Canada's Pipeline Transportation System 2016

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1 Foreword

The National Energy Board (NEB or the Board) is an independent federal regulator of pipelines, energy development, and trade. The Board's purpose is to promote safety and security, environmental protection, and efficient infrastructure and markets in the Canadian public interest within the mandate set by Parliament.

The Board's main responsibilities include regulating: the construction, operation, and abandonment of pipelines that cross international borders or provincial/territorial boundaries, as well as the associated pipeline tolls and tariffs; the construction and operation of international power lines and designated interprovincial power lines; and imports of natural gas and exports of crude oil, natural gas, oil, natural gas liquids, refined petroleum products, and electricity.

In support of its regulatory role, the Board actively monitors energy markets and produces neutral, independent, fact-based energy information for Canadians. These products increase the transparency of Canadian energy markets and support Canadian energy literacy. This report, *Canada's Pipeline Transportation System*, provides information about major pipelines regulated by the Board.

This report does not indicate whether any application filed with the Board will be approved or denied. The Board takes decisions on specific applications based on the evidence before it at that time. If a party wishes to rely on this report in any regulatory proceeding before the Board, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party would adopt the material and could be required to answer questions about it.

Contributors to this report include: Kiran Hundal (pipeline tolls), Darcy Johnson (financial integrity, crude oil), Amanda McCoy (document coordination), Andrea Oslanski (natural gas), Christian Rankin (crude oil), Jesus Rios (crude oil, NGLs), Margaret Skwara (natural gas), Michael Van Appelen (financial integrity), and Cassandra Wilde (natural gas, pipeline tolls).

2 Executive Summary

Canadians depend on pipelines to deliver natural gas, natural gas liquids, crude oil, and petroleum products across Canada. These pipelines deliver energy safely, reliably, and efficiently to Canadian end-users, connect North American markets and transport energy to ports for sales overseas.

This report, *Canada's Pipeline Transportation System*, provides information about the economic functioning of major pipelines regulated by the Board. In 2015, $99.7 billion worth of energy products were shipped in these pipelines at an estimated transportation cost of $7.3 billion.

The economic environment surrounding the energy sector has changed dramatically since 2014. Significantly lower oil and natural gas prices have led to deep cuts in industry spending and many delayed or cancelled projects. Despite price declines, Canadian oil and natural gas production increased in 2015, as did supply in the United States (U.S.). These and other market factors continue to present opportunities and challenges for Canadian energy pipeline systems.

A well-functioning pipeline transportation system responds effectively to changing market conditions. Some adjustments happen quickly, like changes to pipeline service offerings. Others take time, like seeking regulatory approval for, and potentially constructing, new pipeline facilities.

Key observations for NEB-Regulated Pipelines in 2015:

1. **Oil export capacity remained tight.** This is being driven by increases in crude oil supply in western Canada, primarily from the oil sands, while pipeline capacity additions have not kept pace. Several major pipeline projects have been proposed to expand market options for western Canadian oil supply growth, particularly to access tidewater and international markets. None of these projects are currently under construction. Crude oil transportation by rail has been required to supplement pipelines in moving growing oil supply to market.
2. **There was adequate capacity on most natural gas pipelines.** Production from the Western Canadian Sedimentary Basin (WCSB) remained steady. As a result the Alliance pipeline and portions of the Westcoast and NOVA Gas Transmission Ltd. (NGTL) systems generally operated at full capacity. Capacity was constrained in growing production areas of the WCSB, such as the Montney basin. On the other hand, competition from supply basins in the U.S. northeast resulted in reduced flows on pipelines transporting gas from Alberta to markets in the east. This dynamic has been accompanied by the reversal of some TransCanada Mainline segments to the Canada-U.S. border, allowing additional U.S. northeast gas imports into Ontario and Quebec.
3. **Pipeline companies and shippers were generally able to resolve the majority of their tolls and tariff issues through the negotiated settlement process.** The Board adjudicated some toll applications and shipper complaints that the independent parties were not able to resolve otherwise.
4. **NEB-regulated pipeline companies were financially sound.** Credit ratings continued to be investment grade, and key financial ratios were stable.

3 Canada's Pipeline Transportation System

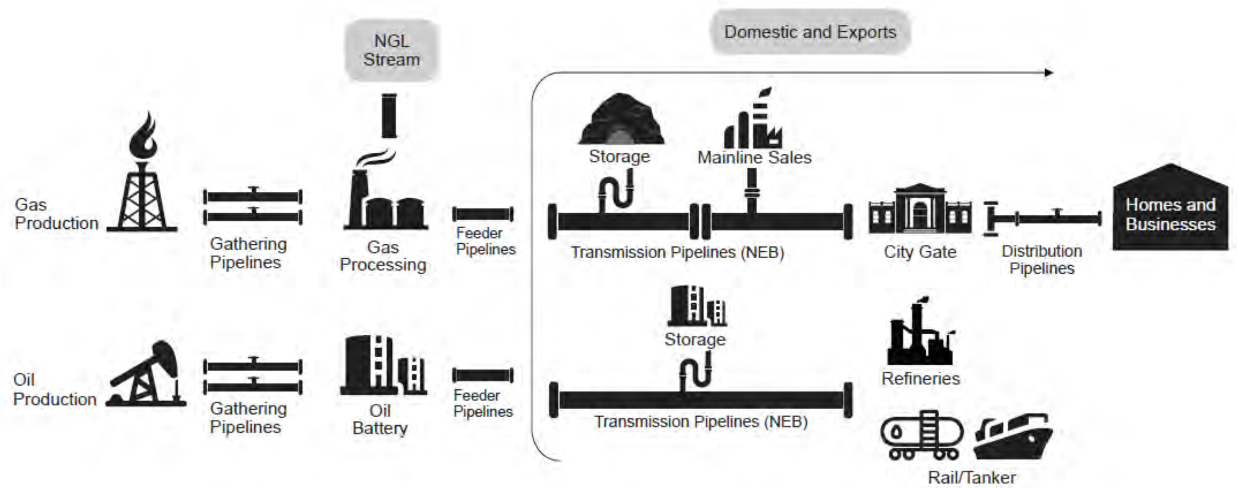
3.1 Pipeline System Overview

Canada's pipeline network is comprised of four main groups of systems; each one plays an integral part delivering energy to Canadians and export markets (Figure 1).

- Gathering Pipelines move crude oil and natural gas from wellheads to oil batteries or natural gas processing facilities. These pipelines are mainly concentrated in the producing areas of western Canada.
- Feeder Pipelines transport crude oil, natural gas, and other products such as natural gas liquids (NGLs) from batteries, processing facilities, and storage tanks to transmission pipelines. These pipelines are also mainly concentrated in the producing areas of western Canada.
- Transmission Pipelines are the major conduits of the pipeline network, transporting crude oil and natural gas within provinces and across provincial or international boundaries.
- Distribution Pipelines operated by local distribution companies or provincial cooperatives, these pipelines deliver natural gas to homes, businesses, and various industries.

FIGURE 1

Pipeline System Overview



If a pipeline crosses provincial or international boundaries, it is regulated by the NEB. If a pipeline is contained within a province, it is under the jurisdiction of a provincial regulator unless deemed as a federal undertaking. For example, in British Columbia, these pipelines are regulated by the BC Oil and Gas Commission.

The Board regulates approximately 73 000 km of pipelines, or about 10% of the length of pipeline in Canada. In 2015, energy products worth approximately $99.7 billion were transported in these pipelines (mainly transmission pipelines) at an estimated cost of $7.3 billion.

Figure 2 and Figure 3 show the major oil and natural gas pipelines regulated by the NEB.

FIGURE 2

Larger NEB-Regulated Crude Oil Pipelines

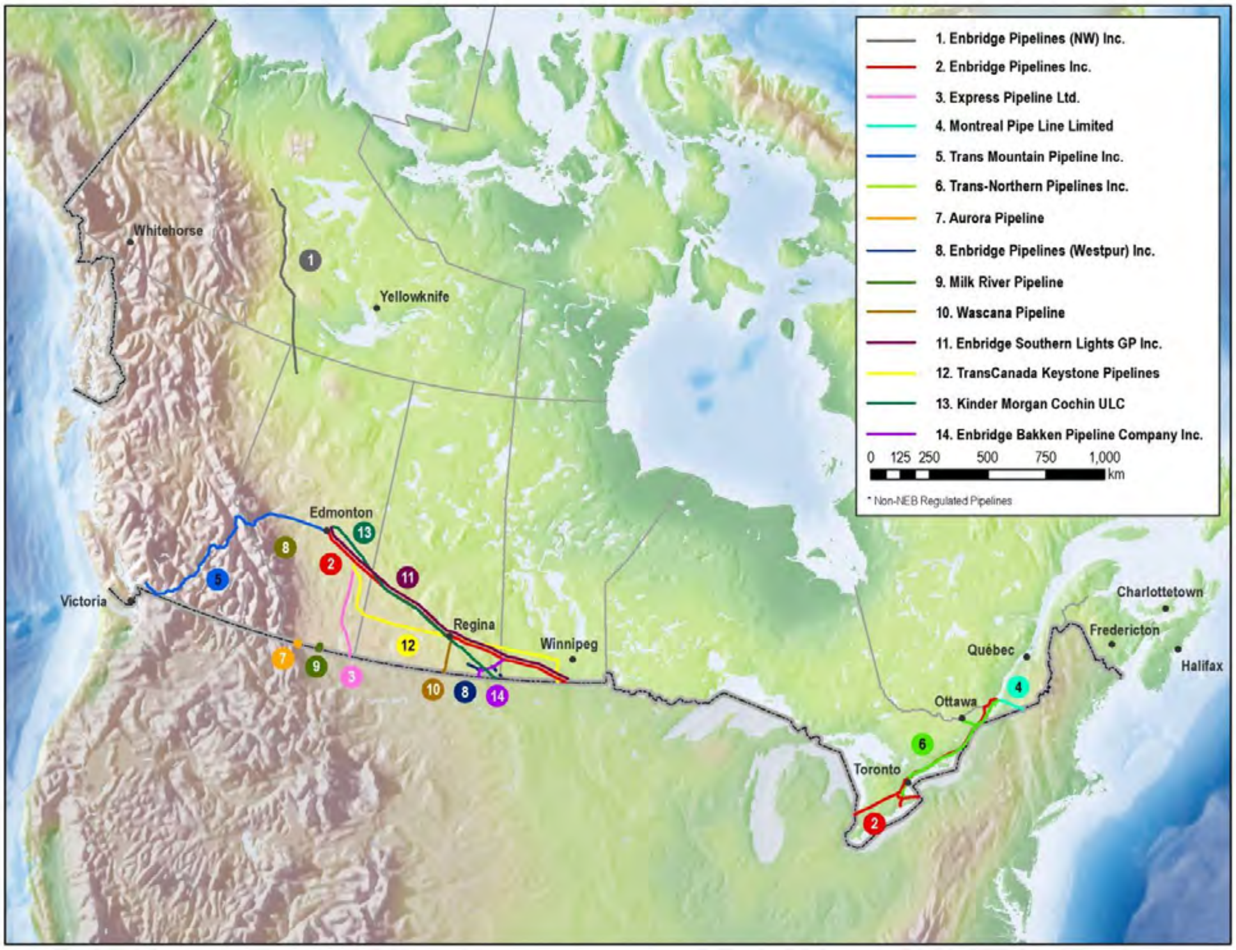


Table 1 provides an overview of some of the largest NEB-regulated crude oil and petroleum product pipelines. Four of these transport the majority of the crude oil out of western Canada, almost all of which is delivered to markets in eastern Canada and the U.S. The Kinder Morgan Trans Mountain pipeline (Trans Mountain) and the Enbridge Mainline (Enbridge) originate in Edmonton, Alberta and the Spectra Express (Express) system and the TransCanada Keystone (Keystone) system originate in Hardisty, Alberta.

TABLE 1

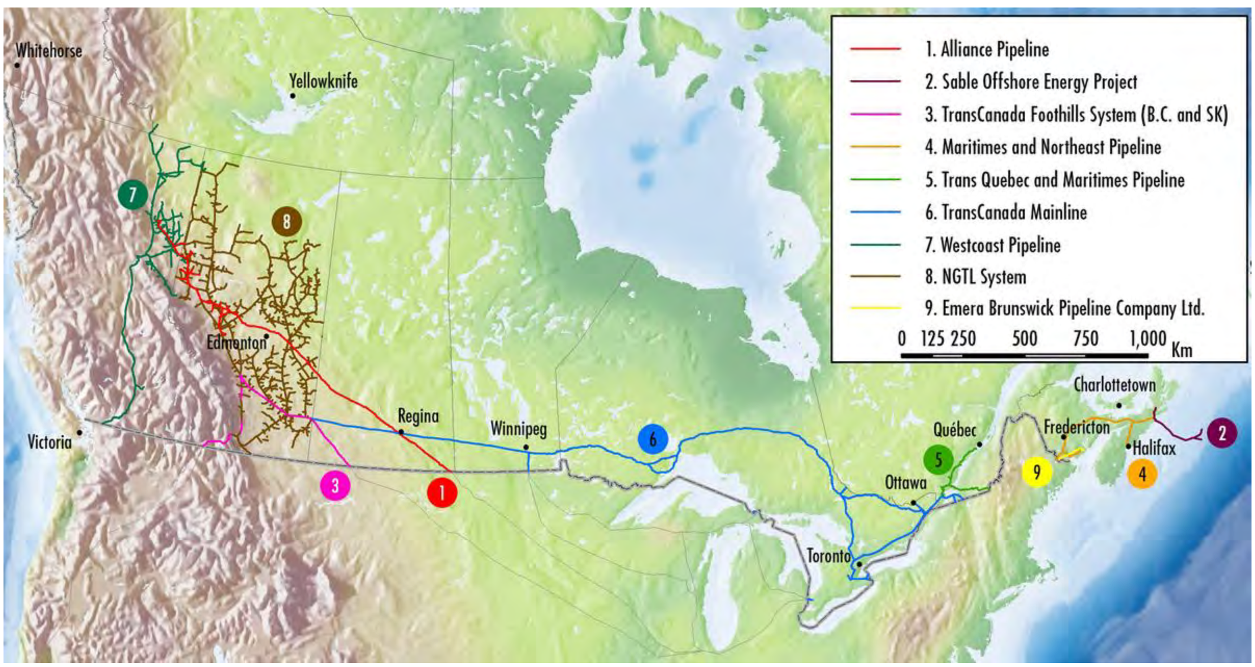
Larger NEB-Regulated Crude Oil Pipelines - Capacity and Throughput

	Capacity	Average Throughput 2015
Enbridge Mainline	453.3 10^3 m^3/d (2,851 Mb/d)*	368.7 10^3 m^3/d (2,320 Mb/d)
TransCanada Keystone	94 10^3 m^3/d (591 Mb/d)	88.3 10^3 m^3/d (555 Mb/d)
Kinder Morgan Trans Mountain[1]	47.7 10^3 m^3/d (300 Mb/d)	50.2 10^3 m^3/d (316 Mb/d)
Spectra Express	44.5 10^3 m^3/d (280 Mb/d)	35.2 10^3 m^3/d (222 Mb/d)
Montreal Pipeline (import)	44.5 10^3 m^3/d (280 Mb/d)	10.2$10^3$ m^3/d (65 Mb/d)
Enbridge Westspur	40.5 10^3 m^3/d (255 Mb/d)	28.1 10^3 m^3/d (177 Mb/d)
Trans-Northern Pipeline	Varies across segments	33.7 10^3 m^3/d (212 Mb/d)

* Effective export capacity is estimated at approximately 2 500 Mb/d, due to constraints on the connecting U.S. portion of the system.

FIGURE 3:

Larger NEB-Regulated Natural Gas Pipelines



Several NEB-regulated natural gas pipeline systems transport western Canadian production to markets in eastern and western Canada. Interconnections with U.S. pipeline systems also transport this natural gas to markets in the U.S. Northwest, Midwest, and Northeast. Table 2 provides an overview of some of the largest NEB-regulated natural gas pipelines.

1 The capacity figure for Trans Mountain assumes that 20% of throughput is heavy crude oil. As the proportion of heavy crude oil decreases, throughput capacity increases.

TABLE 2

Larger NEB-Regulated Natural Gas Pipelines – Capacity and Throughput

	Capacity	Average Throughput 2015
Nova Gas Transmission Limited (NGTL)		
Upstream James River	228 10^6 m^3/d (8.0 Bcf/d)	220 10^6 m^3/d (7.8 Bcf/d)
North and East Flow	121 10^6 m^3/d (4.3 Bcf/d)	87 10^6 m^3/d (3.1 Bcf/d)
Eastern Gate[2]	258 10^6 m^3/d (9.1 Bcf/d)	124 10^6 m^3/d (4.4 Bcf/d)
TransCanada Mainline		
Prairies	195 10^6 m^3/d (6.9 Bcf/d)	84 10^6 m^3/d (3.0 Bcf/d)
Eastern Triangle	148 10^6 m^3/d (5.2 Bcf/d)	69 10^6 m^3/d (2.0 Bcf/d)
Northern Ontario	102 10^6 m^3/d (3.6 Bcf/d)	61 $10^6$$m^3$/d (2.2 Bcf/d)
Foothills British Columbia	85 10^6 m^3/d (3.0 Bcf/d)	56 10^6 m^3/d (1.9 Bcf/d)
Foothills Saskatchewan	63 10^6 m^3/d (2.24 Bcf/d)	40 10^6 m^3/d (1.4 Bcf/d)
Westcoast		
T-North	81 10^6 m^3/d (2.9 Bcf/d)	58 10^6 m^3/d (2.1 Bcf/d)
T-South	44 10^6 m^3/d (1.6 Bcf/d)	40 10^6 m^3/d (1.4 Bcf/d)
Alliance	48 10^6 m^3/d (1.7 Bcf/d)	46 10^6 m^3/d (1.6 Bcf/d)

3.2 Supply and Disposition of Canadian Crude Oil and Natural Gas

In 2015, Canada was the fourth largest producer of oil and NGLs in the world, accounting for 4.8% of total global supply.[3] In 2015, crude oil production averaged about 615 thousand cubic meters per day (10^3 m^3/d) or 3.9 million barrels per day (MMb/d) of oil, most of which was shipped via pipeline[4] from western provinces to markets in other provinces or the U.S. (Figure 4).

Canadian crude oil production has grown steadily in recent years, mainly due to oil sands development. This has led to incremental expansion of export-oriented pipelines as producers seek new markets, including in the southern U.S. In 2014, substantial increases in pipeline capacity, particularly in the U.S., enabled Canadian producers to meaningfully access the U.S. Gulf Coast market for the first time. The energy industry remains focused on accessing and developing offshore markets to accommodate forecast growth in western Canadian oil supply, and several pipeline projects have been proposed to serve this need.

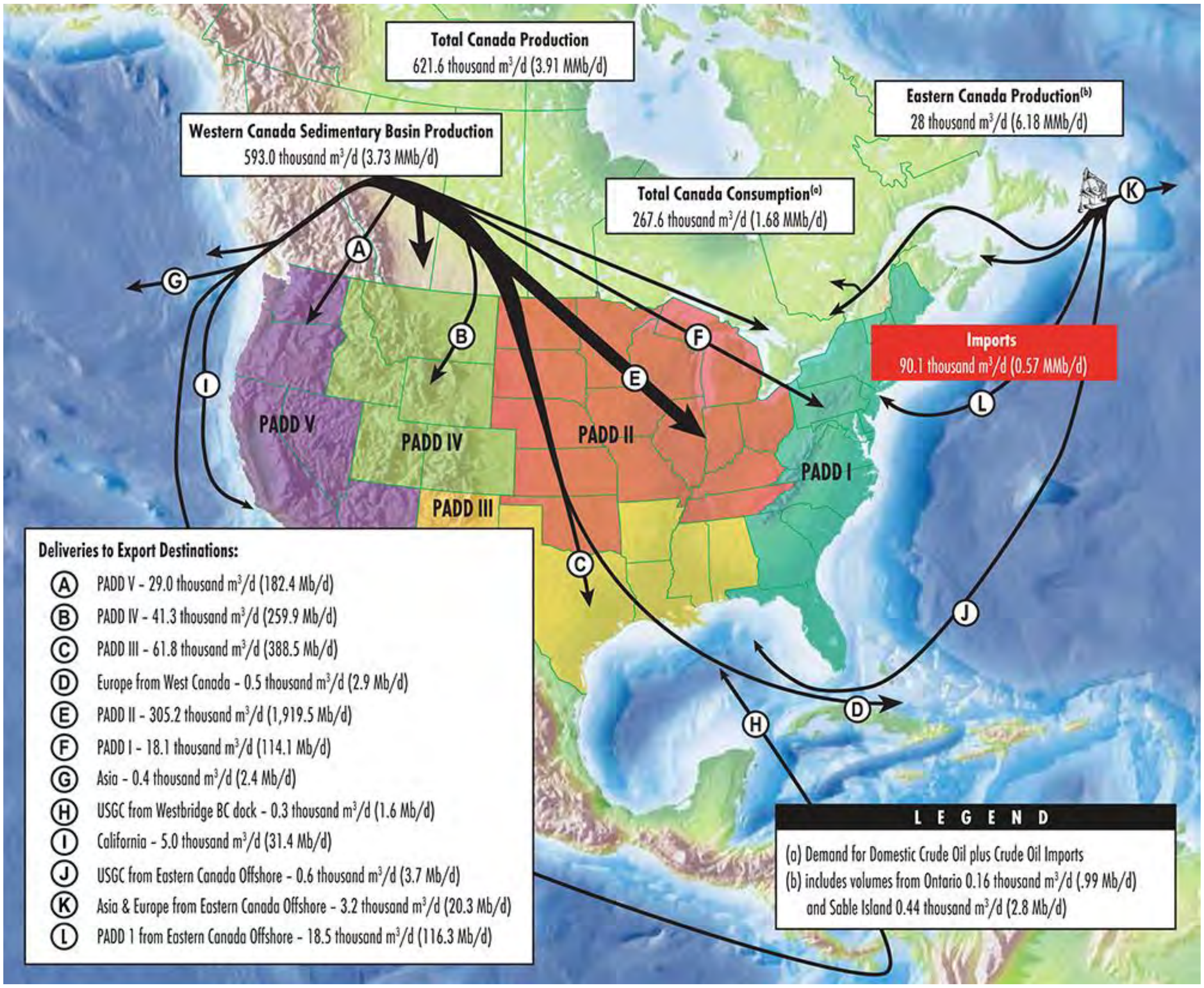
2 Calculation by the NEB based on the combined takeaway capacity of TCPL Mainline Prairies Segment and Foothills SK. TCPL estimates Eastern Gate design capability at 127 $10^6$$m^3$/d (4.5 Bcf/d).

3 BP Statistical Review of World Energy June 2016. BP's total production numbers include NGLs and differ from the Board's numbers.

4 NEB Analysis: Canadian Crude Oil Exports – By Export Transportation System Summary – 5 Year Trend

FIGURE 4

Supply and Disposition of Canadian Crude Oil 2015



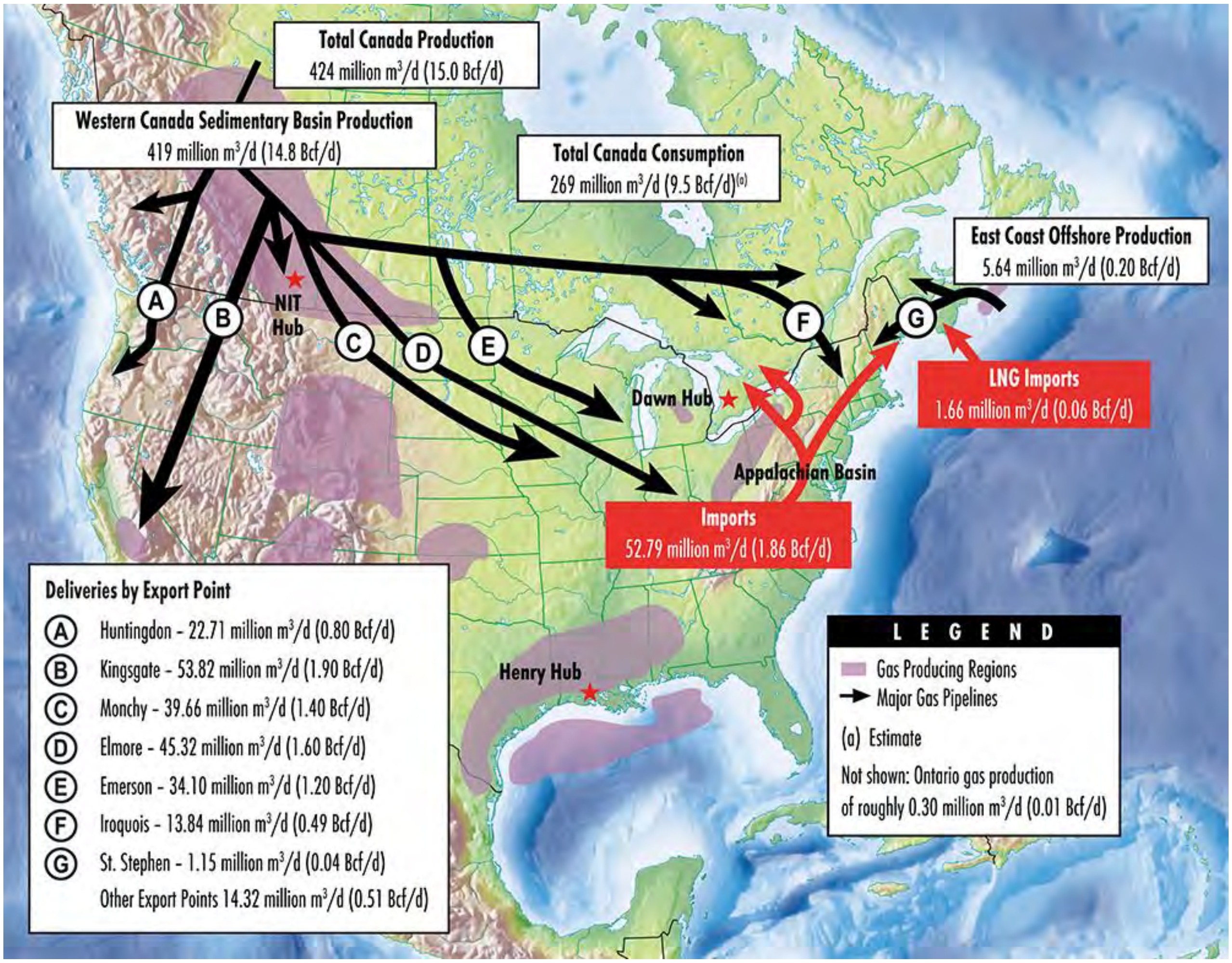
In 2015, Canada was the fifth largest producer of natural gas in the world, accounting for 4.6% of global supply.[5] Canadian natural gas production averaged about 424 10^6 m^3/d or 15 billion cubic feet per day (Bcf/d) in 2015. The vast majority of this natural gas was produced in western Canada and transported by pipelines to consumers in Canada and the U.S. (Figure 5).

While Canadian conventional natural gas production has declined in recent years, unconventional natural gas production is increasing as a result of advancements in horizontal drilling and hydraulic fracturing. Canada exports its surplus natural gas to the U.S., but increasingly, U.S. natural gas is competing with western Canadian supplies in both Canadian and U.S. markets. To find markets for surplus natural gas, many companies have proposed constructing facilities to export liquefied natural gas (LNG) overseas. No LNG export terminals are currently under construction and it would take several years for any of these projects to become operational.

5 BP Statistical Review of World Energy June 2016. Total production numbers differ from the Board's numbers.

FIGURE 5

Supply and Disposition of Canadian Natural Gas 2015

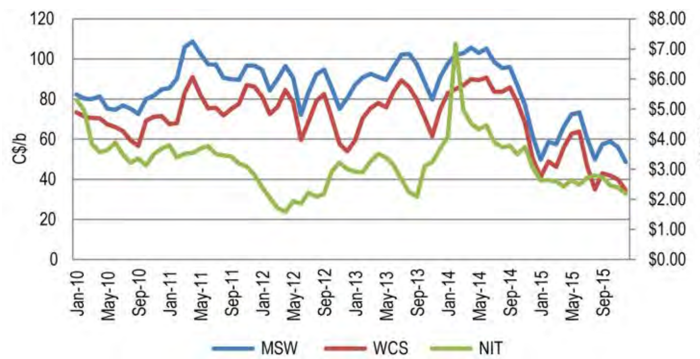


3.3 Commodity Price and Energy Industry Volatility

The economic environment surrounding the energy sector has changed dramatically since 2014. Figure 6 shows Alberta prices for Mixed Sweet (MSW) light crude oil, Western Canada Select (WCS) heavy crude oil, and the NOVA Inventory Transfer (NIT) natural gas price. By year-end 2015, oil and natural gas prices had declined by more than 50% in Canadian dollar terms. Lower prices over this time have resulted in substantial reductions in upstream spending on drilling and new production projects.

FIGURE 6

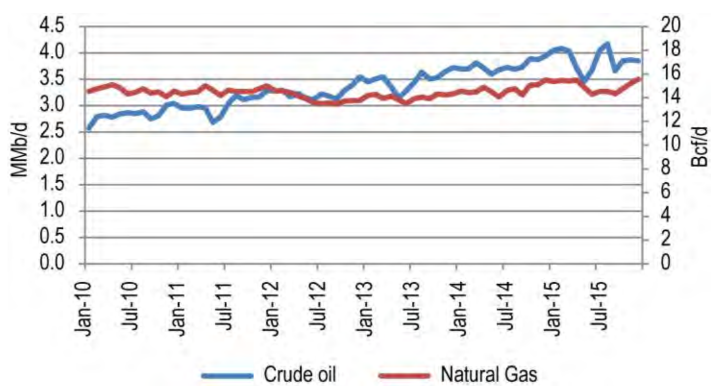
Canadian Crude Oil and Natural Gas Prices



Canadian oil and gas supply has remained relatively resilient, and Canadian crude oil and natural gas production grew in 2014 and 2015 (Figure 7). Canadian drilling levels were down more than 50% in 2015 versus 2014, however, and many major oil sands projects have been deferred or cancelled. These factors have created uncertainty about future levels of production.

FIGURE 7

Canadian Crude Oil and Natural Gas Production



The impact of recent energy industry volatility on NEB-regulated pipeline companies varies. Some companies have assets and lines of business beyond regulated pipelines (e.g. storage facilities and power plants) which can affect their exposure to risks and developments in the broader energy industry.

Returns on pipeline assets are regulated and often supported by long-term contracts[6], which reduces sensitivity to short-term market volatility. As explained later in this report, the prices that pipelines charge for their transportation services (tolls) are generally more directly related to specific pipeline costs than market conditions. In the longer term, expansion and investment in pipeline infrastructure depends in large part on oil and gas industry activity levels.

> **In the Public Interest**
>
> The Board regulates pipelines, energy development and trade in the Canadian public interest. The public interest is inclusive of all Canadians and refers to a balance of economic, environmental and social considerations that changes as society's values and preferences evolve over time.

6 For example, new oil pipeline infrastructure is commonly underpinned with long-term, take-or-pay transportation service agreements which serve to manage volume risk associated with supply and market variables. These are agreements between a pipeline company and its shippers in which the obligation to pay tolls for volumes committed over the contract term is binding regardless of whether commodities are supplied for transport. If a shipper's credit rating drops below investment grade, it could be required to post financial assurances to backstop its shipping commitments.

3.4 NEB Economic Regulation of Pipelines

Financial Regulation and Oversight

Pipelines under the Board's jurisdiction are divided into two groups for financial regulatory purposes: Group 1 pipeline companies have extensive systems and many shippers. Group 2 companies operate smaller, less complex pipelines with few shippers. A list of pipeline companies regulated by the Board can be found in the appendix in section 7.

Because of their size and complexity, Group 1 companies are subject to a higher degree of financial surveillance and have more extensive reporting requirements than Group 2 companies. All of the Group 2 companies (along with two of the smaller Group 1 companies) are regulated on a "complaint basis". Under complaint-based regulation, shippers or potential shippers are encouraged to work out any problems directly with the pipeline company. If this is unsuccessful, then a complaint may be filed with the Board for review.

The Board conducts financial audits to verify compliance with requirements in the *National Energy Board Act* (NEB Act) and associated regulations. The Board also receives and assesses regular surveillance reports from most Group 1 companies to monitor financial performance as well as throughput information. The Board receives audited financial statements from many of the Group 2 companies.[7]

Tolling

Pipeline tolls must be just and reasonable. Since it can be more efficient to build one pipeline rather than many competing pipelines, facilities under the Board's jurisdiction often have market power and in some instances, operate as monopolies in the markets they serve. The Board's role is to ensure that where market power exists, it is not abused and tolls for pipeline services are fair and non-discriminatory.

The Board sets tolls on the premise that a pipeline company should have the opportunity to cover its costs, including those related to safety and environmental obligations. Revenues should allow the company to effectively meet the transportation requirements of its customers and earn a reasonable rate of return for its investors.

Abandonment and Financial Liability

The Board regulates energy infrastructure over its entire life cycle – from project proposal to construction and operation, through to abandonment. In 2009, the Board directed that all NEB-regulated companies would be required to set aside funds to cover future pipeline abandonment costs. The Board stated that pipeline companies, and not landowners, are liable for the costs and financing of pipeline abandonment. Abandonment cost estimates for NEB-regulated pipelines are discussed in section 4.3 of this report.

On 18 June 2015, the *Pipeline Safety Act* (Act) received Royal Assent. The Act introduced absolute liability for all NEB-regulated pipelines, meaning that companies are liable for incident costs and damages irrespective of fault — up to $1 billion for companies operating major oil pipelines.[8] The Act also requires that companies demonstrate and maintain financial resources which match, at minimum,

7 The NEB has granted some pipeline companies exemptions from certain information filing requirements. The details that are provided as part of tariff applications or annual compliance filings differ among pipeline companies.

