
Russia	10.5
Oman	7.9
Brunei	6.8
Yemen	6.7
Egypt	6.4
UAE	5.9
Equatorial Guinea	4.0
Peru	3.8
Norway	2.9
US	0.3
Libya	0.1

Source: IGU[8]

Currently, the largest exporters of LNG are Qatar, Malaysia and Indonesia. Many other countries – Algeria, Australia, Nigeria, and Trinidad & Tobago – are smaller players, but significant and growing. In 2010, Qatar – a relatively new player in the shale game – exported

[4] A Barrel Full, LNG Export Terminals, http://abarrelfull.wikidot.com/lng-export-terminals (accessed on July 22, 2012)
[5] Petroleum Economist website, LNG Insight, World LNG Exporters, http://www.petroleum-economist.com/pdf/LNGInsight_April/LNG%20Exporters.pdf (accessed on July 22, 2012)
[6] ibid
[7] ibid
[8] IGU World LNG Report, 2011, pp. 8

56.7 Mt, up from 28 Mt at end-2007. Malaysia and Indonesia both export 23.5 Mt in 2010, up from 22 Mt and 20 Mt, respectively.[9] Australia and Nigeria are quickly increasing their exports and both have several plants under construction; in 2010, Australia exported 19.3 Mt while Nigeria exported 18 Mt.[10] As of March 2011, Qatar has extended its exporting capacity to 77 Mt, widening its lead as an LNG exporter.[11] In December 2003, Qatar was the fourth largest LNG exporter at 14.9 Mt and planned to increase exports to 60 Mt by 2015.[12] The top 3 exporters in December 2003 were Indonesia (23 Mt), Algeria (19.6 Mt) and Malaysia (15.6 Mt).[13]

With the rapid growth in demand for natural gas worldwide, it is expected that nations with large “stranded” natural gas resources – Angola, Egypt, Iran, Saudi Arabia, Russia, and Venezuela – are likely to become larger players in the near future. This category could possibly include the “remote” shale plays of northeastern British Columbia.

Nations that import LNG include: Belgium, China, Dominican Republic, France, Greece, India, Italy, Japan, Kuwait, Mexico, Portugal, Puerto Rico, South Korea, Spain, Taiwan, Thailand, Turkey, United Arab Emirates, United Kingdom and the United States.[14] As of end 2011, Canada (Canaport LNG is located in Saint John, New Brunswick), Sweden, and the Netherlands joined the countries that import LNG. The list of nations importing is also expected to expand in the next few years. Nations either planning or are constructing facilities include Argentina, Bahrain, Bangladesh, Brazil, Chile, Croatia, Cyprus, El Salvador, Germany, Ireland, Israel, Jamaica, Kenya, Lebanon, Lithuania, Philippines, Poland, Romania, Singapore, South Africa, Ukraine, Uruguay and Vietnam.[15] Table D.2 illustrates LNG importing countries for 2011.

[9] IGU World LNG Report, 2010, pp. 6
[10] GIIGNL, The LNG Industry in 2010, http://www.giignl.org/fileadmin/user_upload/pdf/A_PUBLIC_INFORMATION/LNG_Industry/GNL_2010.pdf (pp. 5)
[11] Qatar Golden Pass LNG terminal in US starts commercial operations. Platts, March 14, 2011, http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/6907450 (accessed on July 22, 20212)
[12] EIA website, The Global Liquefied Natural Gas Market: Status and Outlook, http://www.eia.gov/oiaf/analysispaper/global/exporters.html (accessed on July 22, 20212)
[13] ibid
[14] http://www.giignl.org/fileadmin/user_upload/pdf/A_PUBLIC_INFORMATION/LNG_Industry/GNL_2010.pdf
[15] A Barrel Full, LNG Export Terminals, http://abarrelfull.wikidot.com/lng-export-terminals (accessed on July 22, 2012)

Table D.2: LNG Importing Countries for 2011 as Reported by the IGU

Importer	MT
Japan	78.8
Korea	35.8
UK	18.6
Spain	17.1
China	12.8
India	12.7
Taiwan	12.2
France	10.7
Italy	6.4
US	5.9
Turkey	4.6
Belgium	4.5
Argentina	3.2
Mexico	2.9
Chile	2.8
Canada	2.4
Kuwait	2.4
Portugal	2.2
UAE	1.2
Greece	1.0
Dominican Republic	0.7
Thailand	0.7
Brazil	0.6
Netherlands	0.6
Puerto Rico	0.5

Source: IGU[16]

Table D.3 shows the average LNG importing costs ($/MMBtu) for the various countries for 2011.

