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# Natural Gas in Canada:

## what are the options going forward?

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The contents of this paper are the authors' sole responsibility. They do not necessarily represent the views of the Oxford Institute for Energy Studies or any of its members.



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## About the Author

Ieda Gomes is a Senior Visiting Research Fellow at the Oxford Institute for Energy Studies. Her areas of expertise include natural gas and LNG market fundamentals as well as energy pricing, policy and regulation particularly in developing countries in South Asia, the Middle East, Africa and Latin America. Ieda's career in the gas and energy industry spans more than 30 years. She worked for nearly 14 years at BP plc as Vice President for new ventures and market development on several international assignments and for 19 years at the largest gas distribution company in Brazil, Comgas. She has been a key participant and shaper of events in Brazil's gas industry – from the introduction of natural gas supplies in Sao Paulo to the negotiating and signing of the domestic and Bolivian gas supply agreements, the privatisation of Comgas and the establishment of the Brazilian Association of Gas Distribution Companies (ABEGAS). Ieda is based in the UK and sits on the board and advisory council of various companies, think tanks and associations. She writes a bimonthly column for Brazil Energia. Ieda holds a BSc in chemical engineering and an MSc in energy and environmental engineering.

## Preface

With US shale gas dominating the headlines of the energy media for the past several years, Canadian gas has been somewhat overshadowed. While gas industry followers outside of North America may have been aware of the reduction in Canadian gas exports to the US, they will likely have missed the complex interaction of lower cost US shale invading regional Canadian markets formerly supplied by Canadian gas. This situation has been further exacerbated as Canadian transportation tariffs have been raised to compensate for lower throughput. Ieda Gomes provides a comprehensive analysis of the dynamics of these and other key elements of the Canada's gas fundamentals and how they have, and will continue to evolve.

The loss of Provincial and Federal tax and royalty take due to lowered exports, production growth and prices is another important factor which leads to an assessment of potential new market segments such as natural gas and LNG vehicles and Tar Sands sectors (currently impacted by low oil prices). This inevitably leads to the exploration of the obvious replacement for the lost pipeline export volumes, namely LNG exports.

Readers will already be aware of the numerous proposed LNG export projects on Canada's West and East Coasts. Ieda provides a succinct description of each of these and details at the individual project level, and in overview, the significant challenges to be overcome; both physical in terms of transportation distances and greenfield construction (in a region of insufficient skilled resources), and political in terms of the myriad, overlapping approval and consent processes to be satisfied prior to construction start. Uncertainties on the LNG-specific fiscal framework add yet another uncertainty layer.

The final hurdle is of course the relative competitiveness of Canadian LNG projects relative to US Gulf Coast brownfield and Australian expansion projects at a time when: global demand for LNG over the next decade appears to have declined and the window for new supply requirement appears to have moved back to the early 2020s, and Asian buyers appear set on moving away from oil-indexed long term contract prices.

The OIES Gas Programme aims to address key elements of the global gas market, especially those pertaining to its future evolution. Although the conclusions of this paper set out the scale of the challenges Canadian gas and LNG face, rather than their immediate solution, it develops a detailed, objective and fascinating perspective of a huge gas resource, overall favourably located relative to the Asian growth markets and the dilemmas to be addressed if this is to be successfully monetised

Howard Rogers

Oxford

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## 1. Introduction

Canada is at a crossroads: from being a domestic and regional gas player to becoming an LNG exporter. Despite its large reserves of conventional and unconventional gas, domestic gas production has been stagnant since 2009 as Canada has lost domestic and export markets to US shale gas. Production stood at 154.8 Bcma in 2013, a 15% decrease when compared to the levels of 2007.

The drop in production in Canada is due to increased US shale gas production in the Northeast and Midwest (Marcellus, Utica, and Bakken) which has replaced traditional US markets supplied by Canada and is also displacing large volumes of Canada Western Basin gas in the eastern Canadian domestic markets.

Due to its connection and intrinsic inter-dependence with the US gas market, the gas industry in Canada is very sensitive to supply, demand and price changes in the US and has been doubly hammered by a reduction in export markets and a decline in prices, with gas prices at Alberta's AECO hub falling considerably over the last seven years. As a consequence royalty revenues have also fallen significantly.

The loss of important domestic and export markets has pushed the country to look for alternative markets. New domestic markets are not likely to be significant and would take time to develop; therefore the development of LNG export projects, aiming at premium markets in North Asia, seems a natural next step to counter the decline of traditional export markets.

There are 18 LNG export terminals being proposed in the Province of British Columbia (BC) and four proposed LNG schemes in the East Coast.

Investors in BC projects are attracted by the potential high price differential gained by supplying the oil-indexed premium-priced LNG markets in Asia, for which Canada is advantageously located, when compared to US Gulf Coast projects.

Although West Canada producer prices are traded at a discount to Henry Hub, the greenfield nature of the Canadian LNG projects will result in higher liquefaction and transportation costs and also face additional challenges such as obtaining environmental permits, engaging the support of communities and First Nations, and developing price structures to entice North Asian buyers.

Canada is a late joiner to the LNG export club and the proposed Canadian LNG export projects are not without challenges, namely:

- Higher CAPEX costs when compared to US brownfield projects.
- Expensive pipeline infrastructure requirements.
- Challenges associated with securing long term oil-indexed supply agreements at a time when Asian buyers are looking to move away from the traditional JCC price formulae.
- Balancing the concern of all stakeholders especially the native communities, politicians and timing to reach key Asian markets.
- Insufficient qualified engineering resources and fast-rising labour costs for skilled resources, broader and more costly scope in projects (higher cost locations and large infrastructure costs).
- Perceived red tape on environmental permitting and taxation.

Over the last 5 years, a few Asian companies started acquiring Canadian gas resources, to secure and diversify gas supplies to their domestic markets, and major oil companies are involved in large scale projects in the West Coast.

Land-locked gas regions such as Alberta face additional challenges because they are further away from the LNG export projects than British Columbia producers, and also because their traditional Eastern Canada and Midwestern US markets have been taken by US shale producers.

Similarly to other large oil and gas producing economies, Canada is already feeling the impact of fast falling oil prices which raises the level of uncertainty for greenfield projects and is causing the deferral of investment decisions for LNG and oil sand projects.

At his Opening Statement at the press conference following the release of the Financial System Review in Ottawa, in December 2014, the Governor of the Bank of Canada, Stephen Poloz declared:

***"The recent weakness in oil ... is likely to boost global growth but to moderate growth and inflation in Canada, even though the effects should be tempered by exchange rate depreciation and stronger non-energy exports."*** [1]

As of January 2015, the IMF reduced its 2015 outlook for the Canadian economic growth to 2.3% - down from its former prediction of 2.4% - and its outlook for 2016 is also down to 2.1%, against a previous forecast of 2.4%[2].

The Canadian gas industry is also looking for alternatives to foster other gas applications in the domestic market such as gas to liquids, ethane crackers, propylene derivative plants, methanol-to-olefins, small LNG plants, and natural gas for transportation including Compressed Natural Gas (CNG) and LNG trucking.

The dilemma for Canada is to develop natural gas export projects, in particular LNG, in a limited time window in competition with US brownfield LNG projects, which are cheaper to build and faster to implement and with Australian LNG expansion projects, which are viewed as more expensive, but are also location advantaged for the premium Asian markets. Due to the retreat in investment decisions caused by the drop in oil prices in early 2015, it appears that the 2020 market window is already lost for Canadian LNG projects.

This research paper looks into Canada's energy and natural gas market fundamentals, the alternatives for gas monetisation being currently considered, costs of supply, key risks for implementation and political and environmental constraints. It also provides an overview of the status of proposed LNG projects and its timing to market vis-à-vis 2020-2025 world LNG demand. The paper also compares price alternatives for Canadian LNG delivered into Asian markets; including oil indexed and cost plus/hub pricing.

The paper also raises the question on whether a return to LNG pricing S curves could be a tool to align buyers and sellers whilst the markets adapt to the current and unpredictable low oil price era.

## 2. Canada Energy Fundamentals

Canada is one of the largest economies in the world, with a nominal GDP of approximately US$ 1.7 trillion in 2013[3]. With an area of 9,984,670 km², Canada is the second largest country in the world after Russia. As of October 2014 the population of Canada totalled 35.7 million inhabitants with nearly 30% of the country's population living in 10 cities. Canada is a parliamentary democracy with lawmaking shared among the federal government, ten provincial and three territorial governments.

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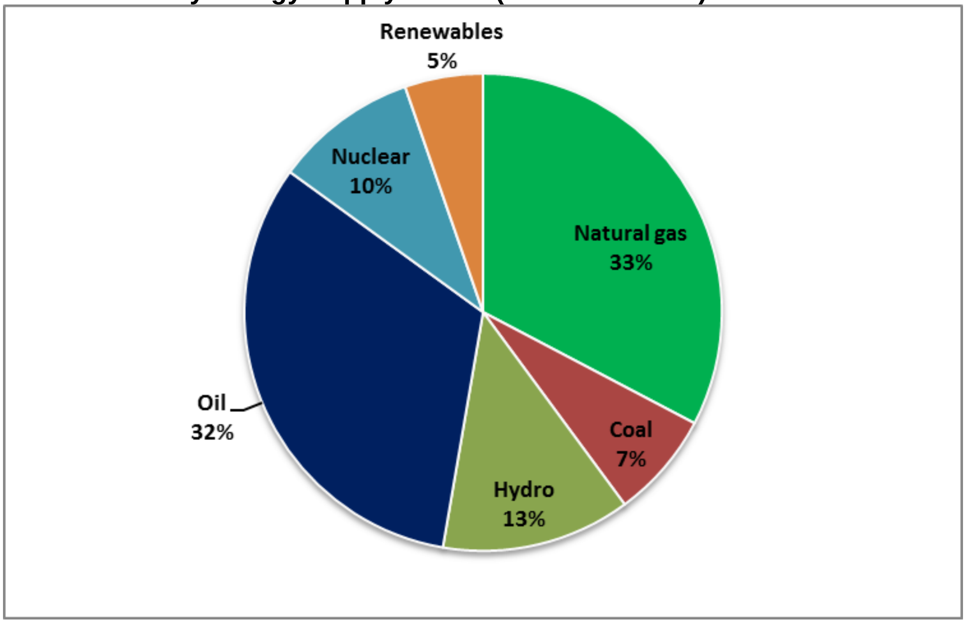
[1] Bank of Canada, (January 2015)

[2] http://www.ctvnews.ca/business/imf-drops-forecast-for-canadian-economic-growth-1.2197318#ixzz3PZp1Vu5N

[3] Bank of Canada, (January 2015)

Canada is endowed with abundant energy resources, including natural gas, oil, coal and a large hydroelectric potential. Primary energy production in Canada increased 3.3% in 2013 to 428 Mtoe4. In 2013 approximately 41% of the primary energy produced in Canada was exported, primarily to the United States, with a remaining total internal energy supply of 251 Mtoe5. Canada exported 75% of its crude oil production and slightly above 52% of its marketable natural gas in 2013. Other sources of renewable energy represent only 5% of the primary supply.

**Figure 1: Canada Primary Energy Supply – 2012 (Total: 251 Mtoe)**




Source: (IEA, 2015)

Canada's recoverable coal reserves totalled 6.6 billion tonnes in 2013, approximately the same size as Colombia's[6]. On a world scale Canada coal reserves are not very significant, particularly when compared with the USA, which holds 237.3 billion tonnes. More than 90% of Canada's coal deposits are located in the western provinces and approximately 45% of Canada's coal production is exported to international markets.

The provinces of Ontario, Quebec and Alberta account for 75% of the country's energy consumption, with the latter showing a steady increase since 2009, partially related to the increase in oil sands production, which require large amounts of steam for in-situ production.

Proven natural gas reserves reached 71.4 Tcf at the end of 2013, and consumption exceeded 100 Bcma, ranking the country as the 6th world largest gas consuming nation. Natural gas has a large share of the country's final energy consumption, approximately 31% in 2012 whereas oil products account for 38%.

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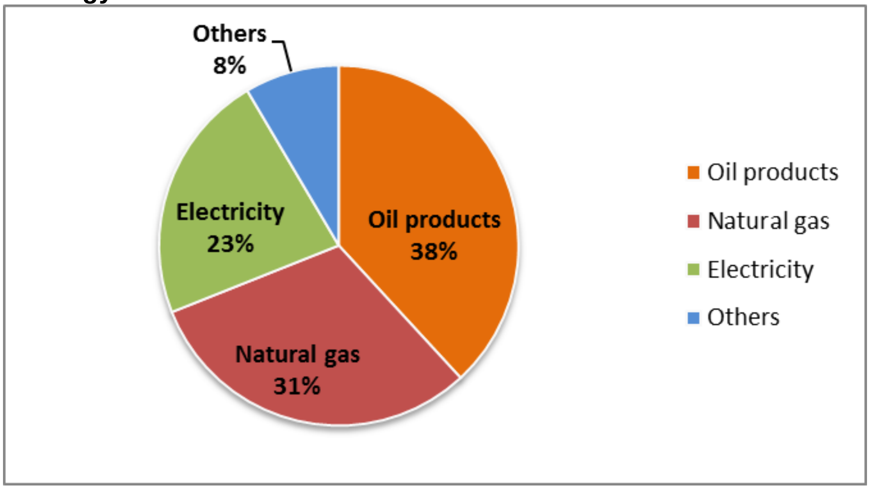
[4]Statistics Canada, (2013)

[5]IEA,(2015).

[6] BP, (2014)

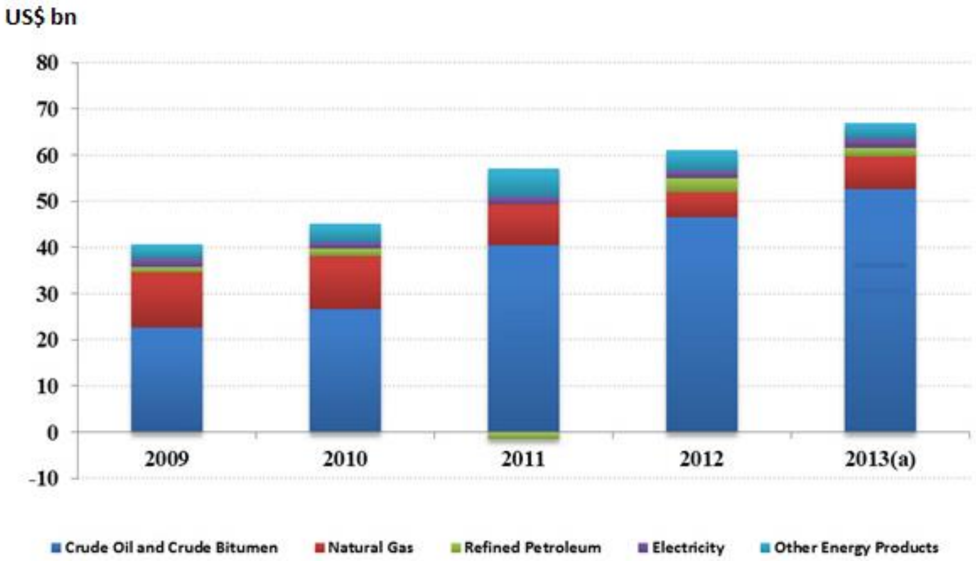
**Figure 2: Final Energy Demand in Canada - 2012**




Source: (Canadian Gas Association, 2015a)

In 2013 the contribution of the energy industry to Canada's GDP and to Canadian export revenues was 9.6% and 23.3% respectively. In 2013, net energy exports totaled nearly CAD 70 billion, led by crude oil and crude bitumen at about CAD 55 billion, with natural gas, refined petroleum, electricity and other energy products contributing about CAD 7 billion, CAD 1.8 billion, CAD 2.0 billion and CAD 3.5 billion, respectively[7]. The contribution from natural gas to Canada's exports has been falling steadily since 2009, when it represented nearly one third of the total exported, CAD 16 billion (circa US$ 13 billion).

**Figure 3: Evolution of Canada Energy Exports (US$ billion)**



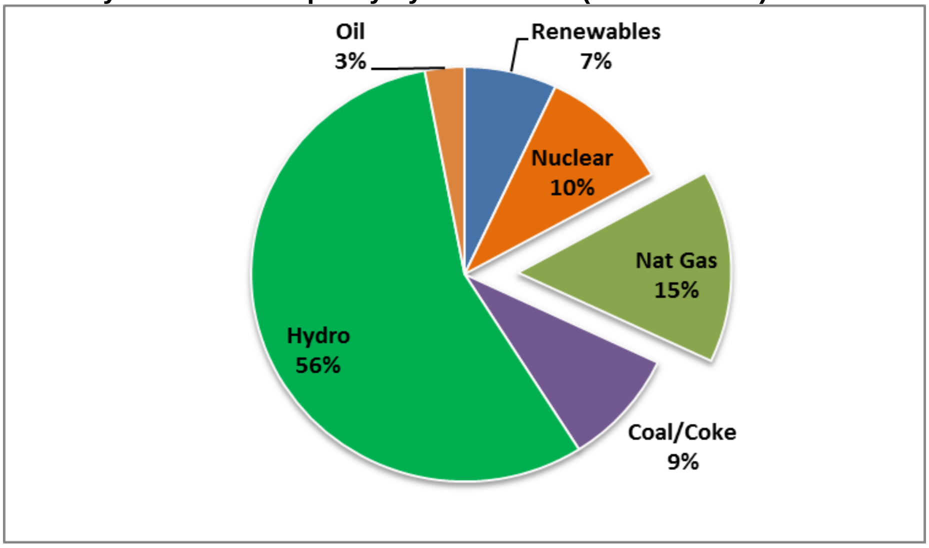

Source: (National Energy Board, 2013b)

In 2013 the oil and gas industry invested CAD 74 billion (US$ 59 bn), of which 94.5% was in oil sands and other Western Basin oil and gas projects.

[7] Canadian Association of Petroleum Producers, (2014), National Energy Board, (2013b)

In 2013 Canada's power generation capacity stood at 137 GW, with hydroelectricity playing the primary role with a share of 56%, followed by natural gas at 15%. The other renewable sources accounted for 7%, of which 3.8% was wind power.

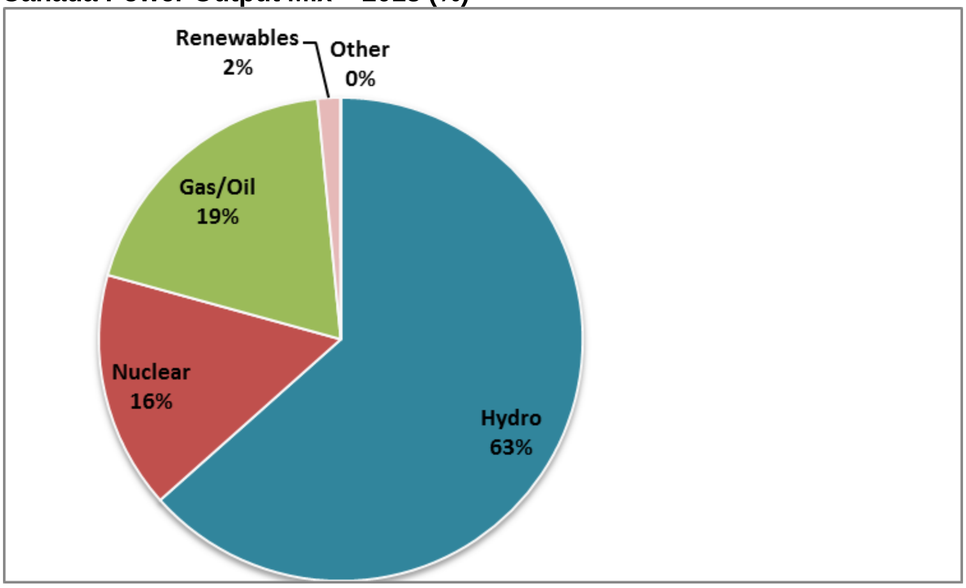
**Figure 4: Electricity Generation Capacity by Fuel – 2013 (Total 137 GW)**




Source: (National Energy Board, 2013a)

On a world scale Canada is second only to China in hydro power generation. In 2013 Canada's hydro generation output accounted for 63% of the country's power production of 611 TWh. Canada electricity exports stood at 62.6 TWh in 2013, whereas imports totalled 10.7 TWh.

**Figure 5: Canada Power Output Mix – 2013 (%)**




Source: (National Energy Board, 2013b), (BP plc, 2014)

Electricity consumption in Canada in 2013 stood at 590 MWh; the industrial sector accounted for 38.8% followed by the residential and commercial sectors, with respectively 29.5% and 26.4%.[8]

[8] Electricity Canada, (2014)

## 3. Natural gas resources and reserves

The Canadian oil industry was born around 1850 in south Ontario[9], after geologist Thomas Sterry Hunt of the Geological Survey of Canada reported seepages of crude oil in the area. Following Hunt's discovery, businessman Charles N. Tripp founded the International Mining and Manufacturing Company, the first oil company registered in North America to exploit asphalt beds and oil springs. He sold his company to James Miller Williams, dubbed the "founding father of Canada's oil industry", who soon started producing oil in larger quantities, which was transported 200 km away and refined in Hamilton to produce lighting oil.

Onshore natural gas was discovered in 1859 in New Brunswick, but initially flared as a waste product. In the west, natural gas was discovered in 1883 near Medicine Hat, Alberta, followed by other gas finds in the same basin. Although available since 1880, natural gas only reached the large cities one hundred years later, with the construction of long distance pipelines. In 1947 Imperial Oil discovered oil in Alberta, which was a major game changer for Canada. The discovery of large amounts of natural gas in Alberta was the enabling factor for the construction of gas transportation pipelines to the east coast area in the 1950s.

Canada has seven major hydrocarbons resources regions, as illustrated in

Table 1: Canada's Main Hydrocarbon Resource Basins below.

**Table 1: Canada's Main Hydrocarbon Resource Basins**

| Basin | (% of conventional hydrocarbon resources) |
|---|---|
| Western Canada Sedimentary Basin (WCSB) | 57% |
| Atlantic Margin | 18% |
| Arctic Cratonic | 10% |
| Arctic Margin | 6% |
| Pacific Margin | 4% |
| Intermontane | 3% |
| Eastern Cratonic | 2% |

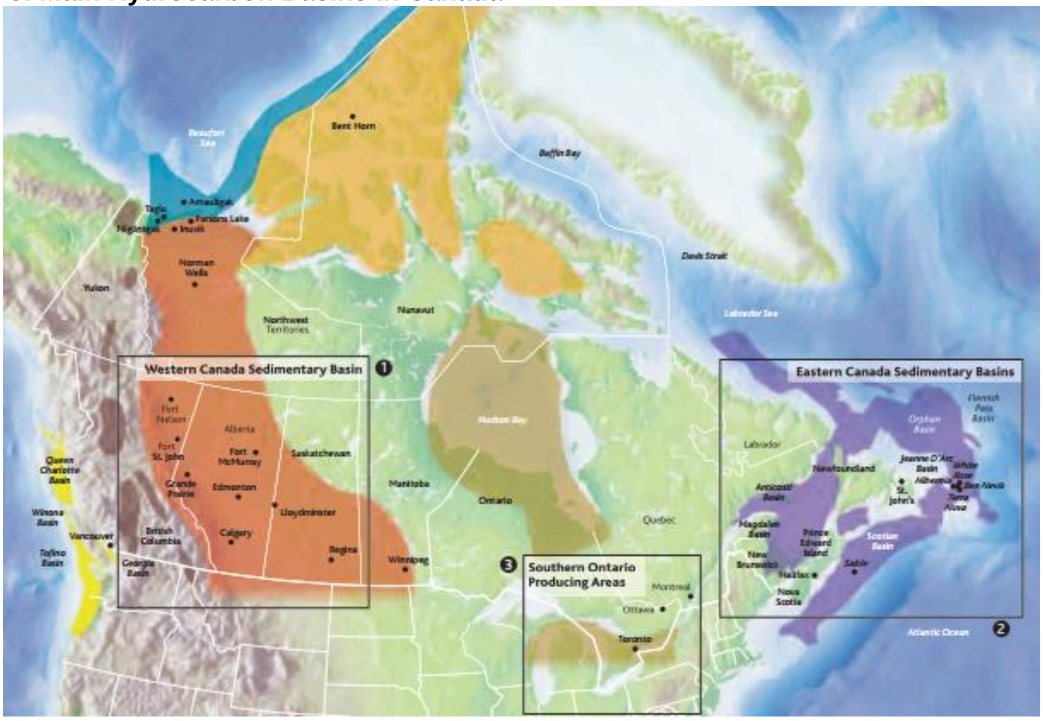
Source: Bott, (2004)

Figure 6 below shows the regions of Western and Eastern Canada that account for the vast majority of Canada's crude oil and natural gas production.

The Western Canada Sedimentary Basin (WCSB) is the most productive hydrocarbon area in the country and includes most of the provinces of Alberta and Saskatchewan, parts of British Columbia, Manitoba, Yukon and the Northwest Territories. Approximately 90% of Canada's natural gas reserves are in Western Canada. Western Canadian shale gas can be found along the Alberta/British Columbia (BC) border and into northeastern B.C.

