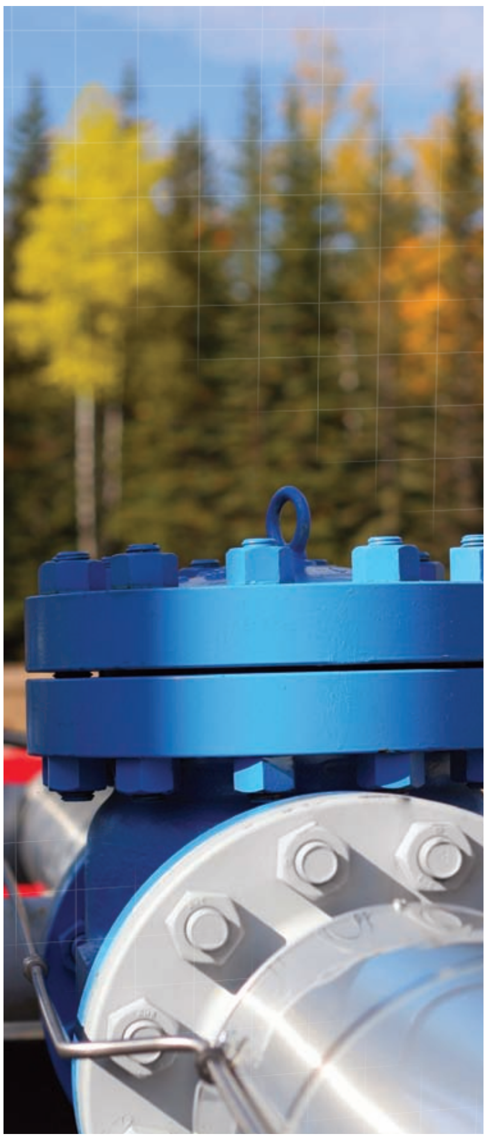
National Energy Board
Office national de l'énergie

CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT



JULY 2007

Canada

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FIGURES

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ACRONYMS AND ABREVIATIONS

AOS	Authorized Overrun Service
Alliance	Alliance Pipeline Ltd.
Altex	Altex Energy Ltd.
CAPP	Canadian Association of Petroleum Producers
CEPA	Canadian Energy Pipeline Association
Cochin	Cochin Pipe Lines Ltd.
Coral	Coral Energy Canada Inc.
DBRS	Dominion Bond Rating Service
EBIT	Earnings Before Interest and Taxes
Enbridge	Enbridge Pipelines Inc.
Express	Express Pipeline Limited Partnership
Foothills	Foothills Pipe Lines Ltd.
FT	Firm Transportation
FT-RAM	Firm Transportation Risk Alleviation Mechanism
GDP	Gross Domestic Product
Gateway	Gateway Pipeline Inc.
IGUA	Industrial Gas Users Association
Irving/Repsol	Irving Oil Company Limited and Repsol YPF
Kinder Morgan	Kinder Morgan Canada Inc.
LNG	Liquefied Natural Gas
M&NP	Maritimes & Northeast Pipeline Management Ltd.

Mackenzie	Mackenzie Gas Project
Moody's	Moody's Canada Inc.
NEB or Board	National Energy Board
NGL	Natural Gas Liquid
OEB	Ontario Energy Board
PADD	Petroleum Administration for Defense Districts
Petro-Canada	Petro-Canada Oil and Gas
PNGTS	Portland Natural Gas Transmission System
ROE	Return on Common Equity
S&P	Standard & Poor's
Terasen	Terasen Pipelines Inc.
T-South	Westcoast's Southern Mainline (Zone 4)
TNPI or Trans-Northern	Trans-Northern Pipeline Inc.
TPTM	Terasen Pipelines (Trans Mountain) Inc.
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada or TCPL	TransCanada PipeLines Limited
U.S.	United States
Union Gas	Union Gas Limited
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc.

UNITS

b/d	Barrels per day
Mb/d	Thousand barrels per day
MMb/d	Million barrels per day
Bcf	Billion cubic feet
MMcf/d	Million cubic feet per day
GJ	Gigajoule
m^3/d	Cubic metres per day
$10^3m^3/d$	Thousand cubic metres per day

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency whose purpose is to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest[1] within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB is an active, effective and knowledgeable partner in the responsible development of Canada's energy sector for the benefit of Canadians.

The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines, as well as tolls and tariffs. Another key role is to regulate international and designated interprovincial power lines. The Board also regulates the imports of natural gas and the exports of natural gas, oil, natural gas liquids (NGLs) and electricity. Additionally, the Board regulates oil and gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements. In its advisory function, the Board provides energy information and advice by analyzing information about Canadian energy markets obtained through regulatory processes and monitoring.

This report marks the third year that the Board has provided an assessment of the Canadian hydrocarbon transportation system. This report utilizes data from various publicly available sources which are collected and monitored by Board staff in addition to throughput data supplied by the pipeline companies. The Board also benefited from discussion with members of the investment community with respect to capital markets. Prior to the release of this report, a draft was sent to the Canadian Energy Pipeline Association (CEPA), the Canadian Association of Petroleum Producers (CAPP), and the Canadian Gas Association (CGA) for comment. Other parties such as the Industrial Gas Users Association (IGUA) also expressed interest and provided comment on the issues and aspects of information in this report. A listing of all organizations that provided comment or information in the production of this report is shown in Appendix 1. Comments by all parties were taken into consideration in the preparation of this report.

Any comments on the report or suggestions for further analysis can be directed to:

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Applications Business Unit
National Energy Board
Telephone: (403) 299-3690
Email: hmah@neb-one.gc.ca

If a party wishes to rely on material from this report in any regulatory proceeding, it can submit the material as can be done with any public document. In such a case, the material is in effect adopted by the party submitting it and that party could be required to answer questions on it.

Information about the NEB, including its publications, can be found by accessing the Board's website: http://www.neb-one.gc.ca.

1 The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that changes as society's values and preferences evolve over time.

INTRODUCTION

Energy is essential to our daily lives. The ability of the pipeline transportation system to deliver energy, in the form of natural gas, natural gas liquids (NGLs), crude oil, and petroleum products is critical to Canada's economic well-being. In 2006, approximately $110 billion worth of products was moved through Canadian pipelines to markets at home and in the U.S. The cost in 2006 of providing these transportation services is estimated to be around $4.7 billion, not including the fuel costs paid by shippers on natural gas pipelines. This was accomplished by infrastructure that is mostly invisible to consumers and that operates safely with minimal environmental impact.

Canadians depend on this infrastructure for a safe, reliable, and efficient energy supply. The 45 000 kilometres (km) of natural gas and oil pipelines regulated by the NEB are a crucial element in Canada's hydrocarbon transportation system (Figures 1 and 2). These include large-diameter, cross-country, high-pressure natural gas pipelines, low pressure crude oil and oil products pipelines, and small-diameter pipelines.

In line with its mandate to promote safety and security, environmental protection and efficient energy infrastructure and markets in the Canadian public interest, the Board has identified five goals which articulate its purpose and core directives[2]:

1. NEB-regulated pipelines and activities are safe and secure, and are perceived to be so.
2. NEB-regulated facilities are built in a manner that protects the environment and respects the rights of those affected.
3. Canadians benefit from efficient energy infrastructure and markets.
4. The NEB fulfills its mandate with the benefit of effective public engagement.
5. The NEB delivers quality outcomes through innovative leadership and effective support processes.

To determine whether the goals are being achieved, the Board has established various measures and a system of monitoring for each goal. Each year, the Board also issues various reports that discuss these different aspects of Canadian energy infrastructure and activities. This report focuses largely on aspects of Goal 3, and provides an update on the Board's assessment on how well the Canadian hydrocarbon transportation system is working. This report marks the third consecutive year for this assessment and utilizes the system of monitoring and measurements for the performance of the transportation system that was established in previous years. For the hydrocarbon transportation system to function efficiently and effectively, it must operate in a safe and environmentally acceptable manner, which relates to Goals 1 and 2. The Board also reports annually on safety, integrity, and environmental performance of NEB-regulated pipelines in a companion report that was published in March 2007, which may be found at http://www.neb-one.gc.ca/safety/SafetyPerformanceIndicators/index_e.htm.

2 NEB Strategic Plan 2007-2010

FIGURE 1

Gas Pipelines Regulated by the NEB

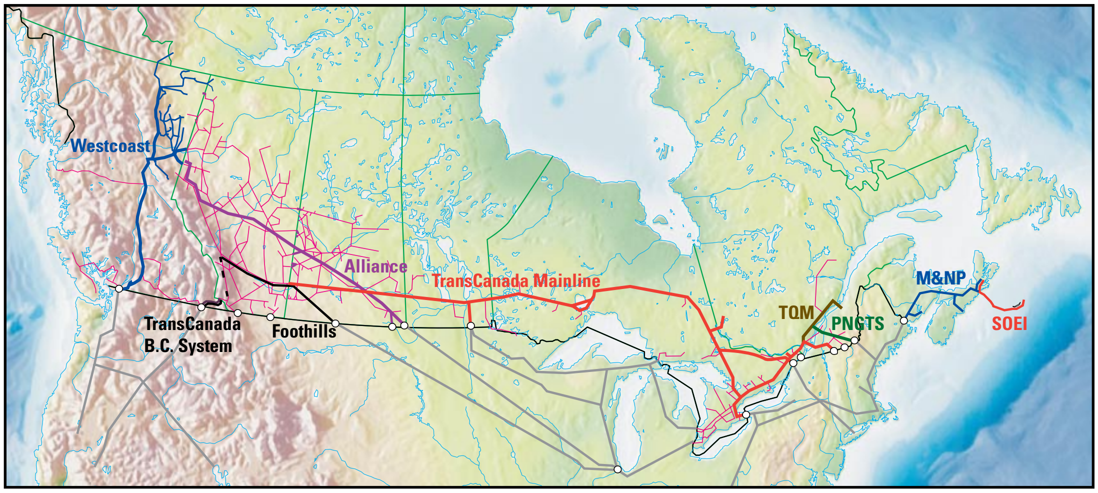
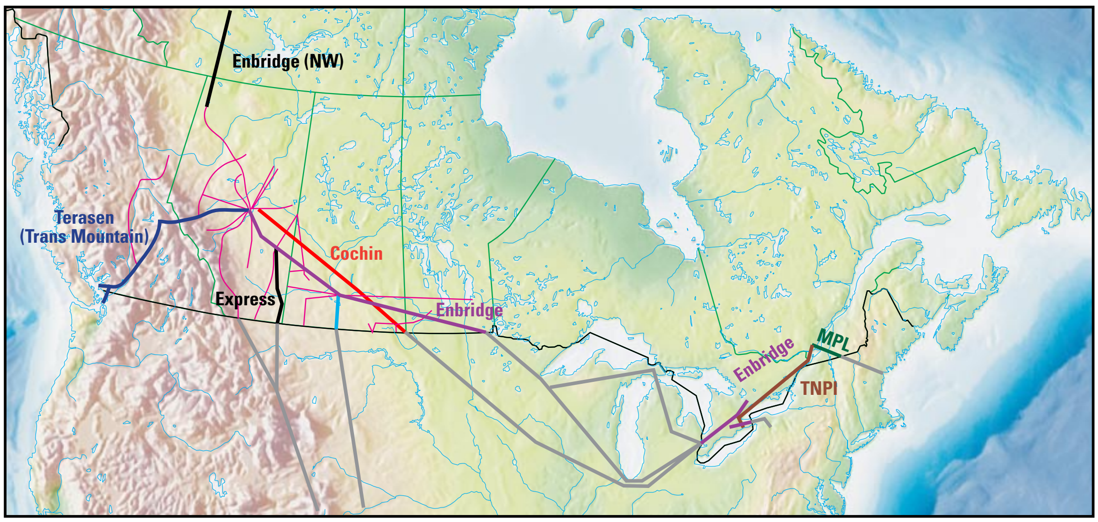


FIGURE 2

Oil Pipelines Regulated by the NEB



The Board believes that the following outcomes are important characteristics of a well functioning hydrocarbon transportation system:

- There is adequate pipeline capacity in place to move products to consumers who need them;
- Pipeline companies provide services that meet the needs of shippers at just and reasonable prices; and,
- Pipeline companies have adequate financial strength to attract capital on terms and conditions that enable them to effectively maintain their systems and build new infrastructure to meet the changing needs of the market.