[16] IGU World LNG Report, 2011, pp. 8

Table D.3: Average LNG Import Cost for Various Countries ($/MMBtu)

Country	Price
Japan	16.32 (March 2012)
China	10.28 (March 2012)
South Korea	13.56 (March 2012)
Taiwan	15.04 (March 2012)
India	9.01 (Sept. 2011)
Belgium	9.00 (March 2012)
France	11.76 (Feb. 2012)
Greece	12.08 (Feb. 2012)
Italy	12.78 (Feb. 2012)
Portugal	7.33 (Feb. 2012)
Spain	9.54 (Feb. 2012)
UK	7.62 (Feb. 2012)
Brazil	13.16 (March 2012)
Canada	2.64 (Sept. 2011)
Chile	10.05 (Feb. 2012)
Mexico	2.87 (Dec. 2011)
US	2.77 (March 2012)
Puerto Rico	4.51 (March 2012)

Source: Argus Media[17]

On the other side of the equation, Japan, South Korea and Spain are the three largest importers of LNG. In 2010, Japan imported 70.9 Mt, while South Korea and Spain imported 20.6 Mt.[18] In 2007, Japan imported 65 Mt, while South Korea and Spain imported 35 Mt and 24 Mt, respectively.[19] Japan and South Korea are the largest importers, accounting for 56 percent of total imports. Interestingly, the percentage is down from 65 percent in 2007. In December 2003, the top 3 importers were Japan, South Korea and Taiwan.[20] While Japan is still the largest LNG importer, their share of imports has been decreasing steadily, from over 65 percent in 1990 down to 29 percent.[21] Japan's extensive regasification facilities are illustrated in Figure D.1.

[17] Argus Media. May 2012. *Global LNG: LNG Markets, Projects and Infrastructure*. Volume 7 Issue 5.
[18] GIIGNL, The LNG Industry in 2011, http://www.giignl.org/fileadmin/user_upload/pdf/A_PUBLIC_INFORMATION/LNG_Industry/GIIGNL_The_LNG_Industry_2011.pdf (pp.8)
[19] A Barrel Full, LNG Export Terminals, http://abarrelfull.wikidot.com/lng-export-terminals (accessed on July 22, 2012)
[20] EIA website, The Global Liquefied Natural Gas Market: Status and Outlook, http://www.eia.gov/oiaf/analysispaper/global/importers.html (accessed on July 22, 2012)
[21] IGU World LNG Report, 2011 (pp. 37)

Figure D.1: Japan's Regasification Plants

Source: http://www.rabaska.net/lng#natural-gaz

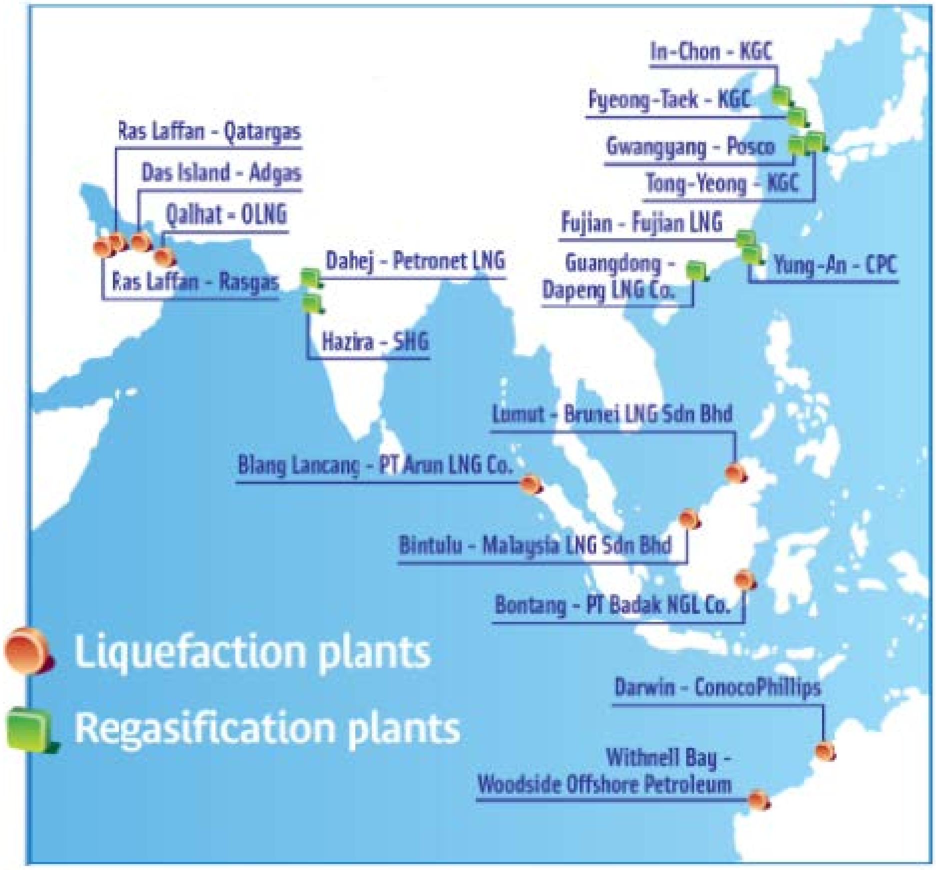
In the 1990s, the Northeastern Asia region was the largest consumer of LNG, with Japan, South Korea and Taiwan leading the way. At the time, the Pacific Basin, more specifically, Malaysia and Indonesia were the primary suppliers. With the rise of exports from the Middle East and the Atlantic Basin, things certainly have changed over the past two decades.