[9] Bott, (2004)

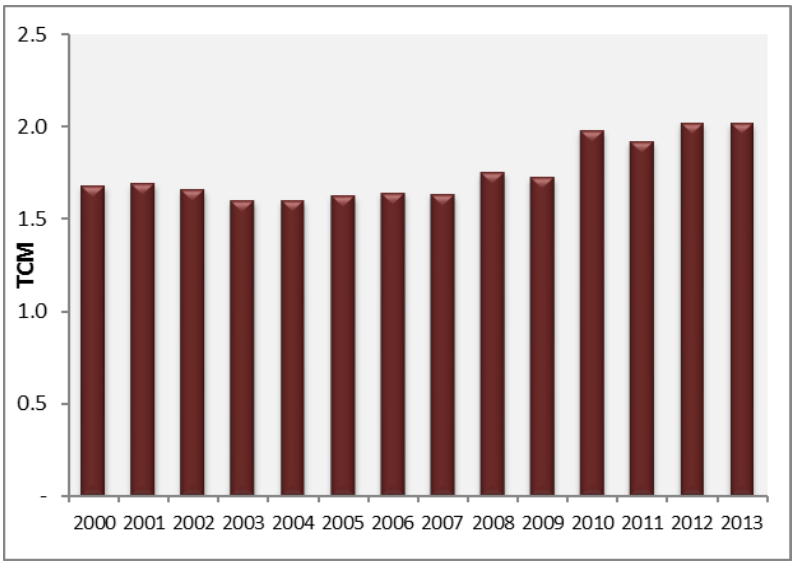
**Figure 6: Main Hydrocarbon Basins in Canada**




Source: Bott, (2004)

Canada ranks as the 16th largest proven gas reserve holder in the world. Natural gas reserves have remained almost flat in the period 2000-2009, rising to around 2 TCM (71.4 Tcf) in 2010, with a Reserves/Production ratio (R/P) of 13 years[10].

**Figure 7: Evolution of Canada's Proven Gas Reserves**

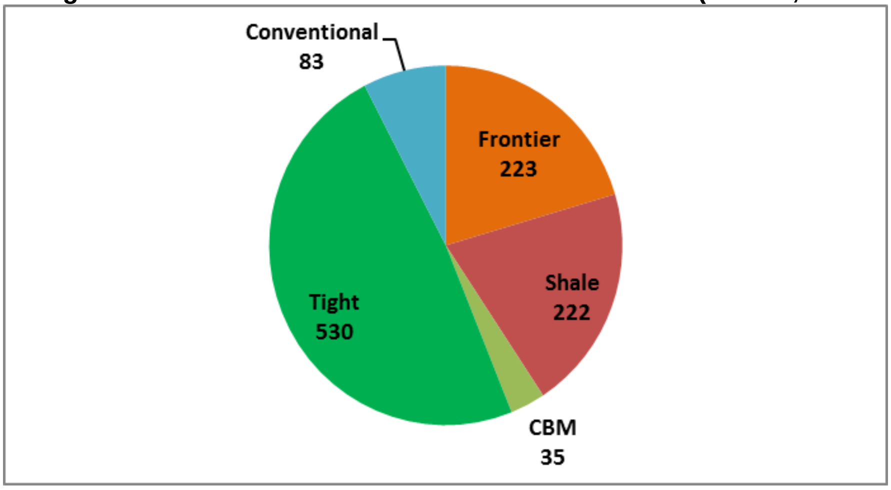



Source: BP,(2014)

[10] BP (2014)

Conventional gas represents less than 8% of the total technically recoverable resources, with shale gas and tight gas estimated at respectively 222 and 530 Tcf according to the National Energy Board[11], which estimates Canada's total gas resources at approximately 1093 Tcf.

**Figure 8: Natural gas resource base as of December 2013 - Canada (Total 1,093 Tcf)**




Source: Canadian Gas Association (2015a), (National Energy Board, 2014b)

According to the National Energy Board the huge unconventional formation Montney which spreads across BC and Alberta is expected to account for nearly half of the ultimate gas potential in Canada. Montney might contain 449 Tcf of marketable natural gas, 14.5 bn barrels of marketable NGL and 1.13 bn barrels of marketable oil[12].

## Shale Gas

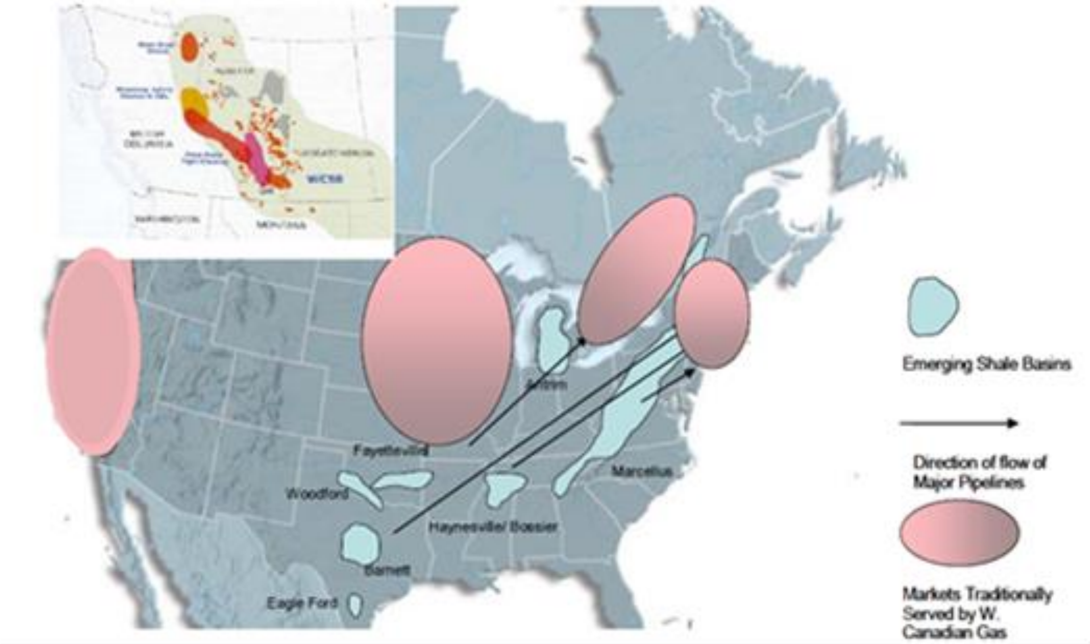
There are different ranges of estimates of Canada's shale resources. The Geological Survey of Canada estimates that Canada has 4,995 Tcf of shale gas in place. The Canadian Society of Unconventional Resources (CSUR) defines marketable gas as "the volume of gas that can be sold to the market after allowing for removal of impurities and after accounting for any volumes used to fuel surface facilities". The CSUR estimates that the range of marketable Canadian shale gas is around 343 Tcf- 819 Tcf, whereas a study by the National Energy Board in collaboration with the governments of Alberta and British Columbia estimates that the Montney play, located in Alberta and B.C., contains 449 Tcf of marketable gas[13]. The US Energy Information Administration (EIA) estimates that 573 Tcf of Canadian shale gas is technically recoverable[14].

The main shale and oil formations are the Horn River Basin, the Cordova Embayment and the Liard Basin (located in British Columbia and the Northwest Territories); the Doig Phosphate Shale (located in both

British Columbia and Alberta); the Banff/Exshaw, Duvernay, Nordegg, Muskwa formations and the Colorado Group in Alberta; the Williston Basin's Bakken Shale in Saskatchewan and Manitoba; the Utica Shale in Quebec and the Horton Bluff Shale in Nova Scotia. Western Canada also contains the large Montney and Doig Resource Plays, spread across British Columbia and Alberta which are categorised primarily as tight sand and siltstone reservoirs[15].

[11] Sourced from Canadian Gas Association, (2015a)
[12] (NEB 2013c)
[13] Chong, (2014)
[14] Energy Information Administration- DOE, (2013)
[15] Energy Information Administration- DOE, (2013)

**Figure 9: US and Canada Shale Plays**




Source: (Canadian Association of Petroleum Producers, 2014a)

The large shale potential resource base located in the Liard Basin, Horn River Basin, Cordova Embayment, and deeper portions of the Montney Formation is almost all dry gas.

## 4. Natural Gas Fiscal Regime

Approximately 90% of oil and gas resources in British Columbia (B.C.) and 81% in Alberta are owned by the Crown (the Province). The Provinces grant exploration and production rights to the industry in exchange for the payment of royalties, bid bonus payments and rents. The remaining 10% and 19% respectively are owned by the Government of Canada in national parks or held on behalf of the First Nations, individuals or corporations as a result of land grants made by Canada in the 1800s.

The oil and gas sector is a significant source of revenue for B.C. and Alberta provincial budgets. These revenue streams are used to fund health, education and infrastructure. In the fiscal year 2009/10, government B.C. revenues from oil and gas, including petroleum and natural gas rights sales, totalled $1.35 billion – almost 60% of total direct revenues from B.C.'s resource industries and 4% of total provincial revenues. Federal and provincial taxes are applicable across Canada using the same base but different rates.

In addition to the established royalty framework that applies to the production and sale of natural gas in B.C and Alberta, the Provinces also possess a comprehensive taxation system, including sales tax, fuel tax, carbon tax and a property tax system.

## British Columbia fiscal regime

Natural gas prices for royalty purposes (Producer Prices) are determined by the provincial Ministry of Energy and Mines by averaging the actual selling prices for gas sales with certain common characteristics for each company and deducting applicable costs[16].

The result is a netback price, generally determined at the plant inlet, which is unique for each producer/plant/month combination. If this price falls below a minimum price known as the Posted Minimum Price (PMP), then the PMP becomes the price of the gas for royalty purposes (the Reference Price). There are currently 5 PMPs calculated each month. Production behind each processing plant is subject to one of these PMPs.

Gas in British Columbia is categorized firstly into conservation (associated) and non-conservation (non-associated) gas. Non-conservation gas is further split into three categories: Base 15, Base 12 and Base 9 gas. The key feature of the natural gas royalty regime in British Columbia is that it is a price-sensitive regime. That is, when the Reference Price is below the Select Price[17], the royalty rate is fixed, while at prices above the Select Price, the rate increases as prices increase.

There are three marketable natural gas by-products associated with natural gas production: Liquefied Petroleum Gas (LPG), Condensate, and Sulphur.

- There are also flat royalty rates of 20% for natural gas liquids and condensates
- The Sulphur rate is 16.667%

Allowances are made for the costs incurred by the producers to transport the gas to the gas processing plants which are the royalty collection point. These allowances are known as Producer Cost of Service (PCOS) and Gas Cost Allowances (GCA).

- PCOS covers the cost of gathering, dehydration, and compression of the Crown share of gas,
- GCA covers the cost of processing the Crown Share of gas into a marketable form. GCA is only deductible for those producers whose gas is processed at a plant owned by a producer (as opposed to a custom processing plant) since the prices determined by the ministry for all other gas is net of the tolls charged by third parties for this service.

These allowances are deducted from the gross royalty to a maximum of 95% of the gross royalty[18]. The calculation of royalties in British Columbia is detailed in Appendix 1.

## Alberta fiscal regime

The Alberta Department of Energy is responsible for the administration of the Mines and Minerals Act which sets out the requirements for responsible development of Alberta's non-renewable resources.

- Royalties are set by a sliding scale formula containing separate elements that account for price and well production.
- Currently the royalty rate for natural gas ranges from 5 – 36%.
- NGLs (natural gas liquids) have fixed rates of 30% for $C_3$ and $C_4$ while $C_{5+}$ is set at 40%.
- Condensate royalty is calculated using the oil royalty formula.

There are various incentive programs in place to encourage drilling and exploration as detailed on Appendix 1.

For the purpose of calculating the royalties paid by the oil companies the Alberta Department of Energy established the Alberta Natural Gas Reference Price which is a monthly weighted average

[16] Information provided by Paul Cheruvathur, Alberta Energy, 2014

[17] A parameter used in the royalty rate formula. At a reference price lower than the select price the royalty rates are fixed, while at higher prices, the royalty rates rise as prices rise (Government of British Columbia)

[18] http://www.empr.gov.bc.ca/OG/oilandgas/royalties/NaturalGasDefinitionsand%20RateDetails/Pages/default.aspx

field price[19] of all Alberta gas sales, determined through a survey of actual sales transactions and adjusted for deductions and amendments.

For example, as of October 2014 the Gas Reference Price was CAD 3.57/GJ (US$ 3.06/MMBtu) and calculated as follows:

**Figure 9: Alberta Natural Gas Reference Price Calculation (October 2014)**

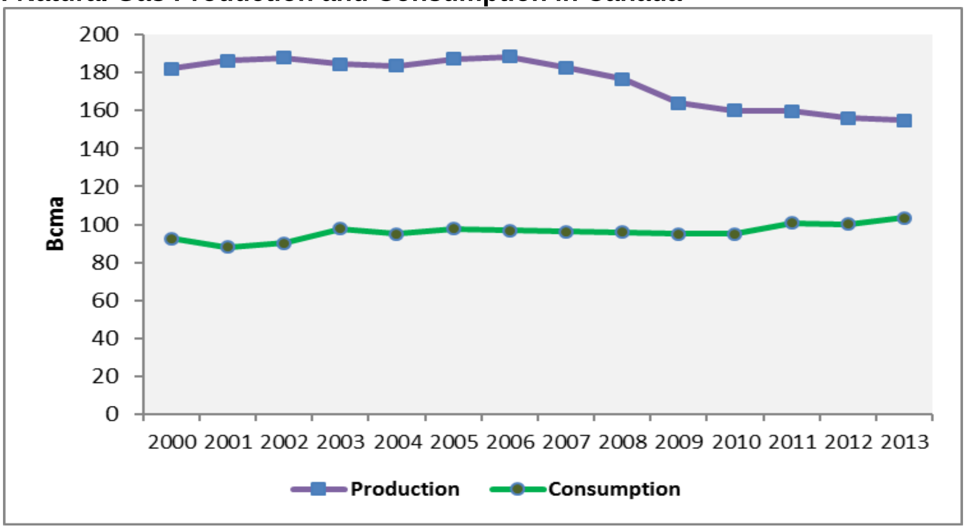
| Component | CAD/GJ |
|---|---|
| Nova Inventory Purchase Price-Alberta Market Price at NGX[20] (A) | 3.795 |
| Intra-Alberta Transportation Deduction (B) | 0.180 |
| Price before Pipeline Factor (C=A-B) | 3.615 |
| Pipeline Fuel/Loss Factor (D) | 0.989 |
| Price before Amendments (E=C*D) | 3.573 |
| Special Amendments (F) | 0 |
| Prior Period RP Amendments (G) | 0 |
| Calculated RP (Price before rounding) (H) | 3.573 |
| Reference Price (rounded) | 3.57 |
| Adjusted Intra-Alberta Transportation Deduction | 0.178 |

Source: http://www.energy.gov.ab.ca/xdata/gas/refprice/rp201410.pdf

## 5. Production, Supply and Demand

Canada is the 5th largest gas producer in the world, with production of 154.8 Bcma in 2013[21], a considerable drop from the 188 Bcma peak in 2006. Domestic gas consumption reached 103.5 Bcma in 2013, an increase of 3.5% when compared to the previous year.

**Figure 10: Natural Gas Production and Consumption in Canada**




Source: BP (2014)

[19] http://www.energy.alberta.ca/NaturalGas/725.asp

[20] NGX is an exchange and clearing agency in Alberta and a registered Derivatives Clearing Organisation

[21] BP (2014)

Western Canada is the major gas producing region, accounting for 98% of the output, followed by Nova Scotia and New Brunswick. The western provinces of Alberta and British Columbia are the first and second largest gas producing regions in Canada. Other regions produce minor volumes. The production activity continues to focus on the liquids-rich gas plays in Alberta and British Columbia. A new EnCana offshore project Canada (Deep Panuke) started production in September 2013 in Eastern Canada.

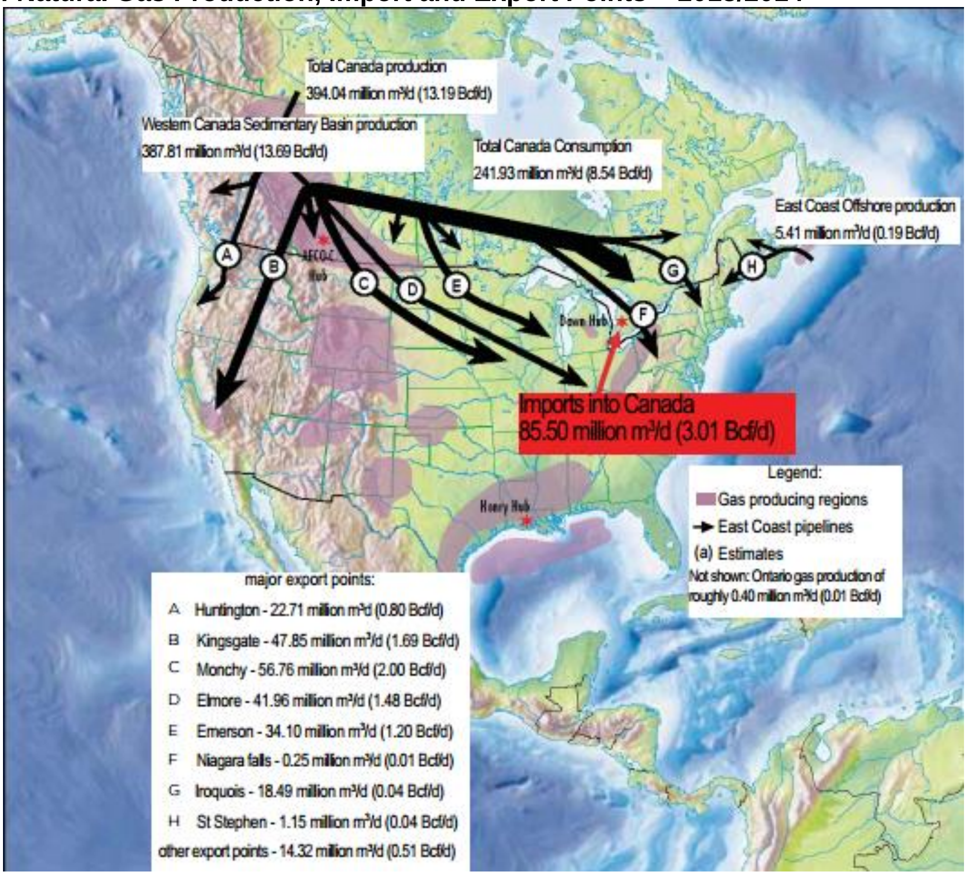
In 2011 shale gas accounted for an estimated 5% of Canada's natural gas production and may account for up to 20% by 2020.

Production of conventional non-tight gas has more than halved from 117 Bcma in 2000 to 55 Bcma in 2012, whereas tight gas production has more than doubled in the same period from 37 Bcma to 75 Bcma[22].

From 1955 to 2013 the oil and gas industry drilled 545,618 wells, of which 205,590 were gas wells. In 2013 there were 809 drilling rigs involved in gas operation activities. In February 2014 the rig count fell to 632, of which 210 are on gas operations, whilst in February 2015 the rig count dropped to 360, of which 176 are drilling for natural gas.[23] The number of natural gas wells drilled dropped from approximately 17,900 in 2004 to 1,800 in 2013.

Gas is transported from the Western Canada Sedimentary Basin (WCSB), to the domestic market and to seven major export points to the USA with total export capacity of 87 Bcma.

**Figure 11: Natural Gas Production, Import and Export Points – 2013/2014**




Source: http://www.cga.ca/wp-content/uploads/2015/01/Natural-gas-trade_January-2015_EN.pdf

[22] National Energy Board (2013b)

[23] http://www.wtrg.com/rotaryrigs.html

The Canadian domestic gas market is divided geographically at the Saskatchewan-Manitoba border into Western and Eastern Canada demand. Western Canada demand includes gas volumes withdrawn during the recovery of natural gas liquids at straddle plants[24]. Approximately 85%-90% of the gas exiting Alberta is processed through straddle plants, which extracts ethane, NGLs and heavier components remaining after field processing.

The East Coast demand is concentrated mainly in Ontario, in the residential sector and large petrochemical and heavy industries.

Historically Canada's gas production continuously exceeded domestic demand with the surplus production exported to the USA. Traditional markets for WCSB production include Ontario, Quebec and the US Northeast, as well as the US Midwest and Pacific Coast. Declining natural gas prices have reduced drilling activity for conventional gas in the WCSB in the last 8 years, with production trending down since 2006. Production in Alberta, BC and Saskatchewan totaled 174.5 Bcma (16.9 bcfd) in 2006, declining to 142.1 Bcma (13.7 Bcf/d) by 2012. The increased production of shale gas in Marcellus and Utica (northeast US) and in the Bakken formation in North Dakota deeply affected the dynamics of the Canadian gas market. In the case of Marcellus shale, gas production rose from 7.6 Bcma (733 MMcfd) in early 2010 to 177 Bcma (17 bcfd) in March 2015[25]. The main impacts on WCSB exports are summarised below:

- Canada east coast markets started importing natural gas from the USA as it became cheaper than domestic gas produced in the WCSB and transported by long distance pipelines. Gas imports from the US increased from 9.7 Bcma in 2006 to volumes around 30 Bcma in 2014, which is roughly 30% of Canada's domestic demand.
- Increased shale gas production in the US reduced the need for Canadian exports to the Northeastern region in the US. Canadian export volumes at the Ontario and Quebec borders fell from 23.8 Bcma in 2006 to 9.3 Bcma in the first 10 months of 2014.

A number of export pipelines in Ontario have been converted to allow for bi-directional gas flow and allow additional imports from the US, whereas the US shale producers are building additional pipelines to evacuate dry gas production.

## 6. Canada domestic gas market

Canada and Saudi Arabia jointly hold the position of 6th largest gas markets in the world, each one consuming 103 Bcma in 2013[26]. Natural consumption in Canada has been flat from 2003 to 2010 around 95-97 Bcma with a 3% growth in the period 2012-2013 due to a winter colder than average which significantly increased natural gas demand for space heating and power generation, coupled to increased demand for gas in the production of oil sands.

The industrial sector accounts for one third of the gas consumption in Canada, followed by oil field operations/steam production and by residential demand. The power sector accounts for only 15% of Canada's gas consumption due to the abundance of hydroelectricity.

In 2013 there were 6.5 million domestic consumers of natural gas, of which 6 million are in the residential sector and nearly 500,000 in the commercial and public sectors[27].

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[24] Straddle Plant: a gas processing plant located on or near a gas transmission line which removes residual NGLs that remain in the sales gas.

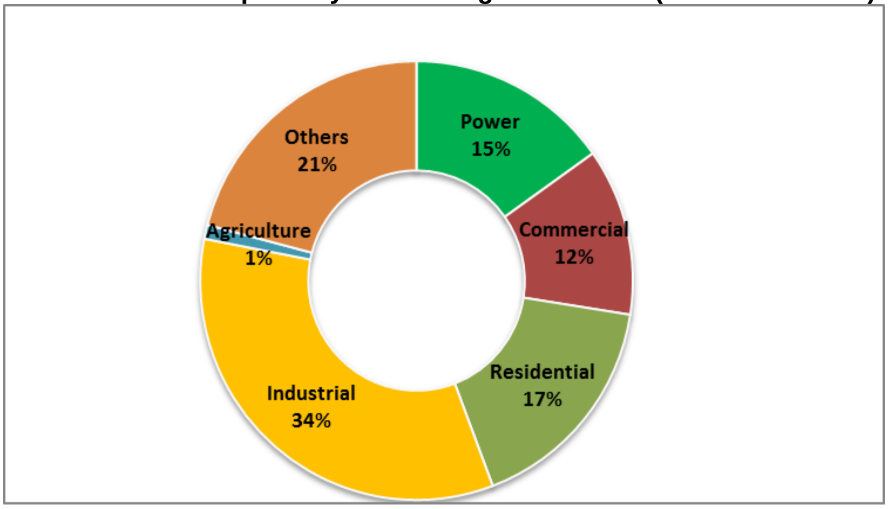
[25] EIA (2015), National Energy Board (2013b)

[26] BP (2014)

[27] Canadian Gas Association: http://www.cga.ca/wp-content/uploads/2011/02/Chart-17-Natural-Gas-Customers.pdf

Power generation was a key mechanism in balancing markets during the 2014 storage refill season in North America with increased natural gas-fired power generation in the US and Canada at the expense of coal-fired power generation.

**Figure 12: Natural Gas Consumption by Market Segment – 2013 (Total: 103 Bcma)**

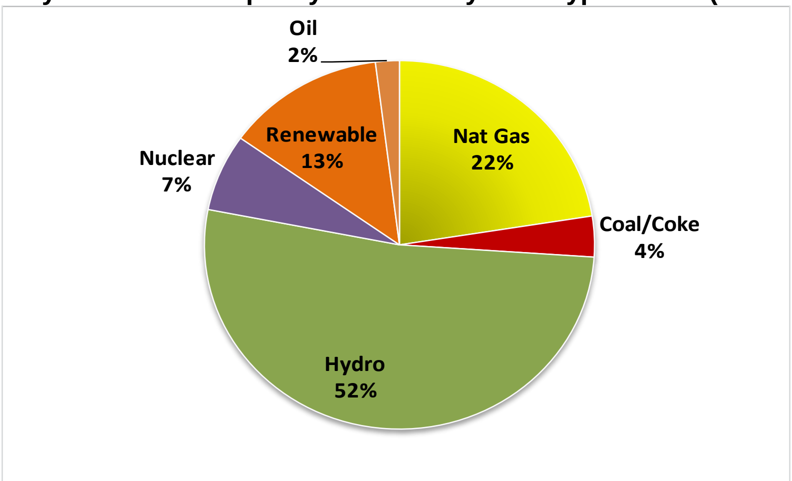



Source: Canadian Gas Association (2015b)

The National Energy Board (NEB) forecast that Canadian electricity capacity will increase at an average annual rate of 1% from 137 GW in 2012 to 164 GW by 2035, a total growth of 22% over the projection period.