In general, an efficient hydrocarbon transportation system will have an ability to respond on a timely basis to changing market conditions. This may entail adjustments to pipeline capacity or enhancement of pipeline services.

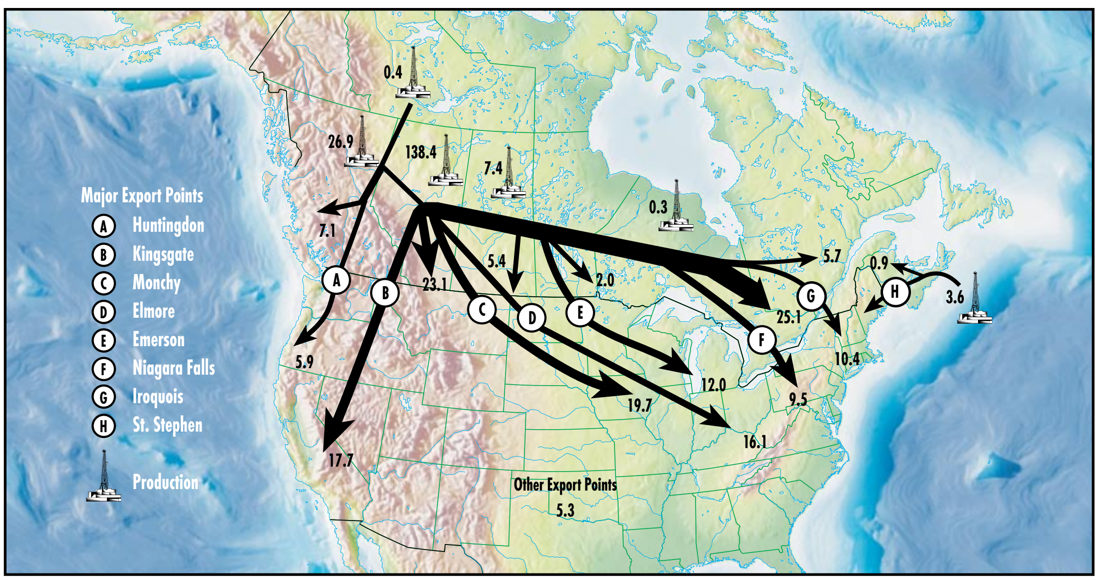
To assess the extent to which these outcomes are achieved, the Board uses publicly available data for Group 1 regulated companies and Express Pipeline Limited Partnership (Express), the largest Group 2 company.[3] These companies represent the major NEB-regulated pipelines and provide a good view of the overall functioning of the hydrocarbon transportation system. In addition, the Board used throughput and capacity information received from the pipelines; discussions with members of the investment community; and input from the users of NEB-regulated pipelines. Although the majority of information presented in this report is an update and assessment for 2006; where available, 2007 information is also provided. A listing of the companies regulated by the NEB, as of December 31, 2006, can be found in Appendix 2.

This report should not be viewed as a regulatory decision. In this report the Board is not making a determination on regulatory matters such as the appropriate rate of return on equity that should be earned by pipeline companies. The factors used to assess the functioning of the transportation system are not necessarily the same as those which are applied in a regulatory proceeding.

Figures 3 and 4 provide an overview of the supply and disposition of natural gas and crude oil in Canada. More information on the supply and disposition of energy in Canada can be found in the Board's Energy Overview report, published in May 2007, which may be found at http://www.neb-one.gc.ca/energy/EnergyReports/index_e.htm#energy_overview.

FIGURE 3

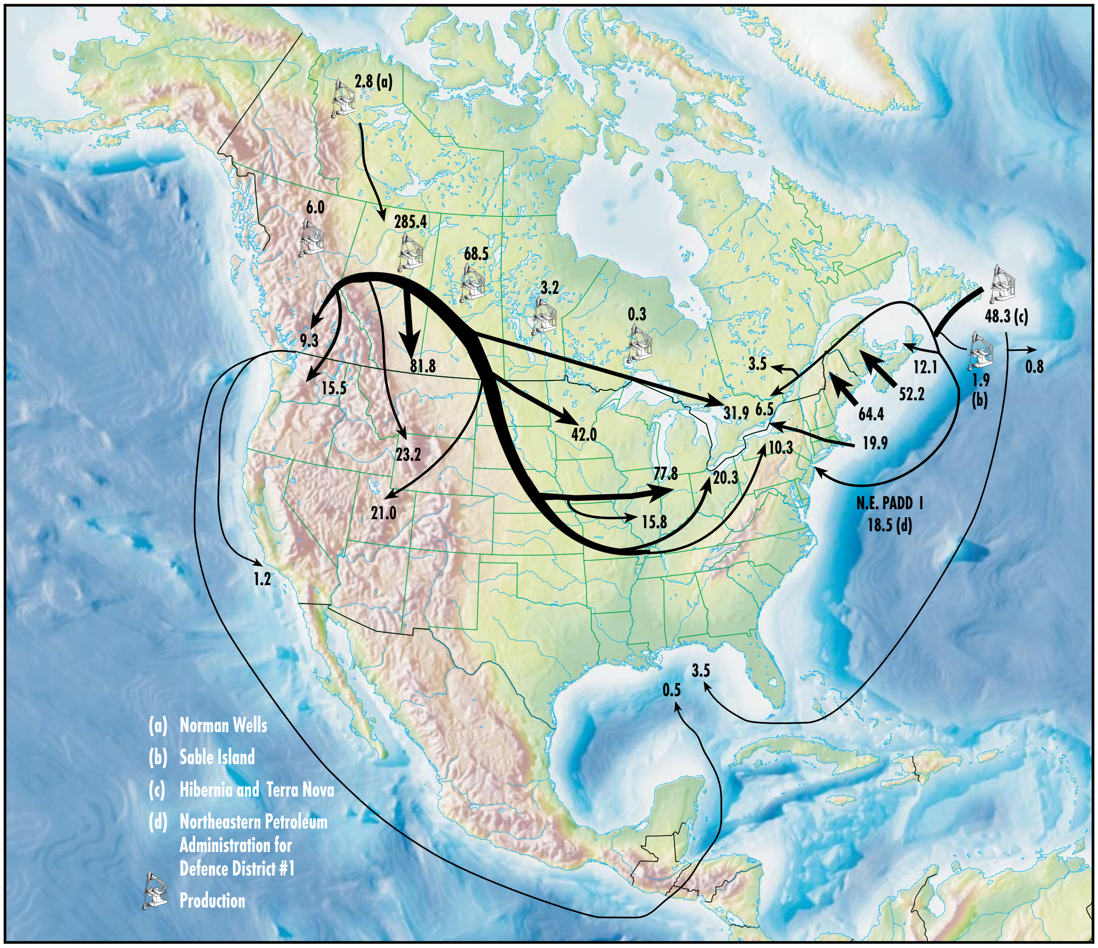
2006 Supply and Disposition of Natural Gas (Billion Cubic Metres)



3 For the purpose of the Board's financial regulation, pipeline companies are divided into two groups, Group 1 and Group 2. Major oil and gas pipeline companies are designated as Group 1 and are generally actively regulated by the NEB. All other NEB-regulated pipelines are designated as Group 2 and are subject to a lighter degree of regulation.

FIGURE 4

2006 Supply and Disposition of Oil (Thousand cubic Metres per Day)



ADEQUACY OF PIPELINE CAPACITY

A key measure of an energy market's operational efficiency is the ability of its pipeline system to adequately transport crude oil, refined products, natural gas and natural gas liquids (NGLs) from producing to consuming regions.

This section will examine the following factors to assess the current adequacy of pipeline capacity:

1. price differentials compared with firm service tolls for major transportation paths;
2. capacity utilization on pipelines; and
3. the degree of apportionment on major oil pipelines.

The Board has generally taken the view that some excess capacity on a pipeline is desirable. This may result in higher tolls for shippers; however, the costs associated with inadequate pipeline capacity can be far greater. Substantial revenue loss for producers and governments can result when producers are unable to move their oil and gas to market. In addition, excess capacity allows shippers the flexibility to access the appropriate markets with the right product, thereby maximizing their revenues.

For example, in the case of oil transportation, if there is inadequate pipeline capacity to transport crude oil to the West Coast (PADD V), producers have the option of transporting crude oil to Ontario, PADD II (Midwest), southern PADD II (Cushing, Oklahoma), PADD III (U.S. Gulf Coast) or PADD IV (Rockies). As well, during periods when refineries are in turnaround (maintenance) in any of these locations, producers can deliver crude oil volumes to other markets, providing there is adequate pipeline capacity.

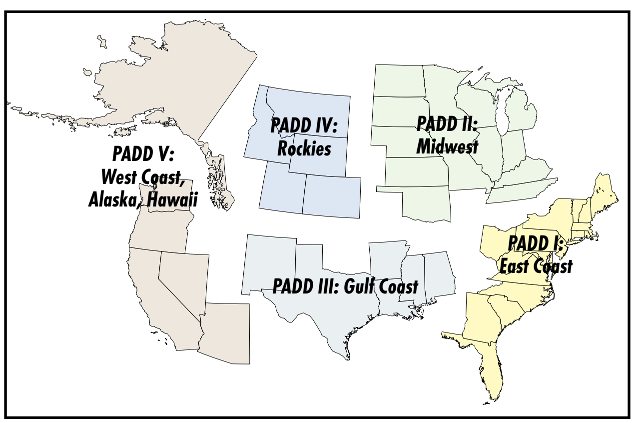
2.1 Price Differentials

Price Differentials and Natural Gas Firm Service Tolls

When there is adequate pipeline capacity between two market hubs, commodity prices will be connected and the price differential will be equal to, or less than, the transportation costs between the two points. As long as the price differential is less than the toll plus fuel, the market is indicating that there is adequate pipeline capacity between the two pricing points. In a market with adequate capacity, suppliers would generally direct their product to the

FIGURE 5

Petroleum Administration for Defense Districts



market that nets the highest revenue back to the seller, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market, resulting in higher prices for downstream consumers or lower prices to producers, creating a higher differential in price between the two end points.

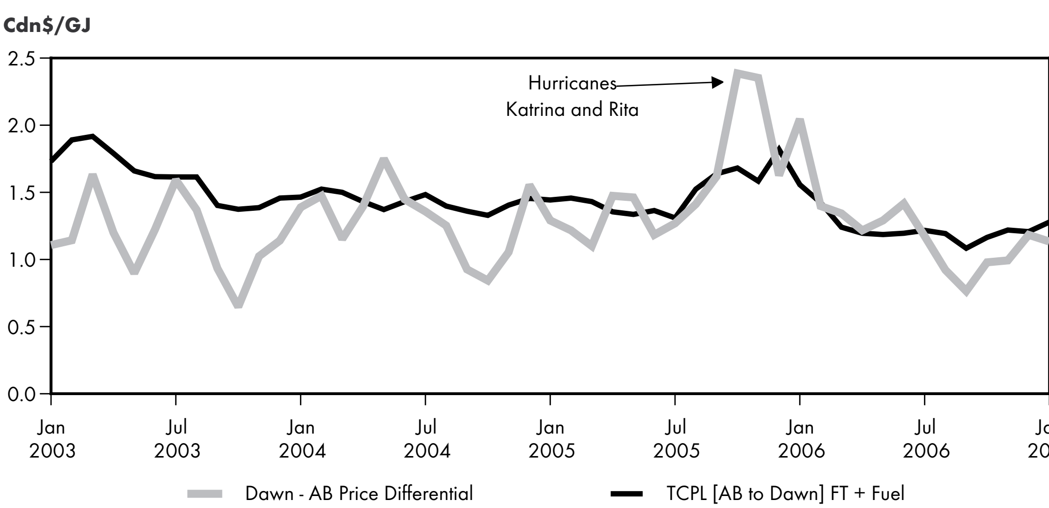
In order to use price differentials as an indicator on the adequacy of pipeline capacity, there must be reasonably good pricing data available. Two examples of price differentials compared with firm service tolls are provided below – one for transportation on TransCanada PipeLines Limited Mainline (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc. (Westcoast).