8 Companies have always been, and will continue to be, subject to unlimited liability when found to be at fault or negligent.

the amount of absolute liability applicable to them. In addition, a portion of these financial resources must be in a readily accessible form in order to facilitate rapid response to an incident. Regulations specifying the details of these requirements will be made by Governor in Council and are under development by Natural Resources Canada.

Monitoring Economic Aspects of the Pipeline Sector

The Board believes that well-functioning markets contribute to outcomes that serve the public interest. Correspondingly, the Board monitors important indicators of the economic functioning of the pipelines under its jurisdiction. Three of these key indicators – pipeline capacity, toll levels, and financial integrity – are discussed in detail in the remainder of this report.

4 Pipeline Capacity

The Board monitors three aspects related to the adequacy of pipeline capacity:

- price differentials compared with firm service tolls for major transportation paths;
- capacity utilization on pipelines; and
- the degree of apportionment[9] on major oil pipelines.

Markets have generally taken the view that some spare capacity on pipeline systems is desirable. This might result in higher tolls for shippers, but the costs associated with inadequate pipeline capacity (substantial revenue loss for producers and governments, and difficulty meeting consumer demand if producers are unable to move products to market) can be far greater. In addition, spare capacity gives shippers flexibility to serve different markets as conditions change, thereby maximizing their revenues and responding quickly to changes in consumer needs.

In a market where adequate capacity exists, suppliers will generally direct their product to the market that achieves the highest netback price.[10] Where inadequate capacity exists, the product cannot get to market, resulting in higher prices for downstream consumers and lower revenues for producers. In this way, higher price differentials may be created between market and supply regions. The Board monitors pricing differentials between relevant market hubs as an indicator of pipeline capacity adequacy. When pipeline capacity between two market hubs is adequate, commodity prices will be connected and the price differential will in general be equal to, or less than, the transportation costs between the two points.

4.1 Crude Oil

4.1.1 Price Differentials

Canada produces and exports both light and heavy crude oil grades. In general, light crude oil is more valuable to refiners because it produces a greater proportion of high-value transportation fuels. Heavy oil generally requires more processing and is run in more complex refineries. The following section reviews oil prices in Canadian and U.S. markets.

Between 2011 and 2013, the traditional markets for western Canadian crude oil, including western Canada, Ontario, the U.S. Midwest and U.S. Rockies regions, became saturated. At the same time, the

9 When shippers nominate more oil, or oil product, in a given month than the pipeline is able to transport, shipper volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be driven by several factors, including growing oil supply, increased oil demand, and reduced pipeline capacity.

10 A netback price is the price received for a product in the market, less the costs of moving the product to the market.

export pipelines serving these markets became increasingly full, and a build-up of crude oil in the U.S. mid-continent dramatically lowered inland North American oil prices relative to international prices.

Beginning in 2014 those discounts were mitigated mainly due to the addition of substantial pipeline capacity between Cushing, Oklahoma and the U.S. Gulf Coast via the TransCanada Cushing Marketlink project and the Seaway Pipeline, a joint venture owned by Enterprise Products Partners L.P. and Enbridge Inc.

In late December 2015, U.S. lawmakers lifted the ban on the export of U.S. crude oil which had been in place since the 1970s. This change will more closely link U.S. crude oil prices to international prices over the longer term, which is likely to benefit western Canadian producers who predominantly sell to U.S. markets.

Figure 8 shows the MSW light crude oil benchmark price at Edmonton, AB versus the West Texas Intermediate (WTI) price at Cushing, OK. These tracked closely in 2015 and the price differential between them was, on average, less than the pipeline transportation cost between the markets. This indicates that, overall, adequate pipeline capacity existed to transport western Canadian light oil supply to market.

Figure 8 also shows the Brent price, an international crude oil benchmark. Between 2011 and early 2014, constrained pipeline capacity between the U.S. midcontinent and the U.S. Gulf Coast, led to deep price discounting for both MSW and WTI relative to international grades. MSW and WTI price differentials to Brent narrowed substantially by the second half of 2015.

Figure 9 shows the WCS benchmark heavy crude oil price at Hardisty, AB versus the Maya heavy oil price at the U.S. Gulf Coast. These tracked closely in 2015 except for the summer months and the price differential between them was, on average, within the range of the pipeline transportation cost between the markets. This indicates that, overall, adequate pipeline capacity existed to transport western Canadian heavy oil supply to market.

However, spare capacity remained limited and prices were very sensitive to disruptions such as refinery operations and pipeline outages. These factors contributed to significantly lower prices for western Canadian heavy oil in July and August of 2015.

FIGURE 8

Mixed Sweet Light Crude Oil at Edmonton (MSW) vs. WTI at Cushing

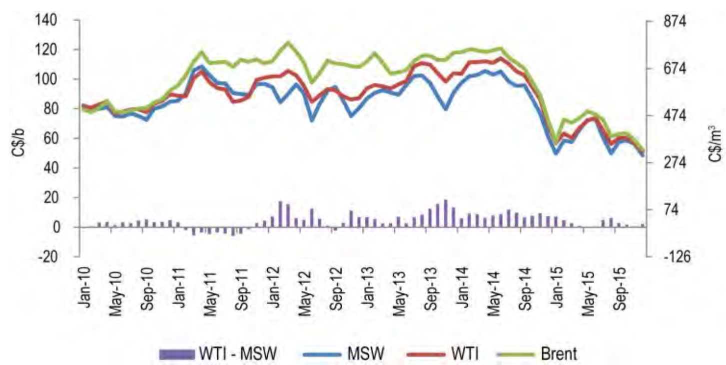
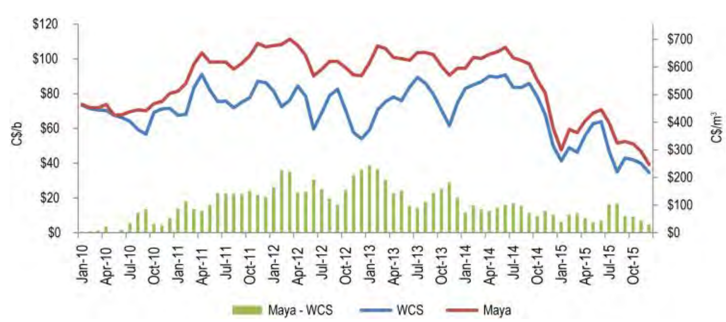


FIGURE 9

Heavy Crude Oil at Hardisty (WCS) vs. Maya at the U.S. Gulf Coast



4.1.2 Capacity Utilization and Apportionment

Information on major NEB regulated crude oil and liquids pipelines can be found in the appendix in section 8 and the appendix in section 9. In general, major crude oil export pipelines have been operating at, or near, capacity for several years as incremental pipeline additions have struggled to keep pace with supply growth.

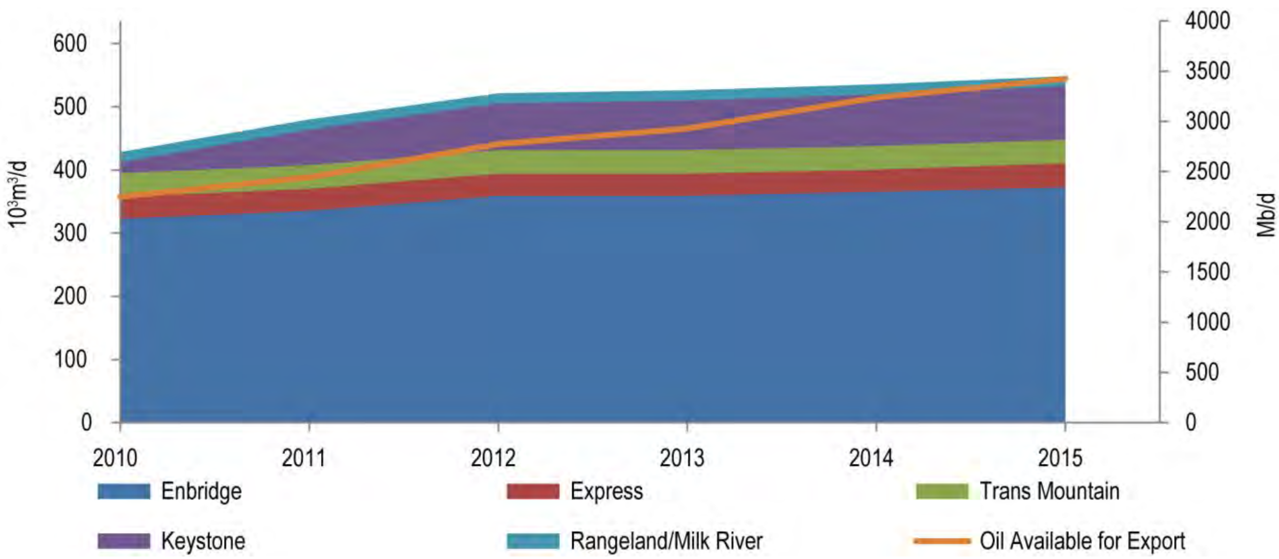
Figure 10 provides a snapshot of the WCSB crude oil transportation balance. While pipeline capacity has been increasing, supplemental crude oil transport by rail has been required since 2012 to move growing supply to market. Export volumes moving by rail increased steadily and peaked in the third quarter of 2014 at about 26.4 10^3 m^3/d (166 Mb/d). Subsequently, volumes were generally lower with increased pipeline capacity and lower crude oil prices. Crude oil exports by rail averaged about 19.9 10^3 m^3/d (125 Mb/d) in the fourth quarter of 2015, although volumes spiked to 26.4 10^3 m^3/d (166 Mb/d) in October 2015.[11]

Capacity and throughput increased on the Enbridge Mainline in 2014 and 2015 due to system flexibility enhancements and the Alberta Clipper expansion. While Enbridge Mainline export capacity at the end of 2015 was 453 10^3 m^3/d (2.85 MMb/d), effective export capacity was estimated at approximately 397 10^3 m^3/d (2.5 MMb/d) due to pipeline constraints on the U.S. portion of the system downstream of Superior WI. In December 2015, the Enbridge Line 9B reversal became operational, providing Québec refiners with access to western Canadian crude oil by pipeline. Capacity utilization increased modestly on the Express and Keystone systems, while Trans Mountain has generally been operating at capacity for the past several years.

Unlike Keystone and Express, which have long-term contracts for the majority of their capacity, shippers on Trans Mountain[12] and Enbridge nominate volumes for delivery into the pipeline each

FIGURE 10

WCSB Pipeline Takeaway Capacity vs. Supply Available for Export



11 NEB Canadian Crude Oil Exports by Rail Monthly Data

12 High demand for pipeline capacity to the west coast has contributed to apportionment on Trans Mountain and triggered several applications to allocate capacity between Land Shippers (mostly B.C. and Washington State refineries) and Dock Shippers (marine exporters). Currently, approximately 26% of capacity is allocated to the Westridge Dock, including 8.6 10^3 m^3/d (54 Mb/d) of firm service and 4.0 10^3 m^3/d (25 Mb/d) of interruptible service which is auctioned each month.

month. In a given month, if shippers nominate more volume than the pipeline can transport, each shipper's nominated volume is apportioned (reduced) by the same percentage. Enbridge and Trans Mountain have had significant apportionment over the past several years, indicating that pipeline capacity on these systems has at times been inadequate to meet shipper demand.

4.1.3 Proposed Export Pipelines

Western Canadian oil supply continues to grow steadily despite significantly lower crude oil prices. This is driven by the completion of production projects, especially in the oil sands. Industry has proposed a number of crude oil pipeline projects that would expand capacity exiting western Canada and diversify markets available to producers. Major proposed projects under the Board's jurisdiction are described below and shown in Figure 11.

Enbridge Line 3 Replacement Project (Line 3)

On 25 April 2016, the Board recommended approval of the facilities application for the Line 3 project. The project would bring Line 3 to its original design capacity of 121 $10^3 m^3/d$ (760 Mb/d), allowing the additional flow of 58.8 $10^3 m^3/d$ (370 Mb/d). Line 3 is part of the Enbridge Mainline, which delivers crude oil from western Canada to the U.S. Midwest. Its proposed in-service date is 2019.

Enbridge Northern Gateway Pipeline (Northern Gateway)

The Joint Review Panel recommended Northern Gateway for approval with conditions in December 2013, and in June 2014, the Governor in Council approved the project. In a decision released on 30 June 2016, the Federal Court of Appeal quashed the Governor in Council approval directing the Board to issue the Certificates for the Project. The Court also quashed the Certificates. Northern Gateway has an initial design capacity of 83.5 $10^3 m^3/d$ (525 Mb/d) and would originate in Bruderheim, Alberta (near Edmonton) and terminate in Kitimat, British Columbia. The project also includes a parallel pipeline that would be designed to import up to 30.7 $10^3 m^3/d$ (193 Mb/d) of condensate for use in blending at oil sands operations.

Kinder Morgan Trans Mountain Expansion (TMX)

On 19 May 2016, the Board recommended approval of the TMX facilities application. The project would increase the capacity of the existing Trans Mountain system by 93.8 $10^3 m^3/d$ (590 Mb/d) to 141.5 $10^3 m^3/d$ (890 Mb/d). It would originate in Edmonton, Alberta and terminate in Burnaby, British Columbia. The project proposes to serve Pacific Basin markets with a target in-service date of 2019.

TransCanada Energy East (Energy East)

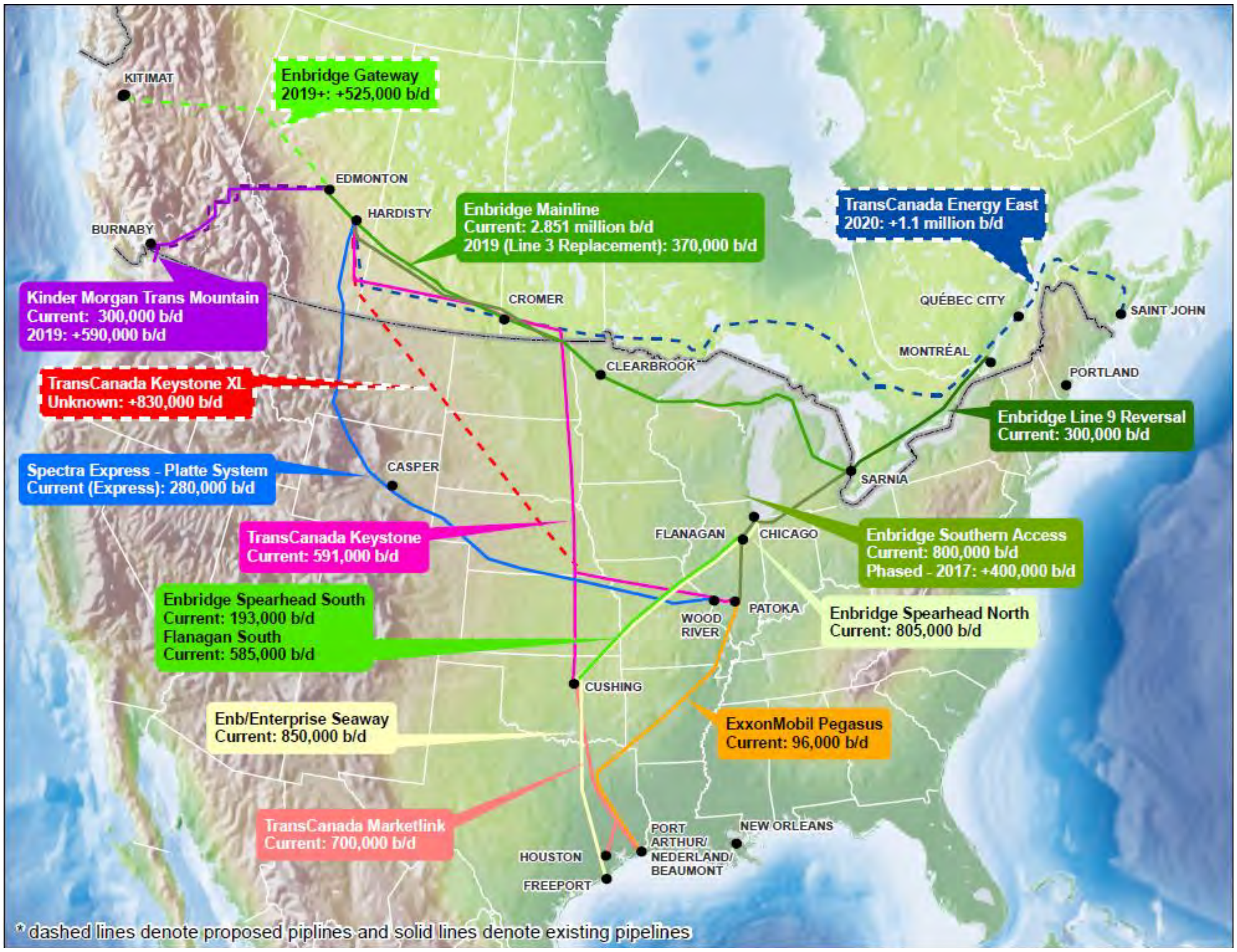
As of June 2016, the facilities application for Energy East was before the Board. The project is designed with an initial capacity of 174.9 $10^3 m^3/d$ (1.1 MMb/d). If approved, it would originate in Hardisty, Alberta, terminate in Saint John, New Brunswick, and serve eastern Canadian and international markets. It has a proposed target in-service date of 2020.

TransCanada Keystone XL (Keystone XL)

The Canadian portion of the Keystone XL project was approved by the Board in March 2010. TransCanada applied to the U.S. Department of State for a Presidential Permit in September 2008 for the U.S. portion of the system, and in November 2015, this application was denied. TransCanada has stated that it and its shippers remain committed to the project, and is challenging the U.S. decision legally.

FIGURE 11

Canadian and U.S. Oil Pipelines and Proposals



4.2 Natural Gas Liquids

In 2015, Canada exported approximately 21.7 $10^3 m^3/d$ (137 Mb/d) of propane and butanes, the majority by rail.[13] Propane and butanes pipeline exports mainly occur via the Plains Eastern Delivery System which originates near Sarnia, ON.

In April 2014, the Kinder Morgan Cochin Pipeline (Cochin) was reversed and ceased exporting propane as it had historically. Condensate imports on the Cochin system began July 2014. The Cochin pipeline has been operating at high utilization rates since it reversed flow. Like Cochin, the Enbridge Southern Lights pipeline also imports condensate from the U.S. for bitumen blending. It operated at approximately 60% of capacity in 2015. Further information about Canadian NGL import and export pipelines can be found in the appendices in sections 8 and 9.

U.S. NGL supply has been growing in recent years as a result of steep increases in shale gas production. The abundance of low-cost ethane in the eastern U.S. (Marcellus and Utica), and in North Dakota (Bakken), has supported new ethane import pipelines connecting to petrochemical hubs in Canada.

13 NEB 2015 Propane and Butanes Exports Summary

Two new NGL import pipelines began operation in recent years to bring ethane supplies to Canada:

- The Vantage pipeline (also called the Pembina Prairie Facilities) originates in Tioga, North Dakota and moves ethane sourced from Bakken gas to the Alberta Ethane Gathering System at Empress, Alberta, which then delivers it to the NOVA petrochemical plant in Joffre. Vantage came into service in late 2014.
- The Genesis pipeline originates near Marysville, Michigan, crosses the St. Clair River into Canada, and continues to the NOVA petrochemical complex in Corunna, Ontario. Genesis delivers ethane transported by the Mariner East pipeline from the Marcellus region. Genesis came into service in late 2013.

In general, these import pipelines have been operating at medium to high utilization rates. Planned and announced Canadian petrochemical plant capacity expansions could possibly increase future imports via these systems. NOVA is currently constructing a $1.0 billion expansion of its polypropylene facility in Joffre which has a fourth quarter 2016 target in-service date. NOVA is also considering building a new polyethylene plant in Sarnia, and expanding its NGL cracker at Corunna, ON. If approved by 2018, these could be in operation by 2022.

4.3 Natural Gas

4.3.1 Price Differentials

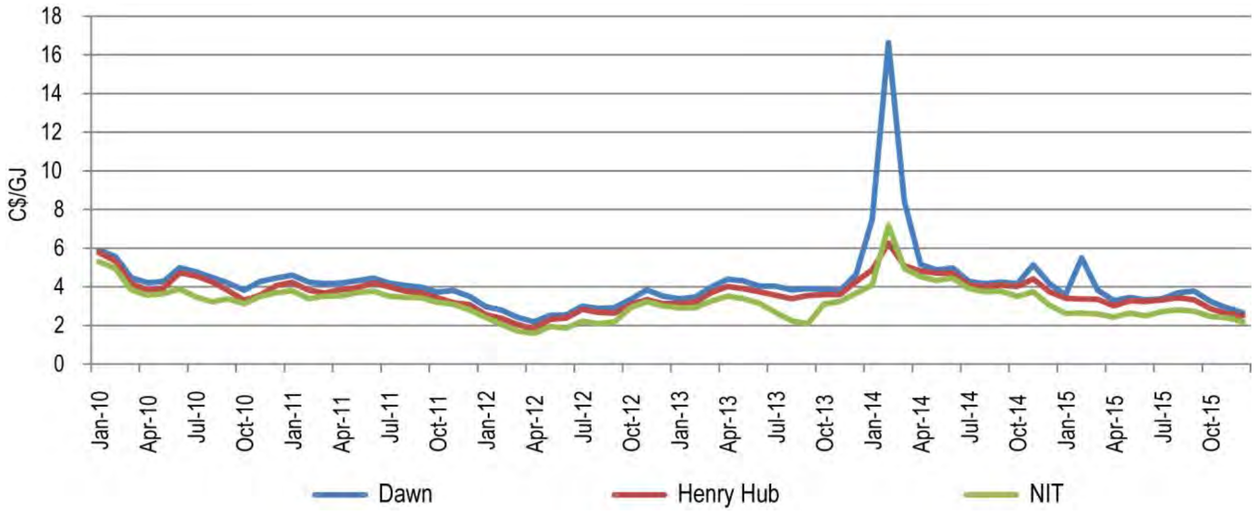
North American natural gas markets are generally well connected by pipeline. As a result, natural gas prices are also well connected. Gas prices tend to be lower near major supply areas such as the NIT hub in Alberta, and higher near demand centres such as the Dawn hub in southern Ontario. Over the long term, prices in different markets tend to move up and down together. The price differential represents the value of transportation. The better connected the markets, the more closely the prices will track.

Figure 12 shows monthly averages of daily natural gas prices at the NIT hub, the Dawn hub, and the Henry Hub in Louisiana. The three prices generally moved together with variations caused by local weather events or temporary capacity restrictions. For example, when natural gas prices spiked at Dawn in early 2014 due to the extreme cold conditions referred to as the Polar Vortex, gas prices also increased at Henry Hub and at NIT (Alberta) even though these areas were experiencing a temperate winter. Throughout 2015, these three prices declined together, indicating a connected market.

Historically, the large volumes of natural gas produced in the WCSB have been delivered to markets in Canada and the U.S. via pipelines such as the TransCanada Mainline. Since the late 1990's, the price difference between the NIT hub in the west and Dawn or Henry Hub in the east was approximately equal to the cost of moving the gas from west to east. In other words, a producer would end up with the same net amount of money whether the gas was sold in the east or west.

FIGURE 12

Natural Gas Prices at Major North American Hubs



In the last decade, technology has made it possible to produce natural gas from shale at low cost. In the U.S., production has increased dramatically in the Appalachian Basin (Figure 5), particularly the Marcellus Shale. From little production in 2008, it now produces more natural gas than all of Canada and it is located very close to highly populated Canadian markets in Ontario and Quebec, and traditional Canadian markets in the U.S. Northeast. Consequently, markets in eastern Canada are sourcing increasing amounts of gas from the U.S. and less gas from the WCSB.

Figure 13 shows the differential between gas prices at NIT in Alberta and Dawn, Ontario. The cost to move gas between these hubs on NGTL plus the TransCanada Mainline on a firm basis is shown by the red line. Shippers which sign long-term contracts with pipelines, pay tolls that are based on the costs of the pipeline regardless of prices in the market. As a result, the toll to move gas is often higher than the price differential between the supply and market areas. On the TransCanada system the price differential fluctuates, but it is generally well below the total cost of transportation. This indicates that there is unutilized pipeline capacity between the two hubs.

In the winters of 2014 and 2015 when demand was at its highest because of extremely cold weater in central Canada, the Dawn price became much higher than the NIT price. At certain times, the differential was higher than the tolls, as shown in Figure 13. Throughput on the Mainline increased during these periods, but pipeline capacity was not generally constrained.

In 2015, the differential averaged approximately $1/GJ while the firm transportation cost was almost double at approximately $2/GJ. In theory, producers transport natural gas to those markets that will result in the highest netback, and buyers will source their natural gas from supply areas that will result in the lowest landed cost of gas. In practice, natural gas moves for many other reasons, such as supply security, path diversity, costs of alternative transportation services, and price hedging to manage risk. Eastern consumers still depend on a mix of gas from the WCSB and other sources, so they still pay to transport gas from the WCSB. That said, additional changes in supply, contracting and pipeline utilization to serve central and eastern consumers are expected.

FIGURE 13

Alberta-Dawn Price Differential vs. Firm NIT to Dawn Toll Including Fuel

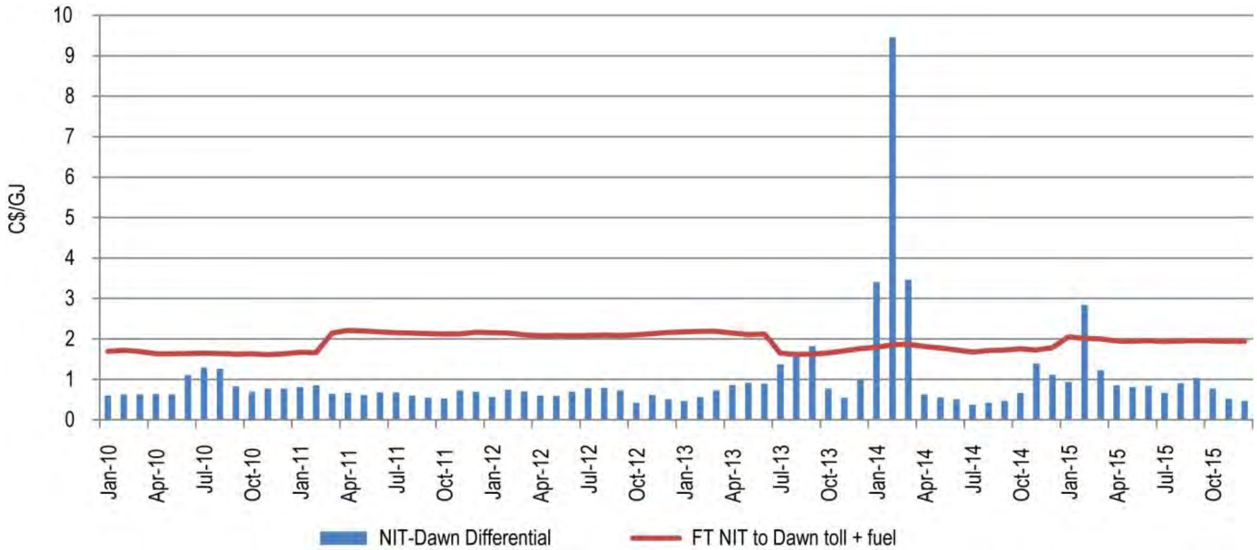
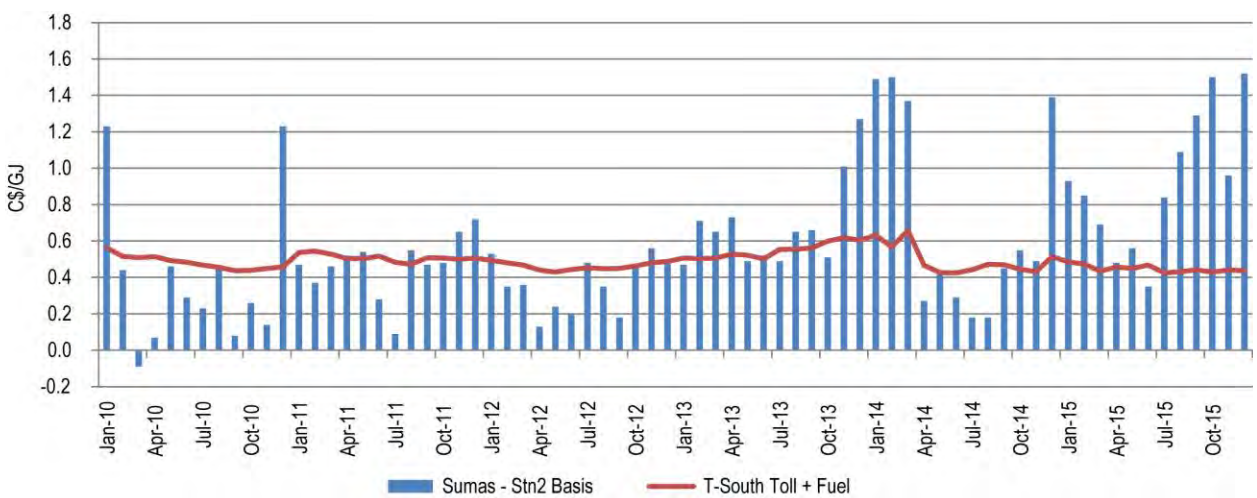


Figure 14 shows the price differential compared with the firm tolls on Spectra's Westcoast T-South system between the Station 2 hub in northern British Columbia and the Sumas export point to Washington State. Historically, the price differential between Station 2 and Sumas was comparable to the transportation cost between the two points. This indicated adequate pipeline capacity.

FIGURE 14

Sumas-Station 2 Price Differential vs. Westcoast T-South Toll



In most months since late 2013, the price differential between these two points has been higher than the cost of transportation. This means that shippers could earn more by selling their gas at Sumas than at Station 2, provided that they were able to transport it there. However, due to strong production from northeastern British Columbia, capacity is constrained. Consequently, prices have fallen at Station 2 and the price differential between Sumas and Station 2 has increased, reflecting capacity constraints.

4.3.2 Capacity Utilization

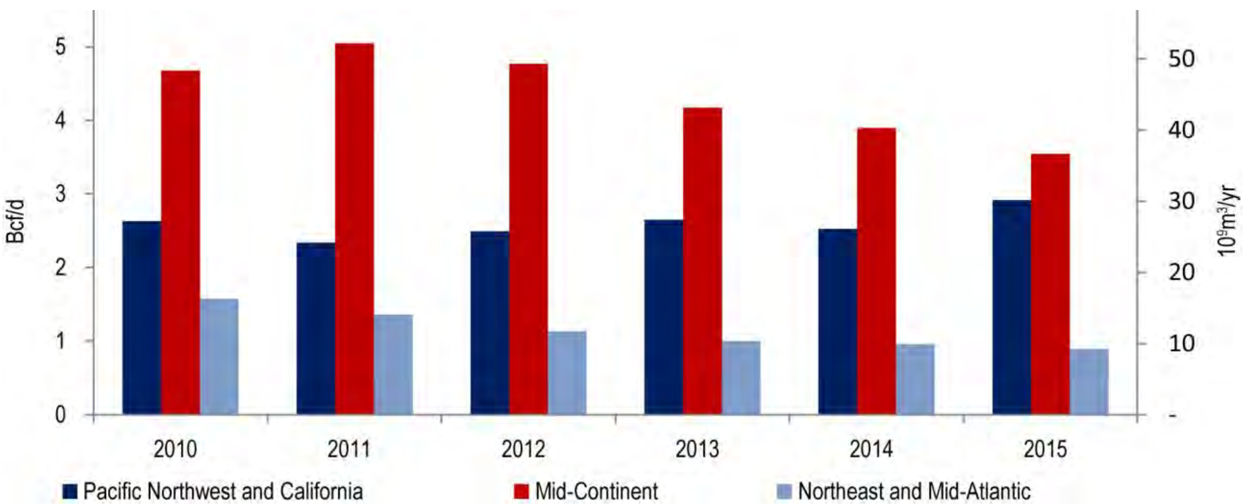
Throughputs on natural gas pipelines in Canada tend to be higher in the winter due to weather related demand, and decrease over the summer season. Over the long-term, utilization trends are determined by evolving supply and demand. An analysis of capacity and throughputs for major NEB-regulated natural gas pipelines can be found in the appendices in sections 9 and 10.

The Alliance pipeline, portions of the Westcoast and NGTL systems, and the Niagara and Chippewa eastern Canada import points on the TransCanada Mainline have, in general, been operating at full capacity. On the other hand, some pipeline systems or portions of pipeline systems have excess capacity. These include the Prairies and the Northern Ontario Line sections of the TransCanada Mainline, as well as the Emera Brunswick Pipeline.

These capacity and utilization patterns are highly linked to production and export trends. While WCSB production remained steady over the last five years, net exports to the U.S. declined by 24% as growing demand for natural gas in Canada decreased gas available for export, and as requirements for Canadian gas in the U.S. market declined. Figure 15 shows that between 2010 and 2015, exports to the U.S. Northeast decreased by 44% and exports to the mid-continent decreased by 24%. During this time, supply growth from the Appalachian Basin displaced gas traditionally supplied from the WCSB.