The NEB projects a shift in the generation capacity profile with renewable energy (non-hydro) projected to increase its share from 4 to 13%, nuclear declining from 10% to 7% and natural gas increasing its share to nearly 22%. Based upon NEB market projections, the demand for natural gas in the power sector would rise by another 10 Bcma by 2035.

**Figure 13: Electricity Generation Capacity Forecast by Fuel Type – 2035 (Total: 164 GW)**




Source: National Energy Board (2013b)

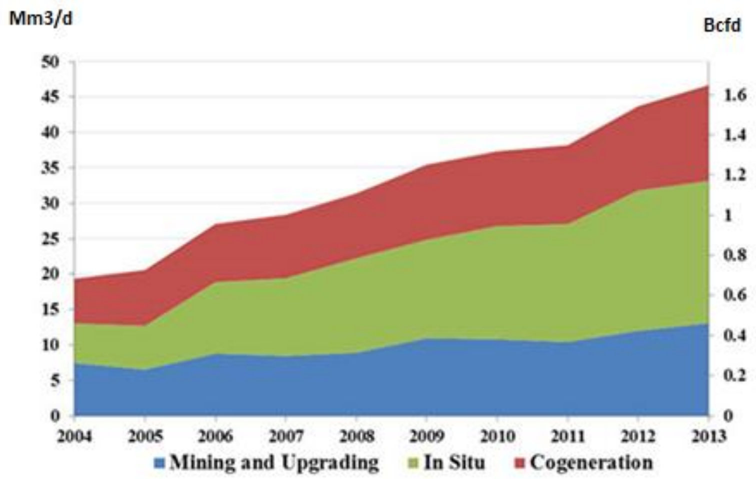
## Natural gas demand in oil sands operations

A growing market segment for natural gas is its use in oil sands operations. There are two predominant methods to extract hydrocarbons from oil sands: traditional pit mining on the surface and in-situ drilling underground. Surface mining has been declining because approximately 80% of bitumen reserves are situated too deep underground to be accessible by surface mining. In-situ extraction injects steam into underground formations to soften the bitumen and pumps it to the surface through wells. Natural gas is used to produce steam for injection and for producing in-situ electricity. It is also used as a source of hydrogen to upgrade bitumen into synthetic crude oil. [28]

In 2013 the production of oil sands was 1.98 MMb/d, and the consumption of natural gas in oil sands operations reached 17 Bcma (1.6 Bcfd) in 2013, an increase of 6.8% when compared to 2012 (Figure 14).

According to the National Energy Board, in situ projects consume about 1,200 cubic feet (34 $m^3$) of natural gas per barrel of bitumen whereas integrated mining projects require 700 cubic feet (20 $m^3$) per barrel.

**Figure 14: Natural Gas Consumption in Oil Sands Operations**




Source: (National Energy Board, 2013b)

The medium term outlook for oil sands projects which have not yet started construction does not look very promising under the current low oil prices. In October 2014, the International Energy Agency (IEA) concluded that one in four new Canadian oil projects would be in jeopardy if crude prices fell below US$80/bbl for any extended period of time. More recently IEA's medium-term oil market forecast, published in February 2015, predicted that Canada's oil production will be cut by 430,000 barrels/day, which represents more than 10% of the current production, by 2020.

While Canadian oil sands projects that have already had capital commitments will go ahead, new projects "are unlikely to be sanctioned and will likely be delayed," the IEA said[29]. "Companies will be much more restrained in committing cash to fund expensive projects in the current price environment."

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[28] http://www.eia.gov/countries/cab.cfm?fips=ca

[29] IEA (2015)

The Canadian Association of Petroleum Producers estimated in January 2015 that oil sands capital budgets will fall to US$20 billion in 2015, a decrease of $6.5 billion from 2014.

The demand for natural gas in oil sands operations is expected to grow to:

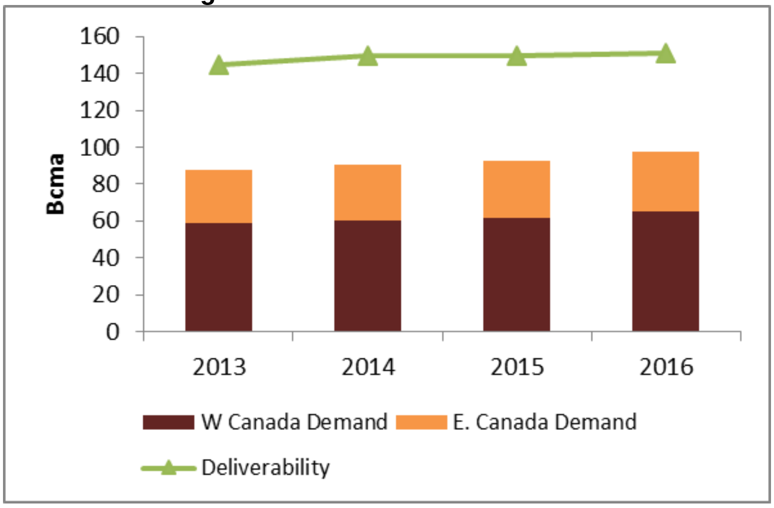
- 23.7 Bcma (2.3 bcfd) in 2015 for a production of 2.4 MMb/d of bitumen, assuming a 50%:50% ratio for integrated and in situ projects.
- 27-31 Bcma by 2020, for a production of 3.1 MMb/d of bitumen, which already takes into account a reduction of 430,000 b/d as per IEA projections.

## 7. Other potential demand levers in the domestic market

Apart from the oil sands business, the opportunity for natural gas to displace competing fuels in traditional space-heating and industrial markets in Canada seems to be relatively limited. Other potential sources for demand growth are the substitution of 4,120 MW of coal fired power generation in Alberta[30] and the use of gas for transportation and as feedstock for petrochemicals, but the latter options require long lead time to become material. For example the National Energy Board forecast that the use of natural gas in the residential sector will grow 0.7% per annum, whereas demand in power generation will grow 1.1% in the period 2013-2035[31].

In the short/medium term the National Energy Board forecast a domestic demand growth of 10 Bcma in the period 2013-2016, which largely derives from the utilisation of natural gas in the oil sands business. After balancing demand with the projected increase in supply, there is an exportable surplus of 57 Bcma in 2013, which drops to 53 Bcma by 2016. The exportable surplus would be sufficient to produce 36 mtpa of LNG after deducting the volumes of gas used as a fuel in the liquefaction process (circa 10% of the feedgas) if there is no room to export via pipeline to the US.

**Figure 15: Medium Term Natural gas demand forecast 2014-2016**




Source: (National Energy Board, 2014b)

[30] http://en.wikipedia.org/wiki/List_of_generating_stations_in_Alberta

[31] (NEB, 2013a)

## Small Scale LNG

LNG can be used in the transportation sector, particularly in long-haulage vehicles and as marine fuel. The diesel/LNG price differential can be quite attractive for end-users. As an example of Canada, ENN Canada is currently charging CAD 0.81/diesel litre equivalent (after taxes) of LNG at its station in Merritt, BC, which compares favourably with diesel retail prices of CAD $1.20/litre in the same region (National Energy Board ( 2015).

The availability of sizeable dry gas volumes in shale producing areas which are not served by pipeline infrastructure prompted the development of small scale LNG facilities, coupled to LNG truck transportation to end-users. Table 2 below summarises the existing and proposed Small Scale LNG projects in Canada.

**Table 2: Small Scale LNG projects in Canada**

| Small LNG plant | Location | Commissioning Date | Capacity (Bcma) |
|---|---|---|---|
| **Altagas** | British Columbia (BC) | 2015 | 0.017 |
| **EnCana** | Alberta (AB) | 2013 | 0.005 |
| **FerusNGF** | BC | 2016 | 0.085 |
| **FerusNGF** | AB | 2016 | 0.085 |
| **FerusNGF** | AB | 2014 | 0.043 |
| **FortisBC** | BC | 1971 | 0.045 |
| **FortisBC** | BC | 2011 | 0.078 |
| **Gaz Métro** | Québec (QC) | 1969 | 0.105 |
| **Northeast Midstream** | Ontario (ON) | 2016 | 0.300 |
| **Stolt LNGaz** | QC | 2018 | 0.709 |
| **Union Gas** | ON | 1968 | n.d. |
| **Total** | | **1.47 Bcma** | |

Source: National Energy Board (2015)

LNG is emerging as an alternative to diesel in areas not currently served by pipeline infrastructure. A power plant in Inuvik has converted to LNG, and Yukon Energy has been approved to start trucking LNG to Whitehorse. Also Gaz Métro in Québec sold LNG to power plants in New England in 2014 and is planning to truck LNG to remote communities and industries in the province.

## Petrochemicals

Alberta possesses a competitive source of supplies for the petrochemical industry, in particular ethane and propane from natural gas.

Alberta has currently near 20 petrochemical plants, using ethane, ethylene, propane and crude oil as feedstock. Canada has over 1 million b/d of fractionation capacity, with over 88% located in the West Coast. The availability of NGLs and the high prices prevailing until 2013 have led to announcements of over US$ 11 billion of investment in deep-cut NGLs processing plants, petrochemical facilities and LPG export terminals.

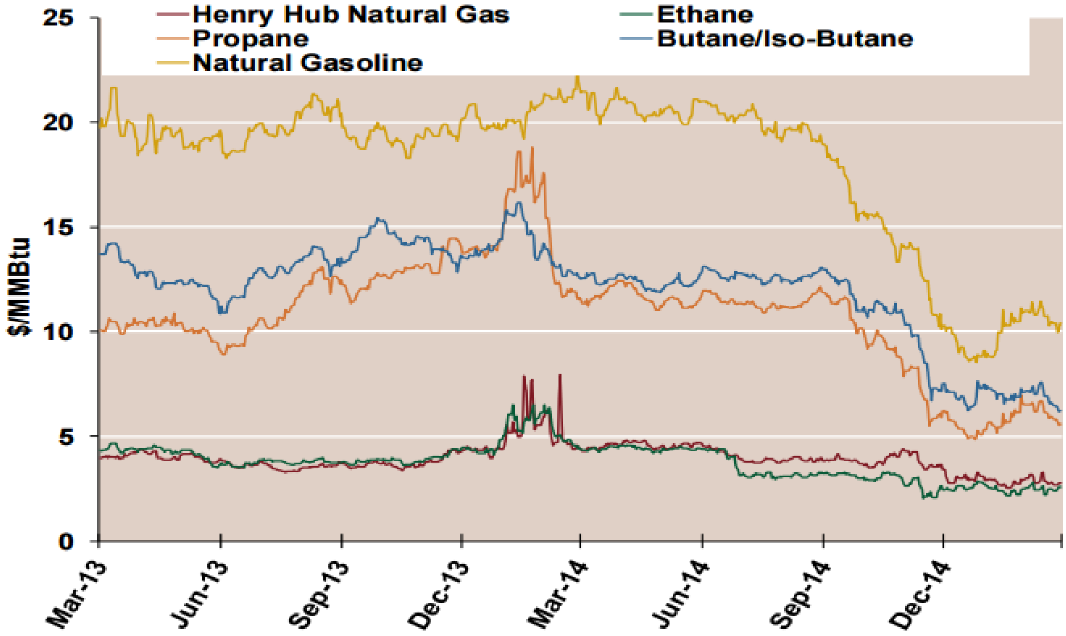
CERI put together a few scenarios for NGLs for petrochemicals focusing on ethane and propane[32]. CERI forecast a surplus of ethane emerging after 2020, with demand reaching 270,000 b/d. In which case, the options are either to invest in additional petrochemical facilities, or leave ethane in the gas stream. CERI also produced two scenarios for propane supplies and forecast a surplus of 20,000-50,000 b/d which can either be exported to the US or seed the development of new propane-based activities in Alberta.

[32] Murillo C. (2014a)

Increased supply of NGLs from the US and lower oil prices are pressuring NGLs prices downwards. As of 23/03/2015, NGLs prices in the US have halved when compared to March 2013, which is likely to impact the attractiveness of the petrochemical business. The impact of lower NGLS prices on natural gas production has not yet been fully felt neither the trades-off between lower ethane prices and increased petrochemical activity.

Market analysts are projecting an ethane surplus in North America, leading to producers leaving increased volumes in the gas stream. Since gas quality standards will impose a limit on how much ethane can be left, there is opportunity to develop ethane export schemes, in particular to Europe and India. Exports from Alberta would be disadvantaged when compared to the USCG, due to logistical constrains and the distance to export harbours in the West or East Coast.

**Figure 16: Evolution of Natural Gas Liquids Prices**




Source: http://www.ferc.gov/market-oversight/othr-mkts/others/ngas-tr-ngl-pr.pdf

## Natural Gas in the transportation sector

According to the Canadian Natural Gas Vehicle Alliance (CNGVA) there are currently about 12,000[33] natural gas vehicles in Canada, including 9,500 passenger vehicles. Canada has only 38 public compressed natural gas (CNG) fuelling stations, 50 private fleet CNG fuelling stations and four private liquefied natural gas (LNG) stations.

In 2013 the number of registered vehicles in Canada exceeded 31.7 million[34], from which more than 9 million were off-road, motorbikes and trailers. There is significant opportunity to replace gasoline and diesel; the gas vs. liquid fuels price differential and reduced emissions are motivating government entities and fleet owners to convert to natural gas. The big challenges are the size of Canada, which would require a comprehensive network of fueling stations for long-haulage vehicles and the current low oil price which reduces the price differential between CNG/LNG and diesel.  The marine sector is another emerging opportunity for use of natural gas as a transportation fuel  as new regulations are

[33] Canadian Energy Pipeline Association (2013)

[34] http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/trade14a-eng.htm

coming into force in North America to lower the emissions from ships when operating near coastlines or on inland waterways.

Assuming a conversion rate of 5% of the light-vehicles fleet and 1% of the heavy-vehicles, the potential demand in the road transportation sector would reach 6 Bcma[35], with a total gas fleet of 870,000 vehicles, which is in line with countries with large geographic spread in terms of the use of natural gas in the transportation sector.

British Columbia has implemented special weight exemptions to provide a level playing field for natural gas heavy-duty vehicles. The B.C. Ministry of Transports is liaising with the CNGVA and preparing a report regarding the adoption of LNG as a marine fuel on the west coast of Canada.

Other topical initiatives are listed below[36]:

- The city of Calgary is planning to operate 400 Compressed Natural Gas (CNG) buses
- The Ledcor Group of Companies announced they will take ownership of over two hundred CNG vehicles, creating one of the largest fleets of CNG vehicles in Canada.
- Ryder System, Inc., a leader in commercial fleet management and supply chain solutions, announced that Canadian American Transportation, Inc. has signed a full-service lease agreement for 100 CNG sleeper tractors.
- Union Gas is partnering with the City of Hamilton to build and maintain a CNG station that will fuel the city's transit bus fleet. The new station will have the capacity to grow from the current 35 to a total of 120 vehicles over the next six years.
- Three LNG passenger ferries announced for St. Lawrence River use in Quebec in 2015. Also in Québec, Groupe Desgagnés ordered two freight vessels and Seaspan Ferries Corporation ordered two ferries, both for delivery in 2016.
- BC Ferries plans to have five vessels using dual diesel/small LNG-fuelled engines by 2018.
- Shell and Caterpillar have agreed to test LNG on heavy-haulers in the oil sands in Alberta starting in 2016.

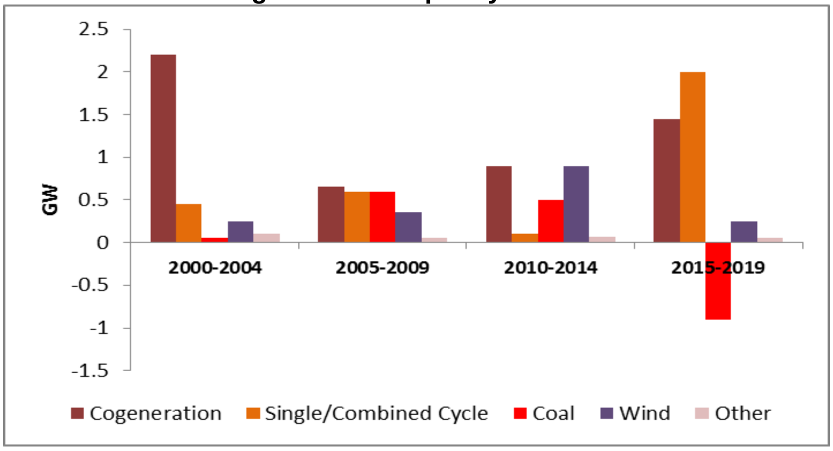
## Cogeneration

Cogeneration might become an attractive market opportunity in Canada. In the period 2010-2014, the total power capacity installed in Alberta was 2.5 GW, the majority of which was co-generation and wind, followed by coal, and natural gas open or combined cycle. For the period 2015-2019, a total of 3.0 GW of capacity is being planned, the majority of which will be open or combined cycle natural gas and cogeneration, in particular for oil sand operations. It is expected that 0.9 GW of coal-fired generation will be retired over this period.

[35] Assumptions: 1 light vehicle consumes 15m$^3$/day and a heavy vehicle consumes 70m$^3$/day of natural gas.

[36] http://www.cngva.org/

**Figure 17: Historical and forecast generation capacity additions and retirements - Alberta**

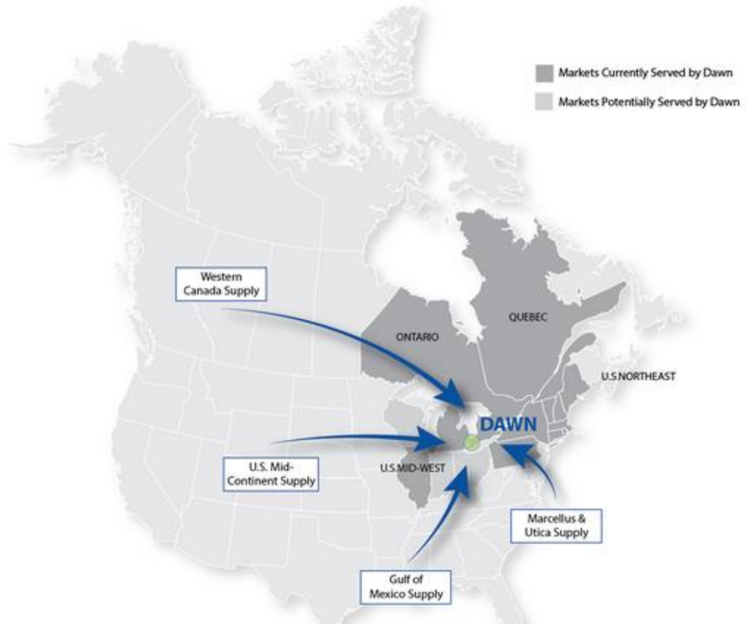



Source: Alberta Government and Alberta Electric System Operator

## 8. Gas Hubs in Eastern Canada and Northeast US

The eastern Canada gas consumers can access the Dawn Hub, a nodal point out of the Union Gas Dawn Facility, south of Ontario, which is the largest underground storage facility in Canada with 4.5 Bcm of working storage capacity. The Dawn Hub is interconnected with numerous pipelines connecting US supply basins to markets in central Canada, the Great Lakes region and the northeast US[37]. The Dawn Hub current take-away capacity is 66 Bcma, growing to 83 Bcma by 2020. The facility serves a market encompassing over 9.9 million consumers in eastern Canada and the northeast US.

**Figure 18: Markets served by Union Gas' Dawn Hub**




Source: https://www.uniongas.com/storage-and-transportation/about-dawn/dawn-hub/reach-of-dawn

[37] https://www.uniongas.com/storage-and-transportation/about-dawn/dawn-hub

The Appalachian basin has become an increasingly important source of gas supply in the US, accounting for 20.4% of the Lower 48's gas production in 2014.[38] The surplus gas production in the Marcellus and Utica shale plays has prompted the construction of new pipelines to evacuate natural gas into US and Canadian markets. The increased connectivity results in increased liquidity in gas hubs in East Canada and Northeast US. In September 2014 the Dominion South Hub which is a key supply point in the Marcellus shale has averaged nearly 400,000 MMBtu/day gas trade compared to 290,000 in 2009[39].

The prices at key trading hubs in the Marcellus production area highlight differences in available production, takeaway capacity, and storage capacity across the region[40].

1. **Leidy and Tennessee Zone 4**. The Leidy Hub is the nodal price point for the the Transco, Dominion Transmission (DTI), National Fuel, Columbia Gas Transmission (TCO), and Texas Eastern Transmission (Tetco) pipelines, the Tennessee Gas Pipeline (TGP). According to Ford, (2014) the production of dry gas in the northern and central portions of the Marcellus Shale averaged 234 Mm3/d in the period from January 1 to October 13, 2014, a 27% increase from the same period in 2013. In February and March 2014, Marcellus spot prices at these hubs fell below Henry Hub on days when pipeline constraints prevented additional production in these areas from reaching Northeast consumers.

2. **Dominion (North and South).** Since April 2014, gas prices at the Dominion North and Dominion South Hubs have remained below Henry Hub due to increasing amounts of Marcellus gas being delivered to DTI from other pipelines in the region (Ford (2014).

**3. TCO Pool [41].** The TCO Appalachia Pool Hub is the nodal point for gas prices at Columbia Gas Transmission pipeline (Kentucky and Ohio), and West Virginia. Most of the gas marketed at the TCO Hub is produced in the West Virginia and southwestern Pennsylvania portions of the Marcellus, with dry production rising to 174 Mm3/d by October 2014, TCO has offset production growth by reducing deliveries of gas produced in other regions, therefore the TCO spot price trades at closer parity with Henry Hub prices

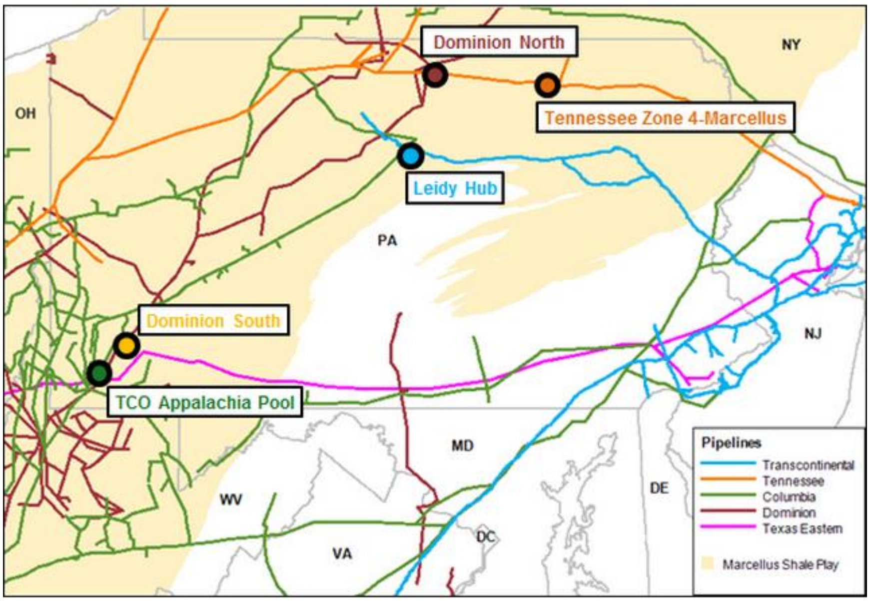
[38] Natural Gas Intelligence (2015)

[39] http://uk.reuters.com/article/2014/09/25/natgas-henryhub-marcellus-idUKL1N0RA1IB20140925

[40] http://www.eia.gov/todayinenergy/detail.cfm?id=18391

[41] Columbia Gas Transmission's Interruptible Paper Pool

Figure 19: Natural Gas Price Hubs in Northeast US



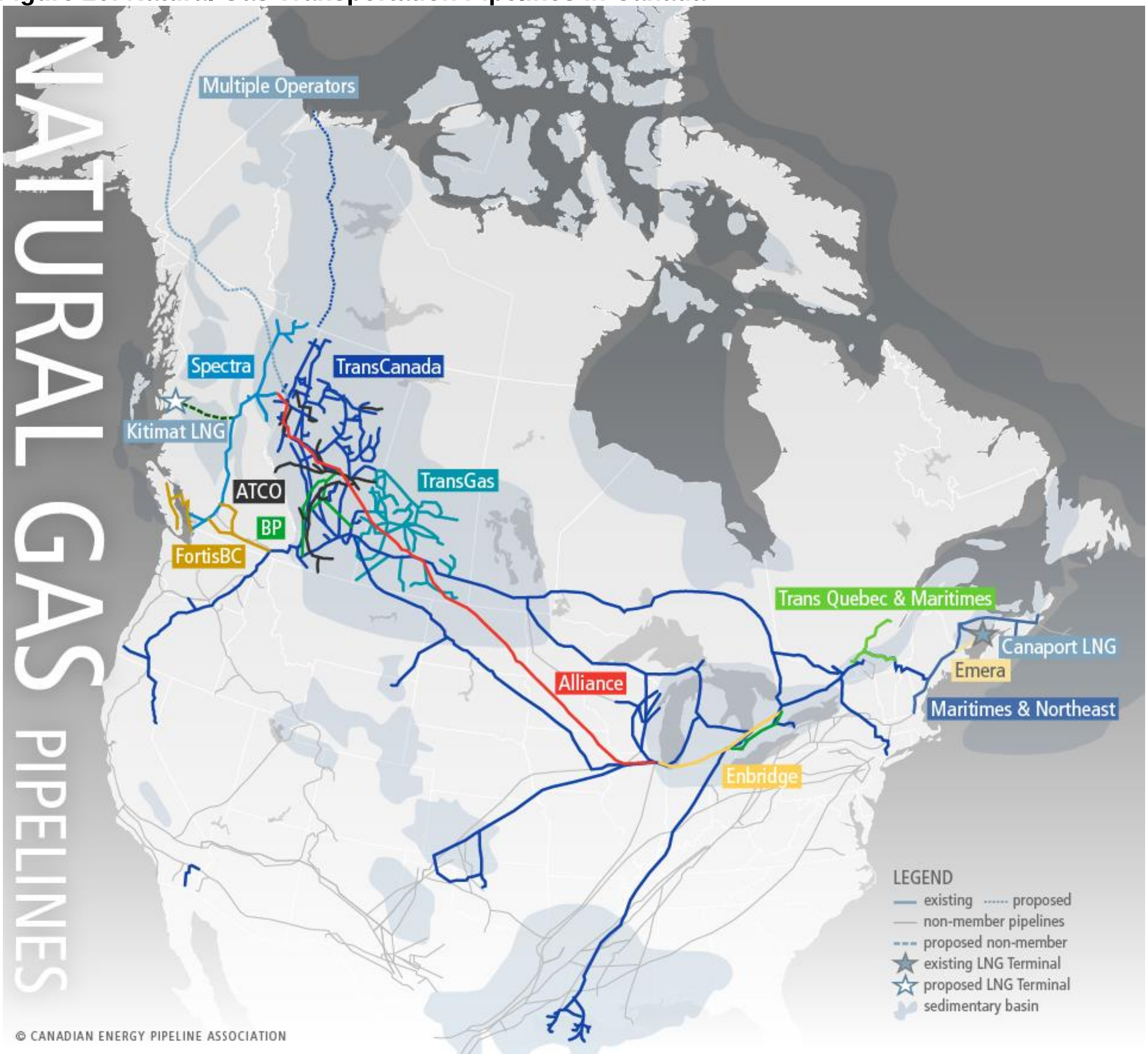

Source: Ford (2014)

## 9. Canada's Natural Gas Pipeline System

In Canada there is a massive infrastructure of 510,000 kilometres of transmission and distribution pipelines, of which 78,000 km are high pressure transmission pipelines as of 2013.