Figure 6 shows the basis differential between Alberta and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The price differential between Alberta and the Dawn delivery point is generally below the total cost of transportation (firm transportation plus fuel) via the TransCanada pipeline connecting these two markets. This indicates that pipeline capacity is adequate between these locations. As indicated by the variation in the price difference between the two locations, natural gas pricing is very responsive to relatively small changes in flow or demand. Times of exceptional natural gas demand in eastern markets, such as the summer heat waves of 2005 and 2006 that produced a strong demand for natural gas-fired power generation for air conditioning in eastern markets, or reduced supplies from the Gulf of Mexico in the months following hurricanes Katrina and Rita (August 2005 to January 2006), have resulted in short term increases in the price differential. Conversely, mild weather and ample gas in storage can moderate the price differential and the demand for gas and transportation services such as occurred in the autumn of 2006 and the early part of the 2006/2007 winter heating season.

Figure 7 shows the price differential between Compressor Station 2 on the Westcoast system and the export point at Huntingdon/Sumas compared with the firm service toll for transportation between the two locations (T-South or Southern Mainline), including fuel costs. Since January 2003, except for the peak winter months in recent years, the price differential has been lower than the cost of transportation, indicating that there has been adequate capacity in place. Overall, the comparison of price differential and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. However, natural gas pricing is volatile. Short-term increases in the price differential have been observed in recent years as a result of changes to market conditions such as,

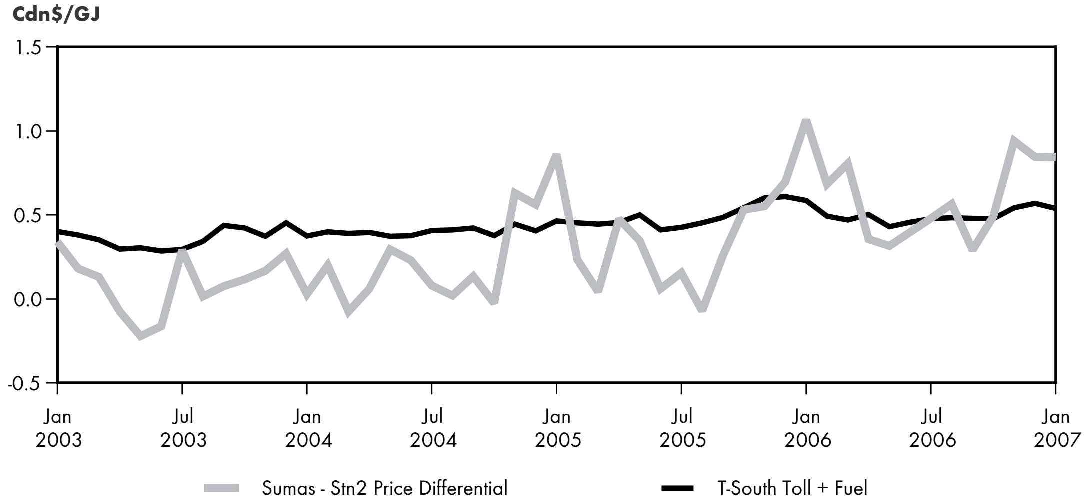
F I G U R E 6

Dawn – Alberta Price Differential vs. TransCanada Toll and Fuel



F I G U R E 7

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



hurricane-induced supply disruptions in the United States, unpredictable weather-related demand, and availability of other transportation options during such periods.

Overall, the comparison of price differentials and natural gas firm service tolls shows that pipeline capacity between these markets is adequate at most times. In general, the price differential between pricing points has been slightly lower than the cost of pipeline transportation (tolls) and fuel. However, natural gas prices can fluctuate in response to weather and can impact both price differential and pipeline fuel costs. Pipeline tolls tend to be more constant. Figures 6 and 7 both indicate occasions where the price differential exceeded transportation (toll) and fuel costs. These events proved to be temporary, and gas flows and prices moderated.

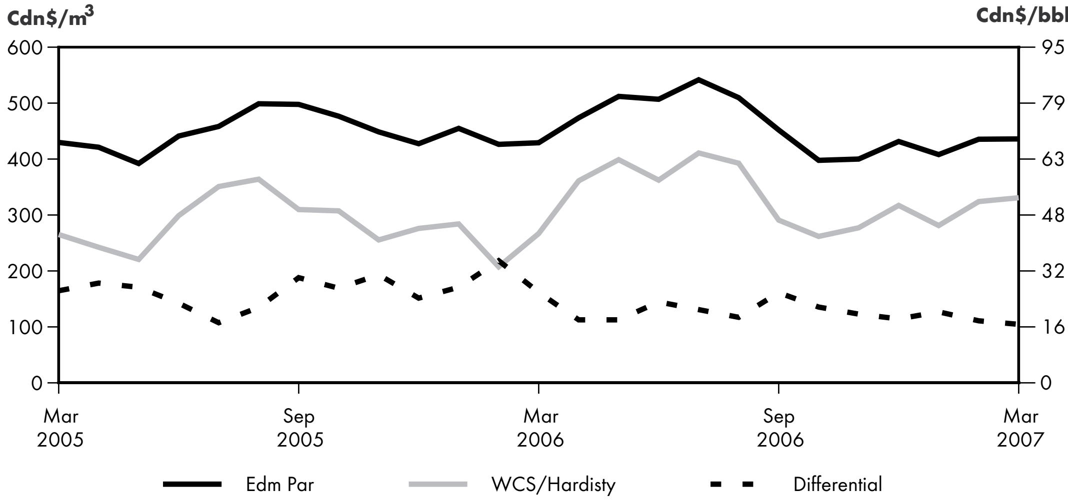
Price Differentials and Tolls on Oil Pipelines

The price differentials for crude oil are determined by a number of factors, including availability of pipeline capacity, supply and demand fundamentals, seasonality and the grade (quality) of crude oil. Price differentials are increasingly becoming an issue on oil pipelines because of increasing production from the oil sands. Oil sands crude oil is a heavier bitumen blend and has limited market access because it requires specially equipped refineries to process it into useable refined products. This limited access exerts downward pressure on heavy crude oil prices and widens the light-heavy differential during certain times of the year. Historically the discussion on price differentials have been exclusive to heavy crude oil; however, with increased production of upgraded bitumen or light synthetic crude oil - the price differential between synthetic crude oil, Canadian light crude oil, and other crude oil supplied to U.S. refineries is becoming an increasingly important issue. Largely as a result of increased synthetic crude oil production and limited pipeline capacity to downstream markets, price discounts have also been observed for Canadian synthetic and light crude oil.

Figure 8 illustrates the light-heavy differential as indicated by the difference in the price of Edmonton Par light crude oil and Western Canadian Select (WCS), a heavy crude oil blend that is priced at Hardisty, Alberta. As illustrated, the differential between them has been wide and volatile during the time period shown; however, there has been a narrowing trend since September 2006. In the first quarter 2007, the light-heavy differential was 27 percent. In particular, in the month of March, the light-heavy differential narrowed to its lowest level since August 2004. There are two main reasons

FIGURE 8

Canadian Crude Oil Prices and Differential



for this narrowing; one is the Syncrude upgrader expansion, which is processing more bitumen, up to 350 Mb/d per day from 240 Mb/d in 2006; the second is the Spearhead and Mobil pipeline reversals which are transporting almost 200 Mb/d of crude oil south of Chicago to as far as the U.S. Gulf Coast. Typically, during the summer months, the differential narrows because of an increase in seasonal demand for heavier crudes for the production of asphalt.

2.2 Capacity Utilization on Major Routes

Where adequate pricing data is not available at major receipt and delivery locations on pipeline systems, another measure of adequate capacity comes from directly comparing the throughput or flow on the pipeline with its capacity. The Board monitors capacity utilization for most of the large pipelines it regulates.

The following figures show pipeline average monthly throughput compared with capacity for some of the largest NEB-regulated pipeline systems, including the TransCanada Mainline, Foothills Pipe Lines Ltd. (Foothills), TransCanada B.C. System, Westcoast, Alliance Pipeline Ltd. (Alliance), Trans Québec & Maritimes Pipeline (TQM), Maritimes & Northeast Pipeline (M&NP), Enbridge Pipelines Inc. (Enbridge), Kinder Morgan Canada's Terasen Pipelines (Trans Mountain) Inc. (TPTM), Express and Trans-Northern Pipeline Inc. (TNPI).

Natural Gas

Figure 9 compares the average monthly throughput on the TransCanada Mainline (which is approximately equal to the amount of gas flowing east on the Mainline from Saskatchewan) to the capacity of TransCanada's prairie line. This comparison illustrates that there has consistently been capacity in excess of throughput volumes over the time period shown. The excess capacity even persisted through the period of July 2005 to July 2006, which included two hotter-than-normal summers that produced strong demand for natural gas for power generation in eastern markets, and greater demand for Canadian gas due to production losses in the U.S. stemming from the late summer hurricanes of 2005.

On the eastern part of the TransCanada system, a number of expansions occurred in 2006 or are proposed for 2007 which are directed towards reducing bottlenecks to connect additional supply from Dawn and to access growing markets in Eastern Canada and the U.S. Northeast.

Overall, the indicator shows that there has been adequate pipeline capacity to move volumes to eastern markets. Excess capacity, which averaged 1.4 Bcf/d over the past four years, provided the impetus for the TransCanada Keystone Pipeline project. In this initiative, TransCanada proposes to transfer Line 100-1 of the Mainline to TransCanada Keystone Pipeline GP Ltd. for conversion to oil service. This transfer and conversion, if approved, could result in an annual average capacity reduction on the Mainline of approximately 0.5 Bcf/d. The Board approved the facilities transfer on 9 February 2007, however the TransCanada Keystone application for the construction of the requested oil facilities is still before the Board.