The rapidly growing economies of China and India, which account for over 2 billion people, are demanding more gas. Currently, China and India import nearly 4 percent of global LNG, ranking them 5th and 6th, respectively.[22] Both are up 2 spots from IGU's 2010 World LNG Report. Western European growing imports are also playing an important role in world LNG trade. On the supply side, new suppliers have entered the game and are having a significant impact on LNG volumes and trade flows: the Atlantic Basin, Australia and the Middle East in particular.

Figure D.2 illustrates liquefaction and regasification plants in Asia, excluding Japan.

[22] IGU World LNG Report – 2011 (pp. 11)

Figure D.2: Asia's Liquefaction and Regasification Plants



Source: http://www.rabaska.net/lng#natural-gaz

North American LNG Terminals

While there are currently more than 60 permitted and proposed terminals for North America, the vast majority of proposals are importing facilities. Many of these terminals were built when global and North American natural gas prices were high, making LNG a profitable venture, and domestic demand increased year-after-year. As previously mentioned, North America was not alone in building regasification terminals; European and Asian countries were building import terminals as well.

Even several years ago this posed an interesting problem: the global LNG supply from liquefaction facilities falls short of the requirements of all the proposed re-gasification terminals. At end-2007, globally there were 26 existing liquefaction terminals and 60 regasification terminals, with approximately 65 liquefaction terminals proposed and 181 regasification terminal projects proposed.[23] The statistics of liquefaction and regasification terminals in North America is skewed even more prominently – currently there are only 2 liquefaction facilities in North America: Kenai LNG and Atlantic LNG. The former is located in

[23] California Energy Commission website, LNG Worldwide, http://www.energy.ca.gov/lng/international.html (accessed on July 22, 2012)

Nikiski, Alaska and is North America's first LNG facility. Kenai dates back to 1967 and was constructed to store and export Alaskan natural gas to Japan.[24] The Atlantic LNG terminal, located in Trinidad and Tobago, is one of the largest producers of LNG in the world.[25] Trinidad and Tobago provided 75 percent of LNG imports to the United States in 2008.[26]

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. Increases in US natural gas production, due to domestic shale gas, along with Canadian imports and LNG imports, is changing the continental natural gas game. Many regasification terminals are operating at reduced volumes, while others are authorized to re-export delivered LNG. Many that were proposed or pending have been put in stasis or scrapped outright.