FIGURE 15

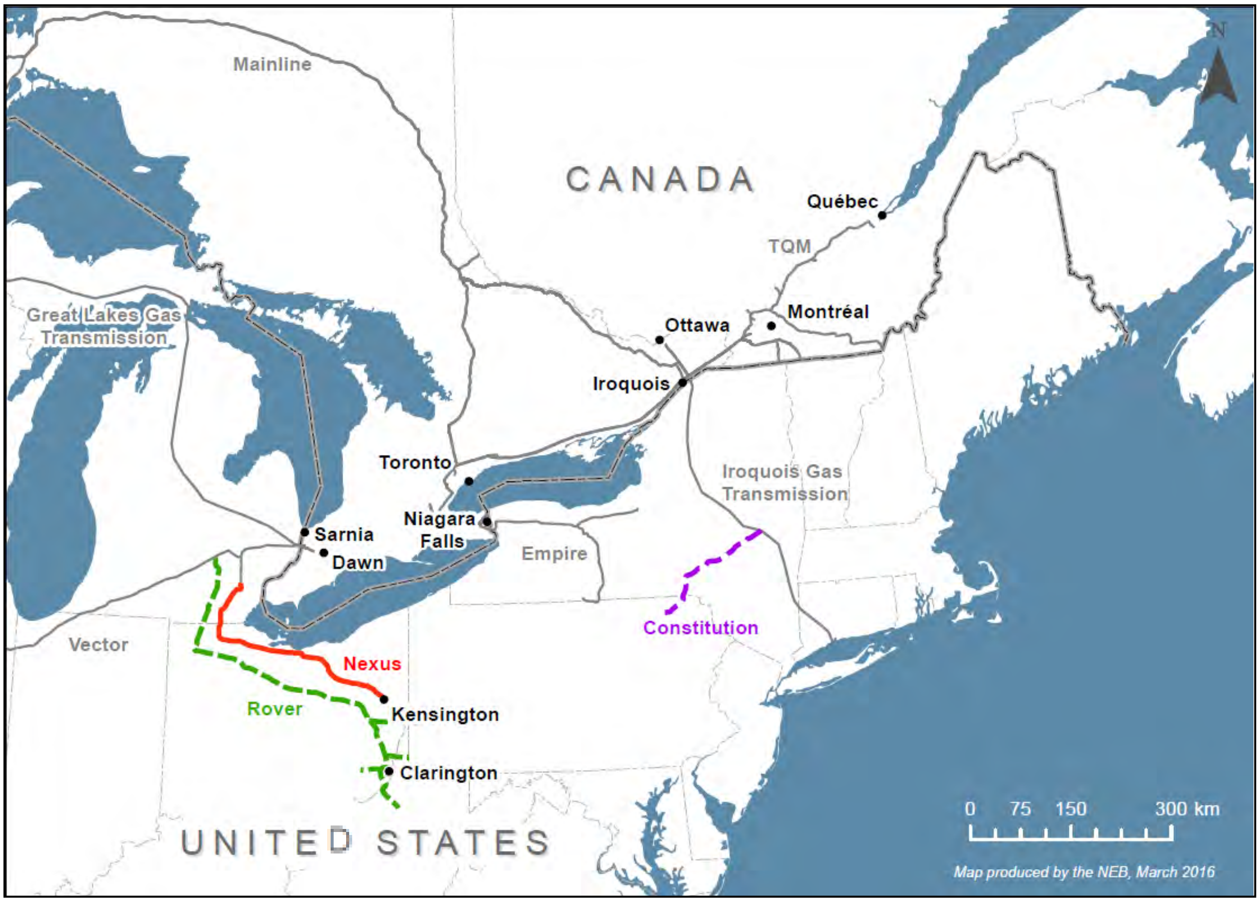
Canadian Natural Gas Exports to the U.S. by Region



Given the significant decrease in Canadian net exports, utilization patterns on some NEB-regulated natural gas pipelines have evolved such that physical flows on certain segments have been reversed. For example, some export points on the TransCanada system were converted to import points: Niagara in November 2012 and Chippewa in November 2015. Combined imports at these two points averaged 21.2 10^6 m^3/d (0.75 Bcf/d) in 2015, compared to exports which were as high as 39.6 10^6 m^3/d (1.4 Bcf/d) in the winter months between 2006 and 2008.

FIGURE 16

Pipeline Proposals to Supply Gas to Ontario and Quebec



With expectations of significant long-term growth in U.S. natural gas production, industry has proposed a number of new pipeline projects that would diversify supply for consumers in Ontario and Quebec (Figure 16). Several projects propose to increase Appalachian Basin deliveries to the Dawn hub in Ontario by connecting to the Vector Pipeline which brings gas into Canada. These increased deliveries will likely further impact west-to-east flows, particularly on the TransCanada Mainline and other systems in the U.S., such as the Great Lakes Gas Transmission System.

In 2015, supply from offshore Nova Scotia varied significantly due to a production shut-in at the Deep Panuke platform from June to November. In addition, Sable production also continued to decline from historical levels. Combined production from Deep Panuke and Sable averaged 5.7 10^6 m^3/d (0.2 Bcf/d), a decrease of 40% from 2014. Due to lower gas supply in the Maritimes, the St. Stephen export point on the Maritimes and Northeast Pipeline (M&NP) was used increasingly to import natural gas from the U.S.

5 Pipeline Tolls and Shipper Services

The Board regulates tolls and tariffs for the pipelines under its jurisdiction to ensure they are just and reasonable. The Board also requires that pipeline companies operate according to the principle of "open access". This means that all parties must have access to transportation on a non-discriminatory basis, as long as they meet the requirements of the tariff.

In addition, tolls for services provided under similar circumstances and conditions with respect to all traffic of the same description, carried over the same route, must be the same for all customers.

The Board uses a number of mechanisms to monitor whether pipeline companies are providing services that meet the needs of shippers at reasonable prices (tolls), and whether pipeline companies are complying with regulatory requirements. This includes monitoring pipeline tolls, requiring regular filings by companies, conducting financial audits, and directly soliciting shipper feedback in surveys. Parties may also file formal complaints with the Board if they are unable to resolve concerns on specific toll and tariff matters.

Tariff

A tariff is a document containing the terms and conditions under which the service of a pipeline are offered or provided. It includes the tolls, rules and regulations, and practices relating to specific services.
A pipeline company cannot charge a toll unless it is included in a tariff filed with the Board or approved by an order of the Board. The tariff also outlines the rights and responsibilities of both the pipeline company and shipper once service begins.

5.1 Negotiated Settlements and Toll Proceedings

A negotiated settlement is an agreement between a pipeline company and its stakeholders concerning issues related to the company's revenue requirement[14], tolls, tariffs, and operational matters. In discussions leading to such an agreement, interested persons must have a fair opportunity to participate and have their interests recognized. The need for a formal hearing process before the Board would normally be eliminated if:

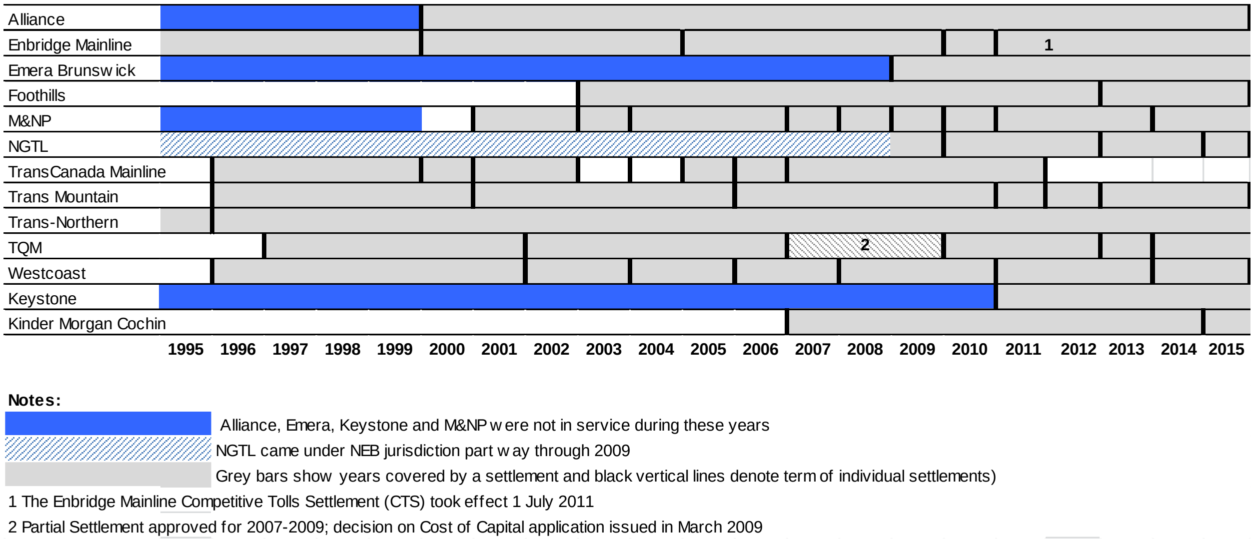
- the parties are able to settle all outstanding issues,
- the Board is satisfied that there are no public interest considerations that extend beyond the immediate concerns of the negotiating parties, and
- the settlement results in just and reasonable tolls and does not contradict the NEB Act.

Pipeline companies and shippers continue to resolve most toll and tariff issues with negotiated settlements. Figure 17 shows that most major pipelines regulated by the Board have operated under negotiated settlements during all, or a portion, of the last five years. Between mid-2013 and the end of 2015, the Board issued six decisions on contentious toll and tariff applications that were not resolved through negotiation. As of June 2016, one proceeding was ongoing.

14 The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, and return on rate base.

FIGURE 17

Negotiated Settlements Timeline



Some of the issues adjudicated by the Board were related to the toll treatment of changes to facilities such as reversals, expansions, or extensions of existing systems. For proceedings that were purely related to tolls, some considered the entire toll structure or methodology while others looked at specific components of the tariff.

From mid-2013 to 2015, the Board received 10 complaints from shippers. Half of the complaints were withdrawn and the Board issued direction on the other five complaints. The Board upheld two complaints, directed further action on two complaints, and found insufficient evidence to proceed further on one complaint.

5.2 Pipeline Tolls Index

Stable and reasonable tolls are a key concern for shippers and therefore one of the indicators of the efficiency of a transportation system. Often, lower throughput leads to higher tolls as the pipeline's costs are shared by the remaining shippers on the system. With cost of service regulation, large expenditures such as facility expansions can increase or decrease tolls depending on the impacts on throughput and revenue. The following section reviews toll variations and trends since 2010 for some NEB-regulated pipelines.

5.2.1 Oil Pipeline Tolls

The benchmark tolls for major Group 1 oil and liquids pipelines, as well as the gross domestic product (GDP) deflator[15] normalized[16] to 2010, are shown in Figure 18.

> **Shipment and payment**
>
> The tariff sets out the procedure by which shippers must nominate and tender their product for transportation, and the terms of payment. Nominations for transportation are generally made on a monthly basis for oil pipelines and up to several times daily for gas pipelines. Shippers are typically invoiced monthly.

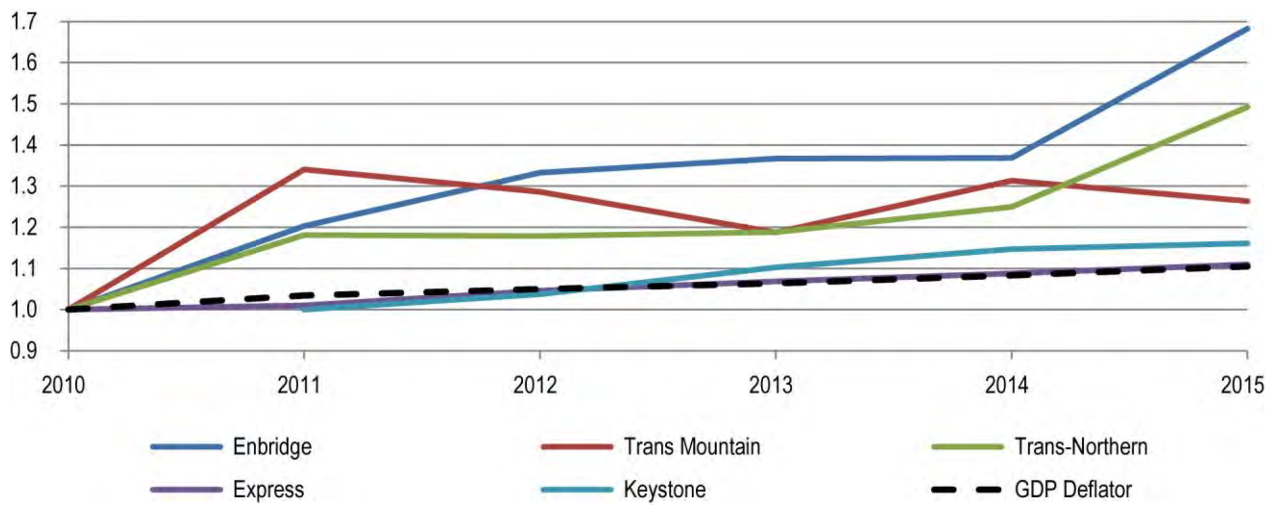
15 The GDP deflator is a measure of inflation. Pipeline tolls are compared to the GDP deflator to indicate how they have changed relative to overall inflation.

16 Differing pipeline distances add to the challenges of comparing tolls between pipelines. To allow comparison, all tolls and the GDP deflator are compared to their own values in 2010 by normalizing so that the 2010 value equals one.

A variation in pipeline tolls can be the result of a number of factors, such as changes in throughput as well as operating and capital costs. Trans-Northern Pipelines Inc. (Trans-Northern) and Enbridge both experienced notable increases in their respective benchmark tolls in 2015. The Trans-Northern toll rose by 19% in 2015 due in part to spending on pipeline integrity. Enbridge's increase of 23% in 2015 can be attributed to the addition of a surcharge related to the Edmonton to Hardisty Pipeline Project.

FIGURE 18

NEB-Regulated Oil Pipeline Benchmark Tolls



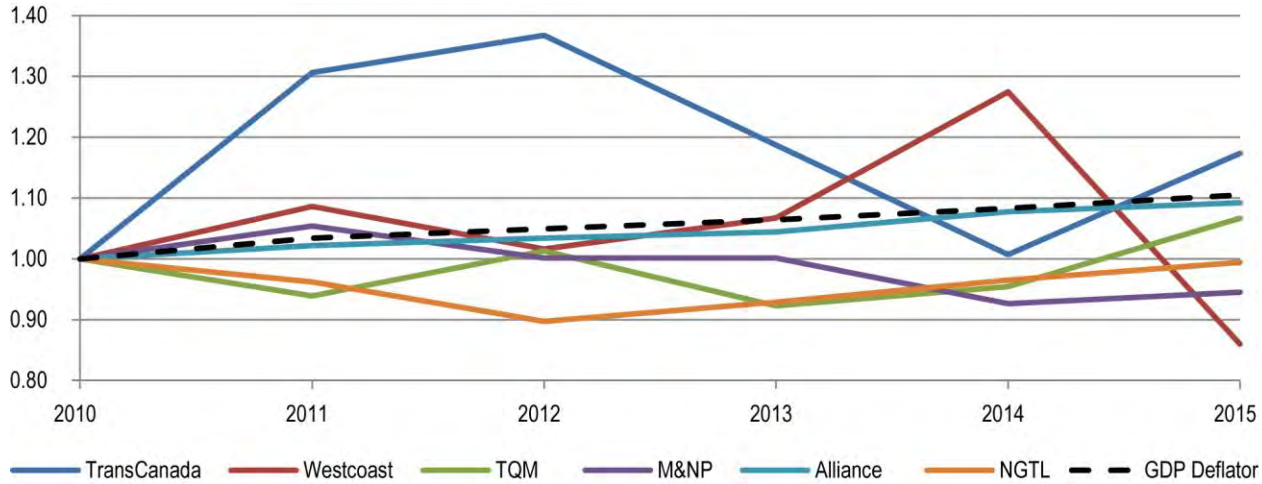
5.2.2 Natural Gas Pipeline Tolls

The benchmark tolls for major Group 1 natural gas pipelines as well as the normalized GDP deflator are shown in Figure 19. Tolls on TransCanada increased almost 40% between 2010 and 2012 due to lower use of the Mainline to move gas from the WCSB to eastern markets. Tolls were restructured in 2013 and in 2015 and have returned to more stable levels.

Under many negotiated settlements, if a pipeline earns too much or too little to cover costs in one year, the difference is made up the following year. Tolls on Westcoast increased in 2014 due to under-collection in 2013, while excess revenue in 2014 resulted in lower tolls in 2015.

FIGURE 19

NEB-Regulated Natural Gas Pipeline Benchmark Tolls

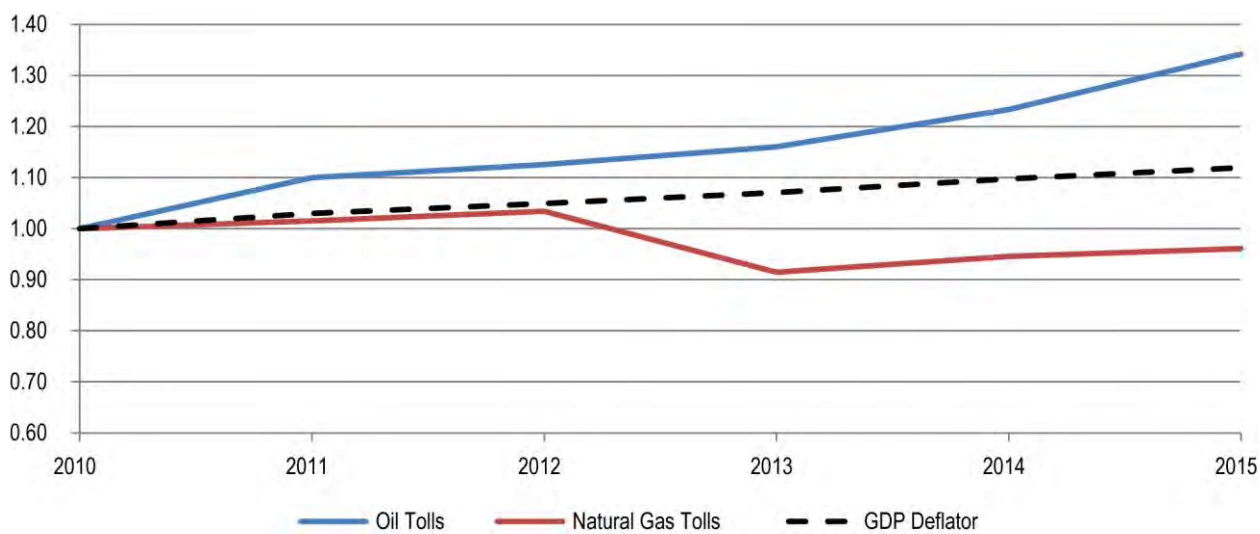


5.2.3 Comparison of Oil and Natural Gas Pipeline Tolls

Figure 20 shows the simple averages[17] of Group 1 natural gas and oil benchmark pipeline tolls with the GDP deflator. From 2010 to 2015, average oil pipeline tolls increased and exceeded the GDP deflator while average natural gas pipeline tolls declined.

FIGURE 20

Oil and Natural Gas Pipeline Benchmark Tolls



17 No adjustments are made for the relative volume, capacity, or length of the individual pipelines.

5.3 Abandonment Funding

NEB-regulated companies must collect and set aside funds to cover future pipeline abandonment costs. The underlying principle is that pipeline companies, and not landowners or governments, are liable for the costs and financing of safe and environmentally responsible pipeline abandonment. Collectively, NEB-regulated companies will need $8.6 billion dollars for future pipeline abandonments based on current estimates (Table 3).

In May 2011, NEB-regulated pipeline companies began filing summaries of the locations of their pipelines by pipe diameter and land type.

Throughout 2012, the NEB examined the companies' preliminary estimates of the costs to abandon their pipeline systems.

In February 2013, the NEB released Reasons for Decision MH-001-2012 regarding preliminary abandonment cost estimates.

Most companies have many years to fund these future costs. In 2013, companies filed their plans to accumulate the necessary funds, as well as their mechanism for securely holding those funds.

The NEB released Reasons for Decision MH-001-2013 in 2014 which found that trusts, letters of credit, and surety bonds were acceptable mechanisms.

In December 2014, companies submitted their finalized trust agreements, abandonment toll surcharges, investment policies, letters of credit, and surety bonds to the NEB. After some adjustments were made by the Board, these filings implemented the abandonment funding initiative, and companies are now collecting and setting aside money for future abandonment costs.

TABLE 3

Estimated Costs to Abandon Pipeline System

	Estimated Cost in millions of dollars[18]
Alliance	310
Enbridge	1 115
Enbridge (Norman Wells)	37
Foothills	198
Keystone	236
Kinder Morgan Cochin	26
Maritimes and Northeast Pipeline	151
NGTL	2 185
TransCanada Mainline	2 530
TransQuébec and Maritimes	103
Trans Mountain	340
Trans-Northern	77
Westcoast G&P	363
Westcoast Transmission	320
Total Group 1 Pipelines	7 991
Total Group 2 Pipelines	562
Total NEB Regulated Pipelines	8 553

Companies report related information to the NEB each year, including amounts contributed to trusts and earnings on investments in these trusts. Companies using letters of credit or surety bonds, as well as companies that were exempted from the requirement to provide a set-aside mechanism, report information to the Board by 31 January each year. Companies using trusts report information to the Board by 30 April annually. Regular updates are also required on the estimated amount of funds needed and set aside, especially as pipelines approach the end of their useful lives. In 2016, the NEB commenced a review of the cost estimates to abandon NEB-regulated pipelines.

18 Estimates in current dollars for the dates in which they were made, 2011-2014.

6 Financial Integrity of Pipeline Companies

The tolls discussed in the previous sections are designed to allow pipeline companies to recover capital and operating costs, service debt, and provide a return to its investors. Financial aspects of pipeline companies, such as debt and equity metrics, are important to maintaining their systems, attracting capital to build new infrastructure, and meeting the market's evolving needs.

The following sections review and discuss factors relevant to the pipeline transportation system's financial integrity.

6.1 Common Equity

A common equity ratio is the percentage of common equity in a company's capital structure.[19] This ratio is related to a company's financial risk, which is associated with a company's use of debt. Holding other things constant, higher common equity ratios decrease financial risk by increasing the likelihood of a company being able to meet its financial obligations, including debt service.

Deemed Common Equity Ratios

When the Board approves a Group 1 company's tolls in the absence of a negotiated settlement, it typically approves a return on equity (ROE) and a deemed common equity ratio for the regulated entity. Parent companies often have a variety of business lines consolidated into one capital structure. However, the Board deems an appropriate common equity ratio for the assets which it regulates.[20]

Alternatively, some Group 1 pipeline companies negotiate a comprehensive tolls settlement with their shippers that does not expressly identify a capital structure and return on equity.[21] In these instances, the Board considers the overall settlement for approval.

Where available, the deemed common equity ratios for NEB Group 1 pipeline companies from 2008 to 2014 are shown in the appendix in section 11. These ratios have not changed since 2011.

Return on Common Equity

For NEB-regulated pipeline companies, ROE is determined through either adjudication or negotiation. Actual ROEs achieved by the pipeline companies may vary for numerous reasons such as throughput changes, incentives, profit-sharing mechanisms, and cost variances.

The achieved ROE for several NEB-regulated pipeline companies from 2008 to 2014 are shown in the appendix in section 11. ROE as determined by the RH-2-94 formula is also included for reference.[22]

Actual ROEs are filed with the NEB for most Group 1 companies, while some companies are operating under negotiated settlements and are not required to report actual ROE. NEB staff examine actual ROE patterns, operations spending, maintenance, and feedback from shippers to identify any returns that may be inappropriate or could potentially result in unjust tolls.

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19 For example a 30% equity ratio means that 30% of the capital structure of a company comes from equity and 70% comes from debt.

20 A deemed common equity ratio is a notional capital structure used for rate-making purposes that may differ from a company's actual capital structure.

21 The NEB has granted some pipeline companies exemptions from certain information filing requirements. The details that are provided as part of tariff applications or annual compliance filings differ among pipeline companies.

22 Between 1995 and late 2009, the Board set an ROE annually, using a formula outlined in RH-2-94. In 2009, the Board initiated a written process to review RH-2-94 and considered, among other things, changes in financial and economic circumstances since 1994 and the experience industry had gained reaching negotiated settlements over the intervening 15 years. In October 2009, the Board decided that the RH-2-94 Decision would not continue to be in effect. However, for the convenience of parties which still use it in their settlements, the Board has continued to publish the formula.

6.2 Financial Ratios

Financial risk is based on a company's use of debt and other obligations where fixed payments are used. This differs from business risk, which is attributed to the nature of a particular business activity and, for pipelines, typically includes supply, market, regulatory, competitive, and operating risks.

Financial risk increases as the proportion of debt and interest payments increases relative to equity and cash flow. A company's financial risk may be described by ratios such as interest coverage, fixed-charges coverage, and cash flow-to-total debt and equivalents.

Interest and Fixed-Charges Coverage Ratios

An interest coverage ratio describes a company's ability to make interest payments and repay its debt obligations. It is defined as earnings before interest and taxes divided by interest charges. Similarly, a fixed-charges coverage ratio describes the ability to make interest payments and repay debt obligations, and additionally considers some of the other fixed payments a company is obligated to make. It is defined as earnings before interest, fixed charges, and taxes, divided by interest and fixed charges. Higher ratios indicate a higher likelihood the company will meet its obligations and may indicate greater borrowing capacity.

The fixed-charges coverage ratios for some NEB-regulated pipeline companies or pipeline systems, as calculated by DBRS[23], are shown in the appendix in section 11. In 2014, the average fixed-charges coverage ratio for these companies was 4.3, up from 2.7 in 2010. This indicates that, on average, the ability of these companies to pay fixed charges from earnings was higher in 2014 than in 2010. The difference can mostly be attributed to the reduction of debt by Express and Trans-Northern. Average fixed-charges coverage ratios of Alliance, Enbridge, M&NP, NGTL, Trans Québec and Maritimes Pipeline (TQM), Westcoast and the TransCanada Mainline increased by 9% over the same period.

Cash Flow-to-Total Debt and Equivalents Ratio

The cash flow-to-total debt and equivalents ratio is another way of describing a company's ability to meet its debt obligations and fixed payments. It is defined as operating cash flow divided by total debt and debt equivalents. Again, higher ratios indicate an increased likelihood of a company being able to meet its obligations and indicate greater borrowing capacity.

The cash flow-to-total debt and equivalents ratios for some NEB-regulated pipeline companies or pipeline systems, as calculated by DBRS, are shown in the appendix in section 11. The average ratio for these companies was 30% in 2014, up from about 18% in 2010. The rising trend of debt service coverage ratios is primarily due to continued debt reduction. As a notable example, Express increased its cash flows from $75 million in 2010 to over $175 million in 2014 while simultaneously reducing its total debt from $300 million to under $185 million. Conversely, Enbridge’s debt service coverage ratios have declined, which is partly why Standard & Poor's (S&P) recently downgraded its credit rating from A- to BBB+.

23 DBRS issues credit ratings and reports for some, but not all, of the NEB-regulated Group 1 pipelines. Keystone and Trans Mountain, for example, are covered as part of their parent companies TransCanada PipeLines and Kinder Morgan, respectively.

6.3 Credit Ratings

In Canada, pipeline company credit ratings are generally determined by three independent credit rating agencies: DBRS, S&P, and Moody's. Not all pipeline companies are rated by each agency. Credit ratings provide an assessment of the probability a debt issuer will live up to its obligations and provides an indication of the financial integrity of the rated company.

A company's credit rating generally reflects the consolidated operations of the entire company, not just the regulated portion. Consequently, the credit ratings for companies such as Enbridge, TransCanada, and Westcoast, which have both regulated and non-regulated operations, may be influenced by their non-regulated lines of business. Credit ratings are also somewhat subjective in that a company's ratings are the expert opinion of the credit rating agency and the same company may receive different ratings from different agencies. The appendix in section 12 compares the rating scales for DBRS, S&P, and Moody's.

DBRS

The credit ratings for most Group 1 pipeline companies are shown in the appendix in section 12. All remained investment grade, but some companies' ratings were downgraded between 2010 and 2015.

- In March 2011, DBRS downgraded Enbridge Pipelines to "A" from "A(high)", which followed the announcement by Enbridge of a 10-year Competitive Toll Settlement for its Canadian Mainline.
- In June 2013, TCPL's unsecured debentures rating, as well as NGTL's medium-term notes and unsecured debentures rating, were downgraded to "A(low)" from "A". The NGTL downgrade reflects DBRS's view that continued financial and liquidity support from TCPL is key to NGTL's long-term debt rating.
- In October 2015, Alliance Pipeline Limited Partnership's rating was downgraded two notches from "A (low)" to "BBB". The original 15-year contracts that underpinned the pipeline's construction expired in November 2015. Alliance has re-contracted the majority of the pipeline's capacity, but 60% of the new shippers are not of investment grade credit quality. This exposes Alliance to greater counterparty risk compared to the original contracts, of which 85% were signed with investment grade shippers. In the rating downgrade, DBRS also referred to Alliance's credit concentration risk and the shorter duration of contracts.

S&P

S&P credit ratings for several Group 1 pipeline companies are shown in the appendix in section 12. All remained investment grade, but some companies' ratings were downgraded between 2010 and 2015.

- In November 2013, S&P downgraded Westcoast to a "BBB" rating from "BBB+" following the same downgrade of its parent, Spectra Energy Corp. These actions reflected corporate restructuring (i.e. drop-down of some of Spectra's U.S. assets to another subsidiary). S&P saw this as weakening Spectra's credit quality, as its creditors were now one step away from assets with stable cash flow.
- In June 2015, S&P lowered its ratings on several Canadian Enbridge companies[24], with Enbridge Pipelines' long-term debt rating changing from "A-" to "BBB+". S&P viewed Enbridge's financial risk profile as "aggressive", referring to declining cash flow from operations and $40 billion in capital spending planned before 2020.

24 Enbridge Inc., Enbridge Pipelines Inc., Enbridge Gas Distribution Inc. S&P also downgraded the rating on Houston-based Enbridge Energy Partners L.P. to "BBB" from "BBB+".

Moody's

Moody's rating histories for several Group 1 pipeline companies are provided in the appendix in section 12. All remain investment grade, but some companies' ratings were downgraded between 2010 and 2015.

- Moody's downgraded Alliance's credit rating in 2014 and again in 2015, for similar reasons to those that prompted DBRS's rating downgrade. In its 2015 announcement, Moody's noted that the downgrade was only one notch due to progress Alliance made re-contracting throughput volumes on the pipeline.
- In June 2015, Moody's downgraded the credit rating of Enbridge Inc. (the parent company of Enbridge Pipelines) from "Baa1" to "Baa2". Moody's viewed Enbridge's changes to its corporate structure and distribution policy as a shift toward favoring shareholders at the expense of creditors.

7 Appendix: Group 1 and Group 2 Pipeline Companies

Regulated companies as of 31 December 2015

Group 1: Oil and Liquids

Enbridge Pipelines Inc.'s Enbridge Mainline

Enbridge Pipelines (NW) Inc.'s Enbridge Norman Wells Pipeline

Kinder Morgan Cochin ULC's Cochin Pipeline

Trans Mountain Pipeline ULC's Trans Mountain Pipeline

TransCanada Keystone Pipeline GP Ltd.'s Keystone Pipeline

Trans-Northern Pipelines Inc.'s Trans-Northern Pipeline

Group 1: Natural Gas

Alliance Pipeline Ltd.'s Alliance Pipeline

Foothills Pipe Lines Ltd.'s Foothills Pipeline System

Maritimes & Northeast Pipeline LP's Maritimes & Northeast Pipeline (M&NP)

Nova Gas Transmission Ltd. (NGTL)

Trans Québec & Maritimes Pipeline Inc.'s Trans Québec and Maritimes Pipeline (TQM)

TransCanada Pipe Lines Limited's TransCanada Mainline

Westcoast Energy Inc.'s Westcoast Transmission System

Group 2: Oil and Liquids

1057533 Alberta Ltd.

Aurora Pipeline Company Ltd.'s Aurora Pipeline

Canadian Natural Resources Limited

ConocoPhillips Canada Operations Ltd.

Enbridge Bakken Pipeline L.P.'s Enbridge Bakken Pipeline

Enbridge Pipelines (Westspur) Inc.'s Enbridge Westspur Pipeline

Enbridge Southern Lights GP Inc.'s Southern Lights Pipeline

Express Pipeline Limited Partnership's Express Pipeline

Genesis Pipeline (Canada) Ltd.'s Genesis Pipeline

Glenogle Energy Inc.

Husky Oil Limited

ISH Energy Ltd.

Montreal Pipe Line Limited's Montreal Pipe Line

Nova Chemicals (Canada) Ltd.

Pembina Energy Services Inc.

Pembina Prairie Facilities Ltd.'s Vantage Pipeline

Pembina Resource Services GP Inc.

Penn West Petroleum Ltd.

Plains Midstream Canada ULC – Milk River Pipeline's Milk River Pipeline

Plains Midstream Canada ULC – Wascana Pipeline Ltd.'s Wascana Pipeline

Pouce Coupé Pipeline Ltd. (Pembina North LP)

SCL Pipeline Inc.

Spectra Energy Empress Management Inc. as GP & agent for Spectra Energy Empress LP

Strategic Transmission Ltd.

Sunoco Logistics Partners Operations GP LLC

Group 2: Natural Gas

1057533 Alberta Ltd.

2193914 Canada Limited

6720471 Canada Ltd.

Altagas Holdings Inc. for /on behalf of Altagas Pipeline Partnership

Arc Resources Ltd

Bellatrix Exploration Ltd

Bonavista Energy Corporation

Bow River Energy Limited

Canada Border Services Agency

Canadian Natural Resources Limited

Canadian-Montana Pipe Line Company

Centra Transmission Holdings Inc.

Champion Pipe Line Corporation Limited

Chief Mountain Gas Co-op Ltd.

ConocoPhillips Canada Operations Ltd.

County of Vermillion River No. 24 Gas Utility

Crescent Point Energy Corp.