The volumes shown in Figure 10 are the average monthly throughput on TransCanada's Foothills Pipeline (Sask.) compared with capacity. This pipeline transports western Canadian gas supply to

FIGURE 9

TransCanada Mainline Throughput vs. Capacity

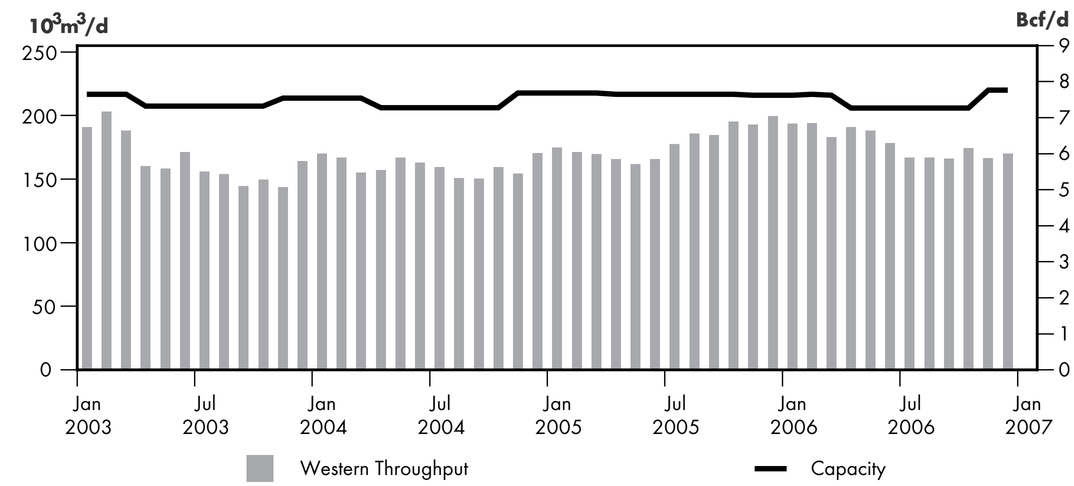
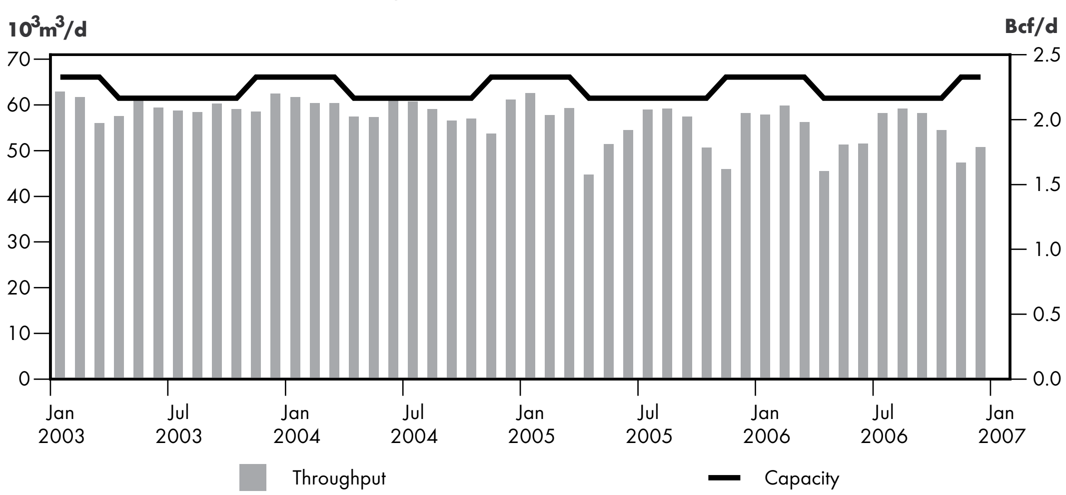


FIGURE 10

Foothills Pipeline (Sask.) Throughput vs. Capacity at Monchy



markets in the U.S. Midwest through a connection with the Northern Border Pipeline Ltd. (Northern Border) at Monchy, Saskatchewan. The Foothills (Sask.) throughput has displayed distinct seasonal patterns in recent years, with annual average capacity utilization running at 88 percent in 2006, down from an average of 94 percent in 2003. Throughput on the Foothills Pipeline (Sask.) runs fairly close to capacity in both the winter and the summer months to meet winter heating demand and to meet summer demand for power generation and storage injection. Throughput subsequently declines in the low-consumption spring and autumn months.

Figure 11 compares the average monthly throughput on Westcoast's Southern Mainline with the capacity on this system between Station 2 and the export point at Huntingdon/Sumas. This figure shows the seasonal nature of throughput on the Southern Mainline with higher volumes being transported during the peak winter months and less during the summer. Contributing factors to the low flows on Westcoast during 2006 and recent years include greater competition with production from the U.S. Rockies region for markets in the U.S. Pacific Northwest, mild winter weather, and increased hydro power generation in B.C. and the U.S. Pacific Northwest.

Figure 12 shows the average monthly capacity and throughput on the TransCanada B.C. System, which primarily serves California. The annual average capacity utilization in 2006 was 64 percent, slightly higher than in previous years. There exists spare capacity on this pipeline to export gas through Kingsgate, B.C. California market players have transportation options enabling them to access supply from the Rocky Mountains, San Juan and Permian basins, in addition to the Western Canada Sedimentary Basin (WCSB). This supply competition has reduced imports from the WCSB at Kingsgate.

Figure 13 shows the average monthly throughput on the Alliance system relative to physically available capacity. Alliance offers approximately 1.325 Bcf/d of firm service capacity, and makes any additional capacity available to its contracted shippers pro rata as Authorized Overrun Service (AOS). Available AOS levels are determined on a daily basis and may be used at the cost of fuel only. The total available capacity is variable, depending on such factors as ambient temperature and compressor unit availability (as influenced by maintenance schedules). Alliance's total available capacity has essentially been fully utilized since the commencement of service, with all available firm service contracted on a long-term basis.

FIGURE 11

Westcoast Mainline Throughput vs. Capacity

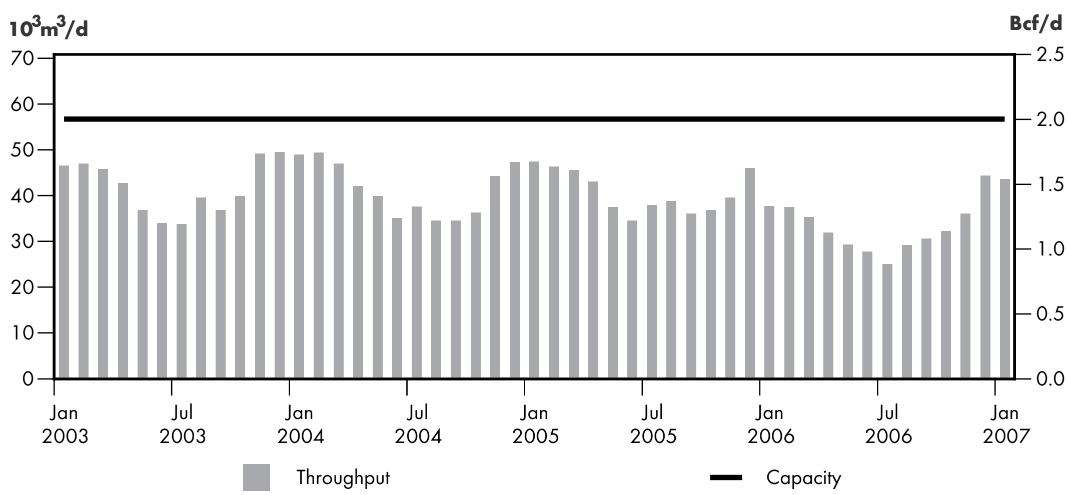


Figure 14 compares the average monthly throughput and capacity on the TransQuébec & Maritimes system (TQM) which delivers gas from the TransCanada Mainline at Saint-Lazare, Quebec to Québec City and the East Hereford export point in Quebec (New Hampshire state border). More volumes are transported during winter months, highlighting the use of natural gas for heating in this region and the seasonal nature of the throughput on this pipeline. With average annual capacity utilization of around 60 percent, there has historically been spare capacity on this pipeline, particularly in summer months. However, with the limited compression on the system needed to meet TQM's delivery pressure at the East Hereford export point, the available spare capacity is very sensitive to the actual load distribution on the pipeline. In 2006, TQM undertook a system expansion to serve an incremental demand arising from the construction of a new gas-fired power plant in Quebec.

Figure 15 compares the average monthly capacity and throughput on the M&NP pipeline. The annual average capacity utilization has declined from about 92 percent in 2002 to an average of about 68 percent in 2006. The reduction in this pipeline's capacity utilization stems from declining natural