While there were several terminals approved or under construction, at end-2004 there were only four operating importing terminals in the US: Cove Point (Maryland), Elba Island (Georgia), Everett (Massachusetts) and Lake Charles (Louisiana).[27] According to the Federal Energy Regulatory Commission (FERC), there are currently 9 existing import terminals, not including offshore terminals, in the US and Puerto Rico. The following list, as of May 24, 2012, includes name, location and operator:[28]

- Dominion Cove Point LNG, Lusby, Maryland - (Dominion Resources)
- Southern LNG, Elba Island, Georgia - (El Paso Energy)
- Trunkline LNG, Lake Charles, Louisiana - (Southern Union)
- EcoEléctrica, Punta Guayanilla, Peñuelas, Puerto Rico
- Sabine Pass LNG, rural Cameron Parish, Louisiana - (Cheniere Energy, Inc.)
- Cameron LNG, rural Cameron Parish, Louisiana - (Sempra Energy)
- Freeport LNG, Freeport, Texas - (Cheniere/Freeport LNG Development, LP)
- Everett Marine Terminal, Everett, Massachusetts - (GDF SUEZ - DOMAC)
- Golden Pass LNG (Phase I & II), near Sabine Pass, Texas – (ExxonMobil)
- Gulf LNG Energy LLC, Pascagoula, Mississippi (El Paso/Crest/Sonangol)

The 3 facilities whose capacity exceeds 2.0 Bcfpd are Sabine Pass LNG (4.0 Bcfpd), Lake Charles (2.1 Bcfpd) and Golden Pass LNG (2.0 Bcfpd).[29] The remaining facilities range between 1.5 and

[24] FERC website, LNG, http://www.ferc.gov/industries/gas/indus-act/lng.asp (accessed on July 22, 2012)
[25] Atlantic LNG website, http://www.atlanticlng.com/v2/?page_id=6 (accessed on July 22, 2012)
[26] EIA website, LNG Energy in Brief, http://www.eia.gov/energy_in_brief/liquefied_natural_gas_lng.cfm (accessed on July 22, 2012)
[27] NGI website, North American LNG Import Terminals, http://intelligencepress.com/features/lng/terminals/lng_terminals.html (accessed on July 22, 2012)
[28] FERC website, LNG, http://ferc.gov/industries/gas/indus-act/lng/LNG-existing.pdf (accessed on July 22, 2012)
[29] FERC website, LNG Existing, http://ferc.gov/industries/gas/indus-act/lng/LNG-existing.pdf (accessed on July 22, 2012)

1.8 Bcfpd. Freeport LNG, Sabine Pass LNG and Cameron LNG are authorized to re-export delivered LNG.[30] Golden Pass LNG's ability to re-export delivered LNG is pending.[31]

FERC has approved 6 additional terminals, 5 of which are import terminals and one is an export terminal. Two of the approved terminals are expansions of existing facilities: Cameron LNG (Hackberry, Louisiana) and Cheniere/Freeport LNG (Freeport, Texas).[32] None of the import terminals are yet under construction.[33]

There are 3 proposed import terminals and 5 export terminals currently in the US. Four are located in Texas and Louisiana, while there is a single terminal proposed in Coos Bay, Oregon. There are an additional 6 export terminals that are categorized as potential, and have identified a site and have project sponsors.[34] The increase of proposed/pending export terminals reveals the shift of the continental natural gas market.

As previously mentioned, the aforementioned list does not include offshore facilities that are approved by FERC but by the US Department of Transportation's Maritime Administration (Marad). In the United States, FERC has permitting authority, including safety review of the terminal's siting. Marad plays the same role on the offshore side of terminal permitting. The Deep Water Port Act was amended to include natural gas/LNG/CNG. This resulted in two significant changes for offshore LNG import terminals. First, such terminals are under the jurisdiction of the United States Coast Guard, and permit applications will have a discrete timeline. Deepwater ports are licensed separately than their onshore counterparts. Second, the FERC, which has the jurisdictional authority for onshore LNG import regasification terminals,[35] ruled that such terminals will be treated similarly to gas processing plants and no longer require open-access regulation.

As of May 24, 2012, there are 3 operational facilities, all of which are import terminals:[36]

- Gulf Gateway Deepwater Port, Gulf of Mexico
- Northeast Gateway Deepwater Port, offshore from Boston Harbor, Massachusetts
- Neptune LNG, offshore from Gloucester, Massachusetts

In addition Marad/Coast Guard has approved 3 offshore applications: Main Pass Energy Hub (FreeportMcMoRan), Port Dolphin (Hoegh LNG – Port Dolphin LLC) and TORP Technology's

[30] ibid
[31] ibid
[32] FERC website, LNG Approved, http://ferc.gov/industries/gas/indus-act/lng/LNG-approved.pdf (accessed on July 22, 2012)
[33] ibid
[34] http://ferc.gov/industries/gas/indus-act/lng/LNG-proposed-potential.pdf (accessed on July 22, 2012)
[35] California Power Commission has challenged FERC's position on this topic. See United States Court of Appeals for the Ninth Circuit, July 22, 2002 at http://www.ferc.gov/legal/court-cases/opinions/01-70678.pdf
[36] FERC website, LNG Existing, http://ferc.gov/industries/gas/indus-act/lng/LNG-existing.pdf (accessed on July 22, 2012)

Bienville LNG.[37] It is interesting to note that all three operating importing terminals are operated by Excelerate Energy LLC. There are no proposed and potential offshore import or export terminals in the US.