Canada's natural gas pipeline system is highly interconnected with the US pipeline system. TransCanada operates a 40,000 km network transporting nearly 14 bcfd that includes the NGTL System, the Canadian Mainline, the Foothills, and the Trans Quebec and Maritimes pipelines that connect supply in western Canada to the United States. Spectra Energy operates a 2,900 km, 2.9 bcfd pipeline system connecting western Canadian gas supply regions with markets in the United States and Canada. Spectra Energy also operates the Maritimes and Northeast Pipeline linking eastern Canadian supplies with consumers in the eastern United States. Enbridge and Veresen operate the Alliance Pipeline, a 3700 km pipeline system, delivering 1.6 bcfd from the WCSB to Chicago, Illinois which is a significant source of natural gas and NGLs for the U.S. Midwest.

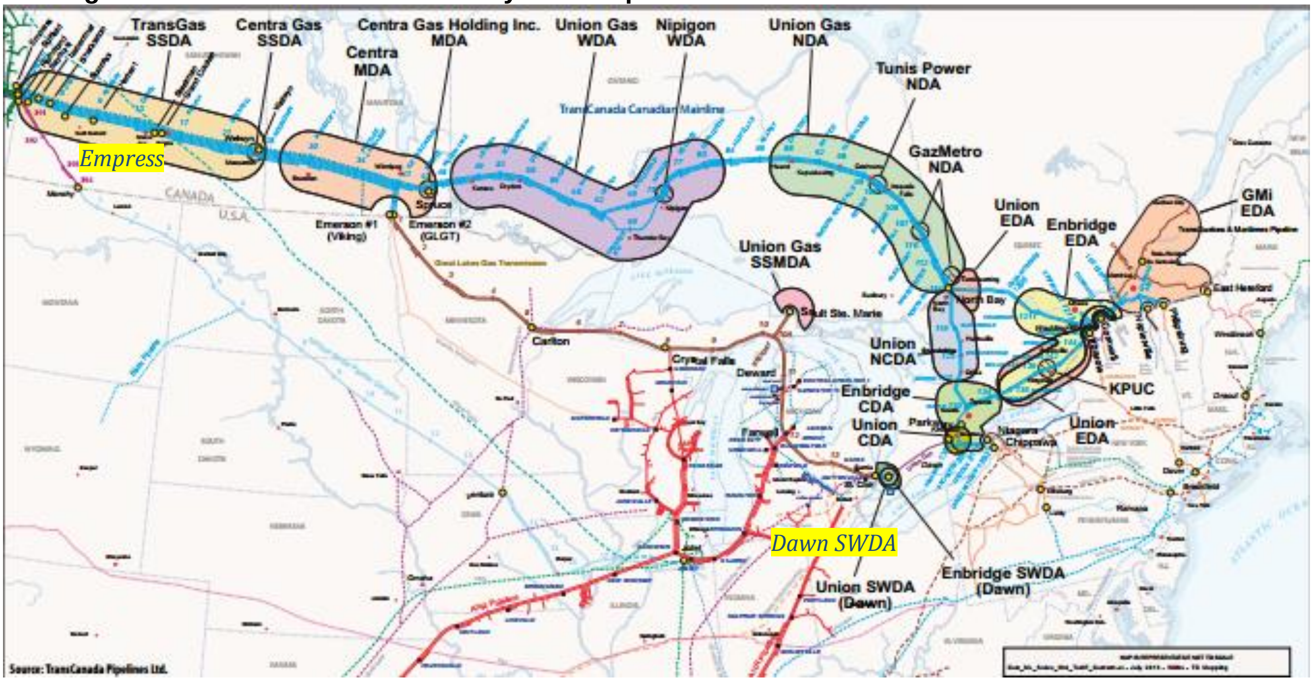
**Figure 20: Natural Gas Transportation Pipelines in Canada**




Source: http://www.cepa.com/wp-content/uploads/2014/10/ng-cepa2014.pdf

The TransCanada Mainline (14,100 km) extends from the Alberta border, and runs across the provinces of Saskatchewan, Manitoba and Ontario, and through a portion of Quebec. It connects to various downstream Canadian and international pipelines as shown on Figure 22.

**Figure 21: TransCanada Mainline System Map**




Source: (National Energy Board, 2014a)

Toll fees regulated by the National Energy Board (NEB) on some natural gas pipelines have increased due to declining use of these pipelines from 2010 to 2012, in particular the TransCanada Mainline. Since less gas was transported from Western Canada on TransCanada's Mainline, the regulated toll fees increased for the remaining customers. The firm transportation toll (and fuel costs) between Alberta and the eastern Canada Dawn hub increased by 73%, from an average of US$ 1.06/MMBtu (CAD1.25/GJ) in 2006 to an average of US$ 1.82/MMBtu (CAD2.16/GJ) in the first half of 2013. Following a comprehensive review the NEB approved new toll fees, which decreased the toll on the Nova Inventory Transfer (NIT) [42]to Dawn route to US$ 1.38/MMBTU (CAD1.64/GJ) starting in July 2013[43].

Figure 22 shows the average monthly throughput on the Prairies segment of the TransCanada

Mainline, which runs from the Alberta/Saskatchewan border to Île des Chênes, Manitoba, and then to a point south of the Canada-US border near Emerson, Manitoba. The Prairies segment connects to the Great Lakes Gas Transmission and Viking Gas Transmission systems which operate in the US.

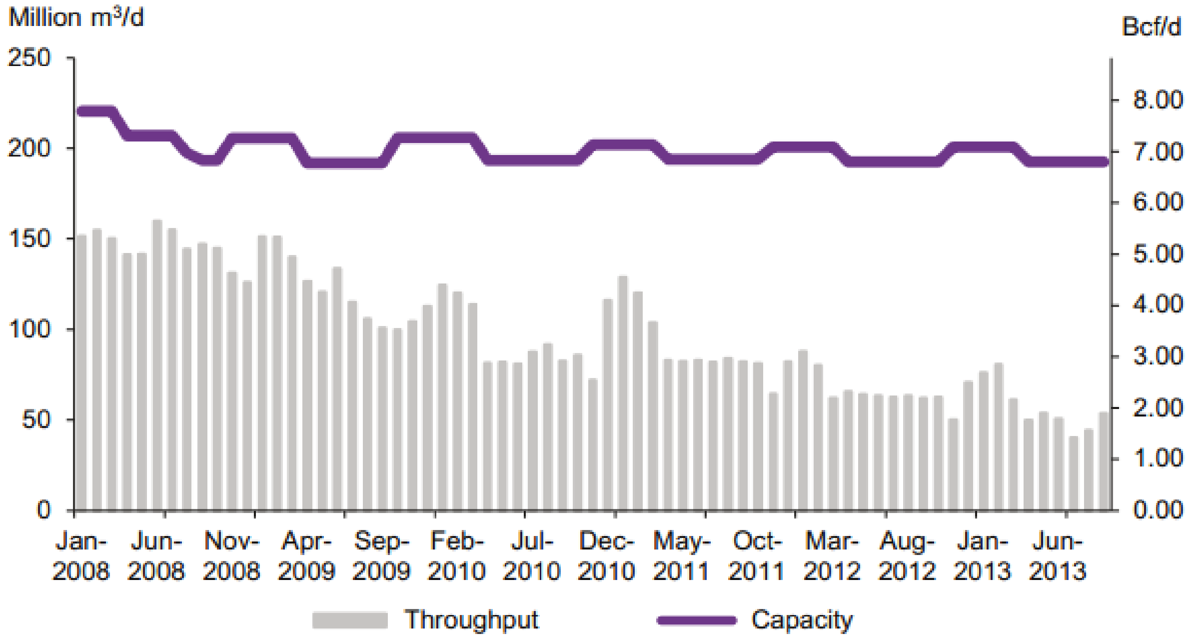
The throughput on the Prairies segment averaged 57 Mm$^3$/d (2.0 bcfd) in the first nine months of 2013. The average utilisation of the Prairies segment was 45% in 2011, 34% in 2012, falling to 29% for the first nine months of 2013, demonstrating a very large spare capacity in the system as a result of gas flows from Western Canada to Eastern Canada ebbing away.[44]

[42] NIT is a Western Canada Sedimentary Basin (WCSB) gas-trading hub for Alberta System customers.

[43] National Energy Board(NEB, 2014a)

[44] Canadian Energy Pipeline Association (2013)

**Figure 22: TransCanada Mainline Prairies Segment Throughput vs. Capacity**




Source: National Energy Board (2014a)

As of January 2015 the interim firm transportation toll between Empress and Dawn SWDA was set at US$ 1.42/MMBtu (CAD 1.6787/GJ) plus an Abandonment Surcharge of US$ 0.11/MMBtu (CAD 0.1325/GJ)[45], totalling US$ 1.53/MMBtu.

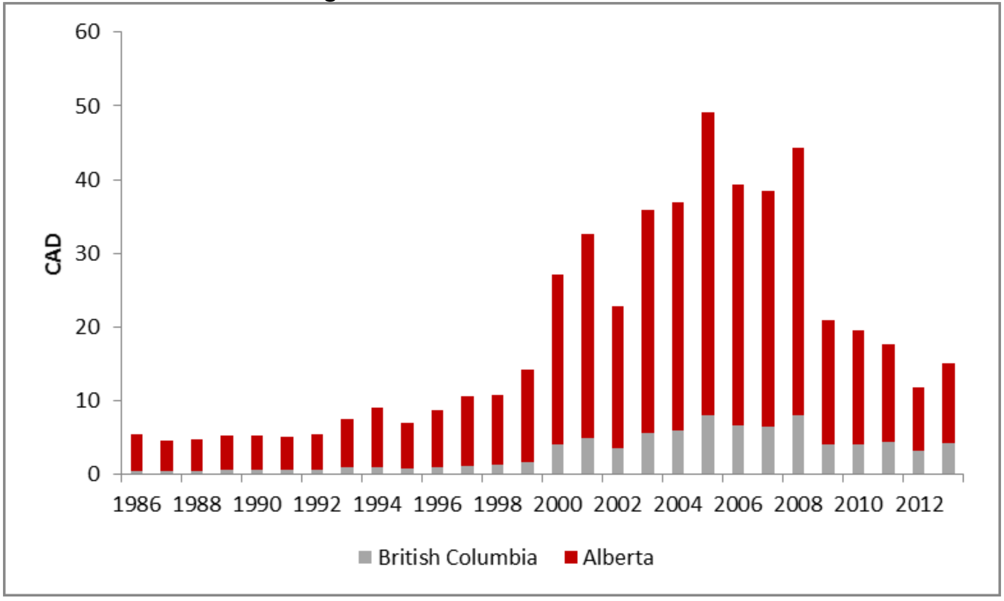
## 10. The Changing Dynamics in Canada's Gas Exports

From 2009 onwards, the provinces of Alberta and British Columbia have seen continuous erosion in gas sales as consumers in the East Coast started switching from WCSB long term gas supply agreements to short term and spot deals from US unconventional gas suppliers.

In Alberta alone, gas sales revenues dropped from 36.3 billion CAD (US$ 29.5 billion) in 2008 to 10.9 billion CAD (US$ 8.7 billion) in 2013.

[45] http://www.transcanada.com/customerexpress/pricing-tolls.html

**Figure 23: Historical evolution of gas sales in Alberta and British Columbia**




Source: (Canadian Association of Petroleum Producers, 2014b)

Overall, Canada pipeline exports to the US declined more than 20% over the period 2008-2014[46]. The completion of the Rockies Express, Bison, and Ruby pipelines has increased connectivity of the US shale plays with US and Canadian markets and thus competition in the US Northeast, Midwest, California and East Canada markets, with gas sourced from Western Canada becoming increasingly disadvantaged. The construction of gas pipeline infrastructure around the liquid rich Bakken Formation in North Dakota is allowing US shale to penetrate deeper the US and Canada Midwest markets, which were traditional markets for Canadian gas.

More recently Ontario and Quebec have sourced natural gas from the US, imported into Ontario via the Dawn Hub, and also through the Niagara and Waddington border points. Imports of gas from the US are replacing gas delivered via the long-haul TransCanada Mainline system which, according to local sources is using only 50% of its capacity in some sub-systems. According to Union Gas[47], the current market differential is approximately $0.45/MMBtu and the 4-5 year outlook should reach US$ 0.50/MMBtu whereas the firm transportation tolls between WCSB and Ontario range from US$ 1.35-1.54/MMBtu, therefore WCSB supply is not attractive for Ontario consumers who can source US supply more cheaply.

The following developments will increase gas flows from Marcellus/Utica shale to the US-Canada border[48]:

a. Pipeline National Fuel Empries (0.034 bcfd)
b. Iroquois Pipeline ( 0.11 bcfd)
c. Atlantic Bridge Pipeline (0.098-0.585 bcfd)
d. DTE Energy/Spectra (up tp 2 bcfd)
e. National Fuel Gas Supply Pipeline - Northern Access and West Side (0.34 bcfd)

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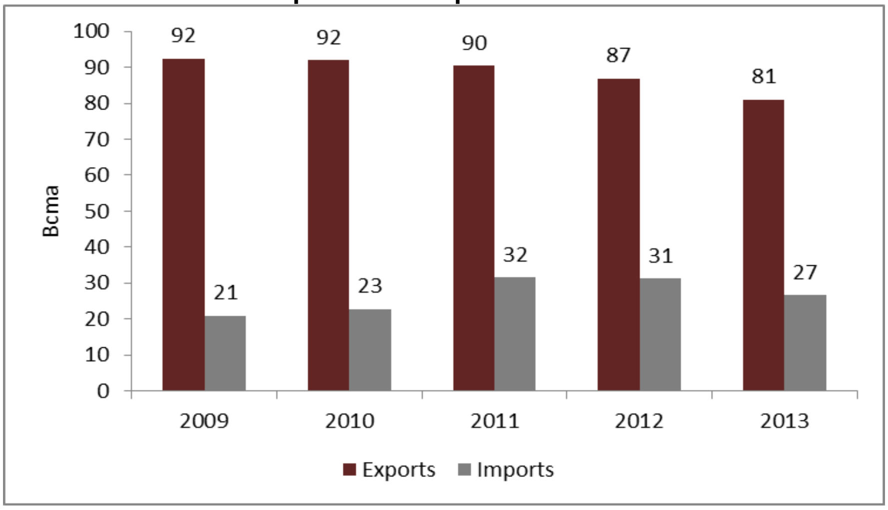
[46] https://www.neb-one.gc.ca/nrg/index-eng.html

[47] https://www.uniongas.com/~/media/aboutus/regulatory/regulatory-projects/eb-2014-0261-dawn-parkway-expansion-project/UNION_EVD_Dawn%20to%20Parkway_20140930.pdf

[48] http://www.eia.gov/todayinenergy/detail.cfm?id=18391

Imports and Exports Figure 24 below highlights the nearly 20% drop in natural gas exports to the US in the period 2010-2014 as well as a relatively stable importing profile.

**Figure 24: Canadian Natural Gas Imports and Exports**

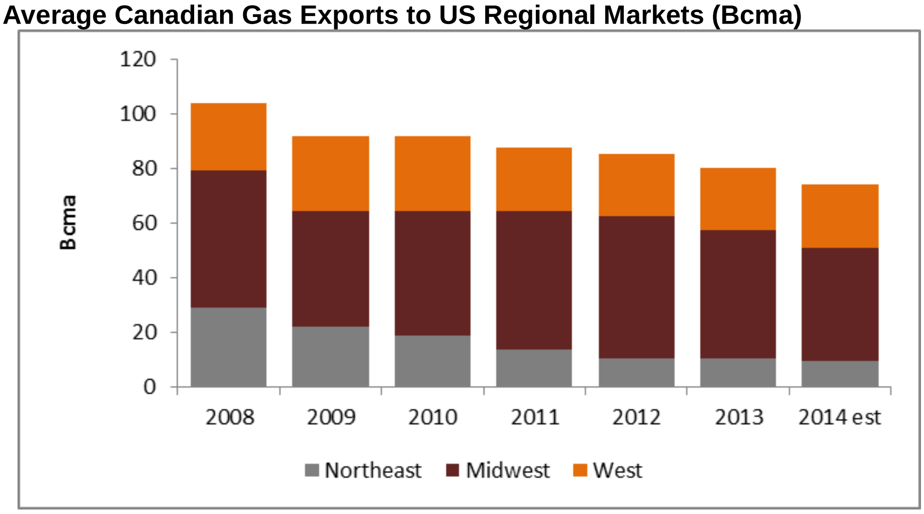



Source: https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ntrlgssmmr/2013/smmry2013-eng.html

The National Energy Board of Canada predicts that exports to the US will be the lowest for almost a decade, with gas predominantly dropping further in US Midwest markets.

The financial impacts on Canada's economy are very significant, with export revenues decreasing from CAD 33 billion (US$ 26.4 billion) in 2008 to CAD 10 billion (US$ 8 billion) in 2013. In absolute terms, the total importation costs did not increase significantly because the larger imported volumes were partially offset by the decrease of the US gas price and the depreciation of the US currency vis-à-vis the Canadian dollar. The trade surplus decreased from CAD 28 billion (US$ 22 billion) in 2008 to CAD 5 billion (US$ 4 billion) in 2013[49].

**Figure 25: Average Canadian Gas Exports to US Regional Markets (Bcma)**



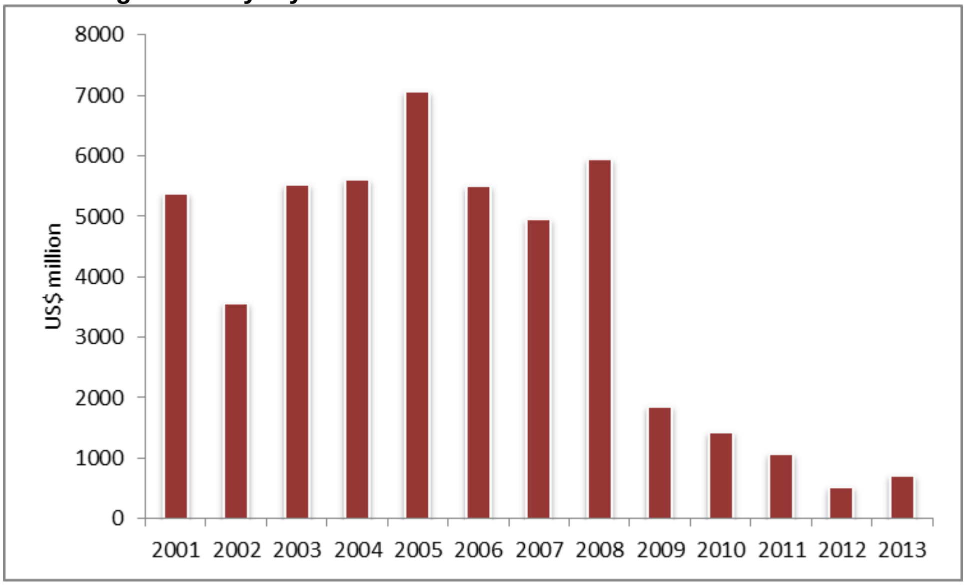

Source: (National Energy Board, 2013b)

The economic impact of lower prices and lower exports is significant in the provinces yearly budget. In the fiscal year 2013 Alberta's royalty revenues dropped nearly 10 fold when compared to the fiscal year 2005/2006. The royalties are set by a sliding scale formula containing separate elements that

[49] Canadian Gas Association (2015a)

account for price and well production. The current royalty rate for natural gas ranges from 5 – 36%. Royalty rates are reduced when prices and well volumes are lower; for example, the royalties for 600 MMcf/d will fall from 33% at gas reference prices of US$ 4.2/MMBtu (CAD 5/GJ) to 23% for gas prices of US$ 2.52/MMBtu (CAD 3/GJ)[50].

**Figure 26: Natural gas net royalty revenues - Alberta**




Source: http://www.energy.alberta.ca/About_Us/1704.asp

The lack of large scale domestic market alternatives to compensate for the loss of US and East Coast markets led to the development of LNG export schemes, a few of them originally expected to start operations in 2017; all of them have been postponed due to market and price conditions.

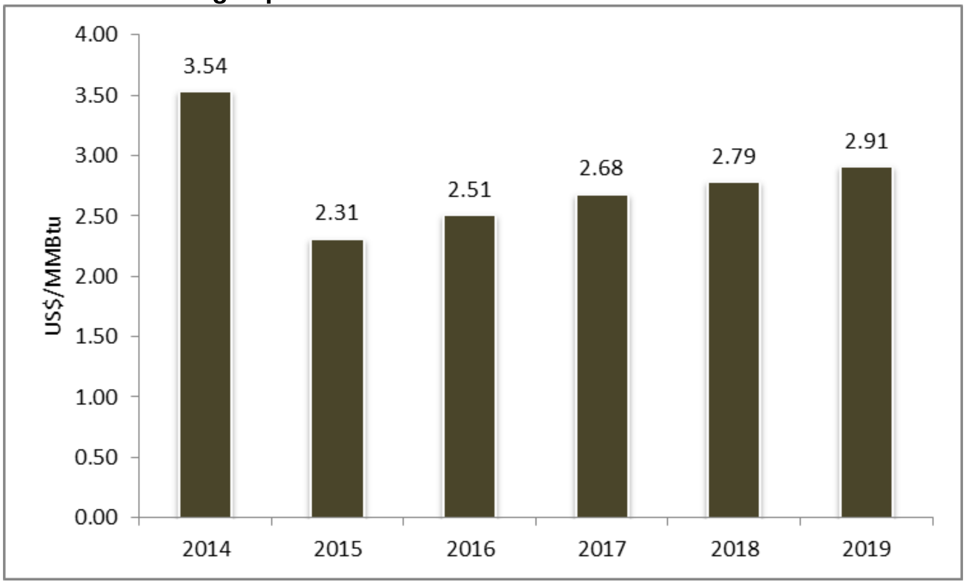
## 11. Gas Prices

Natural gas supply (commodity) prices in Canada are not regulated and are determined by supply and demand forces. Pipeline transmission and distribution rates are regulated, with rates based on the cost of providing services. The National Energy Board regulates transportation rates whereas the provincial authorities regulate distribution rates. The key pricing points in Canada are the intra-Alberta market (AECO “C”), and the Dawn, Ontario market hubs.

AECO prices are predicted to fall to US$ 2.31/MMBtu in 2015, gaining slight momentum at the end of the decade, rising to US$ 2.91/MMBtu by 2019.

[50] http://www.energy.alberta.ca/Org/pdfs/ARFNaturalGasGraphs.pdf

**Figure 27: Alberta natural gas price forecast**




Source: Adapted by author from http://www.gasalberta.com/pricing-market.htm

Figure 28 shows the price differential between Dawn, AECO, HH and Dominion South[51]. The price points for Dominion South were estimated by the author from a report produced by the US EIA.[52]

Natural gas prices continued to drop in Q3 and Q4 2014 when compared to Q2 2014 due to moderate summer weather in parts of North America and record US shale gas production. The slight price differential between AECO and Dawn and the substantial drop in Dominion South Hub price as more gas is produced in the area should be noted.