FIGURE 12

TransCanada B.C. system Throughput vs. Capacity at Kingsgate

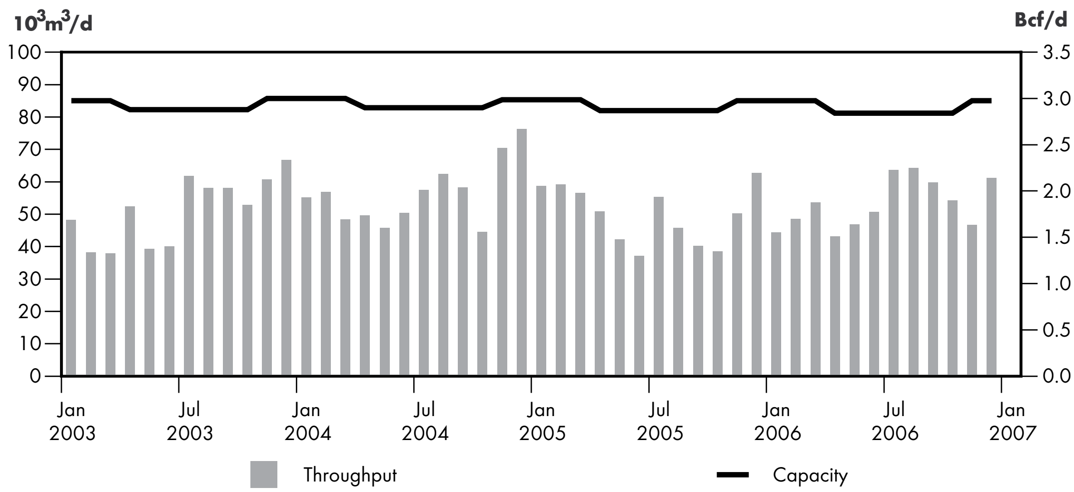


FIGURE 13

Alliance Throughput vs. Capacity

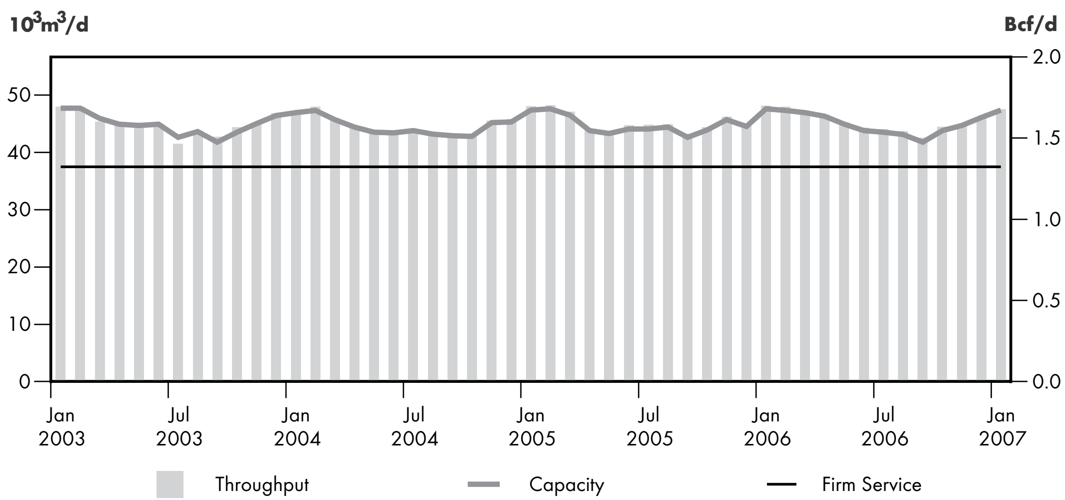


FIGURE 14

Trans Québec and Maritimes Throughput vs. Capacity

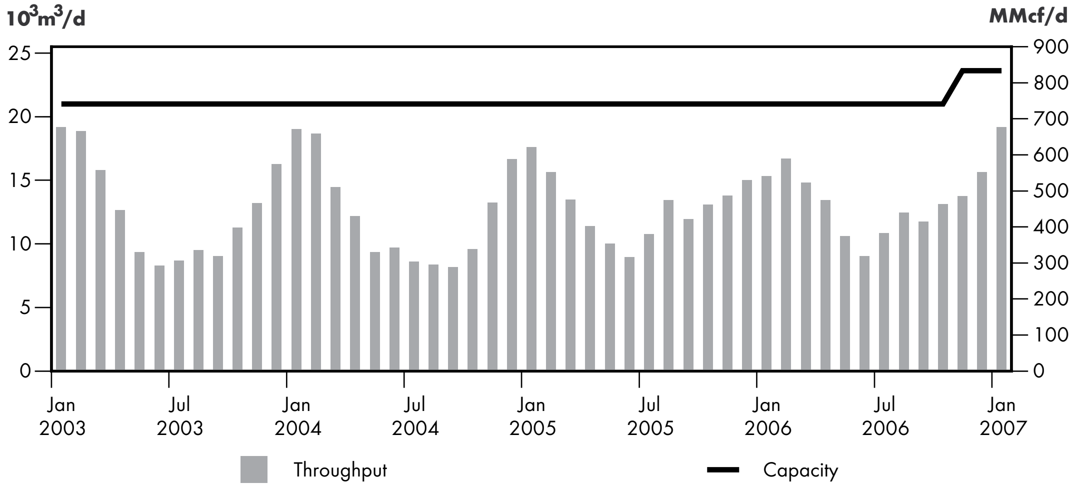
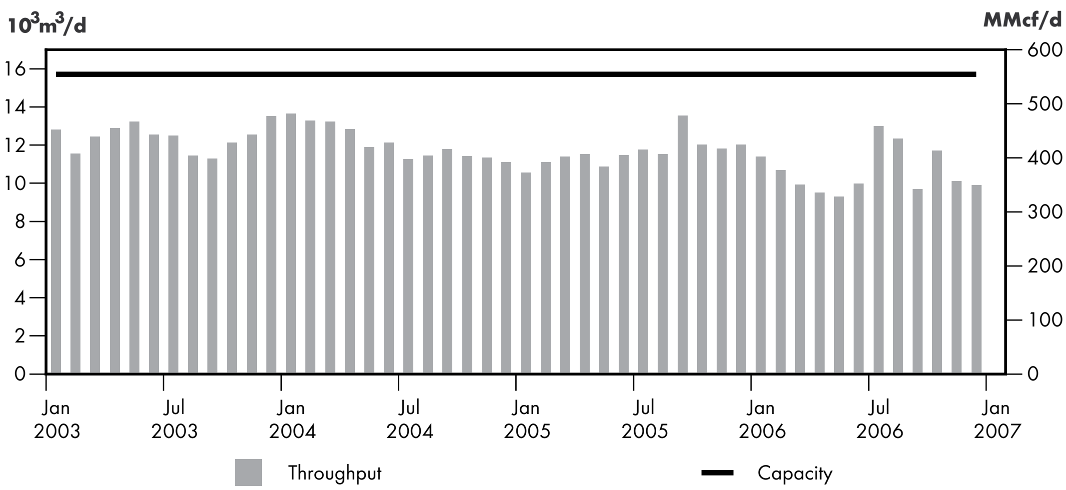


FIGURE 15

Maritimes and Northeast Pipeline Throughput vs. Capacity



gas production from offshore Nova Scotia. Variations in throughput are primarily related to changes in gas supply as the export demand for gas destined to northeastern U.S. markets is consistently strong. In late 2006, additional compression at the offshore platform was installed to boost deliverability. In addition, a couple of gas supply projects are being considered in the region with the potential to supplement supply.

Oil

Determining the capacity and throughput on an oil pipeline can be complex as there are many factors to be considered: the type of product, product mix, type of batching and pipeline configurations.

The Enbridge system originates in Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba where it joins with the Lakehead system in the U.S. It is the largest crude oil pipeline in the world and the primary transporter of crude oil from western Canada to markets in eastern Canada and the U.S. Midwest. The Enbridge system also connects with pipelines that deliver crude oil to Cushing, Oklahoma and the U.S. Gulf Coast. The system consists of many lines transporting crude oil, NGLs and refined petroleum products. Figure 16 illustrates Enbridge throughput versus capacity. In 2006, Enbridge transported roughly 247 000 m^3/d (1.6 MMb/d) of crude oil, petroleum products and NGLs. In the first quarter 2007, Enbridge operated at about 85 percent of capacity. Since the third quarter of 2006, many of its lines have been operating at or near full capacity with some lines in apportionment (see Section 2.3).

Terasen Pipelines (Trans Mountain) Inc., owned by Kinder Morgan, transports crude oil and refined petroleum products from Edmonton, Alberta west to locations in British Columbia, Washington State and offshore. TPTM's current capacity, assuming some heavy crude oil, is 35 700 m^3/d (225 Mb/d). The pipeline has been operating at or near capacity for several years and on many occasions has been under apportionment (See Section 2.3). Figure 17 shows two capacities for the TPTM pipeline; one assumes no shipments of heavy crude oil and the other assumes 15 percent heavy crude oil. When heavy crude oil is shipped, it reduces the capacity of the pipeline. On average, in 2006, 15 percent of TPTM's crude oil receipts at Edmonton were heavy crude oil. In the second quarter of 2007, the TPTM Pump Station Expansion is expected to be in-service. It will add an additional 5 600 m^3/d (35 Mb/d) of capacity.

In February 2006, TPTM applied to the NEB to loop a 158 km segment of its pipeline, extending from Hinton, Alberta to a location near Rearguard, British Columbia. The Project would increase capacity by 6 360 m^3/d (40 Mb/d). An oral public hearing was held in August 2006 and the Board approved the application in October. The targeted in-service date is the fourth quarter 2008.

In the first quarter of 2007, TPTM operated at approximately 77 percent of capacity (see Figure 17). Despite operating at below its nameplate capacity of 285 Mb/d, TPTM was under apportionment in January and February of 2007. Growing oil sands production, strong demand from refiners in Washington State and continuing growth in crude oil shipments off the Westridge Dock are contributing to apportionment on the TPTM system. As well, in the summer of 2006, a temporary shutdown of the Prudhoe Bay field in Alaska, because of pipeline corrosion, resulted in increased throughput on the TPTM pipeline.

During the past several years, Express has been operating at capacity. Despite a major expansion in 2005 that added 16 000 m^3/d (100 Mb/d), bringing the capacity to 44 900 m^3/d (280 Mb/d) there has

FIGURE 16

Enbridge Pipeline Throughput vs. Capacity

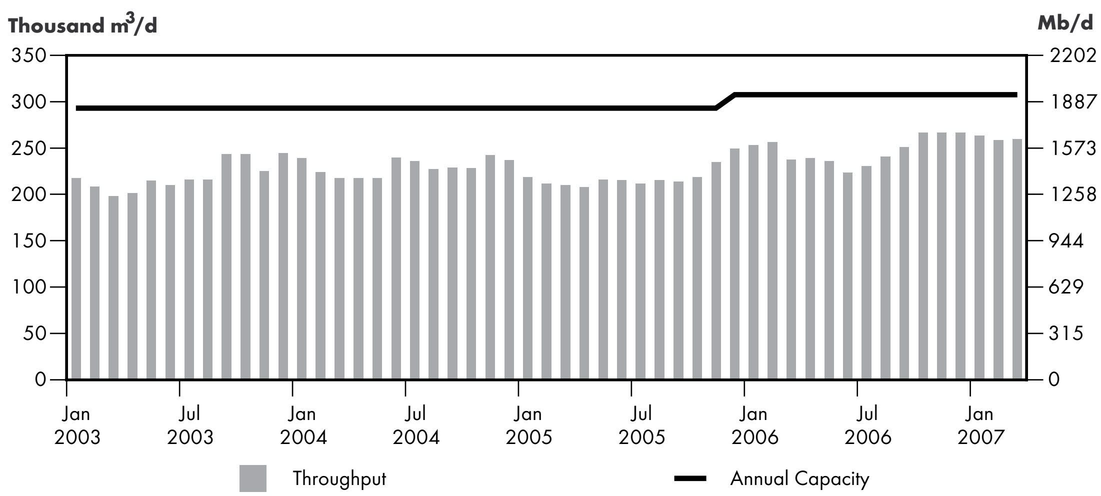


FIGURE 17

Teresen Pipelines Trans Mountain (TPTM) Throughput vs. Capacity

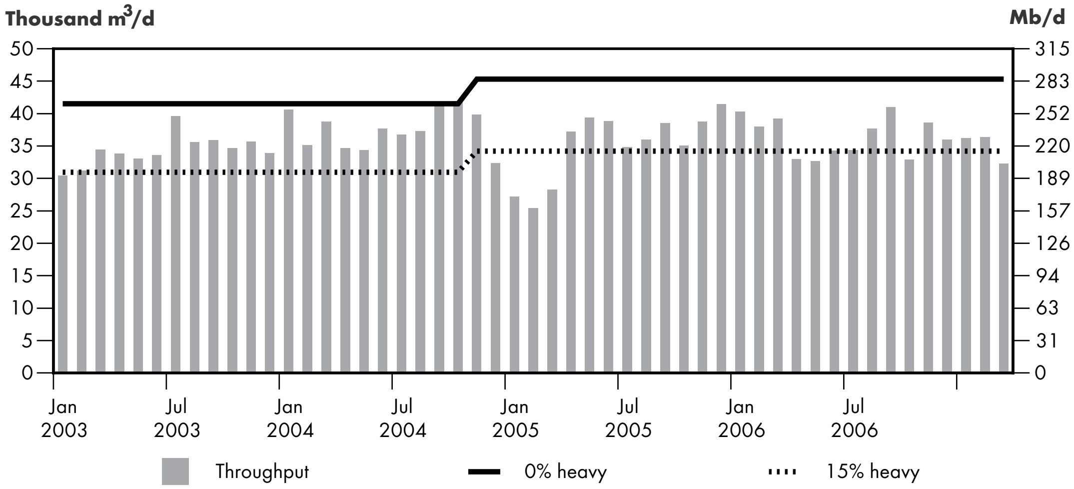
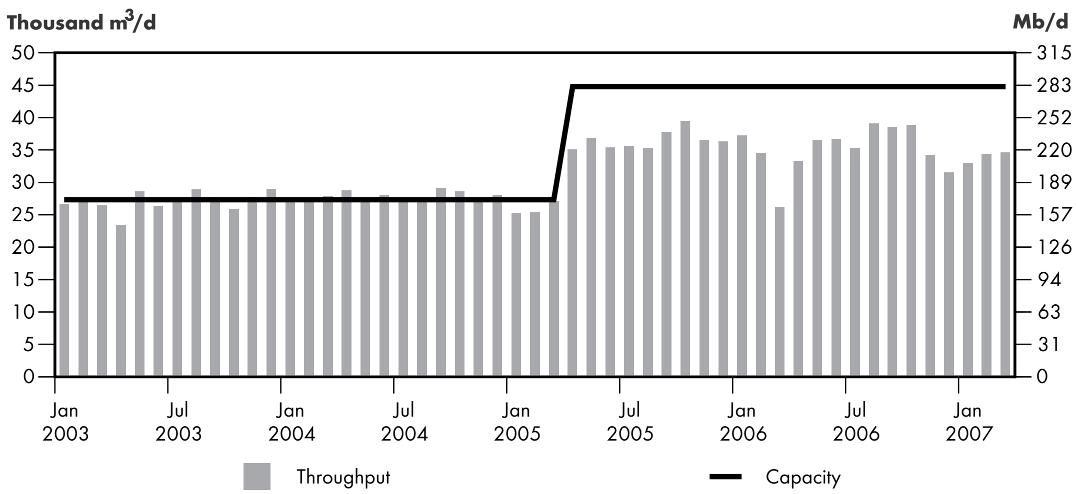


FIGURE 18

Express Throughput vs. Capacity



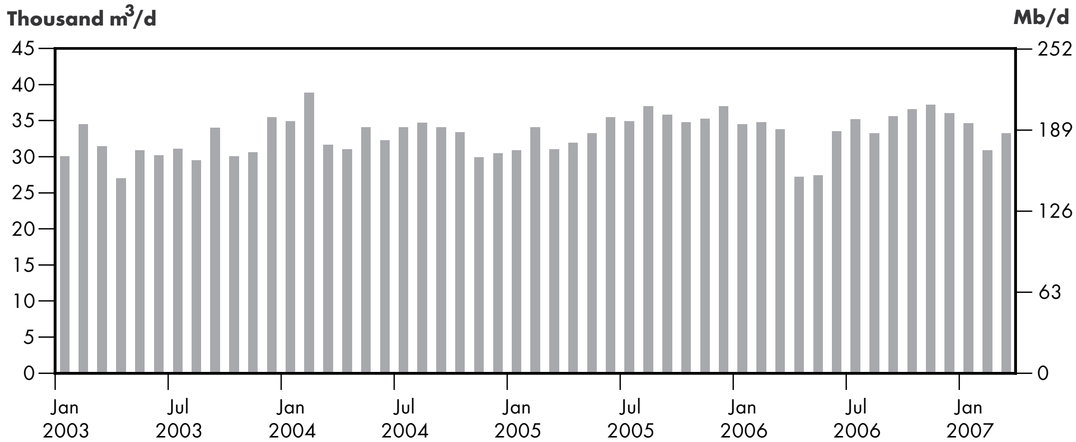
been apportionment on the pipeline in 2006. Express is the only crude oil pipeline in western Canada that operates under long-term take-or-pay agreements with its shippers for a majority of its capacity.