Mexico has 2 LNG terminals, Costa Azul LNG and Altamira LNG. Both are located on the west coast of Mexico and are regasification terminals. Mexico has approved 2 more terminals: the KMS GNL de Manzanillo facility is an import terminal while the Sempra – Energia Costa Azul LNG is currently being approved for a 1.5 Bcfpd expansion.[38]

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.[39] Canaport LNG is a partnership between Madrid-based Repsol (75 percent) and Irving Oil (25 percent).[40] An LNG tanker is shown at the Canaport LNG receiving terminal in Figure D.3.

Figure D.3: An LNG Tanker at the Canaport LNG Terminal

Source: NRCAN[41]

There are currently 2 import LNG terminals and 2 export LNG terminals in Canada that have been approved.

[37] MARAD website, Approved Applications and Operational Facilities http://www.marad.dot.gov/ports_landing_page/deepwater_port_licensing/dwp_current_ports/dwp_current_ports.htm (accessed on July 22, 2012)
[38] FERC website, LNG Approved, http://ferc.gov/industries/gas/indus-act/lng/LNG-approved.pdf (accessed on July 22, 2012)
[39] Canaport LMG website, http://www.canaportlng.com/ (accessed on July 22, 2012)
[40] ibid
[41] NRCAN website, Canadian LNG Import and Export Projects Update, http://www.nrcan.gc.ca/eneene/sources/natnat/imppro-eng.php (accessed on July 22, 2012)

The 2 import LNG terminals, both in Québec, are Rivière-du-loup (Cacouna Energy) and Québec City/Lévis (Project Rabaska).[42] It is however, interesting to note that both projects, in spite of receiving approvals, are suspended. Project Rabaska is a partnership between Gaz Métro, Enbridge and GDF SUEZ (formerly Gaz de France). Québec's natural resources minister suggested that low gas prices, combined with the fact that the province may yet build its own natural gas industry rather than import from elsewhere, may be the culprit.[43] Despite the current moratorium on development, Québec's Utica shale gas is attracting a lot of attention. The province is studying the effects of frac'ing and establishing a regulatory infrastructure. The Rabaska project was planning to import natural gas from Russia to supply Ontario and Quebec's growing demand of natural gas.[44] Likewise, TransCanada and Suncor Energy (successor to Petro-Canada), have elected not to extend the lease on the Cacouna Project site.[45] Both partners suggest that current market conditions and global economics do not support the proposed facility.[46] The decision was announced on November 29, 2009, but the project was in limbo for the year leading up to the decision to suspend/cancel the project.[47]

On the other hand, both approved export terminals are in British Columbia: Kitimat LNG and BC LNG Export Co-operative. While the former is pending construction, the latter was only approved on April 11, 2012. Both terminals are discussed in greater detail in the LNG section of this study.

Other terminals, all import terminals, that have been suspended and/or cancelled are Grassy Point (Newfoundland), Keltic/Maple LNG (Nova Scotia), Énergie Grand-Anse (Québec), Texada Island LNG (British Columbia) and Teekay/Merrill Lynch LNG (British Columbia). None of the terminals received approval from Canadian authorities.

While the process for applying for an LNG terminal is often a long drawn-out process, Canada's status of a single LNG facility will probably change in the near future and will most likely be an export terminal in British Columbia.

LNG Carriers and Shipping

This section reviews characteristics of the LNG tankers and discusses briefly an industry that is, like its oil counterpart, very international in nature.