Delphi Energy Corporation

DR Four Beat Energy Corp.

Emera Brunswick Pipeline Company Ltd.'s Brunswick Pipeline

Encana Corporation

Enerplus Corporation acting on behalf of the Enerplus Partnership

ExxonMobil Canada Properties

FortisBC Energy Inc

FortisBC Huntingdon Inc.

Forty Mile Gas Co-op Ltd.

Glenogle Energy Inc.

Husky Oil Operations Limited

Ikkuma Resources Corp.

Mid-Continent Pipelines Ltd. (SaskEnergy)

Minell Pipelines Limited

Murphy Oil Company Ltd.

Niagara Gas Transmission Ltd

Northern Blizzard Resources Inc.

Omimex Canada Ltd.

ONEOK Rockies Processing Company (Canada) Ltd.

Pengrowth Energy Corporation

Penn West Petroleum Ltd.

Pine Cliff Border Pipelines Limited

Plains Midstream Canada ULC

SaskEnergy (Portal Municipal Gas Company Inc.)

Shiha Energy Transmission Ltd

Spectra Energy Midstream Canada Partner Corporation

Spyglass Resources Corporation

St. Clair Pipelines Management Inc.

Steppe Petroleum Inc.

Strategic Transmission Ltd

Tamarack Acquisition Corp

TAQA North Ltd.

Terra Energy Corp.

Union Gas Limited

Vector Pipeline Limited Partnership

Venturion Oil Limited

Veresen Energy Pipeline Inc.

Yoho Resources Inc.

Other Commodities

Blackpearl Resources Inc.

1057533 Alberta Ltd.

Domtar Inc.

Genesis Pipeline (Canada) Ltd.

Penn West Petroleum Ltd.

Resolute Forest Products (Abitibi-Consolidated Company of Canada)

Souris Valley Pipeline Limited

Tundra Oil & Gas Limited for and on behalf of Tundra Oil and Gas Partnership

Twin Rivers Paper Company Inc.

Venturion Oil Limited

Whitecap Resources Inc

8 Appendix: Profiles of Group 1 Oil and Liquids Pipeline Companies

8.1 Enbridge Pipelines Inc.'s Enbridge Mainline

Commodity and NEB Group	Crude oil, petroleum products, NGL (Group 1)
Average annual capacity	453 300 m^3/d (2.85 MMb/d)[25]
Average utilization 2015	85%
Primary receipt points	Edmonton, Hardisty, AB; Kerrobert, Regina, SK; Cromer, MB
Primary delivery points	Clearbrook, MN; Superior, WI
Rate base 2015	$8 785 million
Revenue 2015	$697 million
Abandonment Cost Estimate and Collection Period[26]	$1 115 million; 40 years

Overview

The Enbridge Mainline system is Canada's largest transporter of crude oil. It originates in Edmonton, AB and extends east across the Prairies to the Canada-U.S. border near Gretna, MB where it joins with the Enbridge Lakehead System. It re-enters Canada at Sarnia, ON and connects with Line 7, and Line 9 which delivers to Montreal, QC. Figure 8.1.1 depicts the system's configuration. The Lakehead system also connects with pipelines that deliver crude oil to Cushing, OK and the U.S. Gulf Coast.

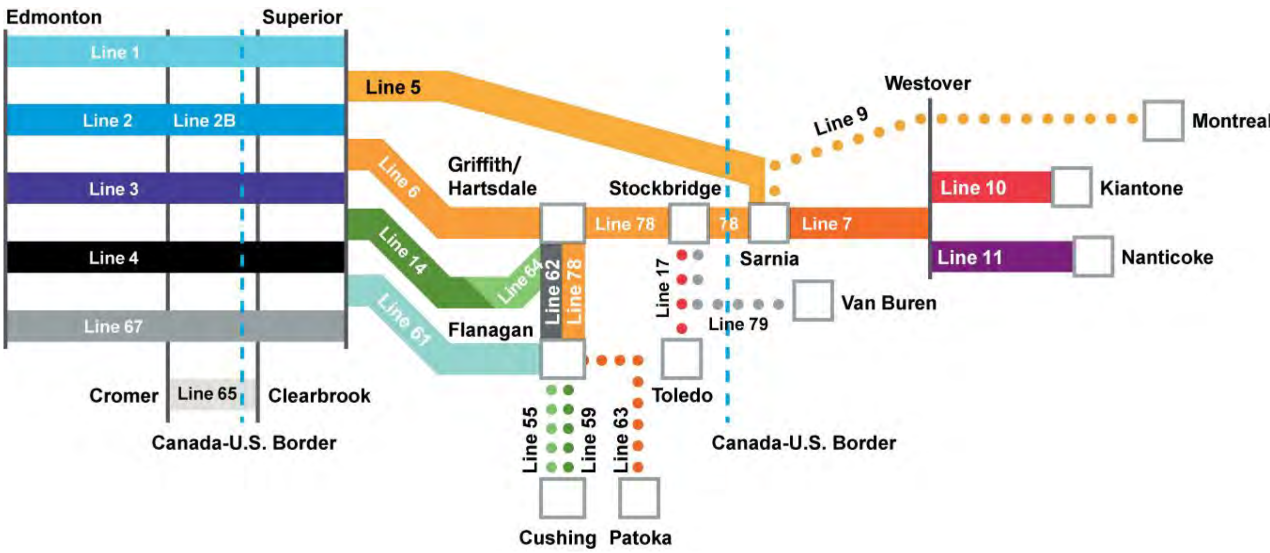
Regulatory Documents
2011 Competitive Toll Settlement
Line 3 Replacement Program
Line 9B Reversal and Line 9 Capacity Expansion
Alberta Clipper Expansion Project Phase II
Alberta Clipper Expansion Project

25 At the international border near Gretna, MB.

26 Collection Period began 1 January 2015.

FIGURE 8.1.1

Enbridge Mainline System Configuration



The Enbridge Mainline has six lines exiting western Canada. Line 65 transports up to 29 600 m^3/d (186 Mb/d) light and medium crude oil, and runs from Cromer, MB to Clearbrook, MN. Five lines originate in Alberta and terminate in Superior, WI:

- Line 1 transports natural gas liquids, synthetic crude oil, and refined petroleum products, with a capacity of 37 700 m^3/d (237 Mb/d). The refined products are delivered upstream of Superior, MN, leaving only natural gas liquids and synthetic crude oil to be delivered to the Superior tank farm.
- Line 2 ships light crude oil and condensates, with a capacity of 70 300 m^3/d (442 Mb/d).
- Line 3 ships light crude oil (and condensates from Edmonton to Hardisty, AB), with a capacity of 62 000 m^3/d (390 Mb/d).
- Line 4 transports heavy crude oil (and light and medium crude oil past Clearbrook, MN), with a capacity of 126 600 m^3/d (796 Mb/d).
- Line 67 (Alberta Clipper) transports heavy crude oil, with a capacity of 127 200 m^3/d (800 Mb/d).

Key Developments

In December 2015, the Line 9B Reversal and Line 9 Capacity Expansion Project became operational, enabling Quebec refiners to access western Canadian crude oil by pipeline.

In 2014 and 2015, Enbridge completed the Canadian portions of the Alberta Clipper (Line 67) Expansion Project, increasing capacity by a total of 55 600 m^3/d (350 Mb/d) to the full design capacity of 127 100 m^3/d (800 Mb/d). This, together with flexibility enhancements, has resulted in higher throughputs on the Enbridge Mainline.

In November 2014, an application for the Line 3 Replacement Program was filed with the Board. It sought to restore the capacity of the pipeline to 127 200 m^3/d (760 Mb/d) by 2019. On 25 April 2016, the Board concluded that the Enbridge Line 3 Replacement Program would be in the Canadian public interest and issued its recommendation for project approval to the federal Governor in Council.

Utilization

Figure 8.1.2 shows throughput and capacity for the Enbridge Mainline for 2010-2015. Capacity ended 2015 at 453 100 m^3/d (2.85 MMb/d); however, effective export capacity is estimated at about 397 300 m^3/d (2.5 MMb/d) due to constraints on pipelines downstream of Superior, WI.

In 2015, throughput averaged 368 70 m^3/d (2.32 MMb/d), compared to 317 100 m^3/d (2.11 MMb/d) in 2014.

Enbridge expects to add 63 600 m^3/d (400 Mb/d) of capacity to Line 61 between Superior and Flanagan, IL by 2017, which would increase effective export capacity from Canada.

Figure 8.1.3 shows Enbridge announced apportionment in the U.S. and Figure 8.1.4 shows Enbridge announced apportionment on the Canadian section of the Mainline. At times, capacity has been inadequate to fully meet shipper demand on parts of the system in Canada and the U.S.

Tolls

Enbridge operates under the 2011 Competitive Tolls Settlement (CTS). The CTS came into effect on 1 July 2011 and expires on 30 June 2021. Tolls for Line 9 are not included in the CTS.

Figure 8.1. 5 shows the Enbridge benchmark toll (light petroleum transportation from the Edmonton Terminal to the international border near Gretna, MB) and the GDP deflator (normalized) for 2010-2015. The benchmark toll increased by approximately 20% in 2011, mainly as a result of Enbridge Alberta Clipper pipeline costs. It increased by 23% in 2015 with the addition of the Edmonton Transportation Surcharge related to the Edmonton-to-Hardisty Pipeline Project.

FIGURE 8.1.2

Enbridge Mainline Throughput vs. Capacity

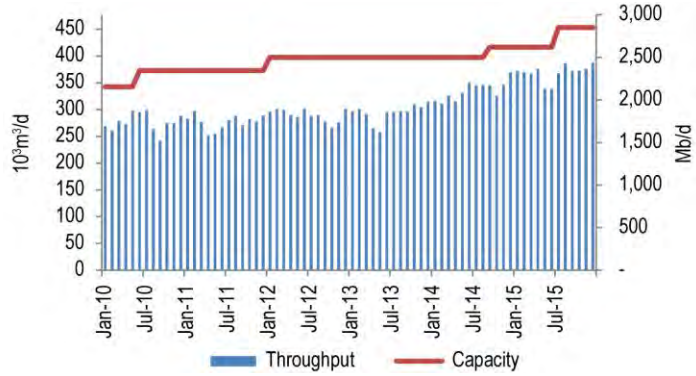


FIGURE 8.1.3

Apportionments Downstream of Superior

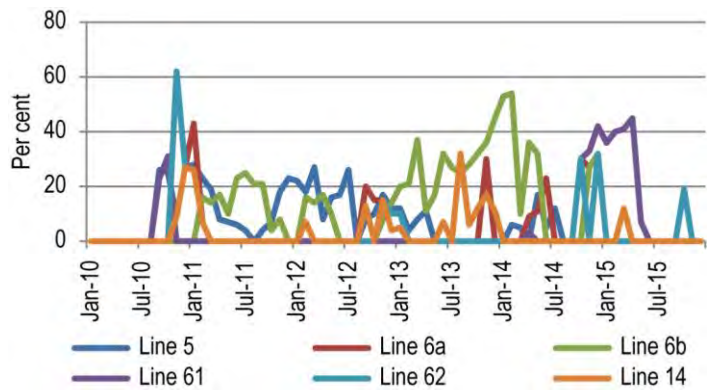
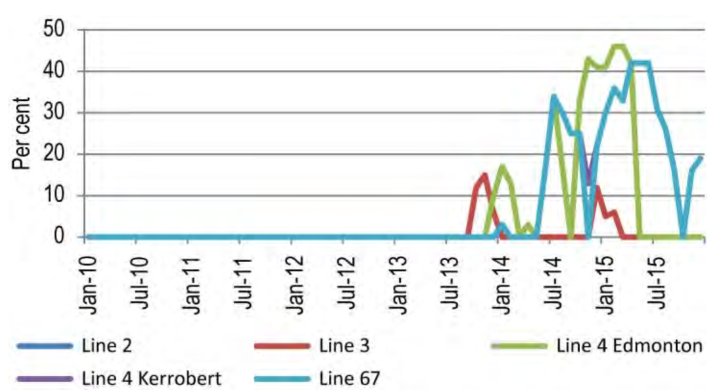


FIGURE 8.1.4

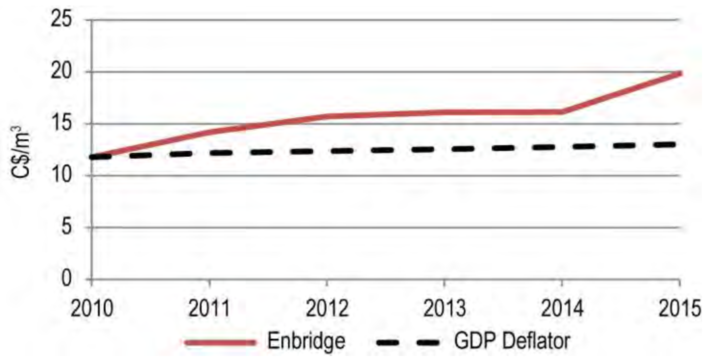
Enbridge Mainline Apportionments Leaving Alberta



Financial

FIGURE 8.1.5

Enbridge Mainline Benchmark Toll



In 2015, Enbridge Inc. completed multiple financial restructuring processes affecting Enbridge Pipelines Inc. Enbridge Pipelines Inc.'s financial ratios have weakened in recent years due to increased debt in its capital structure. Its credit rating was downgraded in 2015 by both Standard and Poor's (S&P) and Moody's, but remains investment grade. Each viewed Enbridge Pipeline's parent company, Enbridge Inc., as having weakened financial metrics, increased structural subordination, and a financial policy that shifted in favour of shareholders. Dominion Bond Rating Service (DBRS) downgraded Enbridge from "A (high)" to "A" in 2011 after Enbridge implemented the CTS which introduced volume and operational risks to the Enbridge Mainline through a fixed-toll methodology as opposed to the previous cost of service method.

Enbridge Pipelines Inc.	2010	2011	2012	2013	2014	2015
Revenues prior to EECI transfer (millions)*	$9 217	$10 536	$8 667	$9 004	$10 568	n/a
Revenues post EECI transfer (millions, 2013 and 2014 restated)				$1 242	$1 222	$697
Revenues from Discontinued Operations				$7 762	$9 346	$4 749
Enbridge Mainline Rate Base (millions)		$4 731	$5 193	$5 683	$6 387	$8 785
Interest and Fixed-Charges Coverage Ratio	2.11	2.52	2.39	1.95	2.08	1.55
Cash Flow-to-Total Debt and Equivalents Ratio	15.2%	11.2%	11.4%	8.8%	8.8%	8.9%
DBRS Credit Rating	A (high)	A	A	A	A	A
S&P Credit Rating	A-	A-	A-	A-	A-	BBB+
Moody's Credit Rating	Baa1	Baa1	Baa1	Baa1	Baa1	Baa2

Financial data sources: revenue and rate base - Enbridge annual filings with the Board; return, coverage and debt ratios – DBRS; credit ratings – DBRS, S&P, Moody's.

*On 10 August 2015, Enbridge completed a restructuring process and transferred certain assets from Enbridge Pipelines Inc. to Enbridge US Holdings Inc. (EUSH), a subsidiary of Enbridge Inc. Enbridge's 2015 filing shows EPI's revenue for the year as $697 million, which excludes $4 749 million in revenue from the assets that were transferred during the year.

8.2 TransCanada Keystone Pipeline GP Ltd.'s Keystone Pipeline

Commodity and NEB Group	Crude Oil (Group 1)
Operating capacity	94 000 m^3/d (591 Mb/d)
Average utilization 2015	94%
Primary receipt points	Hardisty, AB
Primary delivery points	Wood River and Patoka, IL, Cushing, OK,
Net Plant 2015 (millions)	$2 090
Revenues 2015 (millions)	$466
Abandonment Cost Estimate and Collection Period[27]	$236 million; 25 years

Overview

The Keystone Pipeline (Keystone) transports crude oil from Hardisty, AB to refining markets in the U.S. Midwest and U.S. Gulf Coast. The Canadian leg runs from Hardisty east to Manitoba, where it crosses the border into North Dakota and continues south across South Dakota and Nebraska. At Steele City, NE, the pipeline has two branches: one runs east through Missouri to Wood River and Patoka, IL, and the other runs south to Cushing, OK. At Cushing, it links to another pipeline (Cushing Marketlink) which delivers crude oil to the U.S. Gulf Coast. Keystone operates under long-term contracts with its shippers for 90% of its capacity.

Regulatory Documents
Keystone NEB Tariff No. 19
Keystone NEB Tariff No. 17
Complaint by Husky Oil Operations Limited
Keystone XL Pipeline Project
Keystone Cushing Expansion Project
Keystone Pipeline Project

Commercial operations commenced for the first phase of Keystone in July 2010, providing 69 200 m^3/d (435 Mb/d) of capacity from Hardisty, AB to the Wood River and Patoka market hubs. The second phase became operational in February 2011, extending the system to Cushing, OK and adding 24 800 m^3/d (156 Mb/d) of capacity. This increased total system export capacity to 94 000 m^3/d (591 Mb/d).

27 Collection Period began 1 January 2015.

Key Developments

In September 2008, TransCanada applied to the U.S. Department of State for a Presidential Permit for the Keystone XL project, and in November 2015, this application was denied. TransCanada has since challenged the decision and has stated that it and its shippers remain committed to the project.

Utilization

Figure 8.2.1 shows throughput on Keystone for 2010-2015. Throughput averaged about 84 300 m^3/d (531 Mb/d) in 2014 and about 88 300 m^3/d (556 Mb/d) in 2015.

Tolls

Figure 8.2.2 shows the Keystone benchmark toll (10-year committed toll for light petroleum from Hardisty, AB to the U.S. border for ultimate transportation to Cushing, OK) along with the GDP deflator (normalized) for 2011-2015. The benchmark toll increased steadily from 2011 to 2015. In 2012, the benchmark toll rose by 4%, reflecting an adjustment for final project costs. The toll increased by 6% in 2013 and by 4% in 2014, each as a result of a change in operating, maintenance and administration costs.

FIGURE 8.2.1

Keystone Throughput vs. Capacity

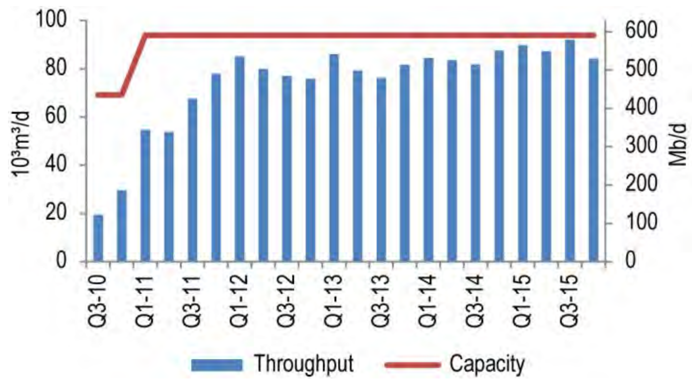
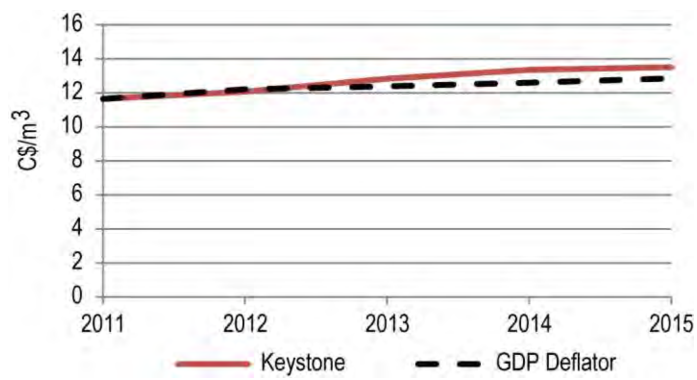


FIGURE 8.2.2

Keystone Benchmark Toll



Financial

TransCanada Keystone Pipeline GP Ltd. is owned and operated by TransCanada Corporation. Throughput increased over the past few years and revenues and returns have also increased. Keystone operations represent approximately 20% of TransCanada Corporation's earnings. TransCanada Corporation's financial ratios continue to be stable and credit ratings for TransCanada Pipelines Ltd. are investment grade. In 2015, a $194 million impairment charge was recorded in connection with the denial of the U.S. Presidential Permit for the Keystone XL pipeline.

TransCanada Corporation	2010	2011	2012	2013	2014	2015
Revenues* (millions) – Keystone Pipeline	$47.5	$310.2	$369.9	$399.1	$431.8	$465.8
Net Plant* (millions) – Keystone Pipeline	$1 805.5	$2 105.8	$2 096.8	$2 060.1	$2 035.1	$2 089.7
Return on Net Plant* - Keystone Pipeline	2.12%	7.78%	9.78%	10.39%	10.94%	11.61%
Interest and Fixed-Charges Coverage Ratio**	2.01	2.39	2.18	2.39	2.59	2.7
Cash Flow-to-Total Debt and Equivalents Ratio**	15.6%	16.4%	15.1%	15.5%	15.4%	14.7%
DBRS Credit Rating***	A	A	A	A	A	A
S&P Credit Rating***	A-	A-	A-	A-	A-	A-
Moody's Credit Rating***	A3	A3	A3	A3	A3	A3

Financial data sources: revenues, net plant and return on net plant - Keystone quarterly filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS, S&P, Moody's.

*Revenues, Net Plant, and Return on Net Plant are reported for TransCanada Keystone Pipeline GP Ltd.

**Coverage ratios are for TransCanada Corporation, as provided by DBRS. The ratios for 2015 include the last three months prior to 31 March 2015.

***Credit ratings are for TransCanada Pipelines Ltd.

8.3 Trans Mountain Pipeline ULC's Trans Mountain Pipeline

Commodity and NEB Group	Crude oil, petroleum products (Group 1)
Average annual capacity	47 700 m^3/d (300 Mb/d)[28]
Average utilization 2015	105%
Primary receipt points	Edmonton, AB; Kamloops, BC
Primary delivery points	Kamloops, Burnaby, Westridge Dock, BC; Cherry Point, Ferndale, Anacortes, WA
Rate base 2015	$996 million
Revenue Requirement 2015	$293 million
Abandonment Cost Estimate and Collection Period[29]	$340 million; 40 years

Overview

The Trans Mountain Pipeline (Trans Mountain) transports crude oil and refined petroleum products from Edmonton, AB to refineries and terminals in both British Columbia and Washington State. Crude oil is also shipped to offshore markets in Asia and the U.S. west coast via the Trans Mountain Marine Terminal (Westridge Dock) in Burnaby, B.C.

Key Developments

In December 2013 Kinder Morgan filed an application for the Trans Mountain Pipeline Expansion project (TMX) and on 19 May 2016, the project was approved by the Board. It would increase the capacity of the Trans Mountain system to 141 500 m^3/d (890 Mb/d).

Regulatory Documents

- 2015 Final Tolls
- Trans Mountain Pipeline Expansion (OH-001-2014)
- 2016-2018 Incentive Toll Settlement
- Trans Mountain Tariff Amendments Regarding Verification Procedures (RHW-001-2013)
- Approval Trans Mountain Tariff No. 95
- Trans Mountain Final Tariff No. 95 (Rules and Regulations)
- Trans Mountain Tariff No.98 (Tolls Crude Oil & Petroleum Products)

28 Assumes 20% of shipments are heavy crude oil.

29 Collection Period began 1 January 2015.

In January 2015, the Board approved tariff amendments which, among other things, incorporated limits for verifying shipper nominations that are based on *historical deliveries* (RHW-001-2013). Nomination verification was previously based on a shipper's *capability* to tender and receive volumes. After an additional comment period, the Board approved a revision of the tariff amendments in April 2015. The amendments contributed to a reduction in apportionment levels on Trans Mountain, which were often above 70% during 2013-2014.

In February 2016, the Board approved the 2016-2018 Incentive Toll Settlement (ITS) for Trans Mountain.

Utilization

Trans Mountain capacity varies depending on the proportion of heavy and light crude oil transported. Figure 8.3.1 shows a capacity of 47 600 m^3/d (300 Mb/d), which assumes 20% heavy crude oil shipped. Capacity is higher if moving less heavy crude oil.

In 2014 and 2015, average throughput was 46 500 m^3/d (293 Mb/d) and 50 300 m^3/d (316 Mb/d), respectively.

High demand for pipeline capacity to the west coast has contributed to apportionment on Trans Mountain and triggered several applications to allocate capacity between Land Shippers (mostly B.C. and Washington State refineries) and Dock Shippers (marine exporters). Currently, approximately 26% of capacity is allocated to the Westridge Dock, including 8 600 m^3/d (54 Mb/d) of firm service and 4 000 m^3/d (25 Mb/d) of interruptible service which is auctioned each month. The remainder of capacity is allocated to Land Destinations. Average Land Destination apportionment was 70.2% in 2014 and 31.2% in 2015.

FIGURE 8.3.1

Trans Mountain Throughput vs. Capacity

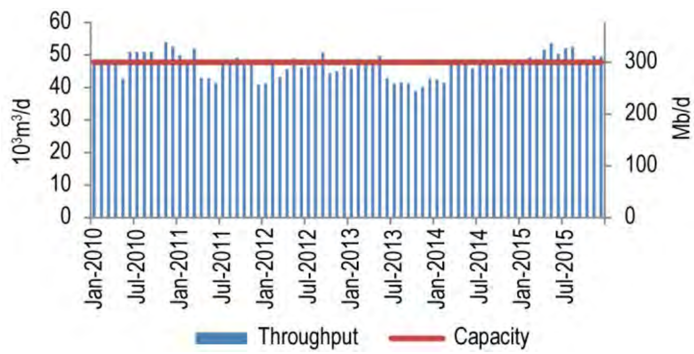
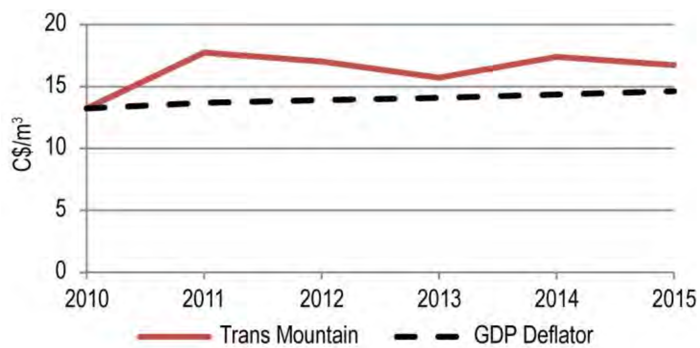


FIGURE 8.3.2

Trans Mountain Benchmark Toll



Tolls

Trans Mountain currently operates under a three-year Incentive Toll Settlement (2016-2018 ITS). Figure 8.3.2 shows the Trans Mountain benchmark toll (light petroleum from Edmonton to Burnaby) along with the GDP deflator (normalized) for 2010 – 2015. Tolls have fluctuated as over or under-recoveries of revenues are transferred to future years.

Financial

Trans Mountain has operated under incentive toll agreements since 2013. The 2013-2015 agreement and the 2016-2018 agreement include a baseline return on equity of 9.5%. These agreements incorporate incentives to increase its return through efficiency improvements.

Credit ratings are not available for Kinder Morgan Canada, which owns Trans Mountain Pipeline ULC and represents approximately 2% of its parent company's (Kinder Morgan Inc.) earnings. Kinder Morgan Canada's access to debt markets is supported by Kinder Morgan Inc., which, for example, DBRS currently assigns a credit rating of BBB.

Trans Mountain Pipeline ULC	2010	2011	2012	2013	2014	2015
Revenue requirement (millions)	$221	$270	$295	$275	$292	$293
Rate Base (millions)	$1 036	$1 020	$996	$990	$994	$1 005
Deemed Equity Ratio	45%	45%	45%	45%	45%	45%
Achieved Return on Equity	----	10.5%	9.82%	9.5%	8.06%	8.5%

Financial data sources: Trans Mountain incentive toll settlement filings with the Board.

8.4 Trans-Northern Pipelines Inc.'s Trans-Northern Pipeline

Commodity and NEB Group	Refined petroleum products (Group 1)
Annual average capacity	Differs for each segment
Average throughput 2015[30]	33 700 m^3/d (212 Mb/d)
Primary receipt points	Montreal, QC; Nanticoke, ON
Primary delivery points	Montreal, QC; Toronto, Clarkson, Kingston, Oakville, Cornwall, Belleville, Maitland and Ottawa, ON
Rate base 2015	Not available
Cost of Service 2015	$81.1 million
Abandonment Cost Estimate and Collection Period[31]	$76.7 million; 40 years

Overview

Regulatory Documents
TNPI Tolls 2015 (TO-009-2015)
TNPI 2016 Toll Application
TNPI ITS (RHW-3-96)

The Trans-Northern Pipeline (Trans-Northern) transports refined petroleum products west from Montreal, QC to Toronto, ON, and from Imperial Oil Limited's refinery at Nanticoke, ON east to Toronto. There are delivery points along both stretches, including a branch line that services the Ottawa area. The pipeline operates bi-directionally between Toronto and Oakville, ON. Capacity varies across each segment of the pipeline. For example, from Montreal to Farran's Point the capacity is 21 000 m^3/d (132 Mb/d); from Farran's Point to Belleville the capacity is 11 400 m^3/d (72 Mb/d); and, from Belleville to Toronto the capacity is 10 000 m^3/d (63 Mb/d).

Key Developments

In October 2010, the Board ordered a system-wide pressure reduction to 80% of the maximum operating pressure after assessing Trans-Northern's integrity management plan. As of June 2016, the restriction remained in effect on parts of the system.

30 Sum of average throughput across main segments.

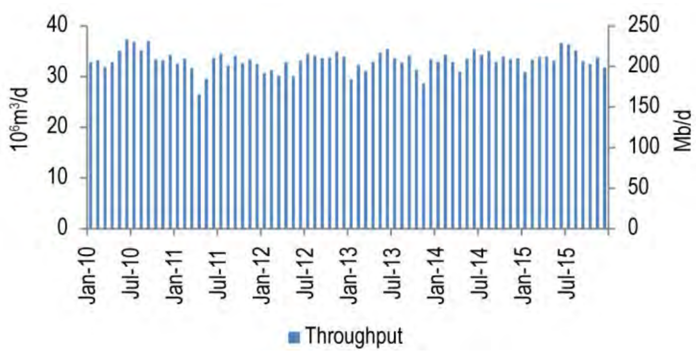
31 Collection Period began 1 January 2015.

Utilization

Figure 8.4.1 shows Trans-Northern throughput from 2010-2015. Throughput averaged 33 600 m^3/d (211 Mb/d) in 2014, and 33 700 m^3/d (212 Mb/d) in 2015. Capacity differs across the various segments of the system. Throughputs shown are the addition of average volumes shipped in each month for all segments of the pipeline.

FIGURE 8.4.1

Trans-Northern Throughput vs. Capacity

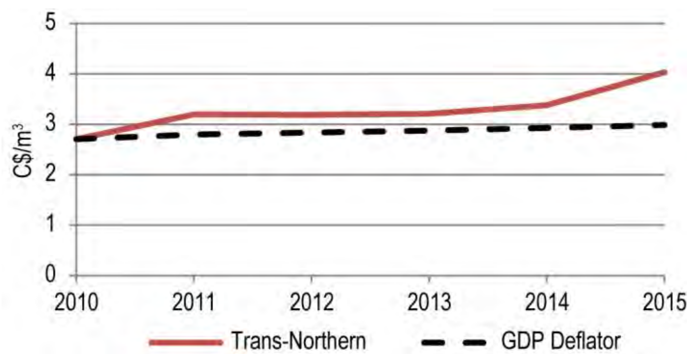


Tolls

The toll settlement (RHW-3-96) established a starting point for the revenue requirement in 1996, and a mechanism to adjust costs each year. Tolls are submitted annually to the Board and are regulated on a complaint basis. Figure 8.4.2 shows the Trans-Northern benchmark toll (Nanticoke to North Toronto) and the GDP deflator (normalized) for 2010-2015. The benchmark toll increased by 18% in 2011, mainly due to a \$6.5 million integrity allowance and a \$4.5 million expense to cover cleanup costs related to events in 2010. It remained steady between 2012 and 2014 after which it increased by 19% due in part to a Non-Routine Adjustment for Pipeline Integrity.

FIGURE 8.4.2

TNPI Benchmark Toll



Financial

Trans-Northern Pipelines Inc. earns a return on equity equivalent to the RH-2-94 formula rate plus 25 points additional return for risk. Its financial ratios have improved in recent years due to stable cash flows and continued reduction of debt. Its credit rating, as assessed by DBRS, remains investment grade.

Trans-Northern Pipelines Inc.	2010	2011	2012	2013	2014	2015
Revenue Requirement (millions)	$56.3	$66.2	$65.1	$65.8	$69.1	$81.1
Interest and Fixed-Charges Coverage Ratio	3.83	3.47	4.83	6.41	5.52	*
Cash Flow-to-Total Debt and Equivalents Ratio	14.1%	23.9%	29.7%	24.1%	37.8%	*
DBRS credit rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)

Financial data sources: revenue requirement – Trans Northern toll filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS. *Coverage ratios for 2015 are not available since DBRS has discontinued its rating report service for Trans Northern.

8.5 Kinder Morgan Cochin ULC's Cochin Pipeline

Commodity and NEB Group	Condensate (Western Portion) Propane – Ethane Mix (Eastern Portion) (Group 1)
Operating capacity	15 100 m^3/d (95 Mb/d)
Average utilization 2015	84%
Primary receipt points	Kankakee County, IL (Condensate) Fulton County, OH (Ethane-Propane Mix)
Primary delivery points	Ft. Saskatchewan, AB (Western Portion) Windsor, ON (Eastern Portion)
Rate base 2015	$146.10 million
Revenue 2015	$49.65 million
Abandonment Cost Estimate and Collection Period[32]	$26.3 million; 19.5 years

Overview

The Cochin Pipeline (Cochin) is a multi-product system spanning from Fort Saskatchewan, AB, to Windsor, ON. At Windsor it connects with the Windsor-Sarnia pipeline (owned by Plains Midstream). Cochin was in eastward propane service between Ft. Saskatchewan and Windsor until March 2014, when it was reversed to transport condensate westbound from its connection point with the Explorer pipeline in Kankakee County, IL to Alberta. The Eastern Portion of Cochin (from Illinois to Ontario) maintains a tariff for ethane-propane mix from the Canada-U.S. border to Windsor, ON, but no flows were reported in 2015.