In the first quarter 2007, Express operated at approximately 76 percent of capacity (Figure 18). Crude oil shipments have been reduced at Hardisty on the Express pipeline because of continuing apportionment downstream on the Platte Pipeline in the U.S.

Trans-Northern Pipelines Inc. is a refined petroleum products pipeline. The pipeline transports refined petroleum products west from Montreal to north Toronto and operates bi-directionally between Toronto and Oakville, Ontario. TNPI also transports refined products from Imperial Oil Limited's (Imperial) refinery in Nanticoke, Ontario west to Toronto. In the first quarter of 2007, TNPI throughput averaged 33 000 m³/d (208 Mb/d) of petroleum products. The pipeline is generally operating at capacity.

FIGURE 19

Trans-Northern Pipelines Inc. Throughput



During the first quarter 2007, there was a fire at Imperial's refinery located in Nanticoke. This resulted in the refinery ceasing operations and a subsequent gasoline and diesel shortage in southern Ontario and Quebec. TNPI throughput was reduced during this period.

Calculating TNPI's capacity is difficult due to multiple delivery locations and the different capacities on each line segment.

2.3 Apportionment

Oil pipelines typically operate as common carriers. Common carriers require shippers to nominate their volumes for delivery into a pipeline on a monthly basis without a contract for pipeline capacity. When shippers nominate more oil or oil products in a given month than the pipeline can transport, shippers' volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations and refinery maintenance. There are a few pipelines in Canada that operate all or part of the pipeline with long-term shipper take-or-pay agreements, including Express, Enbridge Line 9 and TNPI.

Some recent apportionment levels for Enbridge, TPTM and Cochin are discussed below.

Enbridge

Enbridge's Lines 3 and 4 are dedicated to transporting heavy crude oil and Line 2 transports light crude oil. Historically, Lines 2 and 4 were heavy crude oil lines; however, following the Line 2/3 line swap in the fourth quarter 2005, Line 2 transitioned from a heavy crude oil line originating at Hardisty, Alberta to a light crude oil pipeline originating in Edmonton. In addition, Line 3 made the transition from a light crude oil pipeline originating at Edmonton to a heavy crude oil pipeline originating at Hardisty. This swap resulted in a net heavy capacity increase of 39 000 m^3/d (246 Mb/d) and a corresponding decrease of light capacity of 18 400 m^3/d (116 Mb/d). This added some much needed capacity to accommodate growing heavy crude oil output from the oil sands.

Table 1 indicates apportionment and throughput from August 2006 to March 2007. In the fourth quarter 2006, throughputs were very high on the Enbridge system and there was apportionment on Lines 5, 6 and 14. There has not been apportionment on the Enbridge system in the first quarter 2007; however, many of the Lines have been either fully subscribed or operating at maximum capacity.

TABLE 1

Enbridge Apportionment

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment	0%	0%	0%	0%	8%*	0%	0%	0%
Throughput (10^3m^3/d)	240.7	251.0	266.3	266.8	266.7	263.6	258.9	259.7

* Lines 5, 6 and 14

Capacity is also constrained due to a downstream bottleneck at Superior, Wisconsin because the capacity out of Superior is 230 000 m^3/d (1.4 MMb/d), less than the up to 300 000 m^3/d (1.9 MMb/d) that Enbridge can deliver to that destination.

Enbridge throughput fell slightly in the second quarter 2006 as a result of outages at two oil sands plants. In the third quarter 2006, throughput increased reflecting capacity expansions and increases in oil sands production. In addition, competitively priced western Canadian crude oil displaced some import volumes that would typically be delivered to the Sarnia area on Enbridge's Line 9. It is expected that increasing production from the oil sands in 2007 could contribute to further apportionment on Enbridge.

Enbridge's Line 9 has a capacity of 38 150 m^3/d (240 Mb/d) and transports crude oil from Montreal, Quebec to refineries located at Nanticoke and Sarnia, Ontario. There was no apportionment on Line 9 between August 2006 and February 2007. Shipments on Line 9 have been trending downward, particularly since the closure of Petro-Canada's refinery in Oakville in the second quarter of 2005. In 2006, the reduction in throughput was a result of maintenance activity at Imperial's Sarnia refinery in the second quarter and an increase in deliveries of more competitively priced western Canadian crude oil.

In January 2007, Enbridge Pipelines (Westspur) Inc. applied to the National Energy Board pursuant to section 52 of the *National Energy Board Act* (NEB Act), for the Alida, Saskatchewan to Cromer, Manitoba Capacity Expansion Project. The Enbridge Westspur pipeline was built in 1956 as an oil trunkline to transport crude oil. The pipeline also transports NGL from a gas processing plant in Steelman, Saskatchewan. Westspur interconnects with the Enbridge export lines at Cromer where the crude oil accesses the downstream markets.

The project proposes to construct a new 60 km, 168.3 mm (6 inch) pipeline to transport NGL from Alida to Cromer and convert the existing pipeline from its current NGL service to crude oil. Capacity on the existing line would increase from 25 000 m^3/d (157 Mb/d) to 34 600 m^3/d (218 Mb/d)

Terasen Pipelines (Trans Mountain) Inc.

Apportionment on TPTM is calculated separately for domestic destinations, export destinations and Westridge Dock destinations (as shown in Table 2 as Domestic, Export and Dock). Apportionment between August 2006 and March 2007 reflects continuing increases in oil sands supply and strong demand for Canadian crude oil in the Washington State area. In addition, increases in heavy crude oil shipments, result in a decrease in the capacity on the TPTM system. With weakness in the price of West Texas Intermediate (WTI) and discounting of Canadian crude oil because of over-supply in the Cushing area, coupled with a lack of take away capacity in that region, producers may increasingly look to the higher priced west coast and offshore markets for improved netbacks.

TABLE 2

TPTM Apportionment

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment								
Domestic	0%	8%	0%	14%	35%	22%	10%	0%
Export	0%	0%	0%	0%	12%	0%	0%	0%
Dock	0%	0%	0%	0%	0%	0%	0%	0%
Throughput (10^3m^3/d)	37.6	41.0	32.9	38.6	35.9	36.2	36.3	32.4

In April 2006, the NEB approved a request from Kinder Morgan Inc. to include a Westridge Dock Premium in the TPTM tariff to allocate capacity to the Westridge Dock. In the Board's decision, it directed Kinder Morgan to set up a deferral account for any premiums received and refund the money to toll payers in the following calendar year. The Board directed Kinder Morgan to publish the aggregate bid premium information on a quarterly basis; and, it approved the extension of the bid premium process until the start-up of the pump station expansion (PSE).

Cochin

In January 2007, Kinder Morgan Energy Partners purchased the remaining approximately 50 percent of Cochin Pipeline that they did not already own from BP Canada Energy Company (BP). Prior to the purchase, BP operated the pipeline and owned a slight majority stake.

The Cochin pipeline is the largest and longest NGL pipeline in Canada. In the past, it has transported propane, ethane, ethylene and butane, although no butane has been shipped since 2002. Ongoing maintenance work on the pipeline has affected the available capacity; however, (Table 3) there has not been apportionment on Cochin since summer 2005 when the pipeline was forced to unexpectedly shutdown for immediate repairs.

Since March 2006, Cochin has operated at a voluntary pressure reduction due to a defect found in the U.S. portion of the pipeline. This pressure restriction, not to exceed 900 psi, applies to the entire line from Fort Saskatchewan, Alberta to Windsor, Ontario and is in effect through at least to the fall of 2007. Ethylene shipments, because of its high vapour pressure, have been suspended until further notice.

Cochin also announced on 8 February 2007 that it would be suspending delivery of ethane effective 31 March 2007, while the company evaluates its pipeline integrity issues and the related capital expenditures. Cochin will continue to ship propane to all destinations on its system. Shippers were also informed that the pipeline would operate at reduced pressure through at least Fall 2007. With only propane in the line, the average capacity is expected to be around 9 500 to 11 100 m^3/d (60 Mb/d to 75 Mb/d). Once the pressure restrictions are lifted, capacity is likely to return to 16 700 m^3/d (105 Mb/d).

TABLE 3

Cochin Apportionment

	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07
Apportionment	0%	0%	0%	0%	0%	0%	0%	0%
Throughput (10^3m^3/d)	7.6	5.6	9.5	7.6	10.9	7.7	7.4	6.5

2.4 Chapter Summary

Overall, the examination of throughput and capacity on NEB-regulated natural gas pipelines in section 2.2 shows that pipeline capacity is adequate across the country although there may be occasions of short-term limitation at some points depending upon markets, storage and seasonal shifts. The demand for natural gas varies seasonally and, as a result, the flow of natural gas and utilization of some Canadian pipelines can be variable. Where available, the use of storage helps to reduce the variation in flows and allows pipeline capacity to be used more efficiently and at more stable utilization levels.

Although natural gas supply from new sources continue to be added to supplement declining conventional supply from the WCSB, growing demand within Western Canada has resulted in some excess capacity on pipelines transporting gas from the region. The existence of some excess capacity has provided suppliers with the flexibility to access markets of their choice at most times. Natural gas pipeline projects in 2006 were mainly directed towards providing connection to new supplies and addressing bottlenecks in the market area.

While capacity utilization indicators show that there was spare capacity on some oil and petroleum products pipelines in 2006, this was partially due to facility outages reducing the amount of crude oil or products to be transported. Despite operational challenges in the oil sands industry in early 2006, bitumen production levels have increased over the previous year as problems were rectified and new expansions were brought on-line. The production growth in the oil sands and continued strong demand in the U.S. has resulted in very high utilization of capacity on Canadian oil pipelines. In addition, a slight recovery in conventional crude oil production in western Canada, North Dakota and PADD IV are challenging pipeline systems that operate at close to capacity and are in apportionment at times. Overall, growing oil sands production has kept the utilization and demand for oil pipeline capacity very high.

In the past, the lack of excess pipeline capacity and available markets to process heavier crude oil has resulted in the light-heavy price differential widening as illustrated in Figure 8. In the first quarter 2006, the differential widened to 42 percent. However, this has not been the case in 2007, where the differential has narrowed to a two and a half year low reflecting the effect of additional markets accessed through the Syncrude upgrader expansion and the Spearhead and Mobil pipeline reversals which deliver western Canadian crude oil to Cushing and the U.S. Gulf Coast, respectively. This should provide continuing strength to heavy crude oil prices through the summer as demand will increase in response to the upcoming asphalt season.

LOOKING AHEAD – PROPOSED PIPELINES

3.1 Natural Gas

In the coming years, it is expected that demand for natural gas in North America will continue to outpace the growth in North American domestic supplies. In Canada, natural gas supply from new sources such as frontier regions, LNG, and coalbed methane will be increasingly required to supplement declining supply from conventional sources from the WCSB and Sable Island to meet growing demand. In addition, increased consumption for oil sands development in Alberta, and electricity generation in Ontario, are expected to drive significant incremental Canadian requirements for natural gas. The Canadian oil sands projects are a large and growing market for natural gas in both the generation of electricity and steam. Steam is used for in situ oil production and to upgrade bitumen into synthetic blends. In addition, new gas-fired electrical generation will likely be needed to help displace the use of existing coal-fired electricity generation in Ontario.