[42] FERC website, LNG Approved, http://ferc.gov/industries/gas/indus-act/lng/LNG-approved.pdf (accessed on July 22, 2012)
[43] Rabaska Project Future, CBC website, http://www.cbc.ca/news/business/story/2011/03/04/rabaska-project-future.html (accessed on July 22, 2012)
[44] ibid
[45] Cacouna Energy website, "The end of Energy Cacouna", November 29, 2009, http://cacouna.net/projetmethanier_e.htm (accessed on July 22, 2012)
[46] ibid
[47] Cacouna Energy website, Cacouna Energy will close the Cacouna office", December 31, 2008, http://cacouna.net/projetmethanier_e.htm#closed (accessed on July 22, 2012)

LNG tankers are double-hulled ships that are designed and insulated to prevent leakage.[48] Recall that LNG is stored at atmospheric pressure and at a temperature of -256°F.[49] The special containment system is within the inner hull of the vessel, to prevent rupture.[50]

As of end-February 2012, there are 361 LNG carriers in the global fleet, with another 58 being delivered within the next 5 years.[51] The combined capacity of the fleet is 53 MMcm.[52] It is important to note that the fleet is up from 224 carriers in 2007 and 195 carriers at end-2005.[53] The pace of growth in the industry is rapid and is not showing any sign of slowing down. As international LNG trade volumes increase at an unprecedented rate of growth, the shipping industry will face an increased demand for new vessels and larger ships. This pressure is felt among their crude oil counterparts.

In 2002, the size of the typical LNG carrier transported between 125,000 and 138,000 cubic meters (cm) of LNG, or approximately between 2.6 and 2.8 Bcf of natural gas.[54] By 2008, the average size increased to approximately 150,000 cubic meters. It is, however, interesting to note that new LNG super tankers under construction have a capacity of 265,000 cubic meters of natural gas.[55] Most of the Qatar fleet is between 210,000 and 266,000 cubic meters, and the largest LNG exporter in the world has ordered another 13 of these massive vessels.[56]

LNG carriers are often divided into four subclasses: Small (<100,000 cm), Standard (100,000-200,000 cm), Q-Flex (200,000-250,000 cm) and Q-Max (250,000-300,000 cm). As of February 29, 2012, the breakdown of the world LNG fleet is 13 Q-Max, 32 Q-Flex, 292 Standard and 24 Small.[57] Over 75 percent, or approximately 270 vessels, have a capacity of larger than 135 kcm, or 135,000 cubic meters.[58] Of the LNG carriers that are built for delivery before 2016, 58 LNG

[48] Shell Hazira LNG & Port website, LNG Industry, http://www.haziralngandport.com/lng_industry.htm (accessed on July 22, 2012)
[49] ibid
[50] ibid
[51] Ship Building History, LNG Fleet, http://shipbuildinghistory.com/today/highvalueships/lngfleet.htm (accessed on July 22, 2012)
[52] IGU World LNG Report, 2011, pp. 42
[53] Kongsberg Maritime: Leveraging LNG Expertise, http://www.km.kongsberg.com/ks/web/nokbg0238.nsf/AllWeb/6DBDFB538A971E8CC1257A0700457AB8?OpenDocument (accessed on July 22, 2012)
[54] Center for Energy Economics, The LNG Value Chain, http://www.beg.utexas.edu/energyecon/lng/LNG_introduction_08.php (accessed on July 22, 2012)
[55] ioMosaic website, Understanding LNG Fire Hazards, http://www.iomosaic.com/docs/whitepapers/Understand_LNG_Fire_Hazards.pdf (pp. 13)
[56] Qatargas website, Future Fleet, http://www.qatargas.com/AboutUs.aspx?id=130 (accessed on July 22, 2012)
[57] Ship Building History, LNG Fleet, http://shipbuildinghistory.com/today/highvalueships/lngfleet.htm (accessed on July 22, 2012)
[58] ioMosaic website, Understanding LNG Fire Hazards, http://www.iomosaic.com/docs/whitepapers/Understand_LNG_Fire_Hazards.pdf (pp. 13)

carriers are in the Standard class (100-200 kcm).[59] It is interesting to note that the smaller vessels are routinely used for domestic and coastal trades, or trade in remote areas.

While the size of the LNG tankers is getting larger, the design is changing as well. Currently, there are three types of cargo containment systems that are utilized: the spherical (Moss), membrane and structural prismatic designs.[60] Most LNG tankers used to be of the spherical (Moss) tank design, and are usually easily identifiable. Figure D.4 shows an LNG tanker characterized with the spherical-style tanks, and is over 285 meters, or over 3 football fields.[61] While large, they are still smaller than the Very Large Crude Carrier (VLCC) oil tankers, which are able to transport between 200,000 and 320,000 dead weight tonnage (DWT) and average 331 meters in length and nearly 60 meters in width.[62] The capacity of a VLCC is approximately 2,000,000 bbls.[63]