Canadian gas has been typically US$0.30/MMBtu cheaper than US gas in winter and US$ 0.50/MMBtu cheaper in summer. In 4Q2014 the discount rose to US$ 0.6/MMBtu and it may reach US$ 0.90/MMBtu by the end of 2015 in the futures market as of April 2015. In 3Q2013, shale gas from Marcellus was priced at a US$1.1/MMBtu premium above AECO, and in April 2015 it was trading at a discount of US$ 0.60 - 1.5/MMBtu.[53]

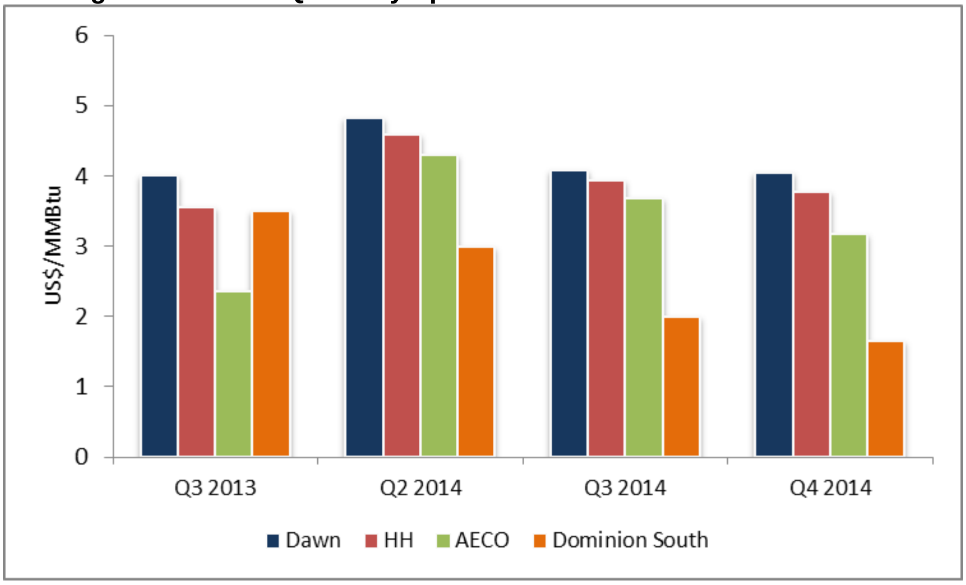
It can be noted that the price difference between AECO and Dawn in 4Q2014 was only US$ 0.86/MMBtu, substantially lower than the interim toll fee approved by the NEB as of January 2015 (approximately US$ 1.53/MMBtu), whereas the Dominion South hub price continued to fall, indicating a surplus of gas in the Marcellus area. The price differential indicates that gas flowing from Marcellus to Canada is cheaper to Ontario consumers than gas flowing from Alberta.

[51] Ontario Energy Report (2014)

[52] Ford (2014); Dominion South price point refers to the last week of December 2014.

[53] http://www.eia.gov/naturalgas/weekly/

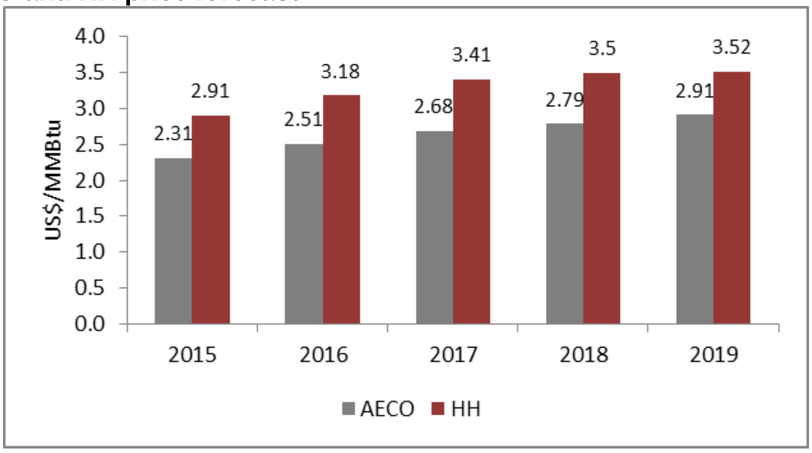
**Figure 28: Average Natural Gas Quarterly Spot Prices in US and Canada**




Source: Ontario Energy Report (2014)

In March 2015 the average AECO for Alberta deliveries was US$ 2.19/MMBtu, compared with HH at US$ 2.75/MMBtu. Going forward, the price differential between AECO and Henry Hub is expected to range from US$ 0.60-0.70/MMBtu in the period 2015-2019.

**Figure 29: AECO and HH price forecast**




Source: Adapted from http://www.gasalberta.com/pricing-market.htm

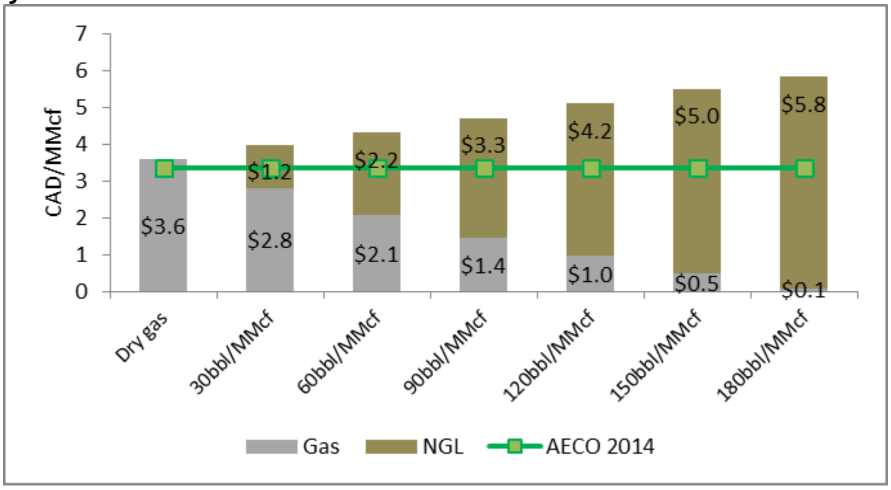
## 12. Natural gas prices and liquid content

Under a constrained gas price scenario, the economics of producing unconventional natural gas are very dependent on the liquids content.

In 2014, the Canadian Energy Research Institute conducted an economic analysis of the breakeven price of producing unconventional dry gas at different NGLs content. The analysis showed that the breakeven price for dry gas was CAD 3.6/MMcf (US$ 3.04/MMBtu) at 2014 prices, whereas for an NGL content of 180 bbl/MMcf, the breakeven for producing dry gas was only CAD 0.1/MMcf (US$

0.08/MMBtu). In 2014 AECO averaged CAD 4.19/MMcf (US$ 3.54/MMBtu), which was barely enough to support dry unconventional production on a standalone basis in Canada. The same author points out that certain areas of the Montney play have a liquid content in excess of 200 bbl/MMcf, which is more than enough to withstand a prolonged period of lower gas prices.

**Figure 30: Dry Gas and NGL Breakeven Prices**



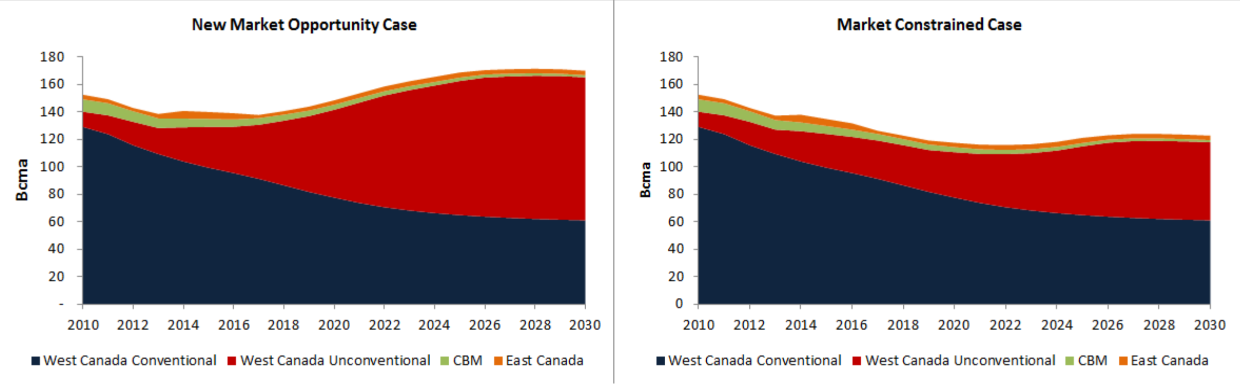

Source: Murillo C. (2014b)

## 13. Export Scenarios and Gas Price Sensitivities

The Canadian Association of Petroleum Producers (CAPP) prepared a study considering two market scenarios for natural gas in Canada, Scenario 1, consisting of a market constrained case and Scenario 2, a new market opportunity case. The most significant difference between the two cases is that Scenario 2 assumes that five 5 mtpa (0.7 bcfd each) LNG export trains will be in-service on Canada's west coast by 2023, totalling 25 mtpa of export capacity and requiring a total of 36.5 Bcma (3.5 bcfd) of natural gas.

Under Scenario 1 there are no LNG exports. WCSB production continues to decline throughout the current decade and remains below 125 Bcma (12 bcfd) until 2030. Under Scenario 2, natural gas production starts to grow post 2018 when LNG export facilities start to be commissioned, then production rises to 167 Bcma (16 bcfd) by 2030. Under Scenario 2, the bulk of the production growth, circa 80 Bcma, should come from West Canada unconventional gas.

**Figure 31: Natural gas production forecast in Canada under two market scenarios**




Source: Canadian Association of Petroleum Producers (2014b)

The National Energy Board also produced a detailed medium term Canadian natural gas deliverability study, based upon the expected level of production for each gas basin, under three price scenarios for domestic natural gas[54].

**Table 3: Price Scenarios for 2014-2016 Natural Gas Marketable Production**

| AECO (US$/MMBTU) | **2013** | **2014** | **2015** | **2016** |
|---|---|---|---|---|
| Mid-Price | 2.39 | 3.43 | 3.62 | 3.82 |
| Higher Price | 2.42 | 3.42 | 3.94 | 4.70 |
| Lower Price | 2.42 | 2.77 | 2.40 | 2.69 |
| Henry Hub ($/MMBtu) | **2013** | **2014** | **2015** | **2016** |
| Mid-Price | 3.73 | 4.15 | 4.25 | 4.35 |
| Higher Price | 3.73 | 4.75 | 5.25 | 6 |
| Lower Price | 3.73 | 4 | 3.5 | 3.75 |

Source: (National Energy Board (2014b)

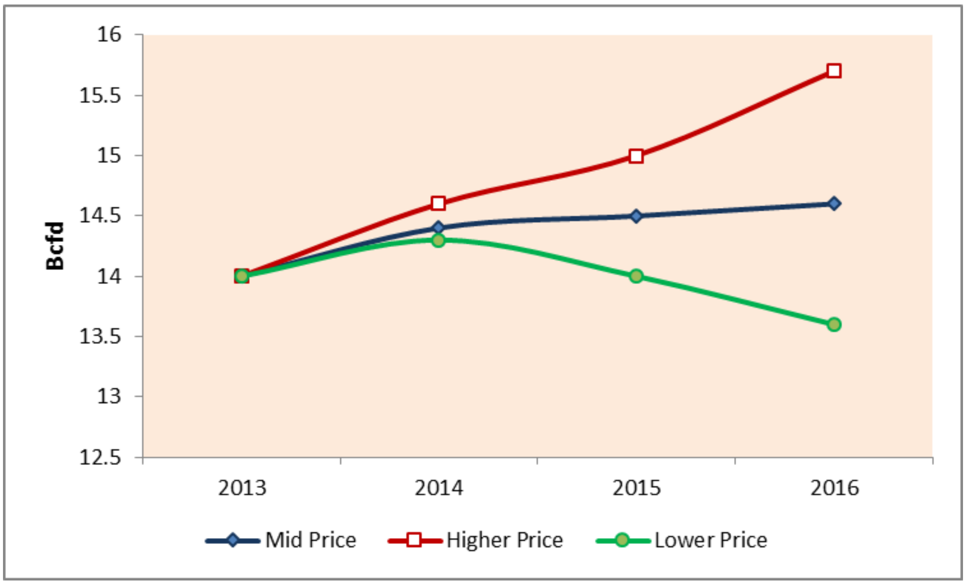
Mid-Range Price Case: moderate growth in Canada and US natural gas demand, and slowing US supply growth, gradually reducing excess deliverability in Canadian and US natural gas markets with a steady rise in natural gas prices which would boost drilling in Western Canada.

- Higher Price Case: predicts some market recovery for Canadian natural gas due to stronger economic growth and less displacement of Canadian gas by US gas supplies, with power generators preferring to use natural gas instead of coal in specific markets to meet stricter environmental regulations. The rise in natural prices gas leads to increased activity both in liquids-rich plays, as well as in dry gas.
- Lower Price Case: slow growth in markets for Canadian natural gas due to mild weather conditions and natural gas storage recovery, modest economic growth and continuous displacement by supplies of US natural gas. Canadian natural gas deliverability would continue to be sufficient to meet market requirements albeit with lower gas drilling activity.

The study estimated that natural gas production would increase from 144 Bcma in 2013 to 151 Bcma in 2016, in the Mid-Range Price Case. Under the Higher Price natural gas marketable production would increase to 163 Bcma (15.7 Bcf/d) in 2016. Under the Lower Price Case, natural gas production is expected to decline to 140 Bcma (13.6 Bcf/d) in 2016.

[54] National Energy Board (2014b)

**Figure 32: Natural Gas Marketable Production vs Price Scenarios**

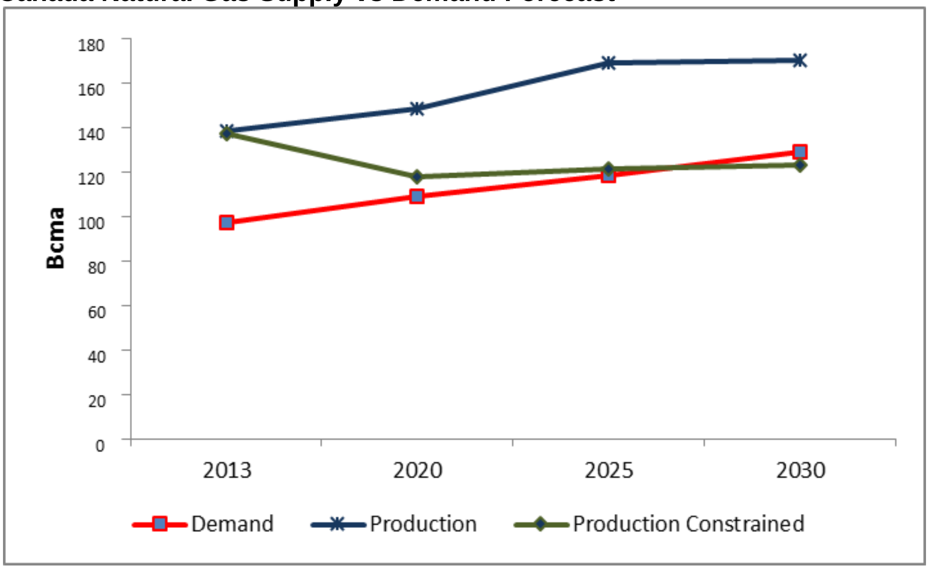



Source: (National Energy Board, 2014b)

In conclusion, the current medium term price forecast of US$ 2.51/MMBtu for 2016 (Figure 27 above) is indicative of a Lower Price Case scenario, with production slated to decline unless there is a significant boost from LNG exports.

After combining NEB's demand forecast (minus the projected demand from LNG plants) with CAPP's and NEB's production scenarios (Figure 31) an exportable surplus of 40-50 Bcma should exist throughout 2030, which could be sufficient to produce 27-34 mtpa of LNG, after discounting the gas volumes used in the LNG production process (around 9%). Under a market constrained scenario, without LNG exports, the domestic production will decline until it equals domestic demand by 2025.

**Figure 33: Canada Natural Gas Supply vs Demand Forecast**




Source: Author adaptation of (NEB 2014b) Canadian Association of Petroleum Producers (2014b)

## 14. LNG exports: a key monetisation option for Canada's natural gas

The key driving factors for the construction of LNG export capacity in Canada are the large resource base located in the western region; the need for Canadian producers to increase their market diversification due to plateau domestic demand and the loss of the US export market; and the relative proximity to Asian markets, which traditionally pay premium prices for LNG (Japan and China are respectively 8-11 sail days away). The proposed LNG export facilities represent large increments to natural gas demand, but involve long lead times, 5-8 years, to obtain approvals, establish overseas markets and build facilities.

A significant number of international and national oil companies have been positioning in Western Canada to develop either integrated LNG projects, by acquiring upstream resources which will feed their proposed LNG facilities, or independent projects which can tap the large undeveloped unconventional gas resources in British Columbia and Alberta.

### Foreign Oil Companies' acquisition of Canada gas resources

In the last four years there has been increasing interest from foreign oil companies to invest in upstream resources in Canada. The vast resource basis, a stable democratic regime, the possibility of developing integrated upstream to LNG projects, the proximity to Asian markets and gas prices discounted to Henry Hub were attractive factors for new investors. In addition to major international oil companies such as Shell, Chevron and BG, a few National Oil Companies (NOCs) who are willing to secure gas supplies for their domestic markets or enhance their LNG portfolio have been also investing in unconventional gas plays in Canada.

- In March 2010, EnCana signed an agreement with Korea Gas (Kogas) which bought a 50% interest in acreage in the Horn River Basin and Montney shale gas plays in BC.
- In August 2010, Penn West Energy Trust entered a gas joint venture with Mitsubishi Corp (Japan) to develop properties located in the northeast of British Columbia.
- In June 2011, Progress Energy Resources Corp. announced a deal with Petronas (Malaysia), which is investing US$ 870 million to access shale gas assets in northeastern BC and to develop a portion of Progress' Montney shale assets in the foothills of Northeastern BC.
- In February 2012 EnCana entered into an agreement (the Cutbank Ridge Partnership) with Mitsubishi Corporation which will invest approximately US$ 2.3 billion for a 40% interest in about 409,000 net acres of Encana's undeveloped Montney natural gas lands in northeast British Columbia.
- In February 2012 PetroChina Co. signed binding agreements to buy, for reportedly US$ 800 million, a stake in a Royal Dutch Shell PLC shale gas asset in Groundbirch, northeastern British Columbia.
- In December 2012 EnCana entered into a joint venture arrangement with Phoenix Duvernay Gas (Phoenix), a wholly owned subsidiary of PetroChina, for a non-controlling 49.9% interest in EnCana's approximately 445,000 acres in the Duvernay play for US$ 1.7 billion.
- In February 2013, CNOOC closed the US$ 15 billion acquisition of Nexen. In addition to assets in the US and Africa, Nexen will provide CNOOC with control of Nexen's Long Lake oil sands project in Alberta, and of billions of barrels of oil sands reserves in Alberta.
- In December 2014 Repsol entered into an agreement to acquire 100% of Canadian oil company Talisman Energy worth US$8.3 billion plus a US$ 4.7 billion debt.

According to Bloomberg, the oil and gas acquisition deals involving Canadian companies have exceeded US$ 39 billion in 2014, before the completion of the Talisman acquisition[55]. Since 2007, Chinese state enterprises have bought US$ 94 billion of Canadian oil and gas assets and from 2011 onwards Chinese oil majors have invested US$ 22 billion in energy companies in the province of Alberta. Restrictions imposed by the Government of Canada on acquisitions made by state controlled companies and the drop in oil prices have dampened interest for new acquisitions.

## LNG Export Licenses Applications

In the West Coast, British Columbia (BC) is well positioned to supply LNG because of the large resource basin and the close proximity to the major Asian markets. BC Government's stated objective is to have at least three LNG plants in operation by 2020. In 2013 BC natural gas production was around 34.4 Bcma (3.3 bcfd). Meeting BC's LNG development goals would require 54.3 Bcma (5.2 bcfd), that could come from BC unconventional gas resources, combined with gas from Alberta. In the East Coast, the proposed projects would either receive gas from the US or from smaller upstream developments in the region.

As of March 2015, 25 completed applications to build LNG export facilities have been submitted for the approval of the National Energy Board (NEB), comprising the following proposed projects:

- Two applications for the export of gas to supply proposed LNG projects in the US Northwest Coast (Jordan and Oregon LNG), totalling 29 Bcma (2.85 bcfd) , both approved by the NEB.
- Five applications to build LNG plants in the East Coast of Canada totalling 38.5 mtpa, requiring 56 Bcma (5.4 bcfd), of which two are filing proposals to import gas from the US.
- 19 applications to build LNG facilities in the West Coast of Canada, totalling 280 mtpa and requiring 415 Bcma (40 bcfd) of feedgas. Ten applications have been approved but the NEB revoked the license of one of the projects, the BC LNG Export Cooperative, also known as Douglas Channel LNG, following the dissolution of BC LNG.

In total, these projects are seeking permission to export more than 500 Bcma of natural gas, which is nearly three times Canada's current gas marketed production. A forecast by the National Energy Board estimates that Canadian natural gas production could grow from 136 Bcma (13 bcfd) in 2013 to 182-238 Bcma (base and high cases), but that would be insufficient to feed all the proposed projects[56].

The NEB is satisfied that the gas resource base in Canada in particular, and also in North America, is sufficient to accommodate reasonably foreseeable Canadian demand, plus the LNG exports already authorised.

Based on a view of a subset of projects already approved by the NEB, the projected LNG-related spending in coming years[57] is expected to reach US$ 152-224 billion as summarised below:

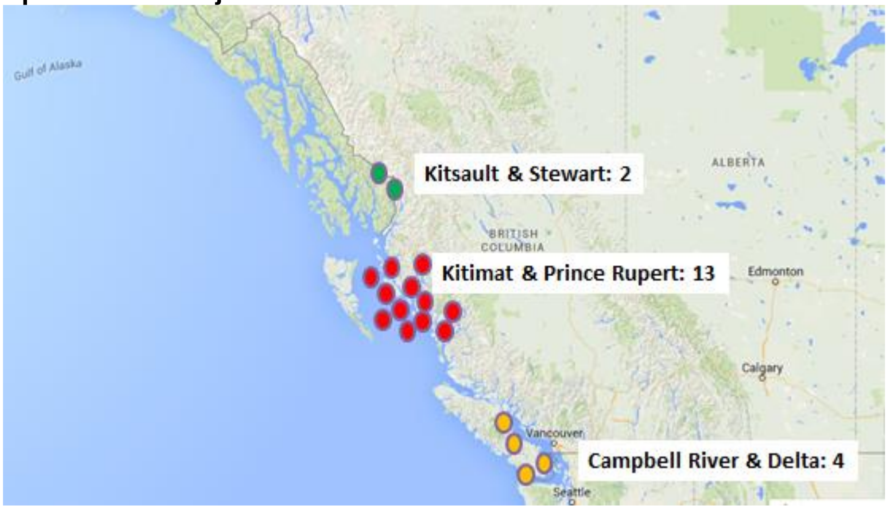
- US$112-160 billion in natural gas drilling programs
- US$24-40 billion for LNG terminals
- US$16-24 billion for pipelines and midstream operations

[55] http://www.bloomberg.com/news/articles/2014-12-08/oil-s-slump-puts-canada-aquistions-streak-on-ice
[56] (NEB, 2013a)
[57] Ernst Young (2014b)

## 15. West Coast LNG Projects

The West Coast proposed LNG projects are located within three main areas across BC: North BC, Kitimat & Prince Rupert area and Campbell River & Delta area (Figure 34). A few LNG projects such as Kitimat, Canada LNG, WCC LNG and PNWLNG have dedicated gas resources, whereas others such as Prince Rupert LNG are not connected to specific upstream developments.

**Figure 34: Proposed LNG Projects in BC**




Source: Adapted from http://engage.gov.bc.ca/lnginbc/lng-projects/

A handful of proposed LNG projects have strong sponsors with LNG experience and have already been granted export licence approval. Only one project, Kitimat LNG, has been granted an environmental permit for the construction of the pipeline connecting the gas resources to the LNG plant, whereas three smaller projects (Triton, Cedar and Wespac) are proposing to utilise existing pipeline infrastructure. None has succeeded in securing LNG supply agreements and are yet to reach final investment decision. A brief description of the main West Coast LNG proposed projects is provided below. Appendix 1 summarises the projects which have filed export license applications with the NEB.

### Kitimat LNG

In December 2012, Chevron Canada Limited and Apache Corporation signed a 50%:50% joint venture agreement to build the Kitimat LNG project. Chevron will operate the LNG facility at Bish Cove near Kitimat, BC, and the 480 km natural gas Pacific Trail Pipeline and will market LNG to customers, while Apache will manage the development and production of natural gas from the Liard and Horn River Basins in Northeast British Columbia.

All major provincial and federal environmental approvals have been granted, including a 2012 NEB export license for two 5mtpa trains of LNG. The proposed Kitimat LNG facility will be built on land leased under a benefit agreement with the Haisla Nation. The project has also signed benefits agreements with all 16 First Nation bands [58]along the right of way for the natural gas Pacific Trail Pipeline. Kitimat LNG has drilled over 50 wells and has already reached 143 MMcfd of gas production[59].

[58] A local form of Aboriginal government in Canada, consisting of an elected chief and councillors

[59] Scotia Bank (2014)

The project's first phase was slated to start in 2017 but this deadline is no longer achievable, as it has not yet signed any LNG supply deals and one of the sponsors, Apache, exited the project in December 2014 and sold its interest to Woodside Petroleum Ltd[60].

Another issue counting against Kitimat LNG is that a host of premium LNG buyers are involved in competing projects in Canada. Korean, Chinese and Japanese firms have signed on to LNG Canada, led by Shell, whose location is near Kitimat whereas Petronas is leading the Pacific Northwest LNG (PNWLNG) near Prince Rupert in BC. Premium Asian LNG buyers have also signed LNG supply deals with US based projects.