Although there were few newly announced natural gas pipeline projects in 2006, there was notable progress in several of the natural gas pipeline projects reported last year. Table 4 below, summarizes the announced proposals on NEB-regulated pipelines. These projects reflect the industry's expectations regarding changes in natural gas supply and demand in coming years, and the industry's outlook on the potential adjustments in Canadian pipeline infrastructure in order to:

- connect incremental gas supply from new sources in the north or from new terminals for receiving liquefied natural gas;
- expand pipeline capacity to growing markets in eastern Canada and the U.S. Northeast; and
- transfer pipeline assets from gas service where adequate capacity may exist, to oil transportation service where demand and value for new capacity is higher.

Liquefied Natural Gas

A key supply source for North America is expected to be the rapidly developing global LNG market. Proven reserves of natural gas worldwide are about 20 times larger than the proven natural gas reserves of North America. While economies of scale advances in liquefaction and transportation have enabled the use of LNG as a cost competitive source of gas supply in North America, those cost efficiencies are starting to be lost to higher input and construction costs. In anticipation of growing natural gas requirements in North America, there are numerous proposals to expand existing U.S. terminals and construct new LNG receiving facilities, including several proposed projects in Canada as summarized in Figure 20.

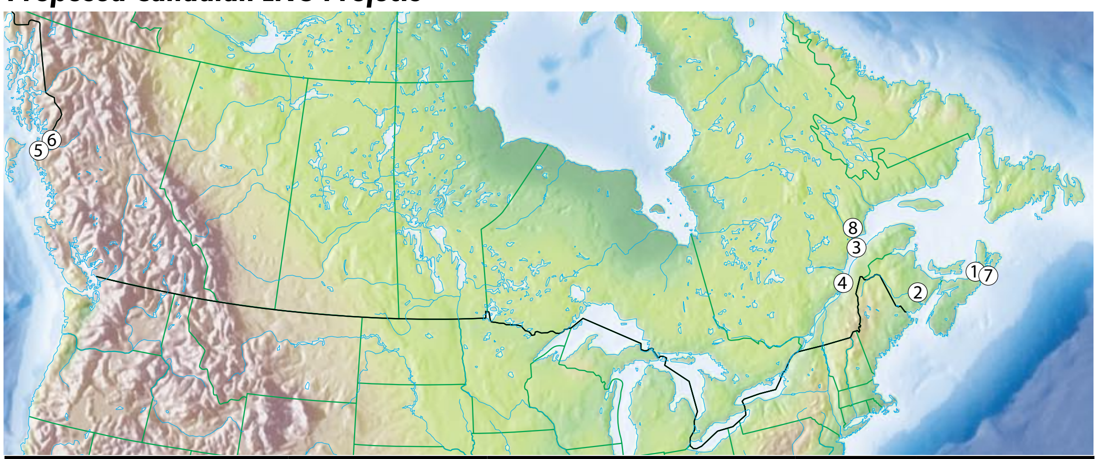
TABLE 4

Canadian Natural Gas Pipeline Proposals — 2006

Pipeline	Location	Capacity Increase (Bcf/d)	Proponents' Estimated Completion Date	Market Impacted
TransCanada PipeLines Limited – 2007 Eastern Mainline Expansion	Ontario, Québec	0.377	Late 2007	Central Canada Northeastern U.S.
TransCanada Pipelines Limited and TransCanada Keystone GP Ltd.	Saskatchewan, Manitoba	-0.5	2009/10	Transfer and conversion of gas pipeline assets to oil transportation service
Mackenzie Gas Pipeline	Mackenzie Delta, Northwest Territories to Alberta	1.2	2014	North America
Emera Brunswick Pipeline	New Brunswick	0 .75	2008	Atlantic Canada, Northeastern U.S.
EnCana – Deep Panuke Pipeline	Nova Scotia	0 .3	2010	Atlantic Canada, Northeastern U.S.
TransCanada PipeLines Limited / Trans Québec & Maritimes Pipeline Inc. – Gros Cacouna and Rabaska	Québec	0.5 0.5	2009/10	Central Canada Northeastern U.S.

FIGURE 20

Proposed Canadian LNG Projects



Location	Terminal	Company	Capacity (Bcf/d)	Proposed on Stream Date
1. Goldboro, Nova Scotia	Maple LNG	4 Gas BV and Suntera Canada Ltd.	1.0	2009
2. Saint John, New Brunswick	Canaport LNG	Repsol YPF and Irving Oil	0.8	2008
3. Rivière-du-Loup, Quebec	Gros Cacouna LNG	Petro-Canada and TransCanada Pipelines Ltd.	0.5	2009
4. Québec City, Quebec	Rabaska	Gaz Métro, Enbridge and Gaz de France	0.5	2009
5. Ridley Island, British Columbia	WestPac LNG	WestPac Terminals Inc.	0.3	2009
6. Emsley Cove, British Columbia	Kitimat LNG	Gavelston Energy	0.6	2010/11
7. Point Tupper, Nova Scotia	Statia LNG	Statia Terminals Canada Partnership	0.5	n/a
8. Saguenay, Quebec	Énergie Grande-Anse	Saguenay Port Authority and Énergie Grande-Anse Inc.	1.0	n/a

However, there is uncertainty around the number of LNG terminals that will be built in Canada as well as the potential effects that imported LNG will have on gas markets and the pattern of natural gas flow. The Canaport LNG facility in Saint John, New Brunswick is currently under construction and is scheduled to start service in 2008. Additional pipeline connections will also be required in most cases to connect the proposed LNG receiving terminals to existing natural gas pipeline infrastructure and natural gas markets.

These potential changes in Canada's natural gas supply and demand have important implications to both existing pipeline transportation systems and proposed new pipeline and LNG projects. Facilities which connect significant new supply from new sources such as the North and LNG or significant changes in regional demand (e.g. oil sands in Alberta and electricity generation in Ontario) will have the potential to influence markets and alter the utilization and gas flow on existing pipelines. In turn, these changes may impact the tolls and associated costs in using those pipelines. For example, introduction of new gas supply in Eastern Canada could result in greater utilization or flow reversals in regional pipelines and may also affect the flow of supply from traditional sources and pipelines. Similarly, greater demand in Alberta or Ontario can also alter the flow and availability of natural gas to adjacent regions.

In addition, the expected introduction of LNG close to Canadian markets has heightened the awareness of potential issues related to gas quality. Consequently, pipelines will need to work closely with their customers to establish gas quality standards and monitoring processes to ensure compatibility with existing equipment and end-use operation.

3.2 Oil

The expected growth in oil sands production is an increasingly important consideration to the pipeline industry as it determines which incremental markets to serve and how to expand the pipeline system efficiently since not all refineries are able to process a full range of crude oil types. Proposed refinery expansions and new construction in eastern Canadian are located close to the major petroleum product markets in the U.S. Northeast and have access to foreign crude oil supplies in addition to east coast offshore production. Other refineries in central Canada and the United States are proposing modifications which will enable them to process the heavier crude oil from oil sands production.

Looking to the future, the NEB expects that Canadian crude oil production will continue to increase, placing greater demands for transportation capacity to connect new supply and markets. Consequently, there are a number of proposals to provide additional pipeline capacity to transport crude oil and to provide additional supplies of diluent required to support growing oil sands operations. This additional pipeline capacity could enhance access to markets and increase market penetration. The North American demand for oil and refined products is also expected to increase, triggering a number of proposals for refinery expansions and the construction of new refineries in Canada and in the United States.

Table 5 provides a summary of the numerous proposals to expand or construct new oil pipeline capacity in Canada. These reflect the industry's outlook on growing oil sands production and the need for additional pipeline capacity to enhance market access. These proposals include pipelines to transport western Canadian crude oil to the west coast for delivery to Washington State and offshore markets, to the U.S. Midwest and southern PADD II and to the U.S. Gulf Coast (PADD III), and to provide new sources of diluent required for growing oilsands production. It is estimated that these pipeline projects comprise over $23 billion in spending.

TABLE 5

Announced and Proposed Canadian Oil Pipelines and Expansions

Pipeline	Potential Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Terasen (TPTM)				
Pump Station Expansion	Filed Feb 2006; Approved in Oct 2006	35	April 2007	PADD V
Anchor Loop – TMX1	Approved in Oct 2006	40	Nov. 2008	Offshore/Far East
Southern Option				
TMPL TMX2	N/A – Open Season unsuccessful	100	Mid 2010	PADD V
TMPL TMX3	N/A	300	2012	Offshore/Far East
Northern Option (TMX North)	N/A	400	2012 (uncertain)	PADD V Offshore/Far East
Enbridge Gateway (oil/diluent)	N/A	400/150	Between 2012 and 2014	PADD V Offshore/Far East Alberta (diluent line)
Pembina Spirit (diluent)	N/A	100	April 2009	Alberta
Enbridge Southern Lights	Filed 9 March 2007		2010	Alberta
Diluent return line		186		PADD II
Line 2 Expansion (oil)				PADD II
Edmonton to Cromer		47		PADD II
Cromer to Clearbrook				PADD II
TCPL (Keystone)	Filed Section 52 – Dec 2006	435	4Q2009	Southern PADD II and PADD III
Expansion / Extension to Cushing, OK		155	4Q2010	
Alberta Clipper	Filed May 30 2007	450	July 2010	Southern PADD II
Expansion	N/A	350	N/A	
Altex Energy	2008	250	2012	PADD III
Enbridge Spearhead Expansion	Open Season (2 Mar -2 April 2007)	65 100	2009 2011	Southern PADD II
Spearhead Looping	FERC only			
Enbridge (Southern Access)	FERC only	315		Midwest/Southern PADD II
Phase I		120	2008	
Phase II		148	2009	
Phase III Extension		47	N/A	

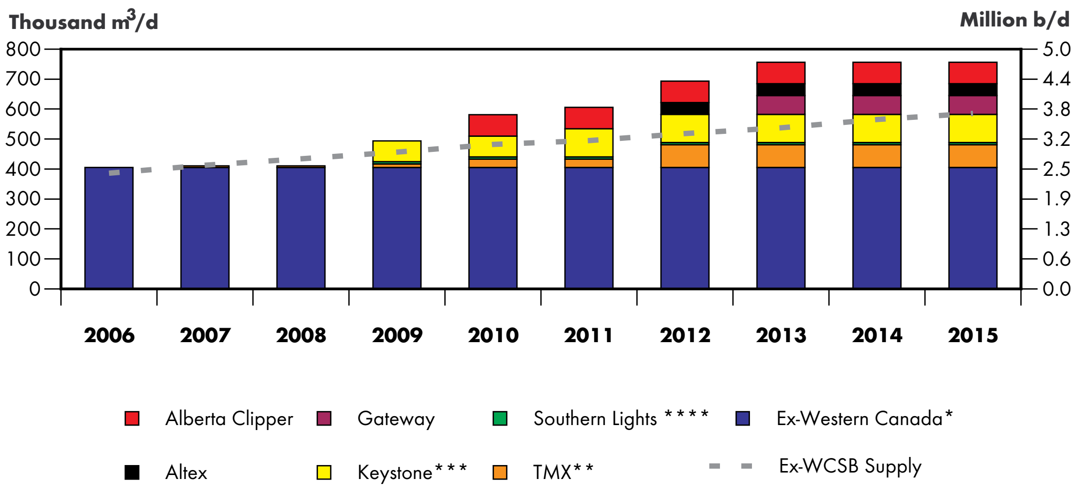
In the past year, the Board has also approved two crude oil pipeline related applications. In October 2006, the Board approved an application filed by TPTM to loop a portion of its pipeline between Hinton, Alberta and Rearguard, British Columbia. The project will increase capacity by 6 360 m^3/d (40 Mb/d). It is expected to be in service by third quarter 2008.