Figure D.4: LNG Ship at Sea

Source: British Petroleum. www.bp.com

The membrane-style design is, however, being used in more recent designs, and the balance has dramatically shifted.[64] Currently, only 30 percent of LNG tankers utilize the most easily

[59] Ship Building History, LNG Fleet, http://shipbuildinghistory.com/today/highvalueships/lngfleet.htm (accessed on July 22, 2012)
[60] Chevron Australia website, LNG Shipping, http://www.chevronaustralia.com/Libraries/Chevron_Documents/Factsheet_LNG_Shipping.pdf.sflb.ashx (accessed on July 22, 2012)
[61] ibid
[62] Danish Ship Finance, VLCC/ULCC Segments, http://www.shipfinance.dk/Default.aspx?ID=407 (accessed on December 16, 2011).
[63] Pacific Energy Partners, "Tanker Information for Pier 400 Crude Oil Receiving Terminal", March 2005, http://www.pacificenergypier400.com/pdfs/TANKERS/TankerBusEmissions.pdf (pp. 5)
[64] Center for Energy Economics, The LNG Value Chain, http://www.beg.utexas.edu/energyecon/lng/LNG_introduction_08.php (accessed on July 22, 2012)

identified Moss-style; the remainder utilizes the membrane design and the spherical tank design.[65]

The safety record of LNG ships is impeccable and far exceeds any other sector of the shipping industry. Over a 50-year period, there have been no collisions, fires, explosions or hull failures resulting in a loss of containment for LNG ships in port or at sea.[66] This includes more than 45,000 deliveries, covering 100 million miles without a major accident.[67] Sandia National Laboratories suggest that over the life of the LNG shipping industry only 8 incidents occurred globally, none of which led to a fatality or a breach of cargo.[68]

The excellent safety record is due to several factors.

First, the LNG industry is constantly evolving in terms of safe and secure operations. It is important to understand that this industry is not new, but decades old and is truly global in nature.[69] Because there is a potential risk in transporting 150,000 cubic meters of natural gas, the industry undergoes more frequent and stringent examinations, certainly more so than its oil counterpart.

LNG carriers are subject to the following that has significantly reduced LNG accidents:[70]

- Double-hulled ship designs,
- Appropriate safety systems to reduce the potential for damage,
- Security management and escort of LNG ships operating in harbours and waterways,
- Vessel movement and control zones (e.g., safety and security zones) to reduce the potential for impacts with other ships or structures.

Secondly, the LNG industry has stringent standards and regulations that it must adhere to.[71] LNG carriers that enter United States and Canadian waters must meet domestic and international requirements. As Member States of the International Maritime Organization (IMO), Canada and the United States endorse and enforce Conventions such as the International Convention for the Prevention of Pollution from Ships (MARPOL), International

[65] IGU World LNG Report, 2010 (pp. 33)
[66] LNG Canada website, LNG Safety, http://lngcanada.ca/about-lng/lng-safety/ (accessed on July 22, 2012)
[67] Center for Liquefied Natural Gas website, FAQs, http://www.lngfacts.org/About-LNG/FAQ.asp#9 (accessed on July 22, 2012)
[68] Center for Liquefied Natural Gas website, LNG Ship Safety, http://www.lngfacts.org/About-LNG/Ship-Safety.asp (accessed on July 22, 2012)
[69] Center for Energy Economics, University of Texas, LNG Safety and Security, http://www.beg.utexas.edu/energyecon/lng/documents/CEE_LNG_Safety_and_Security.pdf (accessed on July 22, 2012), pp. 7
[70] Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water, December 2004, http://fossil.energy.gov/programs/oilgas/storage/lng/sandia_lng_1204.pdf (pp. 72)
[71] Center for Energy Economics, University of Texas, LNG Safety and Security, http://www.beg.utexas.edu/energyecon/lng/documents/CEE_LNG_Safety_and_Security.pdf (accessed on July 22, 2012), pp. 7

Convention for the Safety of Life at Sea (SOLAS) and International Convention on Standards of Training, Certification and Watchkeeping for Seafarers (STCW). The IMO is at the heart of international maritime law and is responsible for the safety and security of shipping, and is also mandated with the prevention of marine pollution by ship.[72] Each member state is responsible to enact domestic laws to implement the Convention. For example, the United States passed the Act to Prevent Pollution from Ships, while the Canadian Federal Government passed the Canada Shipping Act, 2001 (which replaced the old Canada Shipping Act). While Transport Canada (TC), Fisheries and Oceans Canada (DFO) and Environment Canada (EC) are major players in enforcing shipping laws and regulations, the Federal Energy Regulatory Commission, Department of Transportation, USCG and the Department of Homeland Security ensure that the LNG industry is following maritime laws in US waters.