In January 2015 Chevron announced that it was significantly slowing spending on the Kitimat LNG project due to the drop in crude prices and global competition. Chevron CEO John Watson said on a conference call that "it's not clear all the new projects being considered can be profitable at lower prices"[61]. The company is cutting spending on LNG worldwide by 20% in 2015 to $8 billion and does not plan to make final decisions on projects this year, other than for its Tengiz field in Kazakhstan, Watson said.

## LNG Canada

The project is a joint venture of Shell, Korea Gas Corporation (KOGAS), Mitsubishi Corporation and PetroChina. The JV is proposing to build and operate a LNG export terminal in the area of Kitimat, BC, consisting initially of two LNG trains of 6 mtpa each with an option to expand in the future. The project has dedicated gas resources and by September 2014 had drilled over 325 wells with a production of 480 MMcfd.

LNG Canada has selected TransCanada Corporation to design, build, own and operate a 700 km, US$ 3.8 billion pipeline (Coastal GasLink) to connect natural gas from northern BC and the WCSB to the LNG plant. The pipeline is yet to be granted environmental approval.

LNG Canada has been awarded an export licence from the NEB authorising the export of up to 24 mtpa of LNG for 25 years. The project sponsors have provided a wide range of US$20 - $32 billion for construction costs due to uncertainties about various project components.

Industry analysts expect that LNG Canada will make a final investment decision in 2016, which would clear the way for five years of construction and the first phase opening in 2021.

Due to its unique sponsorship by premium Asian buyers, Canada LNG is considered by industry analysts as one of the projects which is likely to be built in the medium term.

## Pacific Northwest LNG (PNWLNG)

PNWLNG is a JV of Petronas (62%), Sinopec (15%), Japex (10%), Indian Oil (10%), and Petro Brunei (3%). It consists of an LNG export facility located on Lelu Island in the District of Port Edward located near Prince Rupert. Initially the project will include two trains of 6 mtpa each, with the possibility to add a third train in the future.

In December 2013 PNWLNG received a 28.6 Bcma (2.74 bcfd) export licence from the NEB. A final investment decision for the project was expected in late 2014 with first LNG exports slated to start in 2018. TransCanada has been selected to design, build, own and operate the proposed $5 billion Prince Rupert Gas Transmission pipeline transporting natural gas primarily from the North Montney (BC) to the LNG plant. The pipeline has not yet received environmental approval.

Petronas' upstream company, Progress, has drilled over 500 wells and has 610 MMcfd of production, with a potential to produce in excess of 700 MMcfd. According to Scotia Bank, the project was

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[60] http://investor.apachecorp.com/releasedetail.cfm?ReleaseID=887611

[61] http://www.vancouversun.com/business/energy/Chevron+puts+brakes+Kitimat+project/10774777/story.html?__lsa=96ef-699b

targeting to book 15 Tcf of 2P reserves by the end 2014, which would be almost enough to fill two LNG trains of 6 mtpa each.

In December 2014 Petronas announced that it was deferring FID on the LNG project. Petronas said that it was necessary to gain more clarity on policies including a "competitive" tax, greenhouse-gas emissions targets for LNG and agreements with aboriginal groups. Petronas also mentioned the need to reduce project costs from the current estimate of US$ 35 billion and its intent to reduce its interest in the project to 50%. The latest announced date for FID is June 2015.62

## BC LNG (Douglas Channel)

This is a small sized LNG project, sponsored by LNG Partners, a Houston-based private equity company and HNLP, a limited partnership established for the benefit of the Haisla First Nation. The project consists of two modules of 0.125 bcfd of feed gas to produce 0.55 mtpa of LNG in a barge-based facility. The sponsors originally announced their intent to have the project commissioned in 2014.

An export licence was granted by the NEB and revoked in early 2015, following the change in ownership control. A consortium formed by Calgary-based midstream and energy firm Altagas, Idemitsu (Japan), EDF (France) and EXMAR (Belgium) has taken possession of the LNG project[63] through a plan of arrangement that ends a Companies' Creditors Arrangement Act process.

The consortium signed long-term land and water lot leases with the Haisla Nation. AltaGas owns Pacific Northern Gas Ltd., a pipeline that would be used to connect the project on the West Coast with natural gas producers. The consortium announced its intent to have the plant operating by 2018 but so far they have not secured buyers or taken a final investment decision.

Altagas is also involved in a larger scale LNG project, Triton LNG, which has not received environmental approval.

## Prince Rupert LNG

Prince Rupert LNG is owned by BG Group, which proposed to build an LNG export facility on Ridley Island, BC. The first phase of the project consists of two trains of 7 mtpa each with a third train slated for a second phase of the project. Prince Rupert LNG received an export licence for 2.91 bcfd from the NEB in December 2013 (phases 1 and 2).

BG announced a joint venture with Spectra Energy to build a 850 km pipeline extension from Northeast BC to Ridley Island near Prince Rupert, BC. The project has no upstream reserves, in contrast to to Shell, Petronas and Chevron led projects.

On 29 October 2014 BG Group announced that it was postponing the project, on the grounds of shifting market conditions[64]. A final investment decision will be delayed to 2017 at the earliest, which means that the project will not be commissioned before 2022. The recently announced acquisition of BG by Shell may result in the cancellation of Prince Rupert LNG.

## WCC LNG

The project is owned by Exxon and Imperial Oil and its proposed location is in Tuck Inlet, north of Prince Rupert. The project is planned in two phases, and once completed would produce 30 mtpa of LNG. The consortium has already drilled over 115 wells and has 81 MMcfd of production. The sponsors' plans do not include building a pipeline, as they might use two pipelines (Prince Rupert Transmission project and the West Coast Connector) which have been already approved by BC government.

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[62] http://business.financialpost.com/news/energy/petronas-to-decide-on-canadian-lng-project-by-june?__lsa=b11a-376b
[63] http://calgaryherald.com/business/energy/douglas-channel-lng-project-taken-over-by-consortium
[64] http://bc.ctvnews.ca/bg-group-pressing-pause-button-on-prince-rupert-lng-plans-1.2078098

## Woodfibre LNG

Woodfibre LNG is owned by Woodfibre Natural Gas out of Vancouver, BC. It is proposing a smaller scale 2.1 mtpa project in Squamish, BC. The project received an export licence for 0.27 bcfd from the NEB in December 2013. Woodfibre has stated that it will be supplied via an expansion of an existing FortisBC natural gas pipeline.

# 16. East Coast LNG Projects

The main LNG export projects being proposed in the East Coast are summarised below and depicted on Figure 35. The East Coast projects primarily aim at supplying European, South American and Asian markets. All proposed projects are in an early development stage and none has been granted export licenses by the NEB. These projects are further disadvantaged when compared to West Coast projects due to the following issues:

1. Longer distance to premium Asian markets,
2. Lower LNG prices in the more proximate markets of Europe when compared to Asian markets,
3. Cost-base disadvantaged to Atlantic basin markets compared with US Gulf Coast brownfield projects,
4. Unpredictability of the demand in South America, coupled to buyers' credit rate issues in Argentina and Brazil,
5. Higher transportation fees if gas feed is sourced from the WCSB.

**Figure 35: Proposed East Coast LNG Projects**


Source: http://interfaxenergy.com/gasdaily/article/14186/eastern-canada-lng-projects-look-to-marcellus

## St John LNG (former Canaport LNG Regasification)

The Canada incorporated Saint John LNG Development Company Ltd is proposing to convert the existing Canaport LNG regasification facility located in St. John, New Brunswick, into a 5 mtpa LNG export project and to import natural gas from the US. The primary point of import of natural gas into Canada will be the crossing point of the Maritimes & Northeast Pipeline on the Canada-United States border in New Brunswick.

## Goldboro LNG

The project is owned by Pieridae Energy Ltd, which plans to build an LNG facility in Nova Scotia. The proposed 10 mtpa facility will be fed via the existing Maritimes & Northeast Pipeline and is planning to import 10.4 Bcma (1 bcfd) from the US to feed the LNG plant. The project is targeting markets in Europe, South America and Asia and its application to import natural gas and export LNG for 20 years is under review by the NEB.

## GNL Quebec Inc. (Energie Saguenay LNG)

GNL Quebec is being developed by the US Ruby River Capital LLC, which is owned by private equity funds and will be located at the deep-water port of Grand-Anse in La Baie, Quebec. The project is seeking authorisation to export 11 mtpa of LNG for 25 years with gas primarily sourced from WCSB supplies, which raises a question mark regarding the pricing competitiveness of the gas feedstock. The project also relies on the construction of a new 650 Km pipeline linking into the eastern portion of the TransCanada PipeLines Limited Eastern Triangle near Iroquois, Ontario. The export application is currently under review by the NEB. According to Pierre-Olivier Pineau, an energy specialist at Montreal's HEC business school, "this is a very ambitious project but there are supply challenges to resolve, it's difficult to think it will see the light of day".

## Bear Head LNG Corp. (Bear Head)

Bear Head LNG is a proposed 4 mtpa LNG export facility located in Nova Scotia. It was initially developed as an LNG import facility and sold to Anadarko in 2004, which completed site work and the LNG storage tank foundations on the site. Anadarko subsequently sold the project to Liquefied Natural Gas Limited (LNGL) in 2014. The project is expected to be fed via the Maritimes & Northeast Pipeline, owned by Spectra Energy Partners, which connects Nova Scotia to Atlantic Canada and the Northeastern United States.

The export license application is under review by the NEB

# 17. Pipelines to LNG plants

The majority of the proposed LNG projects in the West and East Coast depend on the construction of long distance pipelines crossing ancestral land belonging to native inhabitants (First Nations) which are subject to a lengthy and multi-layered environmental permitting process. Some projects such as Prince Rupert LNG and PNWLNG have arranged for separate and nearly parallel pipelines, which could be more efficiently developed as a single pipeline. The same is true of Kitimat LNG and LNG Canada. The timing and permitting of these supply pipelines is a critical path for the implementation of projects such as Kitimat, LNG Canada, PNWLNG and Prince Rupert LNG.

## Kitimat area

- Pacific Northern Gas Transmission Pipeline Expansion: Pacific Northern Gas Limited proposes to expand the existing Pacific Northern Gas Transmission Pipeline from Summit Lake to Kitimat, approximately 525 kilometres, to serve multiple proposed LNG projects, including proposed small LNG plants.
- The Pacific Trail Pipeline is a proposed 480-kilometre natural gas pipeline that would deliver gas from Summit Lake, B.C. to the Kitimat LNG facility site at Bish Cove on the northwest coast of British Columbia. Environmental Assessment Certificate issued by BC EAO on 2008/6/26. Certificate Extension Order issued on 2013/6/20.
- Coastal GasLink Pipeline is a wholly-owned subsidiary of TransCanada Pipelines Ltd, which is proposing to develop a 670 km natural gas pipeline from northeast B.C. to the west coast of B.C.

to serve export markets. Environmental Assessment Certificate issued by BC EAO on 2014/10/24.

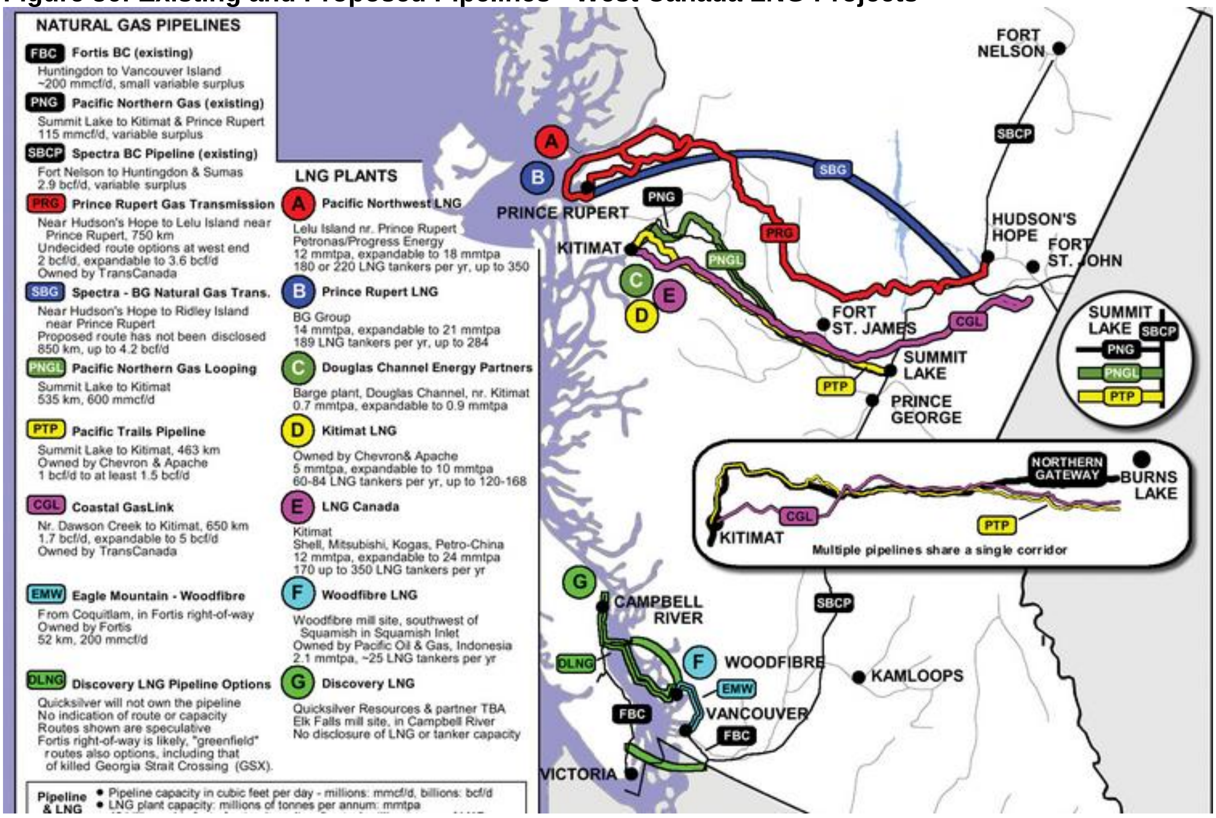
## Rupert area

- Prince Rupert Gas Transmission: TransCanada Corporation has been selected by Pacific NorthWest LNG to design, build, own and operate an approximately 900-kilometre pipeline to deliver natural gas from the Fort St. John area of B.C. to the proposed Pacific Northwest LNG export facility at Port Edward, near Prince Rupert. B.C. Environmental Assessment Certificate issued by BC EAO on 2014/11/25.
- Westcoast Connector Gas Transmission: Spectra Energy Corporation has been selected by BG Group to build a new 850 km natural gas transportation system from northeast B.C. to Prince Rupert to serve the proposed Prince Rupert LNG facility and export terminal. Environmental Assessment Certificate issued by BC EAO on 2014/11/25.

## Squamish area

- Eagle Mountain – Woodfibre Gas Pipeline: FortisBC is proposing to construct and operate a 52 km natural gas pipeline loop off its existing transmission pipeline. The loop would service the proposed Woodfibre LNG facility, running from north of the Coquitlam Watershed in Metro Vancouver to Squamish, B.C. The project is under review.

**Figure 36: Existing and Proposed Pipelines - West Canada LNG Projects**




Source: http://www.watershedsentinel.ca/files/documents/BC-outline-LNG-pipelinesRGB.jpg

## 18. Markets for Canadian LNG

Over 60 LNG projects in excess of 650 mtpa are competing for the market window between 2020 and 2025. Canada has the largest aggregate proposed export capacity when compared to other key countries with large LNG potential: the proposed export capacity in the US is 282 mtpa of which only 30 mtpa has received FID, whereas in Australia the LNG total (including proposed projects) is 140 mtpa of which 24 mtpa is currently operating and 62 mtpa is under construction. This compares to more than 318 mtpa proposed in Canada.

In order to assess how Canadian LNG projects would fit the medium/long term world market dynamics for LNG, the author has produced a supply vs demand analysis for the window 2020-2025, which takes into account a comprehensive list of LNG projects, their development status as of mid-2014 as well as high and low case demand forecasts. LNG demand forecasts are based on the author's assumptions and use sources such as IEA, the Clingendael Energy Institute, Platts and BP[65].

The low case demand scenario predicts a 350 mtpa world LNG demand by 2020 rising to 440 mtpa by 2025, whereas the high case scenario predicts a demand of 400 mtpa by 2020 and 500 mtpa by 2025.

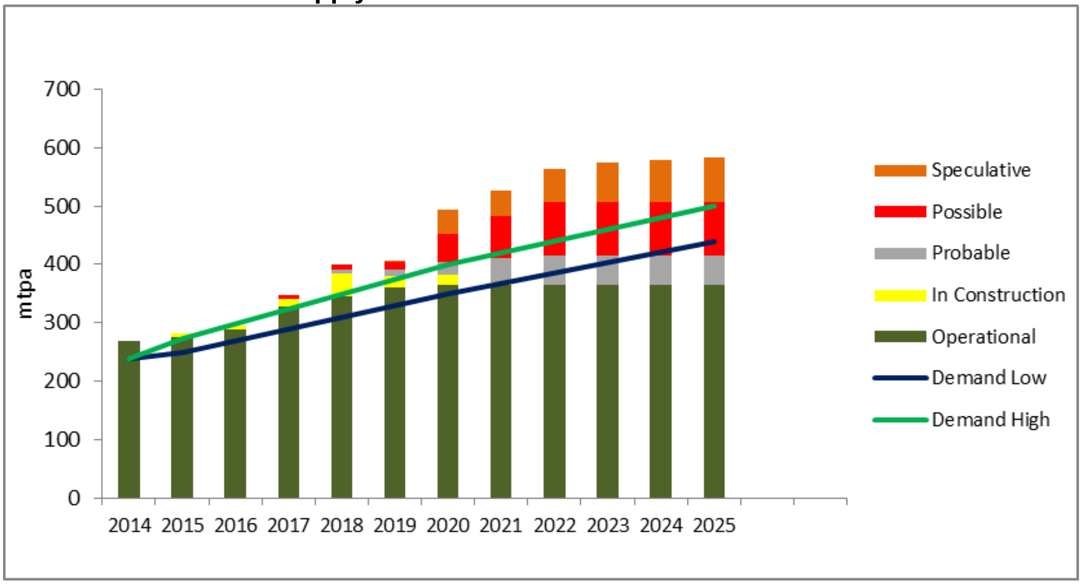
The Probable list includes projects in advanced stages of development, some of them with FID and supply agreements already in place, totalling 55.5 mtpa. The list of possible projects totals 100 mtpa and includes three Canadian projects, Canada LNG, PNWLNG and a smaller LNG scheme such as Douglas Channel or Cedar LNG. The list of Speculative projects totals 52.7 mtpa and includes Kitimat LNG.

Under the low case demand scenario there is no LNG shortfall against operational projects until 2020, and there is no space for any Canadian LNG project before 2024-2025. Under the high case demand scenario there is space for 1 Canadian LNG project after 2022 (Figure 37). The supply forecast assumes 90% of capacity utilisation and doesn't take into account the retirement of older LNG facilities in Indonesia and in the Middle East.

Supply estimates do not include proposed projects in the US, Canada and elsewhere which are in the very early stages of development and have not yet received export approval.

[65] IEA (2014), Roberts (2014), BP (2015), Diaz (2014)

**Figure 37: Worldwide LNG Supply and Demand Forecast**




Source: GIIGNL (2015) & Author estimates based on public and projects data

Market analysts believe that in a best-case scenario 50-55 mtpa of Canadian LNG capacity could be online after 2020 and the projects with best chance of success are PNWLNG and LNG Canada[66] because both projects are advanced from a regulatory perspective, have established a supporting resource base, and have successfully brought on equity.

The reality is less optimistic because these projects have not yet secured approval for the construction of the connecting pipelines and the leading sponsors are cutting back on investment in the wake of the drop in oil prices. If an investment decision is taken in 2016, it is unlikely that these projects will be commissioned before 2021.

US energy economist Kenneth Medlock recently expressed his views at the 2015 Canadian Energy Research Institute's annual conference on natural gas. The conference was called “LNG: Canada's Last Window of Opportunity”. According to Medlock, "We don't see any LNG exports from Canada until almost 2040", which is a very pessimistic view of the market, but indeed it looks unlikely that Canadian LNG will reach international markets before 2025[67]. According to Medlock almost all new LNG supply will come from the United States or Australia.

[66] And, perhaps, 1-2 smaller LNG projects.

[67] Kenneth Medlock/Baker Institute for Energy Studies (Rice University ), http://www.cbc.ca/m/touch/news/story/1.2978953

## 19. Key issues and barriers for the implementation of LNG projects in Canada

Table 4 below summarizes the main strengths and weaknesses of the Canadian LNG projects.

**Table 4: Canada LNG Projects Weaknesses and Strengths**

| Strengths | Weaknesses |
|---|---|
| • Lower gas price basis when compared to new emerging players<br>• Shorter distance to Asia markets when compared to US and East Africa - BC to Asia is only 9-10 days vs. 20-plus days for USGC LNG<br>• Projects led by global players (operators, customers)<br>• Regulatory and market support for exports<br>• Players hold equity interests in gas for most large projects<br>• Stable legal and fiscal business environment | • Greenfield projects - higher CAPEX when compared to US brownfield projects<br>• Cost pressures (project construction, skills shortage)<br>• Additional infrastructure required (pipelines)<br>• Late entrant when compared to US and Australia particularly vis-à-vis the recent evolution of oil prices<br>• Evolving pricing arrangements<br>• Complex First Nations dynamics<br>• Continuing fiscal uncertainty<br>• Complex permitting framework (federal, provincial) |

Source: Author, from public data

Despite a massive and low cost resource base and the advantaged location to supply premium Asian markets, the implementation of LNG projects faces a host of challenges which have slowed down the pace of all projects. In addition the recent drop in oil prices has created an additional layer of uncertainties, forcing project developers to re-assess their project portfolio, cut CAPEX expenditures on a worldwide basis and postpone financial investment decisions for LNG projects.

### Costs, price structure and competition with US and Australian projects

A key challenge for Canada LNG projects is the greenfield nature of all projects with cost disadvantages when compared to the first generation of US brownfield projects. Whilst the latter typically charge fixed liquefaction fees of US$ 3.0-3.5/MMBtu plus fuel costs of 15%-25% of Henry Hub basis price, a greenfield project would need US$ 4.8- 5.3/MMBtu to return 10-12% on CAPEX costs of US$ 1,350-1,400/tonne of LNG. Although British Columbia is endowed with large unconventional gas resources, the gas producing areas are far from the LNG export sites. This will require the construction of long haul pipelines, which will add another US$ 1.5-2.5/MMBtu to the project costs.

Due to expected higher CAPEX the Canadian projects would need to sell LNG on an oil indexed basis[68], which compared unfavourably with cost-plus projects with a hub price component such as the brownfield projects in the US, particularly at a time when Asian buyers are trying to get away from expensive LNG contracts. As a result, despite years in development, no Canadian LNG project has so far secured any long term supply agreement with Asian buyers.

Canadian LNG projects also face competition with the next generation of new and brownfield Australian LNG projects which enjoy lower or similar freight costs to Asian markets when compared

[68] In this context we infer that in the view of the sellers 'oil indexed' generally equates to higher prices. For a discussion on Asian LNG market price evolution see Rogers and Stern (2014).

with Canada's, which erodes Canada main selling point. Chapter 20 of this paper will provide a price comparison between Canadian and other LNG export projects.

Other key issues impacting the development of Canadian LNG projects are detailed below.

## Labour market

The development and construction of at least 3-5 LNG and pipeline projects in parallel on the West Coast of Canada will require, at peak, a workforce of 15,000-22,000 workers, some of them highly skilled. Canada is already facing shortages in the oil and gas labour market, in particular engineers, construction foremen, and welders, with companies offering wages 60% above the US market to lure skilled workers. Canada also has limited specialised LNG skill sets.

This is a cause of concern for the project developers, which fear that labour costs may get out of control, as happened in Australia. A PwC survey with Canadian industry leaders revealed that Canada's small labour force is the second biggest issue of concern for the development of energy projects in the country[69].

To address these issues the Government of British Columbia devised a series of programmes aiming at the development of a comprehensive human resource strategy focusing on four industries, including the oil and gas sector. The provincial government created a LNG-labour working group that included 18 representatives from government, labour unions, LNG industry players and the Haisla Nation. The group produced 15 recommendations regarding apprenticeship, training and other challenges in growing the LNG industry.

The Province created the Labour Market Partnerships program, to provide a wide array of training in support of the sector in complement to several labour market programs.

The BC Government is also taking the following initiatives to try to address the labour issue:

- Assessing Canada's economic immigration programs to determine how it can contribute to long-term labour plans.
- Examining how the new Express Entry application management system increases access to Canada's economic immigration programs to help the LNG sector gain access to skilled talent through the system.
- Discussing recent "putting Canadians first" changes to the Temporary Foreign Worker Program and International Mobility Program to provide the LNG industry with clarity on its recruitment options.
- Analysing foreign credentials recognition and Canadian standards with a focus on different skills required for operations vs. construction and opportunities for immigrants to obtain additional training required to bring them up to Canadian standards.

## Regulatory Challenges

The permitting process for the construction of LNG projects in Canada is complex, expensive and involves the need to obtain numerous licenses and permits and engagement with multiple stakeholders on a federal, provincial and community levels. There is potential for lengthy regulatory processes with overlaps and redundancies involving federal and provincial regulators. The typical timing for the completion of a LNG regulatory process could exceed two years.

The first step is to obtain an export license from the National Energy Board (NEB), the independent federal regulator in charge of regulating the construction and operation of interprovincial and international oil and natural gas pipelines, international power lines, and designated interprovincial

[69] PwC (2014)

power lines. NEB regulates the tolls and tariffs for pipelines under its jurisdiction, the export of natural gas, oil, natural gas liquids (NGLs) and electricity, and the import of natural gas.