Regulatory Documents
Cochin NEB Tariff No. 179 (Condensate)
Cochin NEB Tariff No. 176 (Ethane-Propane Mix)
Application for transfer of the Eastern Portion of the Cochin Pipeline from Kinder Morgan Cochin to Kinder Morgan Utopia
Application for Approval of Toll Methodology and Tolls and Tariffs for the Eastern Portion of the Cochin Pipeline
Cochin Reversal Application

Key Developments

In May 2013, the Board approved an application for the reversal of the Western Portion of Cochin to enable the transport of condensate from Illinois to Ft. Saskatchewan, AB. The reversed pipeline started operations in July 2014.

32 Collection Period began 1 January 2015.

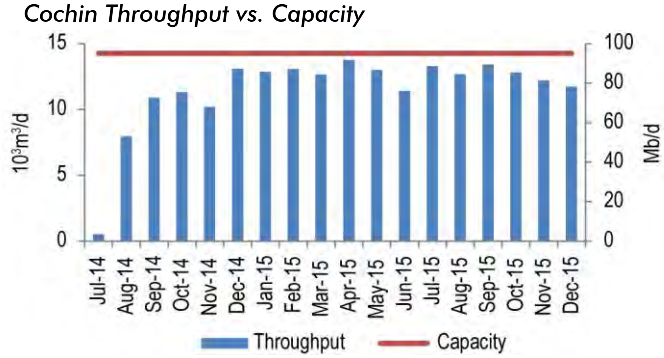
Kinder Morgan is moving ahead with the Utopia East Pipeline Project to transport NGLs from the Utica basin using the Eastern Portion of Cochin. A tolls and tariffs application for the transportation of ethane-propane mix and ethane for the Eastern Portion of Cochin was filed with the Board in November 2015. In March 2016, Kinder Morgan Cochin ULC applied to the Board to transfer ownership of the Eastern Portion of Cochin to Kinder Morgan Utopia ULC.

Utilization

Figure 8.5.1 illustrates throughput and capacity on Cochin. Current capacity is 15 100 m^3/d (95 Mb/d). Throughput from July to December 2014 averaged 9 000 m^3/d (57 Mb/d) and in 2015 averaged 12 700 m^3/d (80 Mb/d).

FIGURE 8.5.1

Cochin Throughput vs. Capacity



Tolls

Cochin provides condensate service to committed shippers from Illinois based on international joint tolls. On the other hand, uncommitted service is provided with an uncommitted toll for local Canadian shipments or an international joint toll for shipments originating in the U.S.

In 2014, the international joint toll for committed service was US$4.950/b, and the uncommitted joint rate was US$7.500/b. The Canadian local toll averaged $23.62 per m^3 ($C 3.76/b). In 2015, the international joint toll for committed service averaged US$5.0635/b, and the uncommitted toll averaged US$7.5776/b. The 2015 Canadian local toll averaged $23.92 per m^3 ($C 3.80/b).

Financial

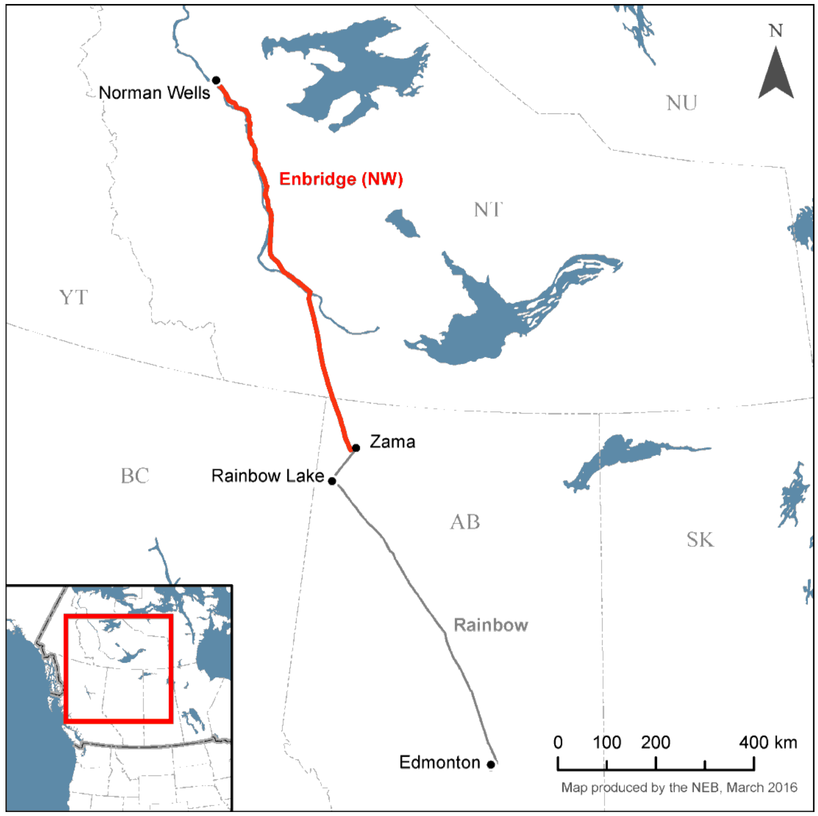
Cochin has been regulated on a complaint basis since 1986 and is allowed to earn a return of 5.75 to 8.25% on its rate base. It earned the minimum return from 2010 to 2014 and in 2015 (the first full year of condensate import service) it realized the maximum allowable return. Credit ratings are not available for Kinder Morgan Canada Company or Kinder Morgan Cochin ULC. Kinder Morgan Canada, which owns Kinder Morgan Cochin ULC, represents approximately 2% of its parent company's (Kinder Morgan Inc.) earnings.

Kinder Morgan Cochin ULC	2010	2011	2012	2013	2014	2015
Revenues (millions)	$22.77	$40.07	$25.52	$19.10	$29.89	$49.65
Average Rate Base (millions)	$84.03	$80.78	$76.26	$74.47	$106.68	$146.10
Return on rate base	5.75%	5.75%	5.75%	5.75%	5.75%	8.25%

Financial data sources: Cochin quarterly filings with the Board.

8.6 Enbridge Pipelines (NW) Inc.'s Enbridge Norman Wells Pipeline

Commodity and NEB Group	Crude Oil (Group 1)
Operating capacity	5 087 m^3/d (32 Mb/d)
Average utilization 2015	24%
Primary receipt points	Norman Wells, NT
Primary delivery points	Zama, AB.
Abandonment Cost Estimate and Collection Period[33]	$37 million; 11 years



Overview

The Enbridge Norman Wells Pipeline (Norman Wells) is 869 km in length and was commissioned in 1985 to transport crude oil from Imperial Oil's facility in Norman Wells, NT to Zama in northern Alberta.

Regulatory Documents
Enbridge Pipelines (NW) Tariff No. 44
SO-102-002-2011
AO-001-SO-E102-002-2011
AO-002-SO-E102-002-2011
MO-066-2015

Key Developments

After a crude oil release on Norman Wells in May 2011, the Board issued an order (SO-102-002-2011) to Enbridge Pipelines (NW) Inc., imposing a restriction on the maximum operating pressure of the pipeline and requiring an engineering assessment of the pipeline to ascertain its integrity. The Board subsequently issued Order AO-001-SO-E102-002-2011 in March 2013, requiring a further pressure restriction. An additional Order AO-002-SO-E102-002-2011 from May 2013 maintained the existing pressure restrictions and instructed the company to perform an additional engineering assessment of the Wrigley to Mackenzie pipeline leg. After verifying that engineering assessments were performed and corrective measures were implemented, the Board granted order MO-066-2015 in November 2015, lifting the pressure restrictions.

33 Collection Period began 1 January 2015.

Utilization

Figure 8.6.1 shows that Norman Wells average throughput was 2 200 m^3/d (14 Mb/d) in 2014 and 1 900 m^3/d (12 Mb/d) in 2015.

Tolls

Figure 8.6.2 shows the Norman Wells benchmark toll (Norman Wells to Zama) and the GDP deflator (normalized) for 2010-2015. The benchmark toll increased 42% in 2013, 52% in 2014, and 21% in 2015. These significant toll increases can be attributed to decreasing throughput and increased integrity spending.

Financial

Norman Wells uses a traditional cost of service methodology in rate making and is regulated on a complaint basis. Norman Wells and its shippers continue to use the RH-2-94 formula to set the return on equity that is incorporated into the pipeline's cost of service.

Credit ratings are not available for Enbridge Pipelines (NW) Inc. Enbridge Pipelines (NW) Inc. is a fully owned subsidiary of Enbridge Pipelines Inc. Norman Wells' credit is strongly related to that of its anchor shipper, Imperial Oil Ltd., which, at the time of writing, DBRS had assigned a rating of 'AA'.

FIGURE 8.6.1

Norman Wells Throughput vs. Capacity

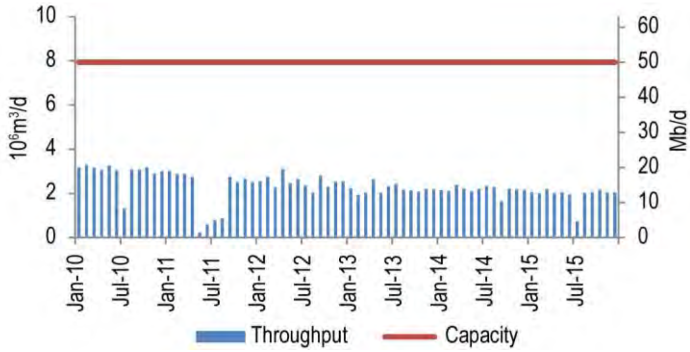
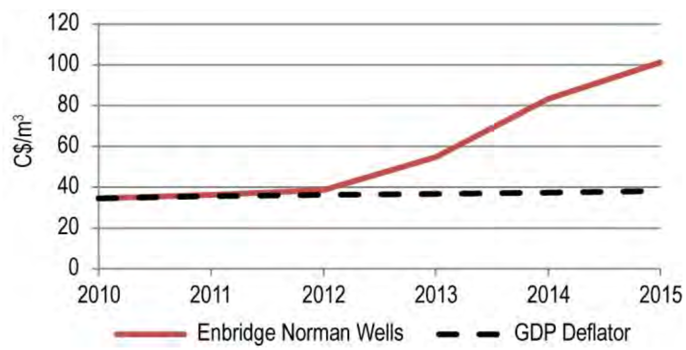


FIGURE 8.6.2

Norman Wells Benchmark Toll



Enbridge Pipelines (NW) Inc.	2010	2011	2012	2013	2014	2015
Cost of Service (millions)	$32.17	$75.03	$46.81	$65.43	$69.21	$61.84
Rate Base (millions)	$113.4	$108.7	$110.0	$141.1	$162.3	$150.9
Approved Return on Equity	8.46%	8.08%	7.58%	7.23%	7.93%	7.64%

Financial data sources: Enbridge NW cost of service filings with the Board.

9 Appendix: Profiles of Larger Group 2 Oil and Liquids Pipeline Companies

9.1 Express Pipeline Limited Partnership's Express Pipeline

Commodity and NEB Group	Crude oil (Group 2)
Average annual capacity	44 500 m^3/d (280 Mb/d)
Average utilization 2015	78%
Primary receipt points	Hardisty, AB
Primary delivery points	Casper, WY
Net-book value of PP&E 2014	$148 million
Abandonment Cost Estimate and Collection Period[34]	$44.3 million; 40 years

Overview

The Express Pipeline (Express) transports light, medium, and heavy crude oil from western Canada to refiners in the U.S. Rockies region. At Casper, WY Express connects with the Platte Pipeline, which transports crude oil to refineries in Kansas and Illinois. Express Pipeline Limited Partnership owns and operates the Canadian portion of Express, and is regulated by the NEB. The U.S. portion is owned and operated by Express Pipeline LLC and is regulated by the U.S. Federal Energy Regulatory Commission (FERC).

Regulatory Documents
NEB Tariff No. 138 NEB Tariff No. 137 FERC Approval Express U.S. Expansion, Tolls & Tariff

Key Developments

In March 2013, Spectra Energy Corp. (Spectra) acquired Express-Platte Pipeline System for $1.49 billion from a partnership of Kinder Morgan, Borealis Infrastructure and the Ontario Teachers' Pension Plan.

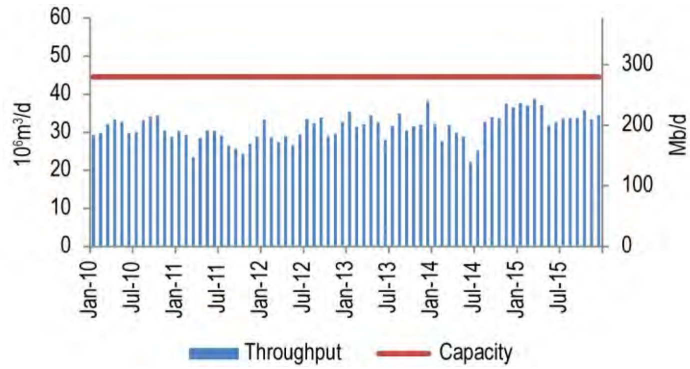
34 Collection Period began 1 January 2015.

Through a 2013 open season, contracted commitments on Express were increased from 18 900 m^3/d (119 Mb/d) to 35 800 m^3/d (225 Mb/d). These contracts cover 80% of the design capacity and have an average term of approximately ten years.

In May 2015, FERC approved an expansion of Express U.S. pipeline capacity from 39 700 m^3/d (250 Mb/b) to 43 100 m^3/d (271 Mb/d). The target in-service-date for the expansion is Q4 2016.

FIGURE 9.1.1

Express Throughput vs. Capacity



Utilization

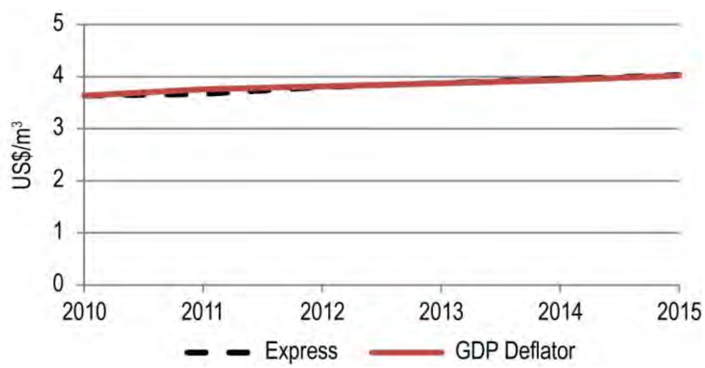
Figure 9.1.1 illustrates throughput and capacity on Express. Throughput averaged about 31 000 m^3/d (196 Mb/d) in 2014. In 2015, throughput averaged 34 700 m^3/d (219 Mb/d).

Tolls

Figure 9.1.2 shows that the Express benchmark toll (uncommitted toll for Light Petroleum from Hardisty to the U.S. border) moved roughly in-line with the GDP deflator (normalized) between 2010-15. Express' tolls are regulated on a complaint basis.

FIGURE 9.1.2

Express Benchmark Toll



Financial

Increased utilization rates and continued depreciation of debt have led to higher revenues and stronger coverage ratios. Credit ratings remain investment grade. After Spectra purchased Express in 2013, $203 million of goodwill was removed from its balance sheet, which is reflected in the partners' equity.

Express Pipeline Limited Partnership	2010	2011	2012	2013	2014	2015
Revenues (millions)	$47.7	$51.6	$55.97	$61.2	$70.8	$92.1
Net Income (millions)	$10.2	$9.2	$17.1	$13.2	$20.1	$30.1
Partner's Equity (millions)	$287.2	$296.4	$296.7	$96.9	$101.6	$98.6
Interest and Fixed-Charges Coverage Ratio	3.11	4.23	6.29	8.66	11.38	16.7
Cash Flow-to-Total Debt and Equivalents Ratio	24.9%	34.9%	51.2%	70.3%	95.1%	139.0%
DBRS Credit Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Moody's Credit Rating	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1

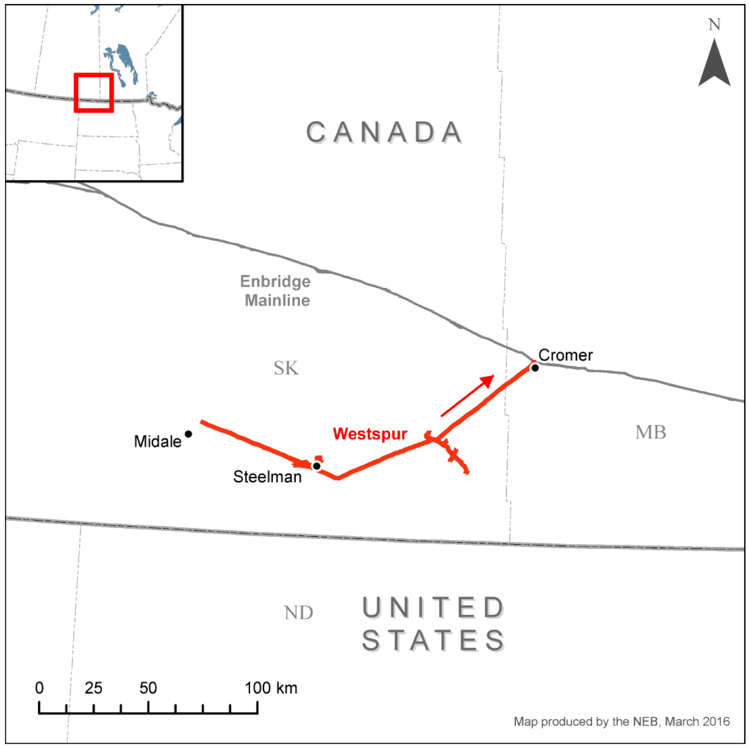
Financial data sources: revenues, net plant and return on equity – Express annual filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS, S&P, Moody's.

*Revenues, Net Income, and Return on Net Plant are reported for Express Pipeline Limited Partnership (Canadian assets only).

**Coverage ratios and credit ratings are for Express Pipeline Limited Partnership and Express Pipeline LLC (Canadian and U.S. assets).

9.2 Enbridge Pipelines (Westspur) Inc.'s Enbridge Westspur Pipeline

Commodity and NEB Group	Crude oil (Group 2)
Average annual capacity	40 500 m^3/d (255 Mb/d)
Average utilization 2015	69%
Primary receipt points	Alida, Bryant, Steelman and Midale, SK
Primary delivery points	Cromer, MB
Abandonment Cost Estimate and Collection Period[35]	$32.3 million; 25 years



Overview

The Enbridge Westspur Pipeline (Westspur) is located in south Saskatchewan and is comprised of approximately 390 km of trunk pipelines and approximately 80 km of gathering pipelines. It transports crude oil collected from gathering systems and truck shipments, as well as NGLs from the Steelman gas processing facility, to the Enbridge Mainline near Cromer, MB.

Regulatory Documents
[Enbridge Westspur Tariff NEB No. 75](#) [Enbridge Westspur Phase II Expansion Project](#) [Enbridge Westspur Tariff Complaint](#)

Key Developments

In February 2010, Enbridge Pipelines (Westspur) Inc. (Enbridge Westspur) applied to expand capacity on two segments of the system (Alida-Steelman and Bryant-Steelman) in southeastern Saskatchewan. The application was approved by the Board in April 2010 and leave to open was granted in January 2011.

35 Collection Period began 1 January 2015.

Utilization

Figure 9.2.1 shows Westspur throughput for 2010-2015. Throughput averaged 28 700 m^3/d (180 Mb/d) in 2014 and 28 100 m^3/d (177 Mb/d) in 2015.

Tolls

Figure 9.2.2 shows the Westspur benchmark toll (crude petroleum from the Midale Terminal in Saskatchewan to Cromer, MB) and the GDP deflator (normalized). The significant increase in tolls in 2011 was concurrent with the change in toll methodology from cost of service to negotiated settlements. The current toll settlement commenced in April 2013 and has a five year term. Westspur tolls are regulated on a complaint basis.

Financial

Revenue and net income have been stable since negotiated settlements replaced the cost of service tolling methodology in 2011. Enbridge Westspur owns an approximately 22% interest in two renewable companies which represented about $227.6 million of its assets in 2015.

FIGURE 9.2.1

Westspur Throughput vs. Capacity

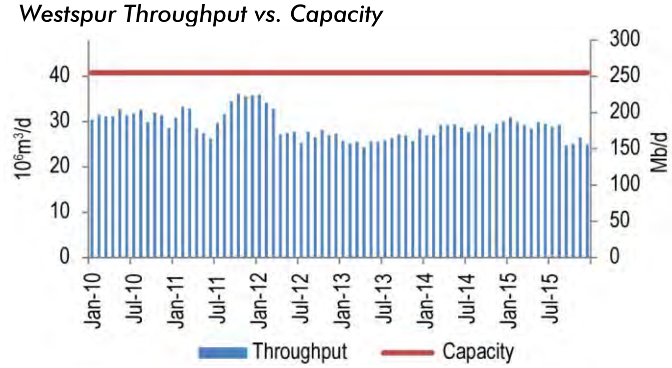
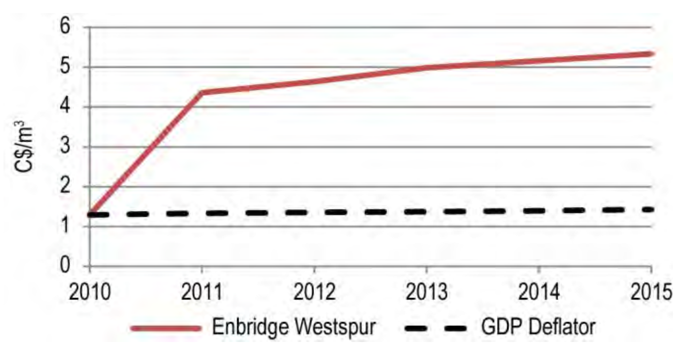


FIGURE 9.2.2

Westspur Benchmark Toll



Enbridge Pipelines (Westspur) Inc.	2010	2011	2012	2013	2014	2015
Revenues (millions)	$43.1	$59.5	$64.9	$54.2	$63.5	$67.3
Net Income (millions)	$14.2	$21.0	$15.8	$17.8	$18.0	$19.6
Property Plant & Equipment (millions)	$104.7	$112.7	$109.5	$109.2	$93.0	$86.0
Assets (millions)	$195	$478	$500.2	$432.3	$409.1	$397.7

Financial data sources: Enbridge Westspur annual filings with the Board.

9.3 Enbridge Southern Lights GP Inc.'s Southern Lights Pipeline

Commodity and NEB Group	Condensate (Group 2)
Average annual capacity	28 600 m^3/d (180 Mb/d)
Average utilization 2015	59%
Primary receipt points	Manhattan, IL
Primary delivery points	Edmonton and Hardisty, Kerrobert, SK
Abandonment Cost Estimate and Collection Period[36]	$100.8 million; 40 years

Overview

The Southern Lights Pipeline (Southern Lights) transports diluent from Manhattan, IL to Edmonton, AB where it is used in blending bitumen and heavy oil. The system was built by reversing approximately 1 465 km of the former Enbridge Line 13, and constructing 1 091 km of new pipeline in the U.S. The pipeline shares the Enbridge Mainline right-of-way.

Regulatory Documents
Southern Lights Tariff NEB No. 14
Southern Lights Application
Southern Lights Tariff No. 1 and No. 2

Key Developments

Southern Lights was approved by the Board in February 2008 and operations began in July 2010.

36 Collection Period began 1 January 2015.

Utilization

Figure 9.3.1 shows throughput on Southern Lights for 2010-2015. Throughput averaged 19 300 m^3/d (121 Mb/d) in 2014 and 16 900 m^3/d (107 Mb/d) in 2015.

Tolls

Figure 9.3.2 shows the Southern Lights benchmark toll (diluent transmission from the U.S. border to Edmonton, AB) and the GDP deflator (normalized) for 2010-2015. Tolls are based on cost of service methodology and are regulated on a complaint basis.

Financial

Enbridge Southern Lights LP total assets had a book value of over $1.1 billion in 2015. Southern Lights tolls incorporate a 10% return on the equity portion of its rate base (which is roughly half the size of its total assets due to a $471 million note receivable from its parent company).

FIGURE 9.3.1

Southern Lights Throughput vs. Capacity

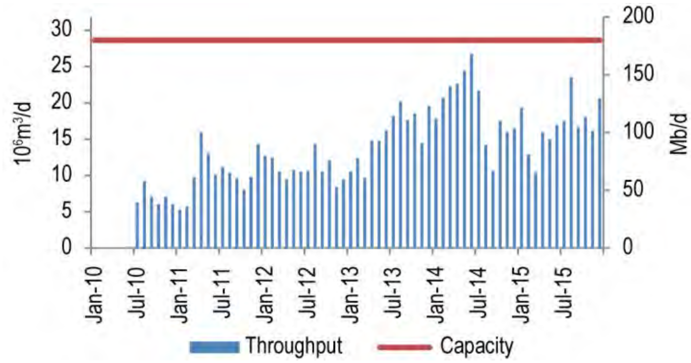
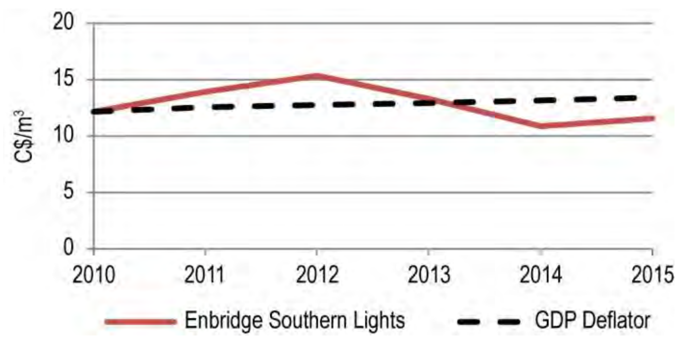


FIGURE 9.3.2

Southern Lights Benchmark Toll

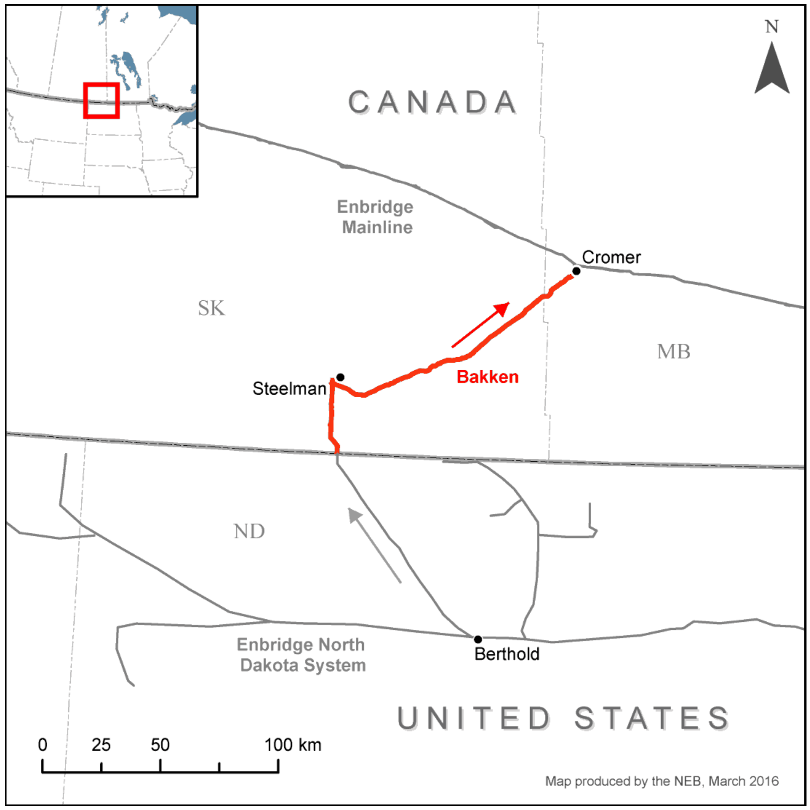


Enbridge Southern Lights LP	2011	2012	2013	2014	2015
Revenues (millions)	$58.5	$65.2	$81.2	$87.1	$98
Net Income (millions)	$33.4	$34.8	$37.8	$41.1	$47.0
Assets (millions)	$1 010	$1 052	$1 049	$1 101	$1 115

Financial data sources: Enbridge Southern Lights annual filings with the Board.

9.4 Enbridge Bakken Pipeline L.P.'s Enbridge Bakken Pipeline

Commodity and NEB Group	Crude oil (Group 2)
Average annual capacity	23 100 m^3/d (145 Mb/d)
Average utilization 2015	61%
Primary receipt points	Berthold, ND; Steelman, SK
Primary delivery points	Cromer, MB
Abandonment Cost Estimate and Collection Period[37]	$9.3 million; 25 years



Overview

The Enbridge Bakken Pipeline (Enbridge Bakken) transports light crude oil from the Bakken region in North Dakota[38] to the Enbridge Mainline near Cromer, MB. The system in Canada consists of the former Enbridge Westspur Line EX-02, which was reactivated and runs 34 km from the U.S. border to the Enbridge Westspur Steelman Terminal, and a new 123 km pipeline between Steelman and Cromer, MB.

Regulatory Documents
Enbridge Bakken Tariff NEB No. 19
Bakken Pipeline Project Canada Application

Key Developments

Enbridge Bakken was approved by the Board in December 2011 and began operations in April 2013.

37 Collection Period began 1 January 2015.

38 The U.S. portion of the pipeline is owned by Enbridge Pipelines (North Dakota) LLC, and is regulated by FERC.

Utilization

Figure 9.4.1 shows Enbridge Bakken throughput for 2013-2015. Throughput averaged 7 900 m^3/d (49 Mb/d) in 2014 and 14 000 m^3/d (88 Mb/d) in 2015.

Tolls

Figure 9.4.2 shows the Enbridge Bakken benchmark toll (uncommitted for crude petroleum from the U.S. border to Cromer, MB) and the GDP deflator (normalized) for 2013-2015. Enbridge Bakken is regulated on a complaint basis.

Financial

Enbridge Bakken Pipeline L.P. recognized $30 million in revenue in 2015, up 12% from its first full year of operations due to higher throughput levels.

FIGURE 9.4.1

Enbridge Bakken Throughput vs. Capacity

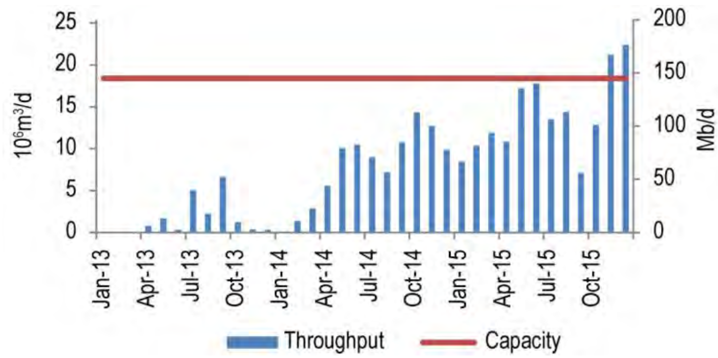
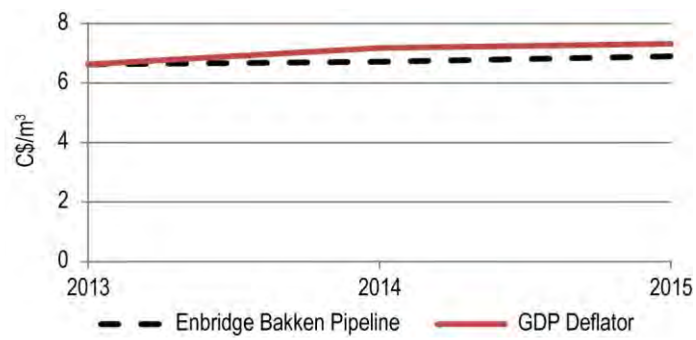


FIGURE 9.4.2

Enbridge Bakken Benchmark Toll



Enbridge Bakken Pipeline L.P.	2012	2013	2014	2015
Revenues (millions)	$0	$16.7	$27.2	$30.4
Net Income (millions)	($2.1)	$5.7	$12.7	$16.5
Assets (millions)	$141.0	$162.3	$160.6	$152.8

Financial data sources: Enbridge Bakken annual filings with the Board.

9.5 Montreal Pipe Line Limited's Montreal Pipe Line

Commodity and NEB Group	Crude oil (Group 2)
Average annual capacity	44 500 m^3/d (280 Mb/d)
Average utilization 2015	22%
Primary receipt points	Portland, ME
Primary delivery points	Montreal, QC
Abandonment Cost Estimate and Collection Period[39]	$19.9 million; 40 years

Overview

The Montreal Pipe Line is the Canadian portion of the Portland Montreal Pipe Line (PMPL). PMPL is a 380 km pipeline system that transports eastern Canadian and international crude oil from Portland, ME to Suncor's refinery and Enbridge's terminal in Montreal, QC. The PMPL system is comprised of three pipelines along the same right-of-way. The largest pipeline (24-inch) is the only line in operation. The other two pipelines (12-inch and 18-inch) were deactivated in 1982 and 2011, respectively.