For example, LNG vessels are boarded by marine safety personnel prior to US or Canadian port entry to verify the proper operation of key navigation, safety, fire fighting, and cargo control systems. Under Title 46 of the United States Code, for example, the LNG ship must meet certain guidelines in its design, construction, equipment and operation.[73] These requirements are particularly unrelenting with regard to cargo temperature and pressure.[74] The mirror organizations in Canada that inspect LNG vessels are the Port Control, Canada Shipping Act and the Canada Labour Code.[75]

One of the most important post-9/11 maritime security developments was the Maritime Transportation Security Act of 2002 (MTSA).[76] The MTSA regulation follows the International Ship and Port Facility Security (ISPS) Code, in which vessels, including LNG carriers, must be issued an International Ship Security Certificate (ISSC).[77] The security measures affect all vessels, marine facilities and their personnel.[78] All LNG tankers entering the United States must adhere to the following:[79]

- Certify security plans that address how they would respond to emergency incidents;
- Identify the person authorized to implement security actions; and
- Describe provisions for establishing and maintaining physical security, cargo security, and personnel security.

[72] IMO website, History of IMO, http://www.imo.org/About/HistoryOfIMO/Pages/Default.aspx (accessed on December 16, 2011)
[73] Department of Homeland Security, The Coast Guard's Role in LNG Security, March 21, 2007, http://chsdemocrats.house.gov/SiteDocuments/20070321152225-32653.pdf (pp, 2)
[74] ibid
[75] Transport Canada, http://www.tc.gc.ca/eng/marinesafety/tp-tp14609-2-marine-acts-regulations-617.htm (accessed on July 22, 2012)
[76] Department of Homeland Security, The Coast Guard's Role in LNG Security, March 21, 2007, http://chsdemocrats.house.gov/SiteDocuments/20070321152225-32653.pdf (pp. 4)
[77] ibid
[78] ibid
[79] FERC website, Maritime Security Regulations, http://ferc.gov/industries/gas/indus-act/lng/marit-secur-regs.asp (accessed on July 22, 2012)

The third factor that contributes to the impeccable safety record of the LNG shipping is that the physical and chemical properties are not only understood, but their risks are incorporated into the technology and operations.[80] For LNG to burn, a unique set of conditions and circumstances must be met. It must first vapourize, and then mix with the air in the proper proportions. The flammable range is between 5 and 15 percent. Then it needs to be ignited. The dangers of LNG result from three of its well understood properties: cryogenic temperatures, dispersion characteristics and flammability characteristics.[81] These properties of LNG are understood and their dangers are incorporated into safety protocol.

Nevertheless, the increasing demand for natural gas will significantly increase the number and frequency of LNG tanker deliveries to ports in North America. The increasing number of shipments from an increasing number of terminals spurs concerns about the potential for an accidental spill or release of LNG. Safety has always been a leading public perception problem, in spite of the fact that the most recent accident – an on-site explosion at Skikda, a major Algerian LNG terminal in 2004 – is only one of four major accidents dating back to the early 1940s. The cause of the accident, which killed 27 workers and injured an additional 74, was a steam boiler explosion at the LNG production plant, which triggered a second, vapour-cloud explosion.[82] The incidents surrounding September 11, 2001 have also increased concerns, where security risks to LNG facilities are perceived as greater and are garnering more public attention in the United States and elsewhere.

Risks, however, from accidental LNG spills, such as collisions and groundings, are small and manageable with current safety policies and practices. Risks from intentional events, such as terrorist acts, can be significantly reduced with appropriate security, planning, prevention, and mitigation.

[80] Center for Energy Economics, University of Texas, LNG Safety and Security, http://www.beg.utexas.edu/energyecon/lng/documents/CEE_LNG_Safety_and_Security.pdf (accessed on July 22, 2012), pp. 7
[81] California Energy Commission, LNG Safety, http://www.energy.ca.gov/lng/safety.html (accessed on July 22, 2012)
[82] History of Accidents in the LNG Industry, February 2008, http://www.laohamutuk.org/Oil/LNG/app4.htm (accessed on July 22, 2012)