In order to grant the export license NEB will test whether the project is in Canada's economic best interests. To grant an export license the NEB must find that the proposal is in the public interest and that the energy commodity to be exported is surplus to Canada's energy needs. The NEB does not take into consideration the environmental aspects of the project when issuing an export license.

At the Province level, the Oil and Gas Commission is the regulatory agency overseeing the LNG sector, for instance in British Columbia.

Other relevant regulatory steps are summarised below:

- Environmental approval, following the filing of an Environmental Assessment for the project with the federal and provincial governments. This is a lengthy process and requires: consultation with stakeholders, such as the First Nations and other communities impacted by the project; the completion of in-depth technical and environmental studies.
- Technical Review Process of Marine Terminal Systems and Trans Shipment Sites, which is a voluntary process focusing on vessel safety and vessel operation in Canadian waters along proposed shipping routes to and from a proposed LNG terminal.
- The project should also seek permits and approval from Provincial and Federal government entities, regarding the construction and operation of the LNG plant and pipelines. In addition the project developer should seek licenses and permits for the use of surface water, waste emission and disposal, including hazardous waste, for investigative work on historical and paleontological resources, and for the construction and operation of construction facilities, among many others.
- The project will need authorisation under the Fisheries Act in the event it cannot avoid harm to fish species or habitats.
- Under the Navigation Protection Act – Transport Canada the project should seek approval of work under and or designated navigable waters.
- Once the LNG facility is built it needs to obtain an operation permit from BC Oil and Gas Commission.

In addition, even if the LNG plant is permitted this does not warrant the approval for the long distance pipeline which will feed the LNG facility. The permitting of a pipeline in British Columbia can be even more complex because it is likely to crosses the ancestral land of Aboriginal people.

In January 2015, the Squamish Council voted to deny FortisBC permission for test drilling for a natural gas pipeline feeding the proposed Woodfibre LNG project in the south of British Columbia. The main concern of the Council was the potential for the drilling to disturb an ecologically sensitive area, which is the home for protected animal species. This was in spite of the approval already given by British Columbia's Ministry of Forests, Lands and Natural Resource Operations, and the Oil and Gas Commission.[70]

## First Nations

According to Canada's Aboriginal Affairs and Northern Development federal government department[71], "Aboriginal People" is a collective name for the original people of North America and their descendants. The Canadian constitution recognises three groups of Aboriginal people:

- Indians (commonly referred to as First Nations),
- Métis;
- Inuit.

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[70] http://www.vancouverobserver.com/news/squamish-council-votes-down-lng-pipeline-drill-tests

[71] https://www.aadnc-aandc.gc.ca/eng/1100100013791/1100100013795

"First Nations people" refers to the native "Indian" people in Canada. Currently, there are 617 First Nation communities, which represent more than 50 nations or cultural groups and 50 Aboriginal languages. According to the 2011 National Household Survey, more than 1.4 million people in Canada identify themselves as an Aboriginal person, or 4% of the population; 50% are registered Indians, 30% are Métis, 15% are non-status Indians and 4% are Inuit. Over half of Aboriginal people live in urban centres.

The Indian Act first enacted in 1876 establishes how the Canadian state interacts with the 617 First Nation bands in Canada and their members. In order to obtain title to Canadian land the Government of Canada signed a series of treaties from 1871 to 1921 with the First Nations. The treaties delineate a tract of land which was thought to be the traditional territory of each First Nation or Nations signing that particular treaty (the "tract surrendered"). In exchange for a surrender of their rights and title to these lands, the First Nations were promised a smaller parcel of land as a reserve, annual annuity payments, implements to either farm or hunt and fish and the right to continue to hunt and trap or hunt, trap and fish on the tract surrendered.

A 1997 decision of the Supreme Court of Canada established that aboriginal title still exists in British Columbia and that when dealing with Crown land, the government must consult with and may have to compensate First Nations whose rights are affected. Furthermore in the case of First Nations without treaties but which can claim to have aboriginal rights and title over tracts of land which have not been object of a treaty but have successfully asserted some degree of title in court to the extent of their property rights, they have the right to control how the land is developed.

Large scale projects involving LNG terminal and pipeline development will require the engagement of First Nations whose traditional lands are affected. First Nations support for Canada's LNG projects is vital for moving projects ahead as they have aboriginal and land rights recognised by numerous court decisions, including at the Supreme Court of Canada.

Anyone who wants to build a pipeline across northern BC will have to consult with at least half a dozen First Nations, each with a different set of expectations and demands. If the project proponents and the affected First Nations reach a preliminary understanding they might sign Impacts and Benefit Agreements (IBA) which outline the impact of the project and how First Nations communities would benefit from it. There is no clear definition on the length and depth of the consultation process and the level of benefits.

Another difficulty lies in the large number of bands involved in each project, and who is empowered to make a decision (the chief, the elders, or the Council) and whether the Canadian government (the Crown) needs to carry on a consultation in parallel to the negotiation process between the bands and the project developers. Also there are expectations that the compensation paid to the affected band should match or exceed the revenues received by the government.

In the case of British Columbia there is a particularity whereby most native bands are living on Indian Act reservations and do not hold title to the land and do not have rights to self-government. In order to address this issue the BC Treaty Commission is trying to negotiate treaties with First Nations that do not have agreements with the provincial government.

There is also some divergence on what is the best way to compensate First Nations, whether in cash or benefits such as job creation, training, or procurement from First Nations businesses. An emerging trend is to offer a stake in the project, which would align the interest of the project with the interest of the bands. A few project developers claim to have successfully negotiated a stake in the project with the First Nations.

In general First Nations have been broadly supportive of the prospect of LNG exports from the West Coast but some of them have showed opposition to gas supply pipelines, when it crosses sensitive areas. The bands seem to favour LNG over oil projects, because it is cleaner and poses less risk of polluting spillages. For example, in the case of Kitimat LNG, the liquefaction terminal is to be located on the lands of the Haisla First Nation[72]. A partnership agreement has been reached between Kitimat LNG and the Haisla providing the latter with the following:

- The opportunity to purchase equity in the LNG project.
- Minimum standards of employment during construction and operations.
- Employment training.
- Procurement opportunities.
- Annual tax revenue and lease payments to be paid to the Haisla Nation.

Pipeline benefits agreements are negotiated between First Nations and the provincial government and are separate from deals signed between aboriginals and project proponents. For example, Pacific Trails Pipeline is proposing to build and operate a pipeline loop of the existing Pacific Northern Gas natural gas pipeline system between Kitimat BC and Summit Lake BC. In order to proceed with the project Pacific Trails Pipelines (PTP), the First Nations (PTP) Group Limited Partnership and the Province of British Columbia have announced a benefits agreement that will ensure that the 15 First Nations bands which are located along the pipeline will receive up to CAD 200 million in financial benefits over the life of the project.

But there are also examples of First Nations opposition to LNG related projects. For example, four BC First Nations, the Wet'suwet'en, the Gitanyow, the Lake Babine and the Gitxsan, in the northwestern part of the province, declared their opposition to PNWLNG citing fear of massive damage to their salmon habitat and lack of proper consultation[73].

## Gas Transportation Issues: Lack of Pipeline Capacity and Toll Fees.

In order to connect the northern shale plays of British Columbia with BC LNG sites, it will be necessary to expand the BC gas pipeline system and several pipeline projects are being developed to serve different LNG areas. The required pipelines range from 52 km to 900 km.

The pipelines cross environmentally sensitive areas as well as First Nations land, requiring a laborious permitting process and lengthy negotiations with all First Nations bands in the area. The timeline and stages required for the issuance of an Environmental Certificate by the BC Environmental Assessment Office may take nearly one year.

There is another issue regarding the conflicting toll rate setting methodologies on federally regulated pipelines in northeast British Columbia. The pipeline tolls for Spectra Energy's Transmission System gathering and process services are being determined differently from tolls on extensions of the TransCanada Alberta System. The so-called "Framework for Light-handed Regulation" that was approved by the National Energy Board in the mid-1990s provides for market forces to determine the pipeline rates on the Westcoast Energy System; however the rate on NGTL expansions into northeast British Columbia is determined by rolling the incremental costs into NGTL's Alberta-wide rate base. This would mean that the rates on extensions of the NGTL system into northeast British Columbia are likely to be much lower than the negotiated stand-alone, cost-based tolls that apply to extensions on the Westcoast Energy System.

The proposed East Coast LNG projects in New Brunswick and Nova Scotia also face transportation hurdles. If built, they would need a gas feed of 42 Bcma. With the fracking moratorium in Quebec, Newfoundland and Labrador, and Nova Scotia the most viable supply sources are the shale plays in Northeast US, but this would require a capacity expansion of the already constrained pipeline system crossing New England in the US. This would open a debate on who would pay for the expansion, the US consumers or Canada LNG plants.

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[72] https:// http://www.cbc.ca/news/canada/british-columbia/skeena-river-first-nations-oppose-petronas-lng-plant-near-prince-rupert-1.2824967. www.enewsletters.gov.bc.ca/LNG_in_BC/February_2013/FNCIDA/article
[73] http://www.cbc.ca/m/touch/canada/britishcolumbia/story/1.2824967

## Project Costs and Execution

Similarly to Australia, the concurrence of several LNG projects being built in the same time frame and in parallel with other capital intensive projects, such as oil sands, has the potential for cost escalation and budget overruns. Also there is a risk of unnecessary duplication of pipeline infrastructure, which could be optimised to serve the same area. For example, in Australia the lack of cooperation between three Queensland located LNG ventures resulted in duplication of ancillary activities such as gas transmission pipelines, workers' housing and transportation.

## Fiscal Uncertainty

Despite Canada's democratic and legal stability, there is some concern among LNG project sponsors about the proposed taxation at Provincial level, in particular additional taxation from the Government of British Columbia, where most of the proposed projects are located.

On October 21, 2014, after months of debate, the Government of British Columbia introduced Bill 6, the Liquefied Natural Gas Income Tax Act containing the proposed framework for an income tax regime applicable to income from liquefaction of natural gas at LNG facilities in the Province. The so called "LNG Tax" will be a two-tier income tax with a tier-one tax rate of 1.5% and a tier-two rate that was initially proposed as 7%. After objections raised by project developers the BC Government amended to start at 3.5% in January 2017, rising to 5% from January 1, 2037.

The Government proposed to apply the tier-one tax (1.5%) to the operator's net income at the commencement of commercial production of LNG, but tier-one tax would be deductible from the tier-two tax (3.5%). The tier-two tax should apply to the net income of the project less the costs associated with the capital investment from the construction of the LNG facility. The tier-two tax would only apply once the capital investment in the LNG facility is recovered.

The following types of income generated by the LNG facility will be subject to LNG income tax:[74]

- sale of liquefied natural gas,
- rents and fees payable for the use of a LNG facility,
- fees for processing natural gas at a LNG facility.

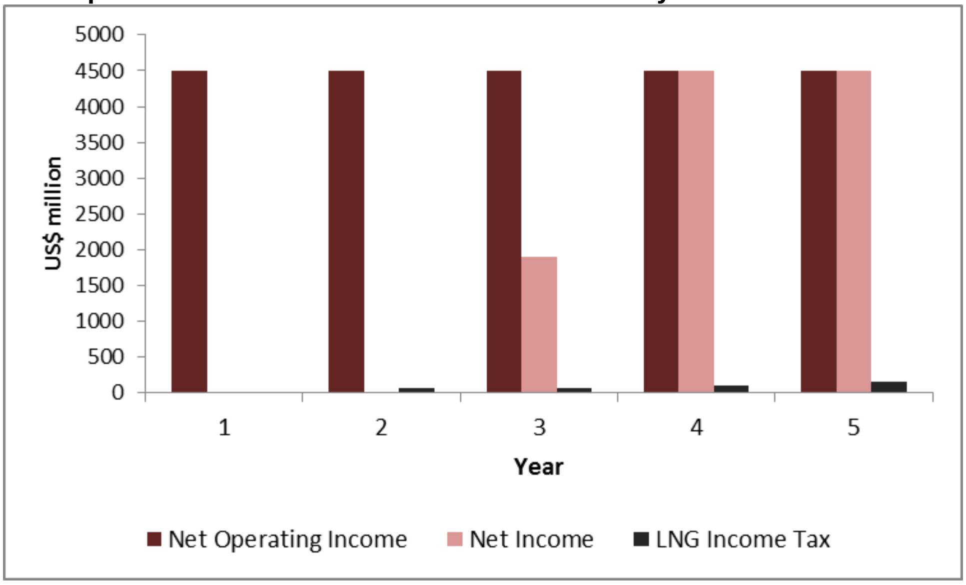
The point of taxation will be profitability at the plant gate. The profitability will be calculated by subtracting shipping, operating expenses at plant, feed gas costs and pipeline tolls from the ex-ship price obtained for the LNG sold DES. Tier 1 rate (1.5%) will be charged after the commercial production begins. The second phase of the tax will be applied once the pay-out is reached, when the initial capital investment is fully recovered.

BC's Government subsequently revised Bill 6 and proposed an amendment, the Liquefied Natural Gas Income Tax Amendment Act, 2015 (LNG Amendment Act) or Bill 26. On March 25, 2015 the Government of British Columbia published a document summarising the key provisions of Bill 26, introducing administration and enforcement provisions and clarifying a number of key components that were included in the Liquefied Natural Gas Income Tax Act (LNG Act), subject to Bill 26 being enacted by the Legislature and receiving Royal Assent[75]. Figure 38 provides an example on how the income tax will be assessed. When the LNG facility is not yet delivering a net income, the tax is 1.5% of the Net Operating Income; once the facility starts to deliver a positive net income, it triggers a tax payment of 3.5% on the Net Income.

[74] http://www.pwc.com/ca/en/tax/budgets/2014/british-columbia-unveils-its-liquefied-natural-gas-tax.jhtml

[75] British Columbia Government (2015a)

**Figure 38: Example of Calculation of LNG Income Tax for a 5-year Period**




Source: http://www2.gov.bc.ca/gov/topic.page?id=F78BB91F872C45B8BB6AD0A5572BBD4B

The proposal covers certain property acquired for use in facilities in Canada that liquefy natural gas to supply LNG to international and domestic markets and to store LNG in periods of low demand and then regasify it in periods of high demand ("peak shaving").

The corporation's income tax is payable after all other BC income tax credits have been deducted.

The new tax proposal also deals with the potential for non-arm's length transactions where the facility off-taker is also the upstream asset owner (e.g., Petronas). Clarity on this item is important as project integration (i.e., owning the upstream assets) is critical to making overall project economics work.

The LNG Act deems that a sale of liquefied natural gas, natural gas liquids, or natural gas has occurred if a taxpayer owns the commodity immediately before and after it leaves the LNG plant. This situation could arise if:

- The LNG income tax payer owns the natural gas, natural gas liquids or liquefied natural gas at the LNG facility and transports and re-gasifies the liquefied natural gas after it leaves the LNG plant; or
- The LNG income tax taxpayer sells the commodity to either an arm's length or non-arm's length party under a contract where the title transfer occurs at a location other than where the commodity leaves the LNG plant.

The sale is deemed to be from the taxpayer to a person that does not deal at arm's length with the taxpayer and is subject to the transfer pricing rules, including the potential application of penalties up to the value of the income tax assessment (3.5%).

According to the Valuation Rules published on March 25, 2015[76], transactions that occur between non-arm's length parties under the LNG Act will be valued using:

- Transfer pricing rules;
- Fair market value rules; and
- Specific rules for the valuation of natural gas at the LNG facility inlet meter.

[76] British Columbia Government (2015b)

The Federal Government rejected the industry's requests for tax breaks for LNG plants in the last two federal budgets but in February 2015 it offered a new incentive for LNG projects, mindful of the current business environment in the wake of the drop in oil prices. A Federal Capital Cost Allowance (CCA) for LNG projects was announced by Prime Minister Stephen Harper on February 19, 2015, containing a proposed acceleration of federal capital cost allowance rates (CCA) to 30% for equipment used in natural gas liquefaction and 10% for buildings associated with LNG facilities.

The capital cost allowance provides for a portion of the capital cost of a depreciable property to be deducted annually as a tax deductible cost (i.e., capital cost allowance or CCA); CCA rates are typically set so that the cost of depreciable property is recognized over the useful life of the property.

Accelerated CCA treatment is an exception to this general practice, allowing taxpayers to more quickly recover the cost of their capital investment.

Eligible capital assets must have been acquired after February 19, 2015, and before 2025 and will be subject to a capital cost allowance rate of 30% for equipment, and 10% for buildings. Currently, equipment is subject to an 8% rate, and structures are subject to a 6% rate, according to the Government announcement.

The proposed CCA aims to encourage the development of Canadian LNG liquefaction facilities taking into account that none of the proposed LNG projects has made an investment decision[77].

Another fiscal uncertainty regards the BC Government proposed carbon tax on LNG, which is yet to be detailed. BC levies a carbon tax, which is a tax based on greenhouse gas (GHG) emissions generated from fossil fuel combustion at the rate of 5.7 cents/cubic metre. The tax does not apply on natural gas transformed into LNG. The BC Government has indicated that it might require the LNG plants to buy offsets to reduce GHG but has not yet detailed how this would be priced.

## 20. LNG pricing and competitiveness

There are three possible scenarios for pricing Canada's LNG

- Oil indexation pricing
- Hub based pricing
- Project based, cost plus pricing

The Canadian LNG project developers are reluctant to move away from oil indexed price formulae because of the expected high costs of greenfield projects. On the other hand the Asian Buyers have demonstrated a preference to work with a more transparent cost plus type of structure, as has been implemented for US projects. Before the collapse of oil prices since late 2014, the oil indexed price formulae for recently signed long term LNG contracts ranged between 13% JCC and the Asian proxy of 14.85% JCC + 0.5. At Brent prices oscillating between US$ 50 and US$ 60/bbl it is difficult to find a point of equilibrium for buyers and sellers, because even the highest-price formula would result in a price of US$ 7.92-9.41/MMBtu DES Asia, which seems insufficient to make the construction of a greenfield LNG project viable.

A cost plus approach would reduce the price risk, but from a Canadian perspective the commodity component should be priced at one of the Canadian hubs (Dawn or Alberta's AECO), whereas the

[77] http://business.financialpost.com/2015/02/19/canada-to-reduce-taxes-for-lng-projects-stephen-harper-says/?__lsa=ef76-2969

buyers would prefer a formula based on Henry Hub, which is currently more liquid and well known than the Canadian hub prices.

The current forecast for HH – Nymex Future Price (2020) is US$ 3.52/MMBtu whereas AECO is projected to reach CAD 3.45/GJ (US$ 2.91/MMBTU) in 2019[78].

Based upon information obtained from Alberta Energy, public sources and the Author's estimates the breakeven price for Canada LNG delivered to Japan is approximately US$ 11.61/MMBtu in 2019-2020, assuming the following parameters:

**Table 5: Cost plus estimate – Generic Canadian LNG DES Japan**

| Value Chain Component | US$/MMBtu |
|---|---|
| AECO (2019) | 2.91 |
| Pipeline fees (US$ 1.0-2.50/MMBtu) | 2.0 |
| Liquefaction fees (US$ 4.8-5.3/MMBtu) | 5.1 |
| Shipping freight to Japan (US$ 1.04 – 1.58/MMBtu) | 1.5 |
| 3.5% Sales Tax on Maximum LNG price | 0.1 |
| Breakeven DES Price | 11.61 |

Source: Li James, Author estimates, http://www.gasalberta.com/pricing-market.htm

At 2015 AECO's average price, CAD 2.74/GJ (US$ 2.31/MMBtu), the breakeven price DES Japan is approximately US$ 11.01/MMBtu). In 2015 LNG shipping rates have fallen to near 5-year lows of US$ 37,000-38,000/day. Assuming lower shipping costs of US$ 1.04/MMBtu and more efficient pipelines rates of US$ 1.1/MMBtu[79], the breakeven cost drops to US$ 10.3/MMBtu.

For LNG indexed on oil prices, the DES Japan prices would range from US$ 6.44 to US$ 15.20/MMBtu at Brent prices of US$ 50-100/bbl depending on the price formula agreed with the buyers (Table 6 and Figure 39 below).

**Table 6: LNG DES oil-indexed price scenarios**

| US$/MMBtu | 14.85%JCC+0.5[80] | | | 13% JCC | | |
|---|---|---|---|---|---|---|
| Brent | $ 50/bbl | $85/bbl | $100/bbl | $ 50/bbl | $85/bbl | $100/bbl |
| DES price | 7.85 | 13.00 | 15.20 | 6.44 | 10.94 | 12.87 |
| Canada Breakeven | 10.3 - 11.61 | | | | | |

Source: Author estimates

For LNG priced at 14.85% JCC+0.5, the higher breakeven price is achieved at Brent US$ 76/bbl, whereas the higher breakeven for LNG priced at 13% Brent is reached at an oil price of US$ 90/bbl. Therefore depending on the oil indexed price formula, Canadian LNG projects are viable for Brent prices above US$ 76/bbl, if the Asian buyers accept signing contracts based on the higher Asian price proxy formula.

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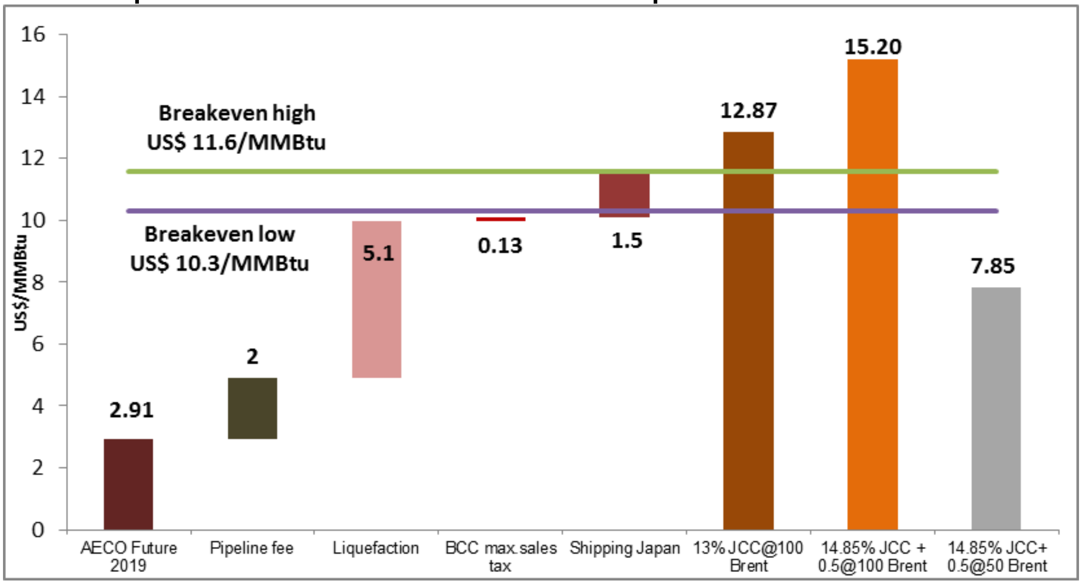
[78] http://www.gasalberta.com/pricing-market.htm

[79] Assumptions: 900 km, 2 bcfd, US$ 6 bn pipeline, IRR 12%.

[80] Assuming JCC price at 1% discount over Brent

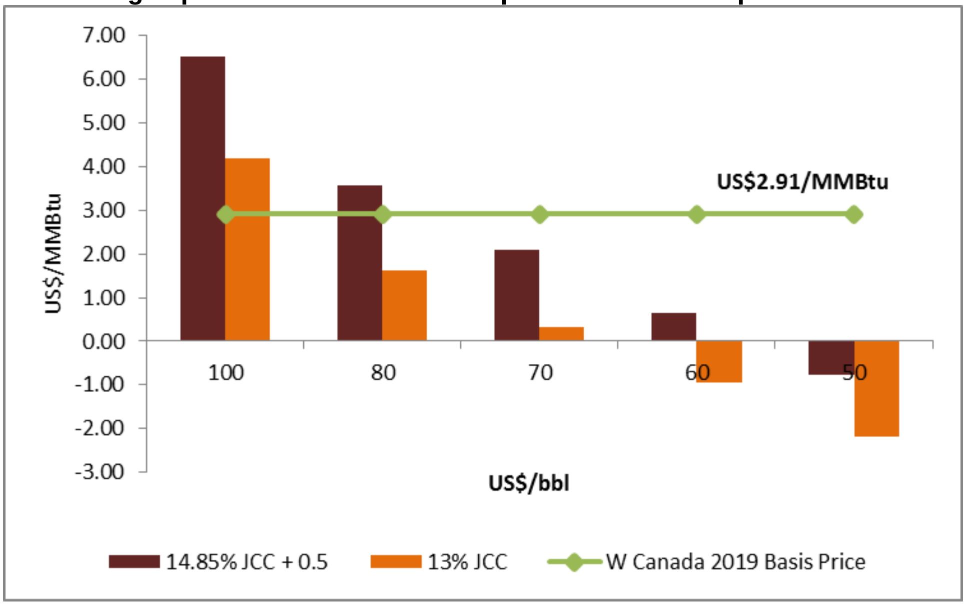
**Figure 39: Comparison of Cost Plus vs Oil Indexed LNG prices**




Source: Author estimates and industry public information

Considering the higher breakeven prices and after deducting liquefaction, pipeline and shipping costs, the netback for West Canada producers is negative for oil prices below US$ 67/bbl for LNG priced at 13% JCC, while the Asia proxy formula delivers a negative netback for oil prices below US$ 55/bbl.