Regulatory Documents

- [Montreal Pipe Line Tariff NEB No. 173]
- [Montreal Pipe Line Tariff NEB No.174]
- [Implementation of Financial Resource Requirements with respect to Pipeline Safety Act Regulations - Pipeline Capacity]
- [Application to Deactivate 18-inch pipeline between Highwater and Montreal, QC]
- [Application to Deactivate St-Césaire Pumping Station]

Key Developments

The Montreal Pipe Line reported no throughputs from January to March 2016. In December 2015, the Enbridge Line 9 Expansion and Line 9B Reversal Project came into service, enabling Quebec refiners to access western Canadian and U.S. crude oil supply by that pipeline.

Due to the implementation of the Financial Resource Requirements of the *Pipeline Safety Act* Regulations, Montreal Pipe Line Limited (MPL) indicated its intention in May 2016 to reduce the capacity of its system to less than 39 700 m^3/d (250 Mb/d).

39 Collection Period began 1 January 2015.

MPL submitted an application to the Board in April 2014 to deactivate its St.-Césaire Pump Station and related facilities. The NEB approved the application in May 2014 and deactivation was completed in December 2014.

MPL received regulatory approval on April 2011 to deactivate its 18-inch pipeline between Highwater and Montreal East, QC and deactivation was completed in December 2011.

Utilization

Figure 9.5.1 illustrates Montreal Pipeline throughput and capacity. Throughput has fallen steadily between 2010 and 2015, averaging 14 200 m^3/d (89 Mb/d) in 2014 and 9 700 m^3/d (61 Mb/d) in 2015.

Tolls

Figure 9.5.2 shows the Montreal Pipeline bench mark toll (transportation from the U.S. border to Montreal East) and the GDP deflator (normalized) for 2010-2015. The sharp increase in tolls between 2013 and 2014 was a result of decreased throughput. Tolls are regulated on a complaint basis.

FIGURE 9.5.1

Montreal Pipeline Throughput vs. Capacity

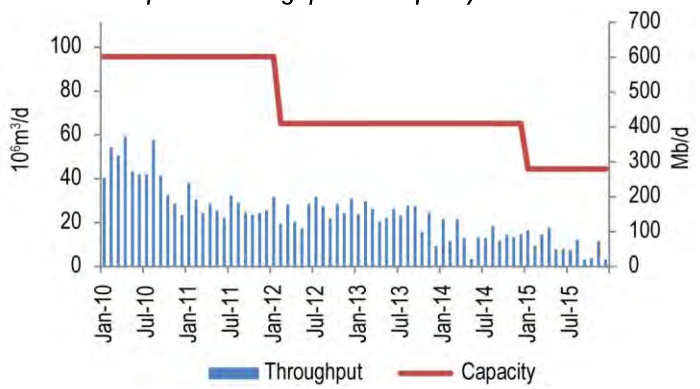
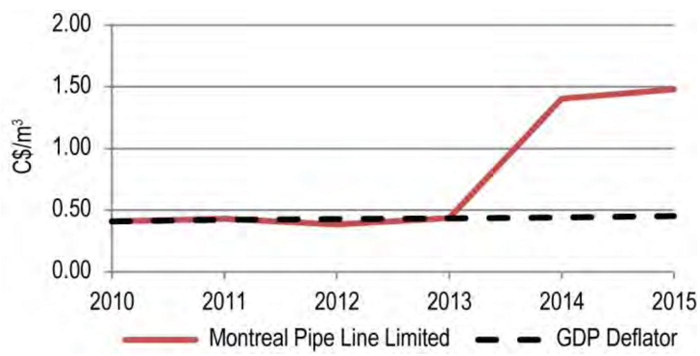


FIGURE 9.5.2

Montreal Pipeline Benchmark Toll



Financial

Revenue and net income have decreased due to reduced throughput.

Montreal Pipe Line Ltd.	2010	2011	2012	2013	2014	2015
Revenues (millions)	$77.3	$71.5	$71.2	$64.3	$49.3	$38.6
Net Income (millions)	$19.9	$19.1	$22.9	$18.1	$10.1	$6.1
Equity (millions)	$38.7	$51.3	$74.2	$90.9	$101.0	$107.1

Financial data sources: Montreal Pipe Line annual filings with the Board.

9.6 Plains Midstream Canada ULC - Milk River Pipeline's Milk River Pipeline

Commodity and NEB Group	Crude oil (Group 2)
Average 2015 throughput	15 087 m^3/d (94.9 Mb/d)
Primary receipt points	Milk River, AB
Primary delivery points	Santa Rita Station, Glacier County, MT
Abandonment Cost Estimate and Collection Period[40]	$4.1 million; 40 years

Overview

The Milk River Pipeline (Milk River) is a 16.5 km pipeline system that connects with the Bow River Pipeline at Milk River, AB. It transports a variety of crude oil streams to the Canada-U.S. border west of Coutts, AB and connects with the Cenex Santa Rita Pipeline System in the U.S. Milk River is owned by Plains Midstream Canada ULC (PMC).

Regulatory Documents
Milk River Tariff No. 86 Application to Deactivate Sections of the Milk River Pipeline Milk River Replacement Application 2012

Key Developments

In April 2012, Plains Midstream Canada ULC (PMC) submitted an application to the Board to replace the 10-inch pipeline between the Milk River Terminal south of Milk River, AB to the Canada-U.S. border. The Board approved the request on August 2012 (XO-P384-011-2012) and Leave to Open was granted in December 2012.

In October 2013, PMC filed with the Board an application to deactivate its 6-inch pipeline and other facilities that were no longer needed after the replacement of the 10-inch pipeline. The Board issued order MO-007-2014 on February 2014, granting the request.

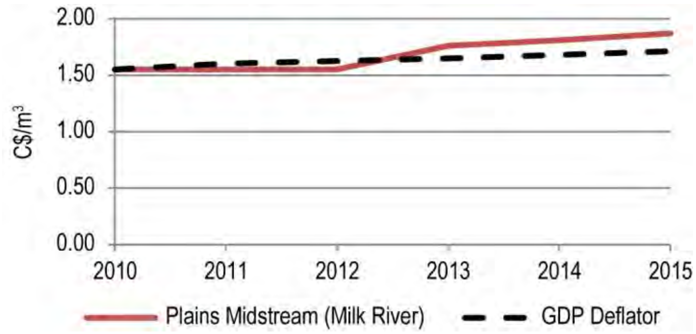
40 Collection period began 1 January 2015.

Tolls

Figure 9.6.1 shows the Milk River benchmark toll (medium crude oil from the Milk River Pump Station to the U.S. border) and the GDP deflator (normalized) for 2010-15. Over this period, the benchmark toll has increased roughly in line with the GDP deflator. Milk River tolls are regulated on a complaint basis.

FIGURE 9.6.1

Milk River Benchmark Toll



Financial

Milk River transportation revenues have increased due to toll increases.

Milk River Pipeline	2010	2011	2012	2013	2014	2015
Transportation Revenues (millions)	\$8.2	\$8.4	\$7.9	\$9.8	\$11.3	\$12.8
Assets (millions)	\$22.2	\$22.0	\$24.3	\$29.7	\$29.4	\$28.6

Financial data sources: Plains annual filings with the Board.

9.7 Aurora Pipeline Company Limited's Aurora Pipeline

Commodity and NEB Group	Crude Oil, Condensate, Butanes (Group 2)
Average 2015 throughput	1732 m^3/d (10.9 mb/d)
Primary receipt points	Carway, AB
Primary delivery points	Cutbank, MT
Abandonment Cost Estimate and Collection Period[41]	$0.1 million; 40 years

Overview

The Aurora Pipeline (Aurora) is the NEB-regulated border segment of the Rangeland Pipeline system. It consists of two parallel (12-inch and 8-inch) 0.75 km sections of pipeline, starting near Carway, AB and ending at the Canada–U.S. border near Cutbank, MT.

Regulatory Documents
Aurora Tariff NEB No.7 Deactivate Aurora NPS 8 Pipeline

Key Developments

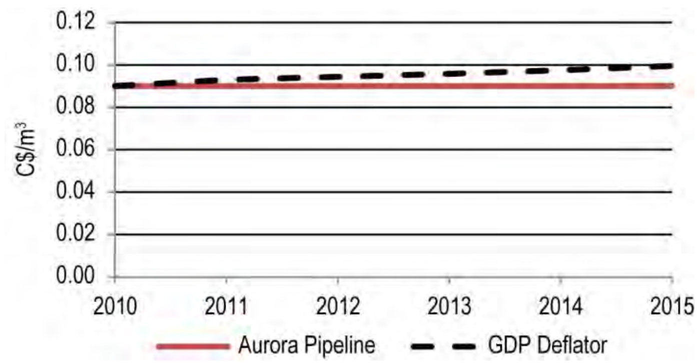
In October 2015, Plains Midstream Canada ULC (PMC) (which owns Aurora Pipeline Company Ltd.) applied to the Board to deactivate its 8-inch pipeline. The pipeline had been deactivated in July 2010; however no application to the NEB was made at that time. The Board approved the application in November 2015, and in December, PMC confirmed that the deactivation was completed in compliance with all applicable conditions to the Order.

41 Collection Period began 1 January 2015.

Tolls

Figure 9.7.1 shows the Aurora benchmark toll (Connection with Rangeland Pipeline to Connection with Glacier Pipe Line Company at the U.S. border) and the GDP deflator (normalized). Aurora's benchmark toll has not changed since 2010. Tolls are regulated on a complaint basis.

FIGURE 9.7.1



Financial

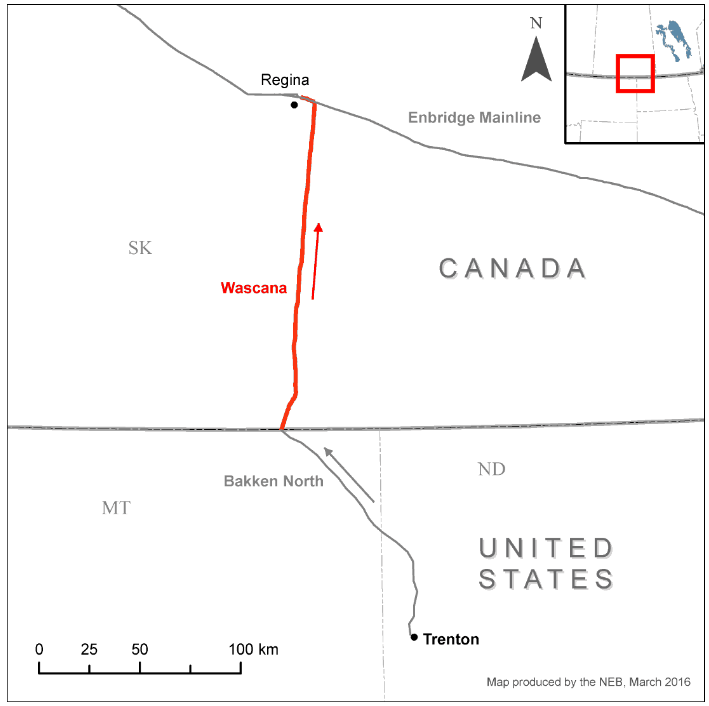
Aurora is operated by PMC. Revenues directly attributable to this pipeline declined from about $83 000 in 2010 to $63 000 in 2015. Over the same time period, Aurora has depreciated $5,000 of its assets each year, bringing the book value of its capital assets down from $308 000 to $283 000.

Aurora Pipeline Company Ltd.	2010	2011	2012	2013	2014	2015
Revenues (thousands)	$83	$81	$62	$39	$60	$63
Operating Profit (thousands)	$69	$73	$54	$31	$52	$54
Assets (thousands)	$308	$303	$298	$293	$288	$283

Financial data sources: Plains annual filings with the Board.

9.8 Plains Midstream Canada ULC - Wascana Pipeline Ltd.'s Wascana Pipeline

Commodity and NEB Group	Crude oil, petroleum products, NGLs (Group 2)
Average 2015 throughput	1540 m^3/d (9.7 mb/d)
Primary receipt points	Raymond Station, Sheridan County, MT
Primary delivery points	Plains Terminal, Regina, SK
Abandonment Cost Estimate and Collection Period[42]	$12.5 million; 40 years



Overview

The Wascana Pipeline (Wascana) is 172 km in length and runs from the U.S. border to the Plains Terminal in Regina, SK. At Regina, Wascana connects with the Enbridge Mainline. Wascana transports light oil from the Bakken region in North Dakota via a connection with the Bakken North Pipeline. Wascana is owned by Plains Midstream Canada ULC (PMC).

Regulatory Documents
Wascana Tariff 2016
Wascana Reversal Application
Order SO-P384-004-2011
Order SO-P384-001-2014

Key Developments

In October 2011 the Board issued Order SO-P384-004-2011 reducing the maximum operating pressure on Wascana until pipeline integrity concerns were addressed. After verifying that PMC fulfilled the requirements of the 2011 order, the restriction was lifted by the Board in Order SO-P384-001-2014.

Wascana was used for oil storage from 2009 to December 2011 when it was taken out of service for repairs. Repairs were completed in December 2012 and the pipeline was deactivated from January 2013 to April 2014.

In October 2012, PMC applied to the Board to reverse the flow of Wascana, enabling it to transport light crude oil from the Bakken region across the U.S.-Canadian border to the Plains Terminal in Regina, SK. The reversal was approved by the Board in May 2013 and Wascana began transporting crude oil in April 2014.

42 Collection Period began 1 January 2015.

Tolls

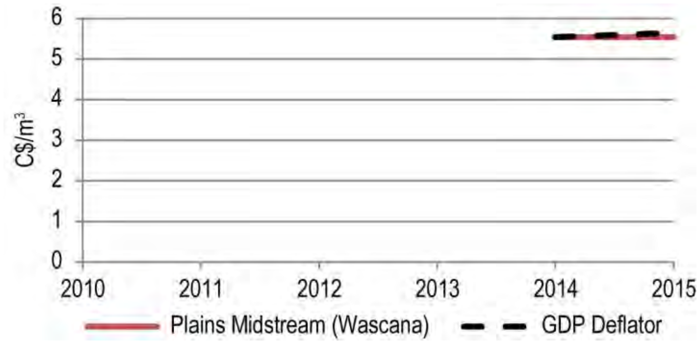
Figure 9.8.1 shows the Wascana benchmark toll for light crude oil from the U.S. border to Regina and the GDP deflator normalized for 2010-2015. Tolls for 2014 and 2015 were $5.54 per m^3 ($0.88/b) reflecting rates agreed to with shippers for the pipeline reversal. Wascana tolls are regulated on a complaint basis.

Financial

Wascana's revenue was zero for 2010-2013, while it was out of service. The pipeline reversal project added $5.6 million to Wascana's capital base.

FIGURE 9.8.1

Wascana Benchmark Toll



Wascana Pipeline	2010	2011	2012	2013	2014	2015
Transportation Revenues (millions)	$0	$0	$0	$0	$3.0	$3.5
Assets (millions)	$3.8	$3.7	$9.2	$9.2	$9.2	$9.3

Financial data sources: Plains annual filings with the Board.

9.9 Pembina Prairie Facilities Ltd.'s Vantage Pipeline

Commodity and NEB Group	Ethane (Group 2)
Average annual capacity	6 400 m^3/d (40 Mb/d)
Average utilization 2015	50%
Primary receipt points	Tioga, ND; Viewfield, SK
Primary delivery points	Empress, AB
Abandonment Cost Estimate and Collection Period	$4.8 million; Not applicable[43]

Overview

The Vantage Pipeline (Vantage) is a high vapour pressure pipeline that transports ethane from Tioga, ND and Saskatchewan to Empress, AB. At Empress it connects with the Alberta Ethane Gathering System for final delivery to the petrochemical plants in Joffre and Ft. Saskatchewan, AB.

Regulatory Documents
Vantage Pipeline Tariff NEB
Vantage Pipeline Application
Vantage Pump Addition Applications
Vantage Pipeline Empress and Assiniboia Pump Station Expansion

Key Developments

Vantage began operations in June 2014.

In October 2014, Pembina Prairie Facilities Ltd. (PPF) entered into an amalgamation agreement with Vantage Pipeline Canada ULC and Mistral Midstream Inc., which effectively transferred ownership of the pipeline from Vantage to PPF.

In late August 2015, the Saskatchewan Ethane Extraction Plant (SEEP) near Viewfield, SK was commissioned, adding 800 m^3/d (5 Mb/d) of ethane supply to Vantage.

In July 2015, PPF applied to the Board for modifications at three pump stations. The Board approved this application in November 2015. As of June 2016, these facilities had not been put into service.

43 Vantage abandonment costs are fully covered under a Letter of Credit.

In March 2016, PPF applied to the Board to expand Vantage capacity to 10 800 m^3/d (68 Mb/d) by adding pumping capacity at two stations (Empress and Assiniboia). The project would allow the pipeline to transport additional ethane volumes from North Dakota to Alberta. If it receives regulatory approval, the company is targeting to have it in service in Q3 2016.

Utilization

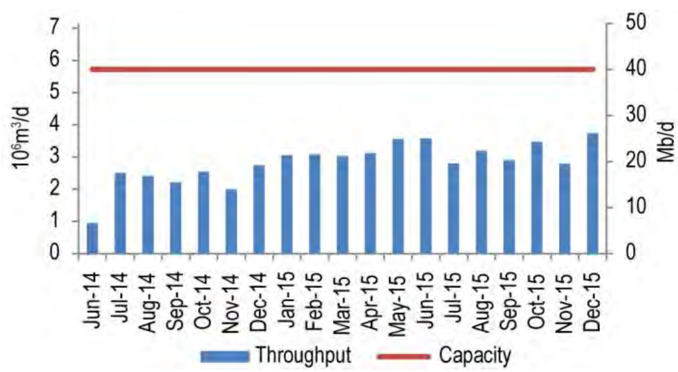
Figure 9.9.1 shows Vantage throughput for 2014-2015. Throughput averaged 2 200 m^3/d (14 Mb/d) in 2014 and 3 200 m^3/d (20 Mb/d) in 2015.

Tolls

NOVA Chemicals Corporation (NCC) is the sole committed shipper on Vantage. NCC's *committed* tolls are governed by agreements with PPF, and have been filed confidentially with the Board. Effective October 2015, the toll for uncommitted service from Tioga, ND is US$0.1402 per gallon and the toll for *uncommitted* service from SEEP is US$0.1113 per gallon. However, no shippers have utilized uncommitted service on the pipeline. Tolls are regulated on a complaint basis.

FIGURE 9.9.1

Vantage Throughput vs. Capacity



Financial

PPF acquired the Vantage Pipeline and Mistral Midstream Inc.'s interest in SEEP for a total consideration of $614 million.

Pembina Prairie Facilities Ltd	2014*	2015
Total Assets (millions)	$669.5	$683.2
Revenues (millions)	$4.9	$34.5
Net Income (millions)	$1.8	$7.2

Financial data sources: Pembina annual filings with the Board.

*For the period from incorporation on 29 August 2014 to year end on 31 December 2014.

9.10 Genesis Pipeline Canada Ltd.'s Genesis Pipeline

Commodity and NEB Group	Natural Gas Liquids (Group 2)
Average annual capacity	5 900 m^3/d (37 Mb/d)
Primary receipt points	Marysville, MI
Primary delivery points	Corunna, ON
Abandonment Cost Estimate and Collection Period[44]	$3.1 million; 40 years

Overview

The Genesis Pipeline (Genesis) includes a one km pipeline which crosses the St. Clair River between St. Clair County near Marysville, MI and Sarnia, ON, and an eight km pipeline between Sarnia and Corunna, ON. Genesis transports pure ethane from the Marcellus basin to the NOVA Chemicals and Imperial Oil petrochemical facilities in Sarnia using the Sunoco Logistics Mariner West Pipeline in the U.S.

Regulatory Documents

[Genesis Tariff NEB No. 8](#)

[Genesis Pipeline Extension Project Application](#)

Key Developments

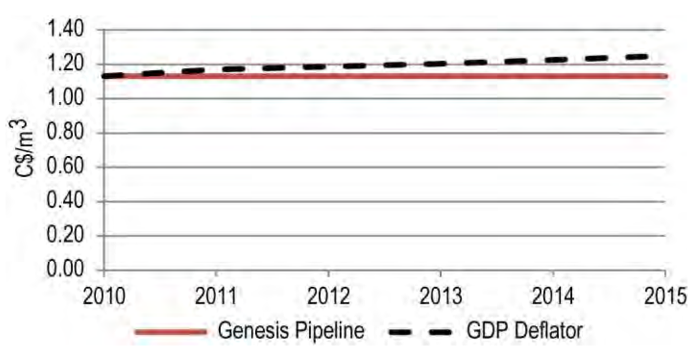
The Genesis Pipeline Extension Project was approved by the Board in June 2012 and began operations in December 2013.

Tolls

Figure 9.10.1 shows the Genesis benchmark toll from Corunna, ON, to the International Border near Sarnia, ON and the GDP deflator (normalized). Tolls are regulated on a complaint basis.

FIGURE 9.10.1

Genesis Benchmark Toll

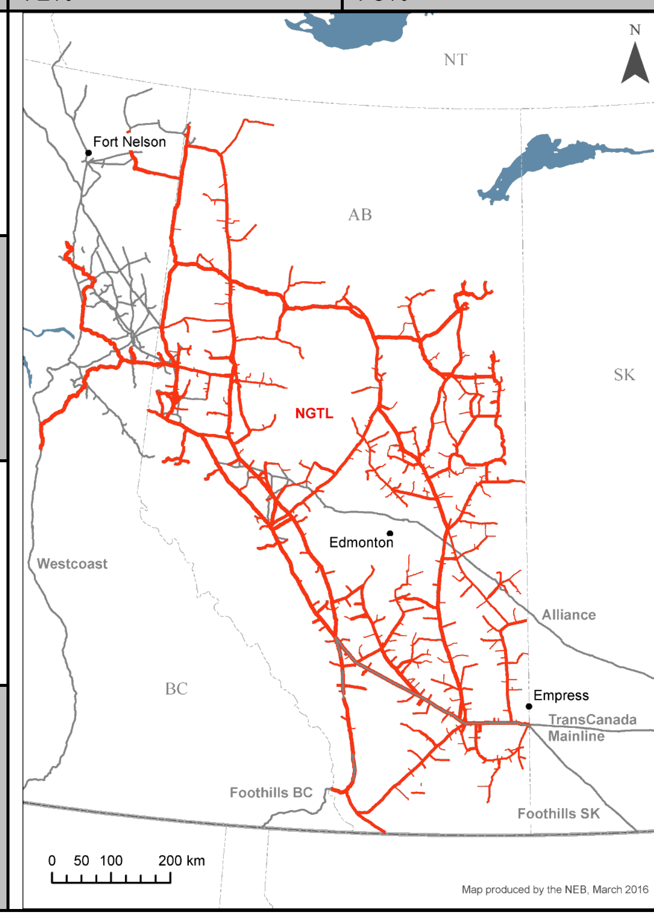


44 Collection Period began 1 January 2015.

10 Appendix: Profiles of Natural Gas Pipeline Companies

10.1 Nova Gas Transmission Ltd. (NGTL)

Commodity and NEB Group	Natural Gas (Group 1)		
Location	Upstream James River	North and East	Eastern Gate
Primary receipt points	Northwestern Alberta and Northeastern BC	North and East Alberta	Intra-Alberta
Primary delivery points	Intra-Alberta and the AB/BC border	Intra-Alberta	McNeill, Empress
Annual average capacity	228 $10^6 m^3$/d (8.0 Bcf/d)	121 $10^6 m^3$/d (4.3 Bcf/d)	126 $10^6 m^3$/d (4.5 Bcf/d)[45]
Average utilization 2015	97%	72%	98%[46]
Total system delivery volume 2015	111.2 $10^9 m^3$ (3.9 Tcf)		
Rate base 2015	$6.1 billion		
Cost of Service 2015	$1.8 billion		
Abandonment Cost Estimate and Collection Period[47]	$2.184 billion; 30 years		



45 Eastern Gate design capability as provided by TransCanada PipeLines Ltd. (TCPL). Design capability is based on the methodology which states that the maximum day deliveries will not exceed the lesser of the capability of the downstream pipeline or the aggregate of the applicable firm contract demand.

46 Based on Eastern Gate design capability as provided by TCPL.

47 Collection Period began 1 January 2015.

Overview

The Nova Gas Transmission Ltd. system (NGTL) consists of more than 25 000 km of natural gas pipeline and associated facilities located in Alberta and northeastern B.C. NGTL has over 1 100 receipt points and over 300 delivery points. The system came under NEB jurisdiction in 2009 and is wholly-owned by TransCanada Corporation.

Regulatory Documents
Application for the NGTL 2016 and 2017 Revenue Requirement Settlement
Application for Interim 2015 Rates, Tolls and Charges
Application for the Towerbirch Expansion Project
Application for the 2017 NGTL System Expansion
Application for North Montney Project

NGTL is divided into three areas: Peace River, North and East, and the NGTL Mainline. Throughput information is provided for these areas as Upstream James River, North and East Flows, and Eastern Gate, respectively.

Key Developments

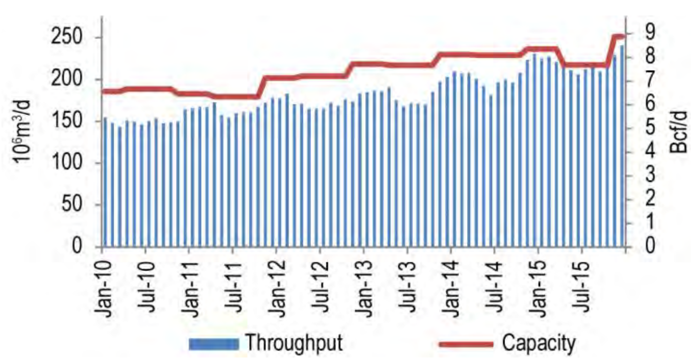
NGTL is expanding at a rapid pace, adding more than $2 billion in facilities between 2010 and 2015. New supply has entered the system, particularly from the Montney formation in the northwest portion of the system. Capacity is constrained in some parts of these rapidly growing areas and NGTL is adding additional facilities.

Utilization

Natural gas from receipt points in northwestern Alberta and northeastern B.C. enters NGTL upstream of James River via the Horn River and Groundbirch pipelines. Figure 10.1.1 shows throughput and capacity for Upstream James River. Capacity was approximately 184 $10^6m^3/d$ (6.5 Bcf/d) in 2011 and has increased to 251 $10^6m^3/d$ (8.9 Bcf/d) at the end of 2015. Throughput has increased on this section of the system with growing supply from the Horn River and Montney formations. Throughput averaged 220 $10^6m^3/d$ (7.78 Bcf/d) in 2015.

FIGURE 10.1.1

NGTL Upstream James River Throughput vs. Capacity



Flows on the North and East areas of NGTL consist of intra-Alberta flows, including natural gas used for oil sands operations in northern Alberta. Figure 10.1.2 shows throughput and capacity for North and East. Capacity varies seasonally and has been increasing since 2010. In 2015, capacity ranged from 111 $10^6m^3/d$ (3.9 Bcf/d) in summer to 141 $10^6m^3/d$ (5.0 Bcf/d) in winter. Throughput averaged 87 $10^6m^3/d$ (3.08 Bcf/d) in 2015.

FIGURE 10.1.2

NGTL North and East Throughput vs. Capacity

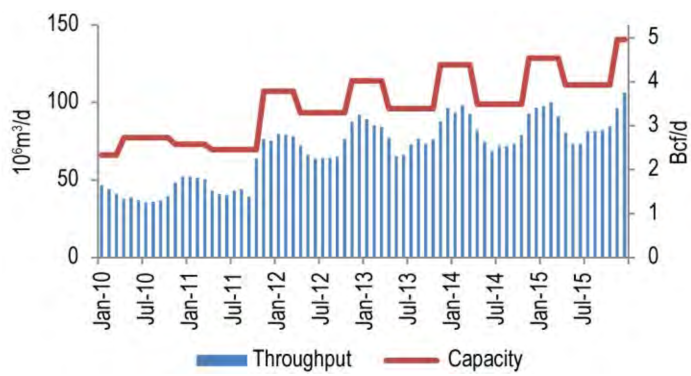


Figure 10.1.3 shows the design capability and throughput at the Eastern Gate, where NGTL interconnects with TransCanada's Mainline at Empress and Foothills Saskatchewan at McNeill, near the Alberta-Saskatchewan border. Design capability is based on the methodology which states that the maximum day deliveries will not exceed the lesser of the capability of the downstream pipeline *or the aggregate of the applicable firm contract demand.*

In recent years the aggregate contract demand quantities of the firm transportation service agreements have determined NGTL's design capability at the Eastern Gate. With the decline in contract demand quantities at the Eastern Gate, NGTL's design capability and capacity in place has declined. In 2015 throughput at the Eastern Gate averaged 124 $10^6m^3/d$ (4.4 Bcf/d). Design capability has been declining as supply shifts farther from the Eastern Gate and intra-NGTL System deliveries increase. The design capability includes assumptions relating to storage levels, ambient air and ground temperatures, flow distribution, and local supply and deliveries. Throughput may exceed the design capability when actual conditions are different from the design assumptions.

FIGURE 10.1.3

NGTL Eastern Gate Throughput vs. Design Capability

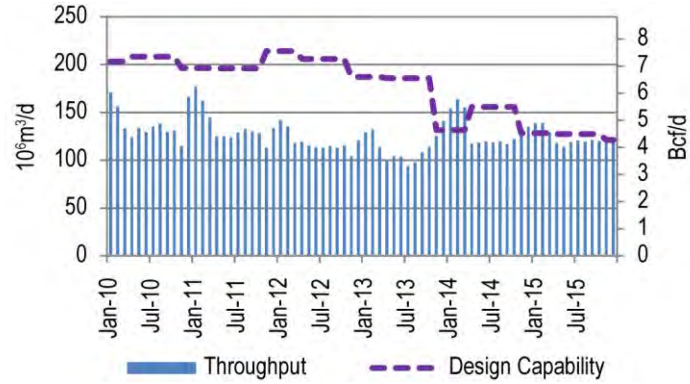
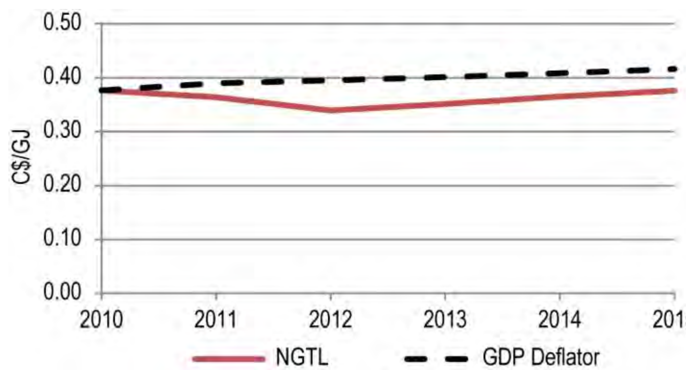


FIGURE 10.1.4

NGTL Benchmark Toll



Tolls

NGTL operated under revenue requirement settlements for 2010-2015.

Figure 10.1.4 shows the NGTL benchmark toll[48] (firm receipt toll, plus delivery toll to Group 1 locations) and the GDP deflator (normalized) for 2010-2015. The benchmark toll declined in 2011 and 2012 with higher throughput and increased in line with the GDP deflator from 2012 through 2015 as system costs and throughput both increased.

48 Based on an energy conversion factor of 1000 m^3 = 37.24 GJ

Financial

NGTL's revenue, net income and rate base have been growing due to system expansions and increased throughput. NGTL's financial ratios have remained stable and its credit ratings remain investment grade.

Nova Gas Transmission Ltd.	2010	2011	2012	2013	2014	2015
Revenues (millions)	$1 117.1	$1 200.2	$1 354.4	$1 506.4	$1 614.4	$1 767.1
Net Income (millions)	$194.1	$195.6	$198.1	$232.0	$228.5	$245.3
Rate Base (millions)	$4 834.2	$4 878.1	$5 177.6	$5 670.7	$5 917.2	$6 094.1
Deemed Equity Ratio	40%	40%	40%	40%	40%	40%
Return on Equity	10.04%	10.03%	9.57%	10.23%	9.65%	10.06%
Interest and Fixed Charges Coverage Ratio*	2.18	2.16	2.1	2.34	2.19	2.11
Cash Flow to Total Debt and Equivalents Ratio*	14.3%	13.5%	12.6%	13.6%	12.6%	12.3%
DBRS Credit Rating	A	A	A	A (low)	A (low)	A (low)
S&P Credit Rating	A-	A-	A-	A-	A-	A-
Moody's Credit Rating	A3	A3	A3	A3	A3	A3

Financial data sources: revenues, net income, rate base, equity and return – NGTL filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS, S&P, Moody's.

*The coverage and debt ratios for 2015 include the last three months prior to 31 March 2015.

10.2 TransCanada Pipe Lines Limited's TransCanada Mainline

Commodity and NEB Group	Natural Gas (Group 1)		
Rate base 2015	$4.6 billion		
Cost of Service 2015	$2 billion		
Abandonment Cost Estimate and Collection Period[49]	$2 530 million; 25 years		
Segment	Prairies	Northern Ontario Line	Eastern Triangle
Average annual capacity	195 10^6 m^3/d (6.9 Bcf/d)	102 10^6 m^3/d (3.6 Bcf/d)	148 10^6 m^3/d (5.2 Bcf/d)
Average utilization 2015	43%	60%	46%
Primary receipt points	Empress	Prairies segment	Northern Ontario Line, Parkway, Niagara, Chippawa, Dawn
Primary delivery points	Emerson, Northern Ontario Line	North Bay, Sault Ste-Marie, Eastern Triangle	Toronto, Ottawa, Iroquois, TQM Pipeline
Economic planning horizon (from 2015)[50]	21 years	5 years	35 years

49 Collection Period began 1 January 2015.

50 Economic planning horizons were provided in the RH-003-2011 proceeding for depreciating the three segments of the pipeline. For example, the Northern Ontario Line is expected to be fully depreciated by 2020.