**Figure 40: Netback gas price to Western Canada producer vs Brent price**




Source: Author and http://www.gasalberta.com/pricing-market.htm

For LNG priced at 13% JCC, the netback to producers is above the 2019 basis price (US$ 2.91/MMBtu) for Brent above US$ 90/bbl, whereas for LNG priced at the Asia proxy the producers will breakeven for Brent prices above US$ 76/bbl.

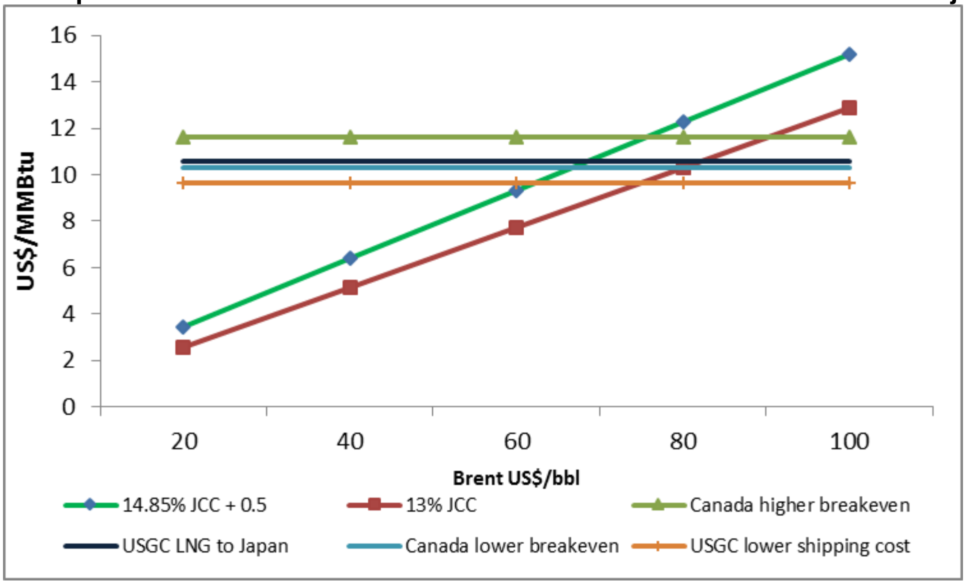
Despite the savings in shipping costs when compared to US Coast projects selling into Asia, the Canadian DES breakeven price is around US$ 1.0-1.50/MMBtu more expensive than the US brownfield projects, when considering liquefaction CAPEX costs of $ 3.0 - 3.50/MMBtu for the latter.

Figure 41 below compares the prices of Canadian LNG at different oil indexed price formulae with a generic Canadian breakeven DES price and USGC LNG projects all DES Japan. The following parameters were used to calculate the US price:

- HH (2020) = US$ 3.52/MMBtu
- Fuel costs = 115% HH
- Liquefaction costs = US$ 3.50/MMBtu
- Shipping US to Japan = US$ 2.1 - 3.0/MMBtu[81]

For the same economic return Canadian LNG projects need higher prices (whether oil-indexed or cost-plus) than US projects due to the higher pipeline and liquefaction costs and will only be competitive with USGC brownfield projects if they can significantly reduce those costs.

**Figure 41: Comparative DES Asia Prices of Canadian and USGC Brownfield LNG Projects**




Source: Author estimates and adapted from (Cheniere Energy, November 2014)

## 21. A return to S-Curves?

At crude prices around US$ 50/bbl, Canadian LNG projects will not breakeven, unless there is a dramatic drop in construction and shipping costs. At these low crude price levels oil indexed curves will be difficult to benefit sellers and buyers.

An alternative for sellers is to offer cost-plus prices; similarly to what has been done to launch USGC brownfield projects, but Asian buyers will be reluctant to commit to fixed prices north of US$ 11/MMBtu when the prices of existing oil-indexed long term contracts will drop to US$ 7-8/MMBtu after July 2015.[82]

Another possibility to re-align sellers and buyers is the reintroduction of "S-curves", which moderate the effect of very high or low crude oil prices on LNG prices. The curve was very popular in Asia until

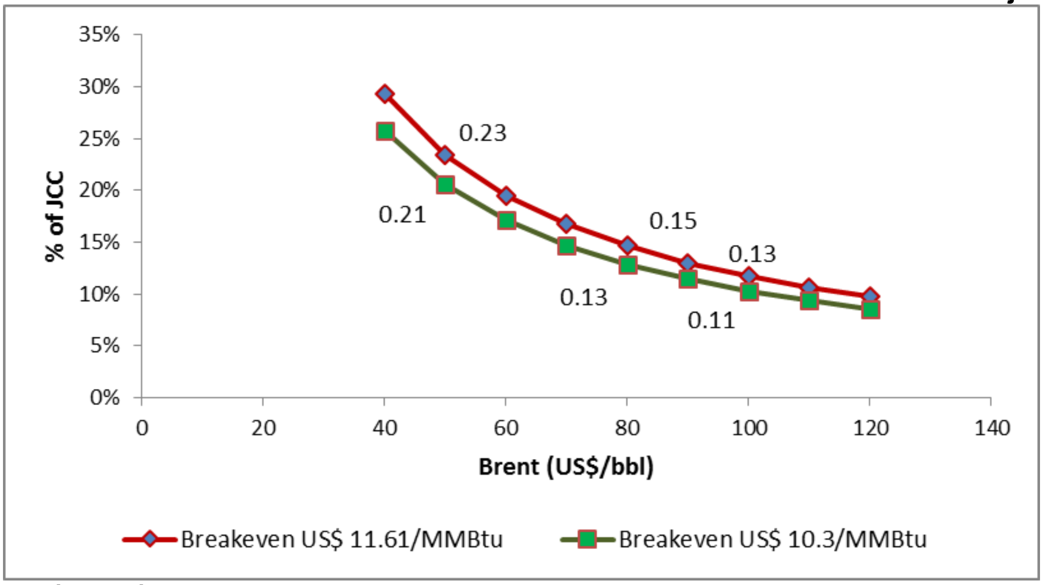
[81] Assuming current and higher LNG shipping rates

[82] Long term contracts in Asia are readjusted with time lags of 3-9 months

2005, and was replaced by straight line formulae when LNG prices started to pick up again. If applied in the Canada case, in order to meet a US$ 11.61/MMBtu breakeven, the equation coefficient at Brent equal to US$ 50/bbl, is 0.23, whereas for Brent equal to US$ 80/bbl, the coefficient is 0.15.

Lower breakeven prices of US$ 10.3/MMBtu require a 0.21 coefficient at Brent US$ 50/bbl and 0.11 for Brent US$ 100/bbl.

**Figure 42: Coefficient on LNG "S-Curve" Price Formula for a Generic Canada LNG Project.**




**Source: Author Estimate**

## 22. Conclusions and Insights

Despite Canada's abundance of gas resources and the plethora of proposed LNG export schemes, the current business environment, characterised by low oil prices and industry consolidation, does not indicate that any Canadian LNG scheme will be commissioned before the middle of the next decade.

Similarly to other greenfield LNG schemes being proposed in East Africa and Australia, the window of opportunity to capture premium Asian markets has eluded the Canadian projects; a new market window will probably open from 2025 onwards.

As of early 2015 all proposed LNG projects have been deferred and have yet to take final investment decision. A few projects look more viable due to a combination of Asian buyers as equity holders and a large resource basis, but even those projects face the hurdle of high CAPEX costs, complex environmental permitting and the individual circumstances of the project leaders. In the case of PNWLNG, the leader Petronas has posted net losses of RM7.3 billion (US$ 1 bn) in the fourth quarter of 2014 due to significant asset impairment (write-downs) as a result of lower oil prices and lower revenue generated for the quarter. In the case of Canada LNG, the project leader Shell will be certainly very busy over the next few months in the consolidation of its acquisition of BG Group. The changes in the Kitimat shareholding structure will also create additional uncertainty in the project timeline. Industry analysts expect only one to three BC LNG projects to be operating by 2025

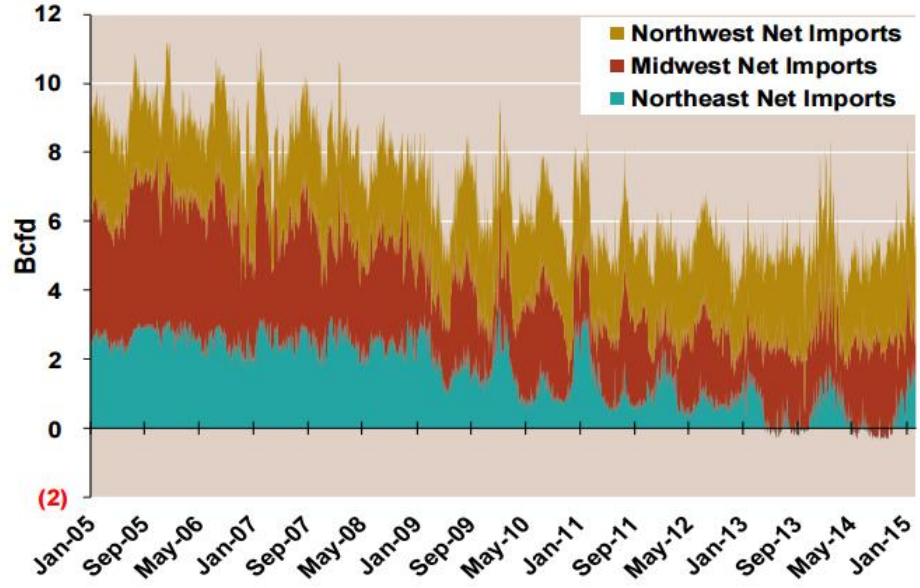
The market outlook for Asia is still uncertain. Demand in Japan is flat; pending a decision on how many nuclear power plants out of 15 GW will resume operation between now and 2017. Demand in South Korea has dampened, due to a combination of mild weather, slow economic growth and the prospect of 7GW of nuclear generation capacity being currently built. The demand for LNG in China has slowed down, with more pipeline gas being imported into the market. In addition, there are approximately 110mtpa of extra LNG capacity under construction/ FID in the US, Australia and other countries coming to market between June 2015 and 2020. The Indian market may offer interesting growth opportunities, due to the current shortage of KG basin gas. However the main gas downstream player, GAIL, has already committed to buy 8.5 mtpa from US and Russian suppliers. According to this market analysis the Asian markets will be well supplied in the period 2015-2020.[83]

Canadian projects will also need prices of around US$ 10.3-11.6/MMBtu to breakeven, which (on an oil indexed pricing basis) necessitates oil prices of US$ 76-90/bbl, which does not seem competitive with the first generation of USGC brownfield projects. Even if the Canadian projects set up cost plus price formulae, the fixed component of US$ 6.5-7.5/MMBtu, which includes enabling pipeline infrastructure, liquefaction plus LNG income tax, looks expensive when compared to US projects.

Gas producers in Canada WCSB will continue to see price erosion until LNG projects materialise, as they continue to lose markets to cheaper shale gas produced in the US. The continuous growth of Marcellus production, followed by the Utica deeper play and the Bakken in North Dakota, coupled with the construction of new pipelines and the flow reversal of the existing ones, will cause the Canadian western producers to lose traditional US and eastern Canadian markets. Under this scenario, WCSB producers will be marginal suppliers and price takers in the North American gas market, a situation which is aggravated by higher transportation toll fees west-east, as less gas from WCSB is transported to the Eastern markets.

Until LNG export projects fully materialise the Canadian market will continue to be intrinsically dependent on the market dynamics in the US and in particular on Marcellus/Utica production and monetisation options. The imports of Canadian gas by the US follow a continuous downwards trend, as illustrated by data available from the FERC as of March 2015.

**Figure 43: Evolution of US Imports of Canadian Natural Gas**

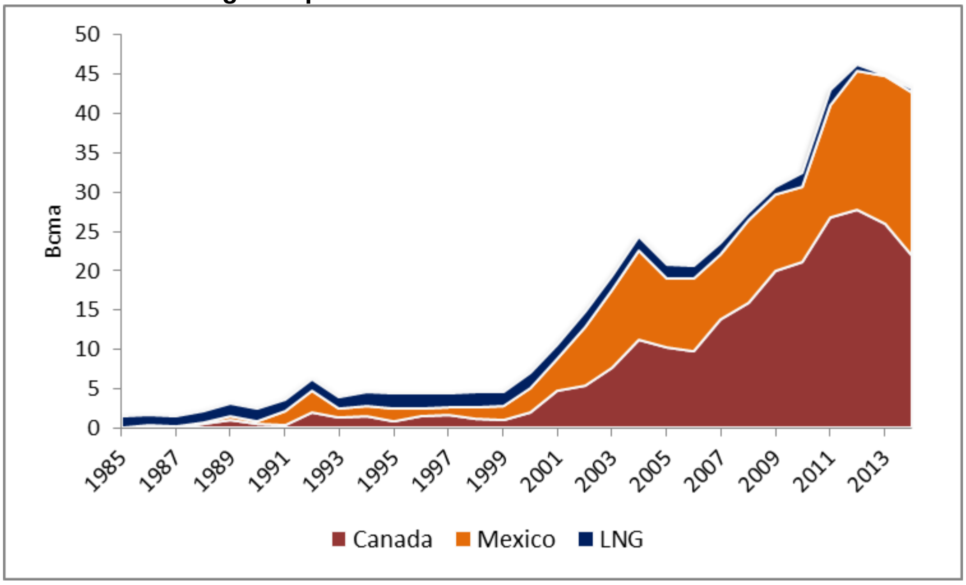



Source: http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-imp.pdf

And the imports of gas from the US into Canada will continue to display a steady upwards trend as illustrated by data provided by the US EIA (Figure 44: Evolution of US gas exports).

[83] Mannes (2015).

**Figure 44: Evolution of US gas exports to Canada**




Source: http://www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm

There are opportunities to redirect production into the domestic market, in particular into oil sands production/upgrading and into power generation. According to the National Energy Board, electricity generation and bitumen production will be primarily responsible for growth in Canada's natural gas demand over the next two decades[84]. Even the oil sands market opportunities are expected to slow down, as lower oil prices will cause the postponement of projects which are yet to start construction.

In any case, the Canadian market can fully absorb a reduced domestic production only after 2025, and this will only happen at the expense of a drop in the current production levels to below 125 Bcma.

This is an opportunity for the Canadian federal and provincial governments to decide on strategies to promote the growth of the domestic market, including cogeneration, uses of gas in the transportation sector and petrochemicals/fertiliser plants. It is also an opportunity to work with the project developers to enhance the permitting framework to speed up the construction of LNG and pipeline facilities once the economic outlook encourages the players to move the projects forward.

LNG projects with Asian buyers as equity partners and a strong resource basis are likely to be first movers once the current oil price scenario improves.

[84] Chong (2014)

## Units

| | |
|---|---|
| Bbl | barrels of liquid |
| Bcf | billion cubic feet |
| Bcfd | billion cubic feet per day |
| BCM | billion cubic metre |
| Bcma | billion cubic metre per annum |
| Bn | billion |
| GJ | Gigajoule |
| GW | Gigawatt |
| GWh | Gigawatt hour |
| $m^3$ | cubic metres |
| $m^3/d$ | cubic metres per day |
| MMcf | million cubic feet |
| MMcfd | million cubic feet per day |
| $Mm^3/d$ | million cubic metres per day |
| MMBtu | Million British Thermal Units |
| Mtpa | million tonnes per annum |
| MW | Megawatt |
| MWh | Megawatt hour |
| TCM | trillion cubic metre |
| Tcf | trillion cubic feet |
| Tonnes | Metric Tonnes |
| TW | Terawatt |
| TWh | Terawatt hour |

## Conversion factors

1GJ = 0.94781712 MMBtu
1 CAD = US$ 0.80

## Glossary/Acronyms

| | |
|---|---|
| AECO | (AECO C) Virtual trade point, wholesale price for Alberta delivery |
| BC | British Columbia |
| CAD | Canadian dollar |
| CAPEX | Capital Expenditure |
| CAPP | Canadian Association of Petroleum Producers |
| CBM | Coalbed Methane |
| EIA | US Energy Information Administration |
| EMA | Energy Market Assessment |
| FERC | US Federal Energy Regulatory Commission |
| GDP | Gross Domestic Product |
| HH | Henry Hub (U.S. Natural Gas Reference Price) |
| IEA | International Energy Agency |
| LNG | Liquefied Natural Gas |
| NEB | National Energy Board |
| NIT | Nova Inventory Transfer |
| NGLs | Natural Gas Liquids |
| PSAC | Petroleum Services Association of Canada |
| R | Royalties |
| US$ | US dollar |
| WCSB | Western Canada Sedimentary Basin |

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Canadian Association of Petroleum Producers: http://www.capp.ca/

Canadian Energy Pipeline Association: www.cepa.com

Canadian Gas Association: www.cga.ca

Chevron/Kitimat: http://www.chevron.ca/our-businesses/kitimat-lng

National Energy Board: https://www.neb-one.gc.ca/index-eng.html

Shell's Canada LNG: www.lngcanada.ca

## Appendix 1 – Calculation of Alberta and British Columbia Royalties

### British Columbia

Conservation gas is defined as gas that is produced in association with oil, and is conserved and marketed, rather than flared into the atmosphere. Conservation gas royalty is charged at a minimum of 8% and is calculated as:

- R% = [400 + 15 × (RP – 50)] / RP

Non-conservation gas comprises all gas not classified as conservation gas (including gas produced in association with oil which is part of a concurrent production scheme) and makes up the vast majority of natural gas production in British Columbia.

Base 15 is all gas produced from wells drilled before June 1, 1998, and with a minimum of 15%. The royalty is calculated as:

- R% = [750 + 25 × (RP – 50)] / RP

Base 12 is all gas produced from wells drilled after June 1, 1998, except all gas categorized as Base 9. The royalty rate is between 12% and 27% and is calculated as:

- R% = [12 × SP + 40 × (RP – SP)] / RP

Base 9 is all gas produced from wells on land acquired after June 1, 1998, and completed within five years. The royalty rate is between 9% and 27% and is calculated as:

- R% = [9 × SP + 40 × (RP – SP)] / RP

Where:

- RP = Reference Price (CAD/$10^3m^3$) is the greater of the selling price and the Posted Minimum Price (PMP) for the processing plant.
- SP = Select Price (CAD/$10^3m^3$) which is set by the government and is currently CAD50.

B.C. Gas Royalty Incentives:

For wells producing volumes below 5,000 $m^3$/d, a reduction is applicable and the adjusted rate is calculated by:

- R% = Rc% - Rc% × [(5000 – V)] / 5000][86]

Where:

- Rc = royalty as calculated before the low productivity reduction.
- V = average daily gas production ($m^3$)

For wells deeper than 2,500 m a program of royalty credits is available. There is a credit provided for the re-entry of wells to a depth of at least 2,300 m.

For discovered wells deeper than 4,000 m and more than 20 $km^2$ away from any other well in a pool of the same formation, the lesser value of 283,000,000 $m^3$ of royalty free gas or a three year holiday is applicable.

There is a royalty rate reduction for marginal wells spudded after May 31, 1998 and another greater reduction for ultra-marginal wells.

There is a summer drilling incentive of a credit of 10% of costs for each well.

[86] http://www.energy.alberta.ca/Tenure/pdfs/FISREG.pdf

A credit of 50% of the cost of road construction, pipelines or associated facilities is available to encourage infrastructure improvement.

In September 2013, the BC government announced the allocation of CAD 115.8 million in royalty credits under the Infrastructure Royalty Credit Program (which has been in place since 2004) for energy companies to construct roads or build pipelines in support of natural gas production in BC's northeast.

Oil and gas companies must fund and complete the entire construction project before they are eligible to recover up to 50% of their costs through the program.

Coal bed Methane wells are given a few concessions such as:

- A royalty credit of CAD 50,000 and CAD 30,000 for crown and freehold land respectively.
- A higher low productivity threshold of 17,000 $m^3$.
- Water handling cost allowances.

## Alberta

Alberta Royalty Framework[87]: Natural Gas - Effective January 1, 2011

R = Royalties

R% = Price Component (rp) + Quantity Component (rq)

R% has a minimum of 5% and a maximum of 36%

For Transition Wells* R% has a minimum of 5% and a maximum of 30%

**Figure 45: Alberta incentive programmes for natural gas exploration and drilling[88]**

| New Well Royalty Rates | Applies to | Maximum 5% Royalty Rate for whichever is reached first, time or volume | |
|---|---|---|---|
| | | Time Limit | Volume Limit |
| New Well Royalty Rate | Well commenced or recommenced production on or after April 2009. | 12 producing months | 14,158 $e^3m^3$ of gas |
| Shale Gas Royalty Rate | Well events that start producing gas exclusively from shale zones on or after May 2010 | 36 producing months commencing with the first month of production | No volume limitation |
| Coalbed Methane Royalty Rate | Well that started producing gas exclusively from coal zones on or after May 2010 | 36 producing months commencing with the first month of production | 21,238 $e^3m^3$ of gas |
| Horizontal Gas Royalty Rate | Horizontal gas wells drilled on or after May 2010 | 18 producing months commencing with the first month of production from the well event | 14,158 $e^3m^3$ of gas |

[87] http://www.energy.alberta.ca/Org/pdfs/GASFormulas2010.pdf

[88] Source: Li, J. (Alberta Energy, 2015)

## Appendix 2 – Status of Proposed LNG Projects in Western Canada

**Figure 46: Proposed LNG Projects in Western Canada (As of December 2014)**[89]

| Location | Projects (Operational year*) | Stakeholders | Status | Estimated Capacity (Bcf/d) | Connection pipeline |
|---|---|---|---|---|---|
| Kitimat | Kitimat LNG (2017) | Chevron 50%, Apache Canada 50% | 20 years export license approved (Oct. 2011) | Up to 1.4 10 mtpa | Pacific Trails Pipeline (proposed) |
| | Douglas Channel Energy Project (N/A) | LNG Partners 50%, HN DC Limited 50% (Haisla nation) | 20 years export license approved (Feb. 2012). Revoked in 2015 | Up to 0.25 1.9 mtpa | Pacific Northern Gas (existing) |
| | LNG Canada (2020) | Shell 40%, Mitsubishi 20%, Kogas 20%, Petrochina 20% | 25 year export license approved (Feb. 2012) | Up to 3.4 24 mtpa | TransCanada Coastal GasLink project (proposed) |
| | Triton LNG (2019) | AltaGas Idemitsu | 25 years export license to NEB approved(April 16, 2014) | Up to 0.32 2.2 mtpa | Pacific Northern Gas (expansion) |
| | Cedar LNG | Haisla Nation | License under review | Up to 2.4 14.5 mtpa | Unknown |
| Kitimat or Prince Rupert | WCC LNG (2021 to 2023) | Imperial Oil, Exxon Mobil | 25 year export license approved (Dec. 2013) | Up to 4 30 mtpa | Unknown |
| Prince Rupert | Pacific Northwest LNG (2018) **Lelu Island | Petronas 62%, Sinopec 15% Indian Oil Company 10% Japex 10% Petroleum Brunei 3% *Petronas plan to sell 10% to Indian Oil Company | 25 year export license approved (Dec. 2013) Filed for environmental assessment(April 2014) | Up to 2.74 19.2 mtpa | Prince Rupert Gas Transmission project by TransCanada (Proposed) |
| | Prince Rupert LNG (2020) **Ridley Island | BG Group PLC, Prince Rupert Port Authority and Spectra Energy | 25 year export license approved (Dec. 2013) | Up to 2.91 21.6 mtpa | Westcoast Connector Gas Transmission by BG group and Spectra |
| | New Times Energy (2019) | | | Up to 1.6 12 mtpa | Unknown |
| | Orca LNG (2019) | | | Up to 3.2 24 mtpa | Unknown |
| | WILNG | Watson Island LNG Corporation | | Small LNG | Unknown |
| Grassy Point | Aurora LNG (2021) | Nexen (CNOOC, China)/INPEX(Japan)/JGC Corps.(Japan) | 25 year export license approved (May 2014) | Up to 3.7 24 mtpa | Unknown |
| | SK E&S | SK E&S | Not yet applied for export license | Unknown | Unknown |
| | Woodside Petroleum Ltd | Woodside Petroleum Ltd | 25 year export license approved (Jan. 2015)) | Up to 2.8 20 mtpa | Unknown |

[89] Source: Paul Cheruvathur.

| | | | | | |
|---|---|---|---|---|---|
| **Stewart** | Stewart Energy (2017) | Stewart Energy | Applied for 25 years export license | Up to 4.04 30 mtpa | Stewart Energy pipeline |
| **Kitsault** | Kitsault Energy (2018) | Kitsault Energy | Applied for 25 years export license to NEB | Up to 2.63 20 mtpa | Unknown |
| **Squamish** | Woodfibre (2017) | Woodfibre Natural Gas Limited(Part of the Pacific Oil & Gas Group) | 25 year export license approved (Dec. 2013) | Up to 0.33 2.1 mtpa | Eagle Mountains-Woodfibre gas pipeline |
| **Campbell River/Delta/ Alberni Inlet** | Discovery LNG (2019) | Quicksilver Resources Canada Inc. | Engagement activities with the public, First Nations, and government | Up to 0.66 4.2 mtpa | Unknown |
| | Wespac LNG (2016) | WesPac Midstream Vancouver | Export License under review | Up to 0.46 3 mtpa | |
| | Steelhead LNG (2022) | Steelhead LNG Corp. & Huu-ay-aht First Nations | Export License under review | Up to 3.7 24 mtpa | Unknown |
| Total LNG output & gas requirement | | | 280 mtpa, 40 bcfd (415 Bcma) | | |

* Operational year is based on NEB files. ** Detailed location within Prince Rupert

Source: http://engage.gov.bc.ca/lnginbc/lng-projects/ and other public sources