Overview

The TransCanada Mainline was built in the 1950s to move natural gas from the Western Canada Sedimentary Basin (WCSB) to eastern markets. The 14 100 km system extends from the Alberta-Saskatchewan boundary, across Saskatchewan, Manitoba and Ontario, and through a portion of Quebec.

Regulatory Documents
2015-2020 Mainline Transportation Tolls (RH-001-2014 Compliance Filing)
Business and Services Restructuring Proposal and 2012 and 2013 Mainline Final Tolls
Application for Approval of Mainline 2015-2030 Tolls Settlement
Energy East Project and Asset Transfer
Eastern Mainline Project

The Prairies segment extends from the Alberta-Saskatchewan border to Compressor Station 41, located near Île-des-Chênes, MB, and from Compressor Station 41, south to a point on the Canada-U.S. border near Emerson, MB. There, the Prairies segment connects to the Great Lakes Gas Transmission (GLGT) and Viking Gas Transmission systems and transports gas to markets in the Mid-western U.S. The Northern Ontario Line (NOL) segment begins at Compressor Station 41 and extends to Compressor Station 116 near North Bay, ON carrying supply from the WCSB. The NOL also contains a small segment that connects Sault Ste. Marie, ON with the GLGT system. South of Station 116, the NOL interconnects with the Eastern Triangle segment of the Mainline. The Eastern Triangle extends to the southeastern and southwestern extremities of the system, supplying Ontario, Quebec, and export markets.

The Eastern Tringle does not depend solely on the WCSB and increasingly receives gas from other sources such as the Appalachian Basin. This has reduced the need for natural gas supplies from the WCSB.

Key Developments

TransCanada PipeLines Limited (TransCanada or TCPL) has been adding pipeline facilities in the Eastern Triangle to relieve constraints, enable more gas to flow into Ontario from the U.S., and meet growing demand.

- The King's North Connection Pipeline is under construction.
- The Greater Golden Horseshoe Facilities Project came online in January 2016.
- The Vaughan Mainline Expansion Project was approved on 4 August 2016, with Reasons for Decision to follow by 9 September 2016.

TransCanada has two additional projects before the Board. Energy East proposes to convert 3 000 km of natural gas pipeline for crude oil transport, and construct 1 520 km of new pipeline. The Eastern Mainline application proposes to expand sections of the pipeline in Ontario so TransCanada can continue serving gas shippers if the Energy East Project goes ahead.

Utilization

Figure 10.2.1 shows throughput and capacity for the Prairie Segment for 2010-2015. Capacity varies seasonally from 187.2 10^6m^3/d (6.6 Bcf/d) in summer to 201 10^6m^3/d (7.1 Bcf/d) in winter. Throughput has increased since mid-2013 due to a change in contracting patterns following the implementation of the RH-003-2011 toll decision. Throughput averaged 84 10^6m^3/d (3 Bcf/d) in 2015.

Figure 10.2.2 shows throughput and capacity for the NOL for 2010-2015. Capacity varies seasonally from 101 10^6m^3/d (3.56 Bcf/d) in the summer to 104 10^6m^3/d (3.68 Bcf/d) in the winter. Throughput increases significantly in winter months, as gas demand for home heating in the Eastern Triangle rises. In general, throughput has increased since mid-2013 in line with the Prairies segment. Throughput averaged 61 10^6m^3/d (2.16 Bcf/d) in 2015.

Figure 10.2.3 shows throughput and capacity for the Eastern Triangle for 2010-2015. Capacity varies seasonally from 161 10^6m^3/d (5.7 Bcf/d) in winter to 139 10^6m^3/d (4.9 Bcf/d) in summer. Throughput averaged 69 10^6m^3/d (2.4 Bcf/d) in 2015.

FIGURE 10.2.1

Prairies Segment Throughput vs. Capacity

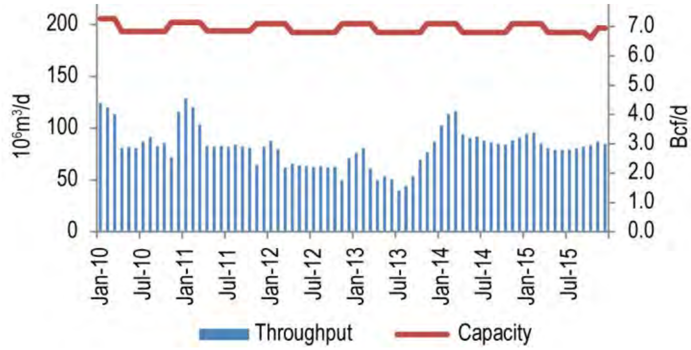


FIGURE 10.2.2

TransCanada NOL Throughput vs. Capacity

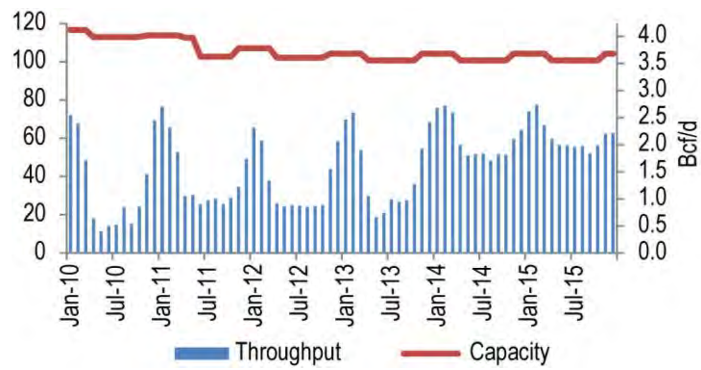
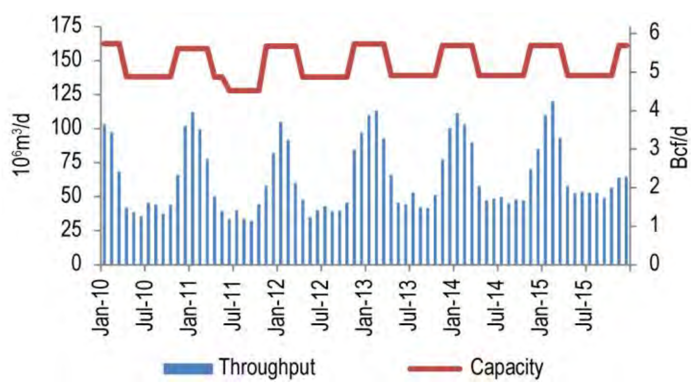


FIGURE 10.2.3

TransCanada Eastern Triangle Throughput vs. Capacity



The TransCanadaMainline connects with the Tennessee Gas Pipeline system near Niagara Falls, ON. Figure 10.2.4 shows throughput and capacity for Niagara for 2010-2015. When Niagara became an import point in late 2012, its capacity was 12 $10^6m^3/d$ (0.4 Bcf/d). The capacity increased to 17 $10^6m^3/d$ (0.6 Bcf/d) in November 2015. Throughput averaged 13 $10^6m^3/d$ (0.46 Bcf/d) in 2015.

At the export point near Iroquois, ON the TransCanada Mainline connects with the Iroquois Gas Transmission System, which supplies natural gas to markets in the U.S. Northeast. Figure 10.2.5 shows throughput and capacity for Iroquois for 2010-2015. Capacity is 39 $10^6m^3/d$ (1.38 Bcf/d). Throughput varies seasonally with utilization rates as high as 79% in winter and as low as 5% in summer. In 2015, throughputs averaged 13 $10^6m^3/d$ (0.46 Bcf/d).

FIGURE 10.2.4

TransCanada Mainline Niagara Throughput vs. Capacity

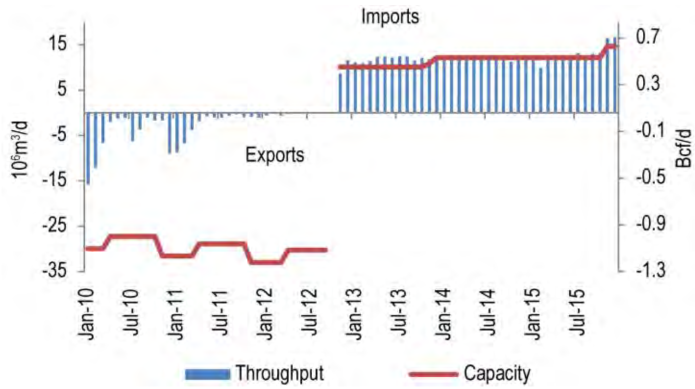


FIGURE 10.2.5

TransCanada Mainline Iroquois Throughput vs. Capacity

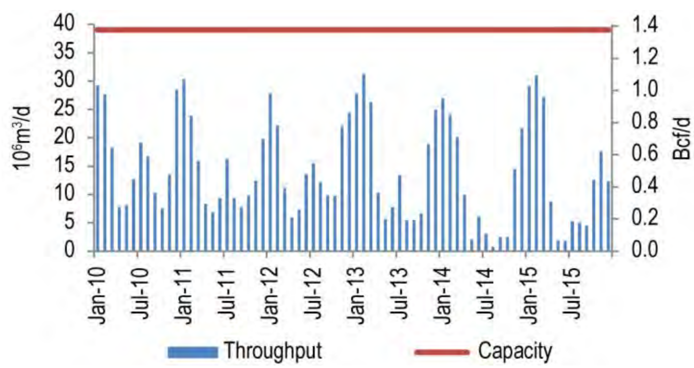
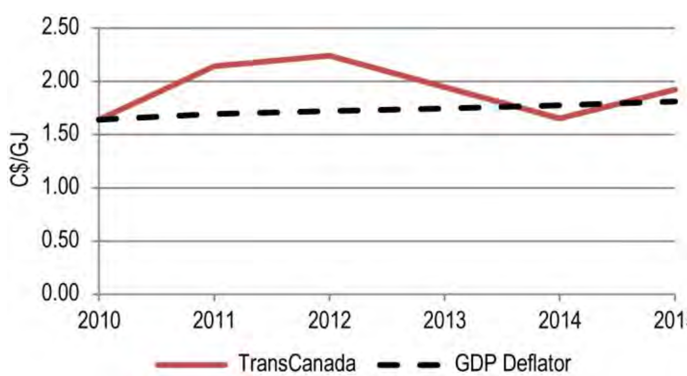


FIGURE 10.2.6

TransCanada Mainline Benchmark Toll



Tolls

From 2007 to 2011, the TransCanada Mainline operated under a negotiated settlement based on a cost of service toll methodology. As average throughput declined and tolls increased, TransCanada and its shippers worked to find solutions. TransCanada filed a contested toll application (RH-003-2011), the outcome of which resulted in much lower multi-year fixed tolls. Since then, the Board has held several proceedings to address issues arising from the transition to this new regime.

TransCanada and three eastern local distribution companies (LDCs) returned to the Board at the end of 2013 with an application for a new toll regime incenting TransCanada to build new facilities in the Eastern Triangle. The Board approved this application in December 2014, resulting in somewhat higher tolls, a return to cost of service tolls, and other features. This toll methodology is expected to be in place until 2020 with a review period prior to 2018.

For several years, contracts on the TransCanada Mainline showed two distinct trends. First, long-haul contracts (from Empress across the Prairies and NOL) declined and short-haul contracts (in the

Eastern Triangle) increased. Across the lower utilized Prairies and NOL sections, shippers were switching to interruptible or short-term firm contracts rather than using full-year firm service. When the RH-003-2011 Decision was implemented mid-2013, this pattern reversed and firm contracts increased dramatically.

Figure 10.2.6 shows the TransCanada Mainline benchmark toll (Empress to the Union Southwest Delivery Area) and the GDP deflator (normalized) for 2010-2015. Tolls increased in 2011 and 2012 due to a decrease in throughput and declining long-haul firm contract demand. The 2012 toll of $2.24/GJ remained in effect for the first half of 2013, while the RH 003-2011 proceeding was ongoing, and then declined to $1.65/GJ. The lower toll continued through 2014 until higher tolls were approved in 2015 to cover the cost of proposed new facilities.

Financial

TCPL is a wholly owned subsidiary of TransCanada Corporation. In addition to the Canadian Mainline, TCPL has other business segments, including NGTL and Keystone. The Mainline's revenue increased in 2014 and 2015 due to increased contracting and the ability to set higher tolls for non-firm services. TransCanada Corporation's financial ratios continue to be stable and TCPL's credit ratings are investment grade.

TransCanada	2010	2011	2012	2013	2014	2015
Revenues (millions)* - TransCanada Mainline	$1 818.3	$1 855.8	$1 558.6	$1 519.1	$1 645.4	$2 396.9
Net Income (millions)*- TransCanada Mainline	$262.9	$246.7	$265.7	$273.4	$293.2	$200.7
Rate Base (millions)*- TransCanada Mainline	$6 446.9	$6 165.3	$5 775.9	$5 751.9	$5 611.7	$4 617.2
Deemed Equity Ratio*- TransCanada Mainline	40%	40%	40%	40%	40%	40%
Return on Equity*- TransCanada Mainline	10.2%	10%	11.5%	11.88%	13.06%	10.86%
Interest and Fixed-Charges Coverage Ratio**	2.01	2.39	2.18	2.39	2.59	2.7
Cash Flow to Total Debt and Equivalents Ratio**	15.6%	16.4%	15.1%	15.5%	15.4%	14.7%
DBRS Credit Rating***	A	A	A	A (low)	A (low)	A (low)
S&P Credit Rating***	A-	A-	A-	A-	A-	A-
Moody's Credit Rating***	A3	A3	A3	A3	A3	A3

Financial data sources: revenues, net income, rate base, equity and return – TransCanada filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS, S&P, Moody's.

*Income statement information and equity ratios are for the TransCanada Canadian Mainline.

**Coverage and debt ratios are for TransCanada Corporation, as provided by DBRS. The ratios for 2015 include the last three months prior to 31 March 2015.

*** Credit ratings are for TransCanada Pipelines Ltd.

10.3 Foothills Pipe Lines Ltd.'s Foothills Pipeline System

Commodity and NEB Group[51]	Natural Gas (Group 1)
Annual average capacity	BC: 85 106m3/d (2.9 Bcf/d) SK: 66 106m3/d (2.2 Bcf/d)
Average utilization 2015	BC: 65% SK: 62%
Primary receipt points	Caroline, AB
Primary delivery points	Kingsgate BC, Monchy, SK
Rate base (Zone 8 and 9) 2016	$341 million
Cost of service (Zone 8 and 9) 2016	$106 million
Abandonment Cost Estimate and Collection Period[52]	$198 million, 30 years

Overview

Capacity in Alberta on Zones 6 and 7 of the Foothills Pipeline System (Foothills) is contracted by NGTL under a transportation-by-others arrangement. This report discusses Zone 8 (Foothills BC) and Zone 9 (Foothills SK).

Regulatory Documents
2016 Rate Filing

Foothills is approximately 1 240 km in length and transports natural gas from an interconnect with NGTL near Caroline, AB, through BC and SK. The Foothills BC system transports natural gas from the WCSB to a point on the Canada-U.S. border near Kingsgate, BC. At the border, Foothills BC connects to the Gas Transmission Northwest system, which serves markets in the Pacific Northwest, California and Nevada. The Foothills SK system transports natural gas from the WCSB to the Canada-U.S. border near Monchy, SK. At the border, it connects to the Northern Border pipeline, which serves markets in the U.S. Midwest. Foothills is wholly owned by TransCanada Corporation.

Key Developments

Throughput on Foothills SK decreased in 2014 and 2015 as Canadian exports to the U.S. Midwest declined. Throughputs on Foothills BC have remained relatively steady.

51 Throughput, rate base and costs of service cover Zone 8 and 9 only.

52 Collection Period began 1 January 2015.

Utilization

Figure 10.3.1 shows capacity and throughput on Foothills BC for 2010-2015. Capacity varies seasonally from 81 $10^6m^3/d$ (2.9 Bcf/d) in summer to 85 $10^6m^3/d$ (3 Bcf/d) in winter. In 2015, throughput at the Alberta/BC border averaged 54 $10^6m^3/d$ (1.9 Bcf/d).

Figure 10.3.2 shows capacity and throughput on Foothills SK for 2010-2015. Capacity at the Saskatchewan-U.S. border varies seasonally from 62 $10^6m^3/d$ (2.2 Bcf/d) in summer to 66 $10^6m^3/d$ (2.3 Bcf/d) in winter. In 2015, throughput averaged 39 $10^6m^3/d$ (1.4 Bcf/d).

Tolls

Foothills operated under a settlement agreement from 2003-2015. Figure 10.3.3 shows the benchmark tolls for Foothills SK and BC and the GDP deflator (normalized) for 2010-2015. The Foothills BC benchmark toll (FS-1 Firm Service) increased in 2011 and 2012 due to declines in the volume of firm contracts. In 2012, this was partially offset by higher revenue from other services. The toll declined in 2013 due to lower expenses and refunding of over-collections in 2012.

The Foothills SK benchmark toll (Zone 9 FT Demand Rate) decreased in 2011 due to higher interruptible and short-term firm volumes and lower expenses. The toll increased in 2012 due to a large decline in firm contracts. In 2013, tolls dropped due to refunding of over-collections in 2012. Tolls increased in 2014 and 2015 with lower throughput.

FIGURE 10.3.1

Foothills BC Throughput vs. Capacity

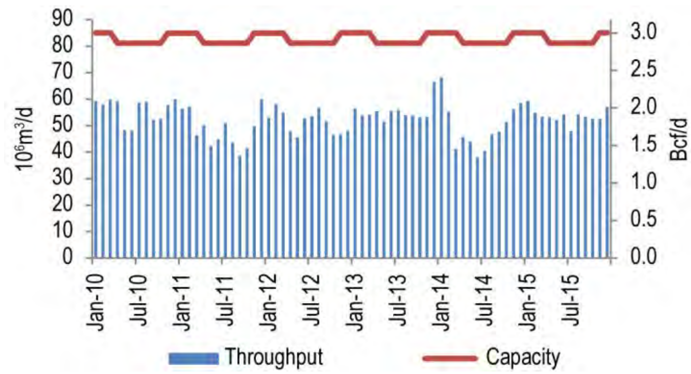


FIGURE 10.3.2

Foothills SK Throughput vs. Capacity

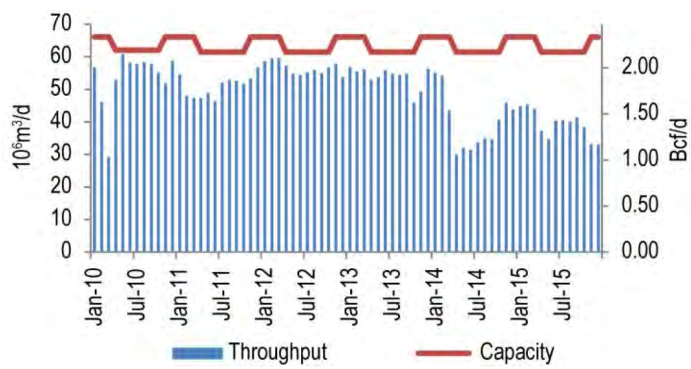
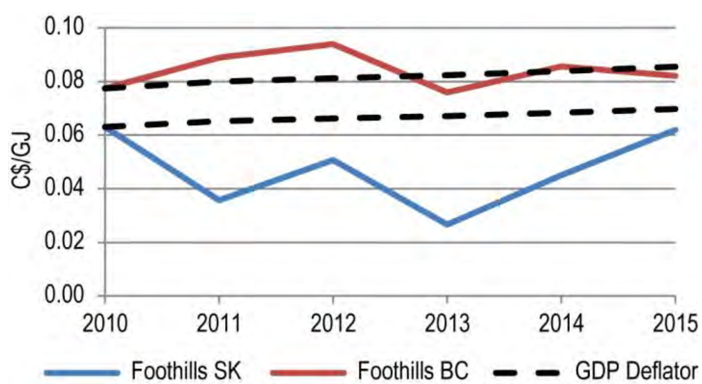


FIGURE 10.3.3

Foothills Benchmark Tolls



Financial

Foothills operates under a cost of service tolling methodology as negotiated with shippers. This has allowed return on equity to remain stable in recent years, while throughput and revenue have decreased. Foothills is a wholly-owned subsidiary of TransCanada Pipelines Ltd, which is a subsidiary of TransCanada Corporation. Foothills represents approximately 2% of TransCanada Corporations' earnings. See the appendix in section 12 for TCPL credit ratings.

Foothills Pipe Lines Ltd. (all Zones)	2010	2011	2012	2013	2014	2015
Revenues (millions)	$204.1	$192.3	$194.2	$193.4	$181.8	$178.9
Net Income (millions)	$25.4	$23.5	$21.7	$20.9	$19.4	$17.7
Rate Base (millions)	$654.6	$605.1	$557.3	$518.4	$480.6	$437.7
Deemed Equity Ratio	40%	40%	40%	40%	40%	40%
Return on Equity	9.7%	9.7%	9.7%	10.1%	10.1%	10.1%

Financial data sources: revenues, net income, rate base, equity and return – Foothills filings with the Board.

10.4 Alliance Pipeline Ltd.'s Alliance Pipeline

Commodity and NEB Group	Liquids-Rich Natural Gas (Group 1)
Annual average capacity	49 $10^6 m^3/d$ (1.7 Bcf/d)
Average utilization 2015	99%
Primary receipt points	Alberta and B.C.
Primary delivery points	Chicago, IL
Rate base 2015	$1.3 billion
Cost of Service 2015	N/A
Abandonment Cost Estimate and Collection Period[53]	$310 million; 40 years

Overview

The Alliance Pipeline (Alliance) is unique among major Canadian gas pipelines because natural gas liquids may be left in the gas stream. The pipeline system draws from 52 receipt points, largely concentrated near the northern end of the system in northeastern B.C. and northwestern Alberta. Alliance transports liquids-rich gas to the Chicago market hub. Extraction of the natural gas liquids occurs at the Aux Sable facility located near Chicago.

Regulatory Documents
Application for Approval of New Services and Related Tolls and Tariffs

Key Developments

Alliance began operations in 2000, supported by 15-year firm transportation contracts. In 2010, when the option to renew these contracts was triggered, few shippers opted to do so (contracts were renewed for just 8% of previously contracted capacity). Accordingly, Alliance developed its New Services Offering (NSO), which incorporated new services and tolling methodologies on the pipeline. Alliance applied for Board approval of the NSO in 2014. By the time the hearing was completed in April 2015, the pipeline was nearly fully contracted under the proposed toll framework. The Board approved the proposed firm tolls and new services, and granted Alliance some discretion in setting bid floors for seasonal firm service and interruptible service, and instructed Alliance to put any excess cash earnings into a reserve account. Alliance is to file a depreciation study for Board approval before it can make any distributions from that account.

53 Collection Period began 1 January 2015.

Utilization

Figure 10.4.1 shows throughput and capacity on Alliance. Capacity varies with ambient temperature, from 45 $10^6m^3/d$ (1.6 Bcf/d) in the summer to 51 $10^6m^3/d$ (1.8 Bcf/d) in the winter. The pipeline has been almost fully utilized since it was put into service. Throughput averaged 46 $10^6m^3/d$ (1.63 Bcf/d) in 2015.

Tolls

Figure 10.4.2 shows the Alliance benchmark toll and the GDP deflator (normalized) for 2010-2015. The benchmark toll was nearly flat between 2010 and 2015. The tariff included an authorized overrun service under which shippers could move an additional amount of gas at very low cost when capacity was available.

Under the new toll regime, firm tolls decreased about 35% on 1 December 2015. However, shippers must pay for interruptible service if they want to move additional gas. The toll[54] dropped from \$34.48/ 10^3m^3 (\$0.84/GJ) to \$23.61/10^3m^3 (0.58/GJ) for Zone 1 full path service[55].

FIGURE 10.4.1

Alliance Pipeline Throughput vs. Capacity

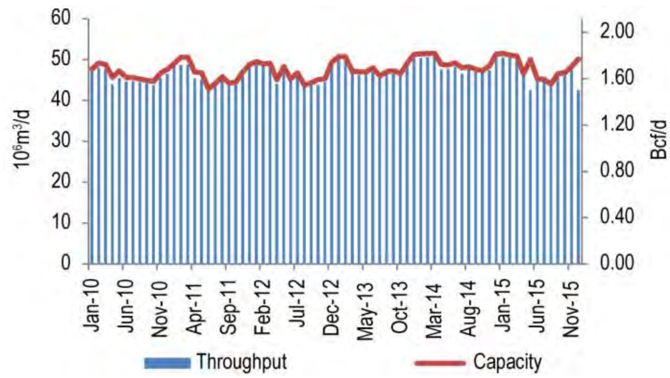
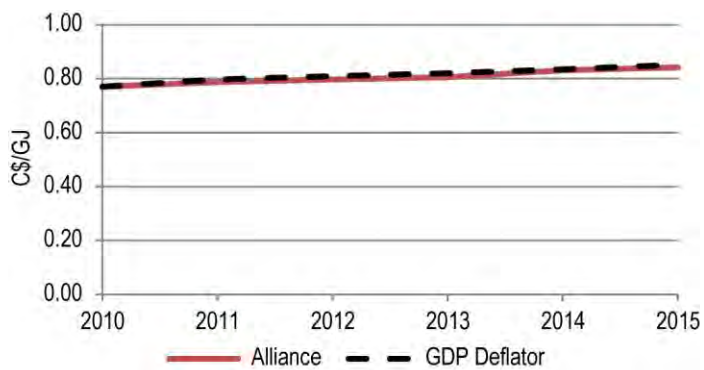


FIGURE 10.4.2

Alliance Benchmark Toll



54 Toll calculated based on an energy conversion factor of 40.97 MJ/m^3.

55 3-year firm full path service from Zone 1 to the international border.

Financial

Alliance Pipeline Ltd. (APL) has earned a return on equity of 11.26% each year since operations began. Return on equity was based on an approved baseline rate of 12.0% with an adjustment for cost overruns during construction. In December 2015, APL began operating under its NSO, and will report achieved return on equity in annual compliance filings to the Board. In addition, it is required to file other information with the Board on a quarterly basis. This information was provided for the month of December 2015. Previously, APL was exempted from filing quarterly surveillance reports with the Board.

APL's financial ratios have improved in recent years, indicating greater ability to service debt payments. However, its credit rating was downgraded by DBRS in 2015 after the company signed new contracts with shippers, in part due to the lower shipper credit quality and shorter duration of contracts.

Alliance Pipeline Ltd.	2010	2011	2012	2013	2014	2015
Deemed Equity Ratio	30%	30%	30%	30%	30%	30%[56]
Achieved Return on Equity	11.26%	11.26%	11.26%	11.26%	11.26%	--
Interest and Fixed-Charges Coverage Ratio*	2.25	2.21	2.29	2.41	2.58	2.75
Cash Flow-to-Total Debt and Equivalents Ratio*	16.9%	18.0%	18.5%	21.2%	22.3%	27.4%
DBRS Credit Rating	A (low)	A (low)	A (low)	A(low)	A(low)	BBB

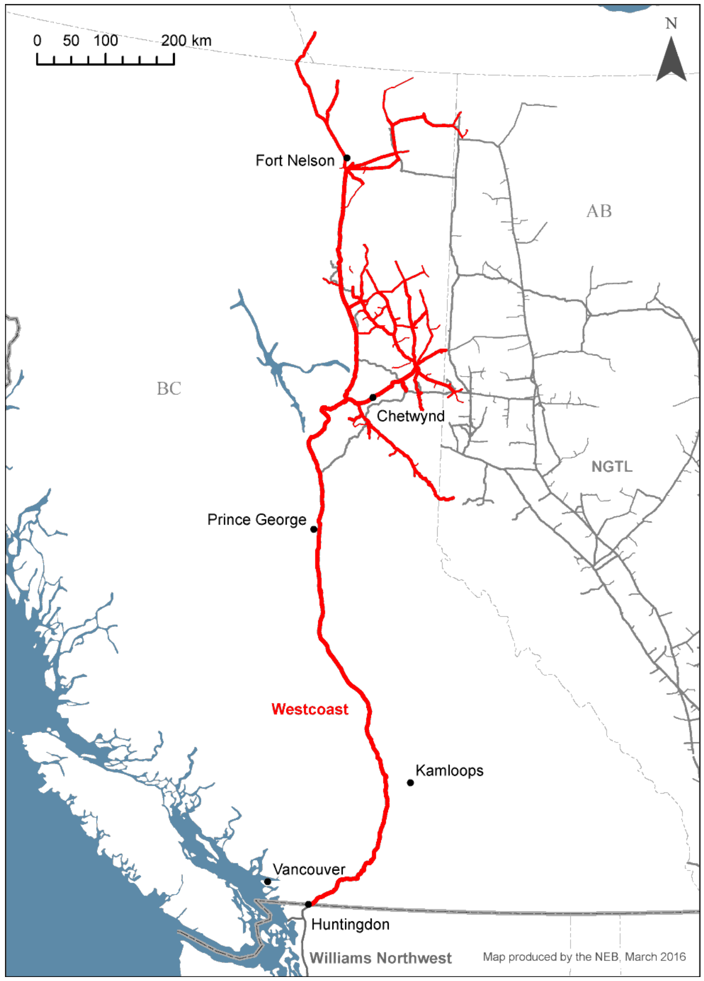
Financial data sources: deemed equity ratio and return on equity – Alliance toll filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS.

* The coverage and debt ratios for 2015 cover the last six months prior to 30 June 2015.

56 Up to 30 November 2015. There is no 'deemed equity ratio' for Alliance's NSO, which was implemented in December 2015. Alliance used a 40% equity thickness in supporting evidence for the NSO application.

10.5 Westcoast Energy Inc's Westcoast Transmission System

Commodity and NEB Group	Natural Gas (Group 1)
Average annual capacity (T-South)	44 $10^6 m^3/d$ (1.6 Bcf/d)
Average utilization 2015	92%
Primary receipt points	T-North
Primary delivery points	Lower Mainland, Huntingdon, BC
Rate base 2015	$1.3 billion
Cost of Service 2014	$377 million
Abandonment Cost Estimate and Collection Period[57]	$684 million; 40 years



Overview

Westcoast Energy Inc., carrying on business as Spectra Energy Transmission, owns the Westcoast Transmission System (Westcoast). Westcoast extends from points in Yukon, the Northwest Territories, Alberta and BC, to the Canada-U.S. border near Huntingdon, BC. At the border Westcoast connects to Williams Northwest Pipeline, which supplies natural gas to the U.S. Pacific Northwest. Westcoast's transmission system is composed of two parts: T-North which is north of Station 2 just west of Chetwynd (deliveries to NGTL and T-South) and T-South south of Station 2 (deliveries to BC Lower Mainland and the Huntingdon export point). T-North connects to NGTL at two points: Nova Gordondale and Sunset/Groundbirch. Westcoast's gathering and processing system, which is regulated by the Board under the Framework for Light-handed Regulation, is also shown on the map.

Regulatory Documents
[2014-2015 Tolls Settlement]
[Jackfish Lake Expansion Project]
[High Pine Expansion Project]

57 Collection Period began 1 January 2015.

Key Developments

Westcoast submitted two applications to the Board that would provide additional firm service in the Peace River area of BC.The Jackfish Lake Expansion Project was approved by the Board on 15 July 2016. The High Pine Expansion is still before the Board.

Utilization

Figure 10.5.1 shows throughput and capacity for T-North for 2010-2015. In 2015, capacity averaged 81 $10^6 m^3/d$ (2.9 Bcf/d) and throughputs averaged 58 $10^6 m^3/d$ (2.1 Bcf/d). Deliveries from Westcoast to NGTL averaged 14 $10^6 m^3/d$ (0.5 Bcf/d) in 2015.

Figure 10.5.2 shows throughput and capacity on Westcoast's T-South Segment for 2010-2015. In 2015, capacity fluctuated between 41 $10^6 m^3/d$ (1.45 Bcf/d) and 48 $10^6 m^3/d$ (1.70 Bcf/d), and throughput averaged 40 $10^6 m^3/d$ (1.4 Bcf/d). Throughputs at the Huntingdon export point averaged 31 $10^6 m^3/d$ (1.08 Bcf/d) in 2015.

FIGURE 10.5.1

Westcoast T-North Throughput vs. Capacity

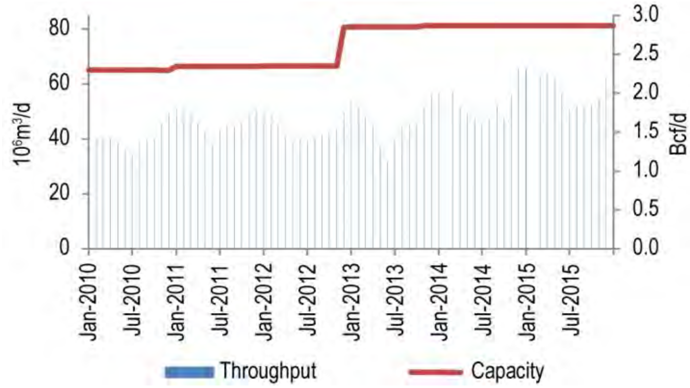
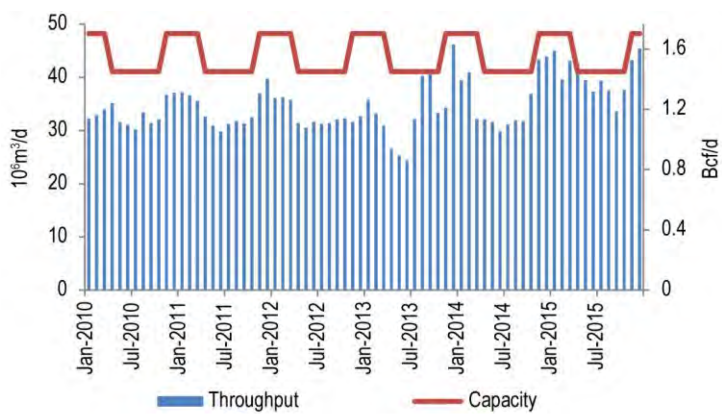


FIGURE 10.5.2

Westcoast T-South Throughput vs. Capacity



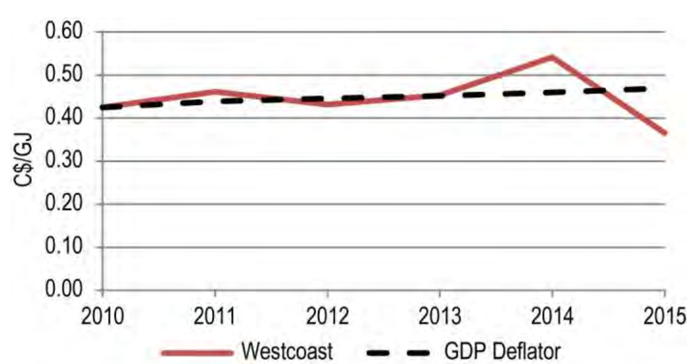
Tolls

Westcoast transmission services are tolled according to the terms of a negotiated settlement, which uses a cost of service framework. Westcoast operated under toll settlements from 2011 to 2015.

Figure 10.5.3 shows the Westcoast benchmark toll[58] (Firm Transportation Service – T-South, 2-year contract delivered to the Huntingdon Delivery Area) and the GDP deflator (normalized) for 2010-2015. The benchmark toll moved in line with the GDP deflator from 2010 to 2013 and increased in 2014 due to forecasts of lower throughput and costs associated with added facilities such as its North Montney project and the T-North Expansion. Actual throughput was higher than expected in 2014 so the extra revenue was applied to tolls in 2015. Along with higher forecast throughput for 2015, this resulted in lower tolls in 2015.

FIGURE 10.5.3

Westcoast Benchmark Toll



58 Based on an energy conversion factor of 1000 m^3 = 37.24 GJ

Financial

Westcoast Energy Inc.'s revenue, net income, and rate base have been growing due to system expansions and increased throughput. Coverage ratios continue to be stable and credit ratings are investment grade.

Westcoast Energy Inc.	2010	2011	2012	2013	2014	2015
Revenues (millions) – Westcoast Transmission	$295.7	$322.9	$325.0	$396.6	$384.8	$393.8
Net Income (millions) – Westcoast Transmission	$35.1	46.1	$49.6	$53.1	$53.9	$50.6
Rate Base (millions) – Westcoast Transmission	$1 092.9	$1 074.3	$1 223.9	$1 349.1	$1 346.4	$1 346.9
Deemed Equity Ratio – Westcoast Transmission	36%	40%	40%	40%	40%	40%
Achieved Return on Equity – Westcoast Transmission	8.78%	10.01%	9.36%	9.54%	9.89%	9.01%
Interest and Fixed-Charges Coverage Ratio*	2.31	2.52	1.96	2.21	2.17	3.46
Cash Flow to Total Debt and Equivalents Ratio*	17.2%	15.4%	13.7%	15.1%	16.0%	20.3%
DBRS Credit Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
S&P Credit Rating	A-	BBB+	BBB+	BBB	BBB	BBB

Financial data sources: revenues, net income, rate base, equity and return – Westcoast filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS, S&P, Moody's.

*Income statement information and equity ratios are for the Transmission Division of Westcoast Energy Inc., as reported to the Board.

**Credit ratings and coverage and debt ratios are for Westcoast Energy Inc., which includes 100 per cent ownership of Union Gas Limited and 78 per cent ownership of Maritimes and Northeast Pipeline Limited, as provided by DBRS and S&P. The coverage and debt ratios for 2015 include the last three months prior to 31 March 2015.

10.6 Trans Québec and Maritimes Pipeline Inc.'s Trans Québec and Maritimes Pipeline

Commodity and NEB Group	Natural Gas (Group 1)
Average annual capacity	24 $10^6 m^3/d$ (0.8 Bcf/d)
Average utilization 2015	62%
Primary receipt points	TransCanada Mainline near Saint-Lazare, QC
Primary delivery points	Montreal, Quebec City, East Hereford, QC
Rate base 2015	$343 million
Cost of Service 2015	$84 million
Abandonment Cost Estimate and Collection Period[59]	$102 million; 25 years

Overview

The 572 km Trans Québec and Maritimes Pipeline system (TQM) extends from an interconnection with the TransCanada Mainline near Saint-Lazare, QC, to a point near Quebec City in the Municipality of Lévis on the south shore of the St. Lawrence River. TQM also extends from Terrebonne, north of Montreal, to a point on the Canada-U.S. border near East Hereford, QC.

Regulatory Documents
[2014-2016 Tolls Settlement Application](#)
[Application for Biogas 2 Transportation (BTG2) Service](#)

The TQM pipeline has 31 delivery points and two compressor stations. At East Hereford, TQM connects to the Portland Natural Gas Transmission System, which supplies natural gas to the U.S. Northeast market, primarily Vermont, New Hampshire, Maine and Massachusetts. TQM is equally owned by TransCanada Corporation and a subsidiary of Gaz Métro Limited Partnership. The TransCanada Mainline holds contracts for all of the capacity on TQM.

Key Developments

There have been no recent major developments on the TQM pipeline.

59 Collection Period began 1 January 2015.

Utilization

Figure 10.6.1 shows capacity and throughput on TQM for 2010-2015. Capacity is 24 $10^6 m^3$/d (0.8 Bcf/d). Throughput varies seasonally with utilization rates as high as 95% in winter months and as low as 41% in the summer. In 2015, throughput averaged 15 $10^6 m^3$/d (0.5 Bcf/d).

Figure 10.6.2 shows capacity and throughput at the East Hereford export point for 2010-2015. Capacity is 6 $10^6 m^3$/d (0.2 Bcf/d), and in 2015 throughput averaged 6 $10^6 m^3$/d (0.2 Bcf/d). Throughputs at the East Hereford were high in 2015, due to decreased natural gas production offshore Nova Scotia and increased demand in the U.S. Northeast market, particularly during the winter season.

Tolls

TQM has operated under toll settlements from 2010-2016. The TransCanada Mainline has firm contracts for all the capacity on TQM and demand charges are paid by TransCanada Pipelines, regardless of flows.

Figure 10.6.3 shows the TQM benchmark toll[60] (T-1 demand charge for they system per month) and the GDP deflator (normalized) for 2010-2015. Tolls decreased slightly from 2010 to 2012 under the toll settlement. Expected throughput increased from 2012 to 2014, reducing tolls each of those years.

FIGURE 10.6.1

TQM Throughput vs. Capacity

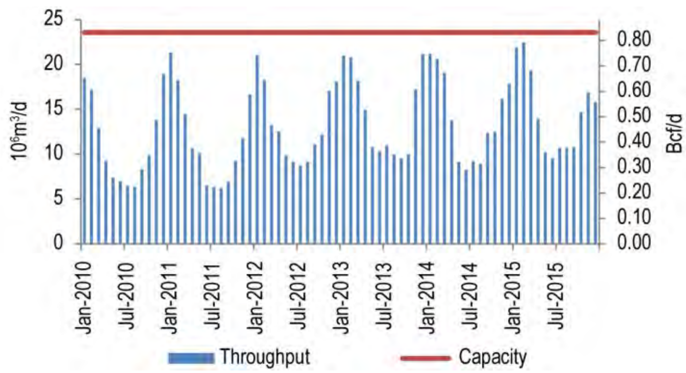


FIGURE 10.6.2

East Hereford Throughput vs. Capacity

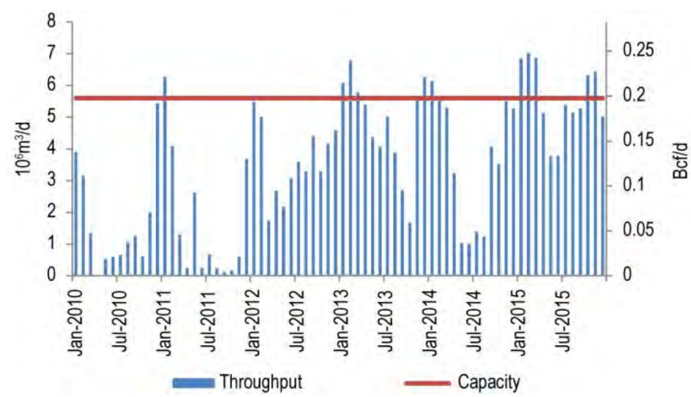
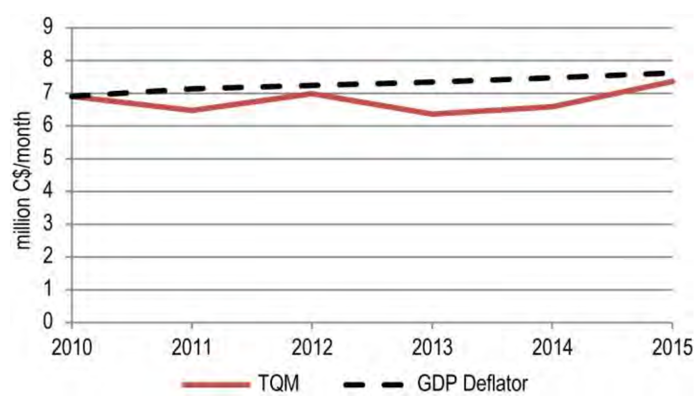


FIGURE 10.6.3

TQM Benchmark Toll



60 Based on an energy conversion factor of 1000 m^3 = 37.24 GJ

Financial

The 2014-2016 TQM Settlement Agreement fixed return on rate base and did not specify a capital structure or rate of return on equity. For illustrative purposes, TQM reports its rate of return on rate base based on the After Tax Weighted Average Cost of Capital (ATWACC) methodology as approved by the NEB's most recent cost of capital decision for TQM, RH-1-2008. Because the ATWACC includes return on debt as well as return on equity, it is typically lower than return on equity. In recent years it has averaged about 6%.

TQM's revenue has been stable, and its costs and rate base have been declining. Due to less debt in its capital structure, coverage ratios have improved in 2014 and 2015. Its credit rating, as issued by DBRS, remains investment grade.

Trans Quebec and Maritimes Pipeline Inc.	2010	2011	2012	2013	2014	2015
Revenues (millions)	$82.0	$82.3	$82.2	$78.6	$80.8	$83.7
Fixed Costs (millions)	$69.6	$69.0	$68.8	$63.6	$60.0	$58.8
Rate Base (millions)	$412.9	$393.8	$373.3	$362.3	$352.7	$343.0
After Tax Weighted Average Cost of Capital	6.4%	6.47%	6.76%	5.66%	6.12%	5.91%
Interest and Fixed-Charges Coverage Ratio*	3.20	4.54	4.31	3.75	3.98	4.24
Cash Flow-to-Total Debt and Equivalents Ratio*	16.4%	19.8%	18.8%	16.7%	17.7%	17.7%
DBRS Credit Rating	A	A	A	A	A	A

Financial data sources: revenues, fixed costs, rate base and cost of capital – TQM filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS.

* The coverage and debt ratios for 2015 include the last 6 months prior to 30 June 2015.

10.7 Maritimes & Northeast Pipeline LP.'s Maritimes & Northeast Pipeline

Commodity and NEB Group	Natural Gas (Group 1)
Average annual capacity	16 $10^6 m^3/d$ (0.56 Bcf/d)
Average utilization 2015	45%
Primary receipt points	Goldboro, NS
Primary delivery points	Halifax, NS; Moncton, Saint John, St. Stephen, NB
Rate base 2015	$401 million
Cost of service 2015	$120 million
Abandonment Cost Estimate and Collection Period[61]	$150 million, 19.5 years

Overview

Regulatory Documents:
[Application for Approval of 2014-2016 Tolls Settlement]

The Maritimes & Northeast Pipeline (M&NP) in Canada extends from Goldboro, NS through New Brunswick to a point on the Canada-U.S. border near St. Stephen, NB. In the U.S., M&NP continues through Maine and New Hampshire into Massachusetts. It interconnects with the Emera Brunswick Pipeline, Portland Natural Gas Transmission System, Tennessee Gas Transmission, and Algonquin Gas Transmission.

M&NP was commissioned in December 1999 to transport natural gas produced from the Sable Offshore Energy Project (Sable) to markets in the U.S. Northeast. It currently also transports offshore natural gas from the Deep Panuke project, and supply from the McCully gas field in New Brunswick. M&NP can flow bi-directionally and natural gas will flow from the U.S. into Canada when offshore production is insufficient to meet domestic demand. Incremental supply comes from the Canaport LNG import terminal via the Brunswick Pipeline or from the Portland Natural Gas Transmission System.

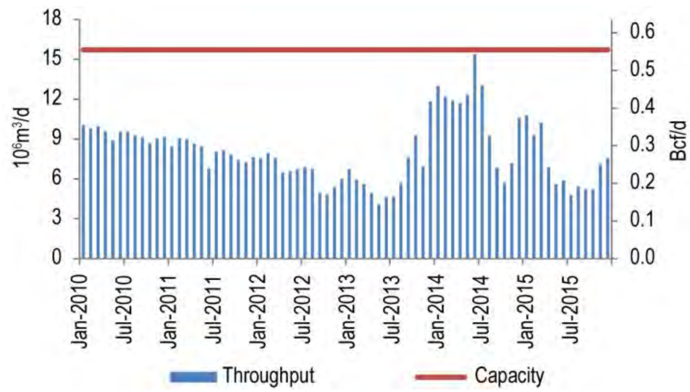
61 Collection period commenced 1 January 2015.

Key Developments

Natural gas supply from offshore Nova Scotia declined in 2015. In mid-May, production at Deep Panuke was shut-in and Encana (the operator) announced that the project would produce only during the winter months when demand and gas prices are highest. In addition, Deep Panuke's reserve estimate was cut by half due to higher than expected water incursion into the reservoir. Production at Sable in 2015 remained steady averaging 4 $10^6m^3/d$ (0.14 Bcf/d); however, the project is in long-term decline.

FIGURE 10.7.1

M&NP Throughput vs. Capacity



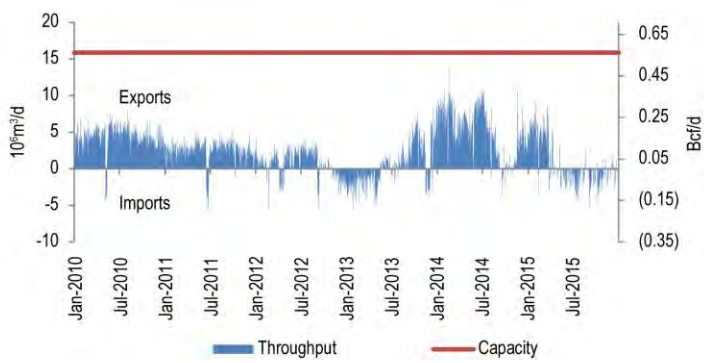
Utilization

Figure 10.7.1 shows capacity and throughput on M&NP for 2010-2015. Capacity is 16 $10^6m^3/d$ (0.56 Bcf/d) and in 2015, throughput (exports and imports) averaged 7 $10^6m^3/d$ (0.25 Bcf/d).

Figure 10.7.2 shows capacity and daily throughput on M&NP at the St. Stephen, NB point. Traditionally, the Maritimes market was a net-exporter of natural gas to the U.S. However, during periods of high demand or when offshore production is insufficient to meet domestic demand, the flow of natural gas on M&NP is reversed and natural gas is imported into the Maritimes from the U.S. Since the spring of 2015, the Maritimes has primarily been a net-importer of natural gas from the U.S.

FIGURE 10.7.2

M&NP Daily Throughput at St. Stephen

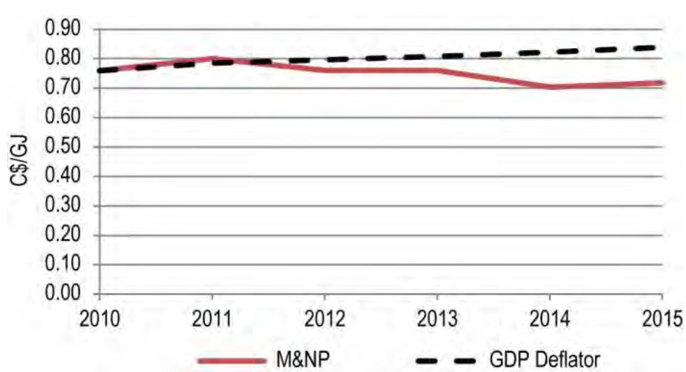


Tolls

M&NP uses a 'postage stamp' tolling model in which the toll is the same for all paths on the system regardless of the distance travelled. M&NP has been operating under a toll settlement for 2014-2016. Figure 10.7.3 shows M&NP's benchmark toll (MN365 Toll) and the GDP deflator (normalized) for 2010-2015. The benchmark toll declined slightly in 2012 and 2013 due to lower revenue requirements, and in 2014 as the rate base decreased with depreciation.

FIGURE 10.7.3

M&NP Benchmark Toll



Financial

Maritimes and Northeast Pipeline L.P.'s financial ratios have improved due to the reduction of debt over time. DBRS has maintained its credit rating at "A" due to its predictable cash flows which are a result of firm transportation contracts with investment grade shippers, a backstop provided by ExxonMobil Canada, and a tolling methodology that is regulated on a cost of service basis.

Maritimes and Northeast Pipeline L.P.	2010	2011	2012	2013	2014	2015
Revenues (millions)	$140.7	$142.4	$133.3	$138.7	$141.6	$119.9
Net Income (millions)	$23.9	$25.1	$24.7	$23.0	$26.0	$25.9
Rate Base (millions)	$591.3	$571.3	$528.0	$492.3	$445.2	$401.4
Return on Equity	6.45%	5.96%	5.55%	5.51%	6.87%	7.32%
Interest and Fixed Charges Coverage Ratio*	3.41	2.78	2.8	3.03	3.49	3.79
Cash Flow to Total Debt and Equivalents Ratio*	22.2%	23.9%	25.9%	30.2%	38.8%	42.6%
DBRS Credit Rating	A	A	A	A	A	A
Moody's Credit Rating	A2	A2	A2	A2	A2	A2

Financial data sources: revenues, fixed costs, rate base and cost of capital – M&NP filings with the Board; coverage and debt ratios – DBRS; credit ratings – DBRS.

* The coverage and debt ratios for 2015 include the last six months prior to 30 June 2015.

10.8 Emera Brunswick Pipeline Company Ltd.'s Brunswick Pipeline

Commodity and NEB Group	Natural Gas (Group 2)
Average annual capacity	28 $10^6m^3/d$ (1 Bcf/d)
Average utilization 2015	7%
Primary receipt points	Canaport LNG Terminal near Saint John, NB
Primary delivery points	St. Stephen, NB
Net investment in Direct Financing Lease, 2014[62]	$485 million
Revenues 2014	$57 million
Abandonment Cost Estimate and Collection Period[63]	$11 million, 19.5 years

Overview

The Brunswick Pipeline (Brunswick) was commissioned in July 2009 and transports re-gasified natural gas 145 km from the Canaport liquefied natural gas (LNG) import terminal near Saint John, NB to the Canada-U.S. border near St. Stephen, NB. At the border it connects with the U.S. segment of the Maritimes & Northeast Pipeline. Emera Brunswick Pipeline Company Ltd., which owns the pipeline, is a wholly owned subsidiary of Emera Inc., an energy company based in Nova Scotia.

Regulatory Documents:
[Negotiated Toll Agreement Between Emera Brunswick Pipeline Company Ltd. and Repsol Energy Canada Ltd.] [2015 Audited Financial Statements]

62 Net investment in Direct Financing Lease consists of the sum of the minimum lease payments and residual value net of executory costs and unearned income. It is presented here in place of rate base.

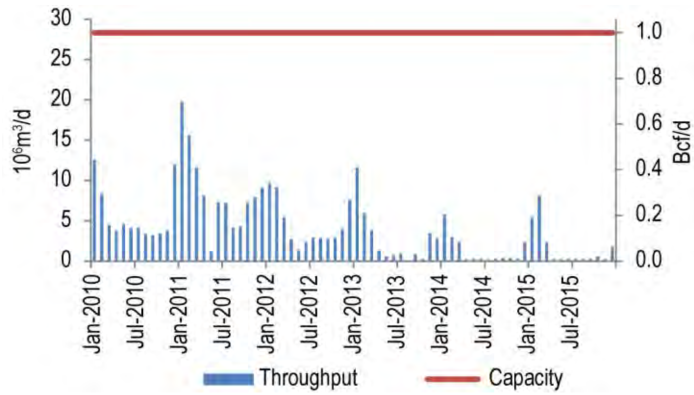
63 Collection Period began 1 January 2015.

Utilization

Figure 10.8.1 shows capacity and throughput on Brunswick for 2010-2015. Capacity is 28 $10^6m^3/d$ (1 Bcf/d) and in 2015 throughput averaged 1.7 $10^6m^3/d$ (0.06 Bcf/d). Throughput tends to increase in the winter to meet peak demand in the Maritimes and U.S. Northeast market.

FIGURE 10.8.1

Brunswick Throughput vs. Capacity

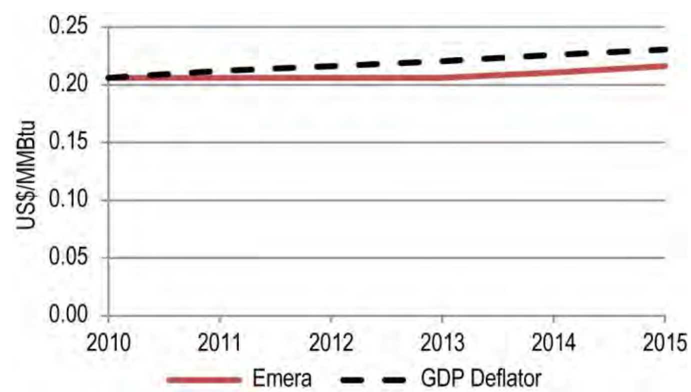


Tolls

Figure 10.8.2 shows the benchmark toll for Brunswick and the GDP deflator (normalized) for 2010-2015. Tolls on Brunswick are set per cargo load per day, and converted to the equivalent price in $US/Million British Thermal Units (MMbtu). Tolls were constant from mid-2009 to mid-2014 at US$0.206 per MMbtu. In July 2014, tolls increased to US$0.216 per MMbtu.[64] Tolls will remain at this rate until mid-2024. Tolls were set for 25 years under a Negotiated Toll Agreement between Repsol Energy Canada Ltd. and Emera Brunswick Pipeline Company Ltd. Brunswick is regulated on a complaint basis.

FIGURE 10.8.2

Brunswick Benchmark Toll



Financial

Emera New Brunswick Pipeline Company Ltd. is a Group 2 Company, operating with a direct financing lease and only one shipper. It maintains negative equity on its balance sheet due to transfer of funds to its parent company, Emera Inc., by way of promissory notes.

Brunswick's access to debt markets is supported by Emera Inc., which, for example, DBRS assigns a credit rating of BBB (high).

64 The annualized toll for 2014 was US$0.211 per MMbtu.

11 Appendix: Company Financial Summaries

Deemed Common Equity Ratios

	2008	2009	2010	2011	2012	2013	2014	2015
Gas Pipelines								
Alliance	30	30	30	30	30	30	30	30[65]
Foothills	36	36	40	40	40	40	40	40
NGTL[66]			40	40	40	40	40	40
TransCanada Mainline	40	40	40	40	40	40	40	40
Westcoast Transmission	36	36	36	40	40	40	40	40
Oil Pipelines								
Enbridge Pipelines (NW)	55	55	50	50	50	50	50	50
Enbridge Southern Lights[67]			30	30	30	30	30	30
Trans Mountain Pipelines	45	45	45	45	45	45	45	45

Achieved ROEs and the RH-2-94 Formula ROE

	2008	2009	2010	2011	2012	2013	2014	2015
Pipelines that were subject to RH-2-94								
Foothills	8.71	8.57	9.7	9.7	9.7	10.1	10.1	10.1
TransCanada Mainline	9.91	10.42	10.2	10	11.5[68]	11.88	13.06	10.86
Westcoast Transmission[69]	8.76	9.08	8.78	10.01	9.36	9.54	9.89	9.01
Other Pipelines								
Alliance	11.26	11.26	11.26	11.26	11.26	11.26	11.26	n/a
M&NP	11.35	n/a	n/a	n/a	n/a	n/a	n/a	n/a
NGTL[70]		10.28	10.04	10.03	9.57	10.23	9.65	10.06
Westcoast Field Services[71]	7.61	12.25	13.65	16.98	19.25	8.93	7.16	2.62
RH-2-94 Formula (no longer in effect)[72]	*8.71*	*8.57*	*8.52*	*8.08*	*7.58*	*7.23*	*7.93*	*7.64*

Source: NEB Surveillance Quarterly and Annual Reports.

65 Up to 30 November 2015. There is no 'deemed equity ratio' for Alliance's NSO, which was implemented in December 2015. Alliance used a 40% equity thickness in supporting evidence for the NSO application.

66 NGTL was regulated provincially until early 2009.

67 Southern Lights was not in operation until 2010.

68 Approved ROE in the RH-003-2011 decision. TCPL's compliance filing used this approved number.

69 Excluded construction work in progress (CWIP) and, in the case of Transmission, deferrals.

70 NGTL was regulated provincially until early 2009; the 2009 ROE was calculated assuming a 35% equity ratio.

71 Excluded construction work in progress (CWIP) and, in the case of Transmission, deferrals.

72 In October 2009, the Board decided that the RH-2-94 Decision would not continue to be in effect. However, for the convenience of parties which still use it in their settlements, the Board has continued to publish the formula.

Fixed-Charges Coverage Ratios

Fixed Charges Coverage Ratios	2010	2011	2012	2013	2014	2015[73]
Alliance L.P.	2.25	2.21	2.29	2.41	2.58	2.75
Enbridge Pipelines Inc.	2.11	2.52	2.39	1.95	2.08	1.55
Express	3.11	4.23	6.29	8.66	11.38	16.7
M&NP L.P.	3.41	2.78	2.8	3.03	3.49	3.79
NGTL	2.18	2.16	2.1	2.34	2.19	2.11
TQM	3.20	4.54	4.31	3.75	3.98	4.24
TCPL	2.01	2.39	2.18	2.39	2.59	2.7
TNPI	3.47	4.83	6.41	5.52	7.8	n/a[74]
Westcoast	2.31	2.52	1.96	2.21	2.17	3.46

Source: DBRS

Cash Flow-to-Total Debt and Equivalent Ratios

Cash Flow/Total Debt	2010	2011	2012	2013	2014	2015[75]
Enbridge Pipelines Inc.	15.2%	11.2%	11.4%	8.8%	8.8%	8.4%
Enbridge Mainline[76]	18.0%	19.6%	20.4%	16.7%	16.7%	n/a[77]
Express	24.9%	34.9%	51.2%	70.3%	95.1%	139%
TNPI	14.1%	23.9%	29.7%	24.1%	37.8%	n/a[78]
Alliance L.P.	16.9%	18.0%	18.5%	21.2%	22.3%	24.5%
M&NP L.P.	22.2%	23.9%	25.9%	30.2%	38.8%	42.6%
NGTL	14.3%	13.5%	12.6%	13.6%	12.6%	12.3%
TQM	16.4%	19.8%	18.8%	16.7%	17.7%	17.7%
TCPL	15.6%	16.4%	15.1%	15.5%	15.4%	14.7%
Westcoast	17.2%	15.4%	13.7%	15.1%	16.0%	20.3%

Source: DBRS

73 Data for 2015 is partial year data for most of the companies.

74 DBRS has discontinued its credit rating service for TNPI.

75 Data for 2015 is partial year data for most of the companies.

76 DBRS publishes summary information for the finances of the Canadian portion of Enbridge's Mainline system, referred to as the 'Mainline', which excludes Enbridge Pipeline's investments in other entities. When consolidated, these entities tend to depress credit ratios relative to the Mainline's credit ratios.

77 At the time of writing, this data was not available.

78 DBRS has discontinued its credit rating service for TNPI.

12 Appendix: Company Credit Summaries

Debt Rating Comparison Chart

This chart provides a comparison of the rating scales used by DBRS, S&P, and Moody's when rating long-term debt. Because of differences between these agencies' rating approaches and definitions, some subjectivity is required in comparing their rating scales. Each agency also provides a rating outlook or trend, which assesses the potential direction of a credit rating. Common outlooks or trends are: 'Positive'; 'Negative'; and 'Stable'.

Credit Quality	DBRS	S&P	Moody's
Investment Grade			
Superior/High grade	AAA	AAA	Aaa
	AA (high)	AA+	Aa1
	AA	AA	Aa2
	AA (low)	AA-	Aa3
Good/Upper Medium	A (high)	A+	A1
	A	A	A2
	A (low)	A-	A3
Adequate/Medium	BBB (high)	BBB+	Baa1
	BBB	BBB	Baa2
	BBB (low)	BBB-	Baa3
Non-Investment Grade			
Speculative	BB (high)	BB+	Ba1
	BB	BB	Ba2
	BB (low)	BB-	Ba3
Highly speculative	B (high)	B+	B1
	B	B	B2
	B (low)	B-	B3
Very highly speculative	CCC	CCC	Caa1
	CC	CC	Caa2
	C	C	Caa3
	D	D	Ca

Note: DBRS and S&P ratings in the CCC category also have subcategories "high/+"and "low/-" and the absence of "high/+" and "low/-" designation indicates the rating is in the "middle" of the category. DBRS also does so for CC and C categories.

DBRS Credit Rating History

Pipeline	2010	2011	2012	2013	2014	2015
Alliance L.P.	A(low)	A (low) /Stable	A (low) /Stable	A(low)/stable	A(low)/stable	BBB
Enbridge Pipelines	A (high)	A /Stable	A /Stable	A /Stable	A /Stable	A /Stable
Express	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
M&NP L.P.	A	A /Stable	A /Stable	A /Stable	A /Stable	A /Stable
NGTL	A	A /Stable	A /Stable	A (low)	A (low)	A (low)
TQM	A (low)	A (low) /Stable	A (low) /Stable	A (low) /Stable	A (low) /Stable	A (low)/Stable
TransCanada	A	A /Stable	A /Stable	A (low)	A (low)	A (low)
Trans-Northern	A(low)	A (low) /Stable	A (low) /Stable	A (low) /Stable	A (low) /Stable	A (low) /Stable
Westcoast	A (low)	A (low) /Stable	A (low) /Stable	A (low) /Stable	A (low) /Stable	A (low) /Stable

While these are representative credit ratings for the listed companies, the type of debt issuances that are directly assessed vary.

In assigning a credit rating to a particular company, DBRS states that it attempts to consider all meaningful factors that could impact the risk of maintaining timely payments of interest and principal in the future. While key credit considerations will vary from industry to industry, some of the common factors considered for most ratings are core profitability, asset quality, strategy and management strength, and the financial and business risk profile.

The following specific factors are also considered for pipelines when deriving their credit ratings: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities.

S&P Credit Rating History

Pipeline	2010	2011	2012	2013	2014	2015
Enbridge Pipelines	A- /Stable	A- /Stable	A-/Stable	A-/Negative	A-/Watch Neg.	BBB+
NGTL	A- /Stable	A- /Stable	A- /Stable	A- /Stable	A- /Stable	A- /Stable
TransCanada Pipelines	A- /Stable	A- /Stable	A- /Stable	A- /Stable	A- /Stable	A- /Stable
Westcoast	A- /Stable	BBB+ /Stable	BBB+ /Stable	BBB/Stable	BBB/Stable	BBB/Stable

While these are representative credit ratings for the listed companies, the type of debt issuances that are directly assessed vary.

S&P indicates that its credit rating reflects a borrower's capacity and willingness to meet its financial commitments on a timely basis. S&P bases its ratings on the overall creditworthiness of a consolidated company. Therefore, the rating of a wholly-owned subsidiary, in the absence of meaningful ring-fencing measures, generally reflects the creditworthiness of the parent.

Moody's Credit Rating History

Pipeline	2010	2011	2012	2013	2014	2015
Alliance L.P.	A3 /Stable	A3 /Stable	A3 /Stable	A3 /Stable	Baa1/Watch	Baa2/Stable
Enbridge Inc.	Baa1	Baa1	Baa1	Baa1	Baa1/Negative	Baa2/Stable
Express	Baa1/negative	Baa1/negative	Baa1/Stable	Baa1/Stable	Baa1/Stable	Baa1/Stable
M&NP	A2 /Stable	A2 /Stable	A2 /Stable	A2 /Stable	A2 /Stable	A2 /Stable
NGTL	A3 /Stable	A3 /Stable	A3 /Stable	A3 /Stable	A3 /Stable	A3 /Stable
TransCanada	A3 /Stable	A3 /Stable	A3 /Stable	A3 /Stable	A3 /Stable	A3 /Stable

While these are representative credit ratings for the listed companies, the type of debt issuances that are directly assessed vary.

Moody's indicates that its credit analysis focuses on the fundamental factors and key business drivers relevant to an issuer's long-term and short-term risk profile. The foundation of Moody's methodology rests on two basic considerations:

- the risk to the debt holder of not receiving timely payment of principal and interest on the specific debt security; and
- a comparison of the level of risk with that of all other debt securities.

Like S&P, Moody's focuses its ratings on the overall creditworthiness of the consolidated entity. In doing so Moody's measures the ability of an issuer to generate cash in the future, thus its primary focus is on the predictability of future cash generation. This determination is built on an analysis of the individual issuer and of its strengths and weaknesses compared to those of its peers worldwide. An examination of factors external to the issuer is also conducted, including industry or country-level trends that could impact the entity's ability to meet its debt obligations. Of particular concern is the ability of management to sustain cash generation in the face of adverse changes in the business environment.