In June 2006, the Board received an application by TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd. to transfer a portion of TransCanada's natural gas pipeline and associated facilities to crude oil service. The Keystone Project is a proposal to convert existing natural gas facilities in Canada and to construct a new crude oil pipeline in the U.S. to transport crude oil from Hardisty, Alberta to Patoka, Illinois. It would have a capacity of 69 000 m^3/d (435 Mb/d) and is expected to be in-service in 2009 if approved. The Board approved the facilities transfer on 9 February 2007; however the TransCanada Keystone application for the construction of new oil facilities is still before the Board.

Looking beyond 2006, Figure 21 illustrates the NEB's forecast of crude oil production and the anticipated pipeline capacity available to transport crude oil and products from Western Canada on existing and proposed new facilities. This chart highlights that oil pipeline capacity is expected to be very tight in the next few years. It is expected that apportionment will occur in the fourth quarter 2007 and that this may be an issue for the next 18 months. As indicated by the figure, between now and 2009 crude oil pipelines out of Western Canada are expected to operate at capacity. The upstream industry is working together with pipeline companies to develop initiatives to reduce the impacts and/or eliminate apportionment. In 2009, TPTM would have an additional 12 000 m^3/d (75 Mb/d) of capacity with its pumping station expansion and the looping; Southern Lights could add an additional 7 500 m^3/d (47 Mb/d) to the Enbridge system from Cromer, Manitoba; and Keystone could be in-service if its application were approved by the Board.

FIGURE 21

Proposed Oil Pipeline Projects & NEB Forecast of Crude Oil Production



* Total current crude oil pipeline capacity out of the WCSB assuming maximum heavy oil volumes.

** Pump Station expansion of 35 Mb/d by 2007 and looping 40 Mb/d by 3Q2008. TMX North would expand capacity by an additional 400 Mb/d but is not shown here.

*** Keystone could be expanded by 155 Mb/d and extended to Cushing, Oklahoma by 4Q2010

**** Net crude oil capacity increase of 47 Mb/d by 4Q2008

PIPELINE TOLLS & SHIPPER SATISFACTION

The Board utilizes a number of indicators to assess whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). This includes monitoring the stability of pipeline tolls as indicated through year-to-year variations in a benchmark toll for each of the major NEB-regulated pipelines; and direct shipper feedback received through response to the NEB's annual survey on pipeline services and via formal complaints. In addition, the frequency and acceptance of negotiated toll settlements, and the development of new or enhanced pipelines services are important indicators that there is alignment between the interest of pipeline companies and their shippers.

Historically, revenue requirements have been established using cost of service methodology, with some components for the return on and of invested capital. The revenue was then assigned to various rate categories and cost drivers for conversion into unit rates, or tolls. The revenue requirement and the toll setting methodology were matters for adjudication before the Board.

4.1 Negotiated Settlements

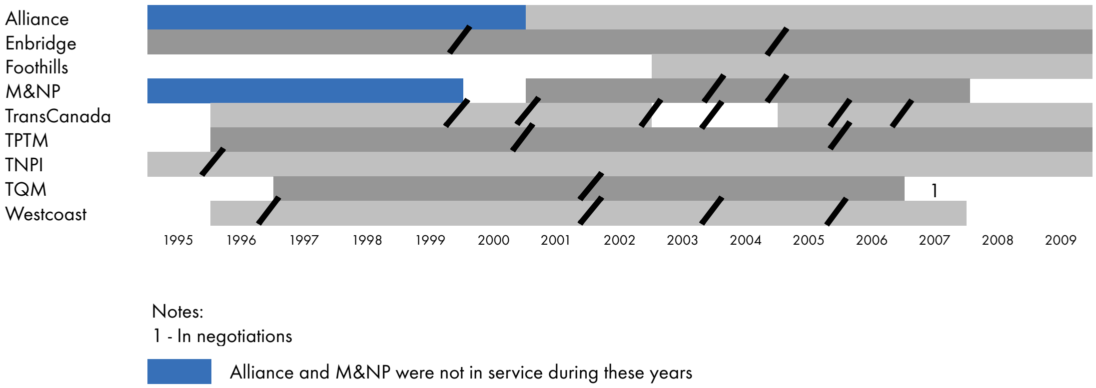
To improve the effectiveness of the regulatory process, the Board has supported the use of negotiated settlements since the mid-1980s as an alternative to toll hearings. In September 1988, the Board issued its first Guidelines for Negotiated Settlements. These guidelines were subsequently updated in August 1994 and revised again in June 2002 to provide flexibility when addressing contested settlements. With increasing use of negotiated settlements, adversarial hearings before the Board on tolls are becoming less frequent. Most of the pipeline companies still rely on cost of service methodology as a framework for the negotiated settlements.

As shown in Figure 22, all of the major pipelines regulated by the Board were operating under negotiated settlements during 2006. In late 2006, M&NP and its shippers successfully negotiated a one-year toll settlement for 2007. TransCanada has also recently negotiated a five-year settlement for 2007 to 2011 that was approved by the Board in May 2007. TPTM negotiated another five-year deal with its shippers for the years 2006 to 2010. TQM is currently operating under interim tolls which are based on a five-year settlement which expired on 31 December 2006. TQM is in discussion with its shippers regarding tolls for 2007 and future years. Westcoast Transmission and its shippers are currently in the second year of a two-year settlement for 2006 and 2007.

These negotiated settlements have resulted in a reduction in the regulatory burden for parties, both in terms of the time spent in hearings and the associated costs. They have also contributed to a better alignment of interests between pipeline companies and their shippers.

FIGURE 22

Negotiated Settlements Timeline



4.2 Pipeline Tolls Index

Stable and reasonable tolls are a key area of concern for users of the transportation and an indicator of the system's efficiency. The Board tracks year-to-year variations in tolls; the section below describes movements in the benchmark toll for each of the major pipelines it regulates (e.g., TransCanada's Eastern Zone toll or Westcoast's T-South Export toll). Under cost of service regulation, pipeline tolls can vary from year-to-year for various reasons. For example, a significant expenditure to modify or expand a system to meet shippers' needs could increase or decrease toll levels depending on the specific circumstances. Falling throughput or contract demand leading to lower capacity utilization could lead to a significant toll increase.

Natural Gas Pipeline Tolls

Figure 23 shows indexes of benchmark tolls[4] for TransCanada's Mainline, Westcoast Transmission, Foothills, the TransCanada B.C. System (B.C. System), TQM, M&NP, Alliance, and the GDP deflator[5] all normalized to the year 2006.[6]

The increase in TransCanada's benchmark toll between 1997 and 2004 is mainly attributed to a large amount of decontracting on the Mainline during that period, particularly after the startup of the Alliance pipeline in 2000. This toll tracked the GDP deflator fairly closely from 2001 to 2004. However, in 2005 and 2006 the toll fell, primarily due to increased contract demand: it remains below the level that it was in 2000.

Westcoast's tolls were relatively flat until 2004, when this toll increased by over 15 percent due to decontracting of firm services. Further reductions in volumes in 2006 caused a further 32 percent increase in 2006 tolls.

4 The benchmark tolls are: TransCanada Eastern Zone; Westcoast T-South Export; Foothills Zone 9; B.C. System Postage Stamp; TQM Saint Lazare to Trois-Rivières; M&NP Postage Stamp; and Alliance monthly demand toll.

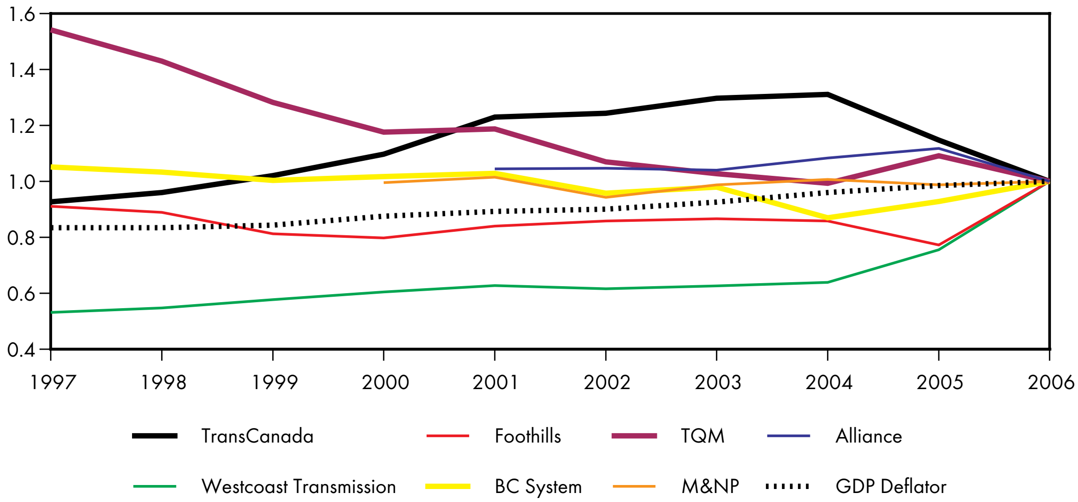
5 The implicit GDP deflator for 2006 is an estimate using actual data for the first half of the year and data estimated by Informetrica for the second half of the year.

6 Differing pipeline distances add to the challenges in comparing tolls between individual pipelines. Some normalization is required. Here the tolls are normalized only with respect to their own changes over time. The year of normalization is arbitrary; the most recent was selected as some tolls are only available for more recent years.

FIGURE 23

NEB-Regulated Natural Gas Pipeline Benchmark Tolls

Normalized to 2006 = 1.00



TQM's benchmark toll is below the 1997-1999 levels. This lower level is partly due to the Portland Natural Gas Transmission System (PNGTS) extension in 1999, which increased throughput over 30 percent from 1998. Foothills benchmark toll dropped in 1999 as a result of a cost-effective expansion of its system, but has increased in 2006 due to lower volumes and the end of the ten year period in 2005 for the deferred tax payback.

The B.C. System benchmark tolls in 2006 were close to the 1997 level. An (over 10 percent) increase in throughput volumes from 2003 reduced the 2004 benchmark toll on the B.C. System. M&NP and Alliance's benchmark tolls have been relatively constant since beginning operations at the end of 1999 and 2000 respectively.

Oil Pipeline Tolls

Figure 24 presents indexed values for the benchmark tolls of Enbridge, TPTM, TNPI, Express and the GDP deflator, normalized to the year 2006.[7]

Enbridge's benchmark toll has risen fairly steadily over the period, growing at a faster pace than the GDP deflator, except for a drop in 2003. The tolls increased the most in 2000, 2004 and 2006. Under its negotiated settlement, Enbridge was able in the following year to recapture the revenue shortfall attributable to the lower throughput. The 2004 increase was primarily due to operating at lower capacity utilization with throughput not filling a recent capacity expansion. Higher fixed costs were spread across relatively lower volumes resulting in higher tolls.

TPTM's benchmark toll rose steadily from 1997 to 2003 but fell in the last three years. The large 1999 increase was due to throughput forecasts. During TPTM's first incentive toll settlement, tolls were calculated on forecast volumes. In 1999 the throughput forecast was 17.9 percent lower than the 1998 forecast, which lead to a corresponding increase in the benchmark toll. In 2004, the benchmark toll dropped, primarily due to the disposition of deferrals for 2003 higher revenue. TNPI and Express's benchmark tolls moved roughly in line with the GDP deflator from 1997 to 2006.

7 The benchmark tolls are: Enbridge Edmonton to International Border near Chippewa; TPTM Edmonton to Burnaby; TNPI Oakville to Montreal; and Express 15-year.

FIGURE 24

NEB-Regulated Oil Pipeline Benchmark Tolls

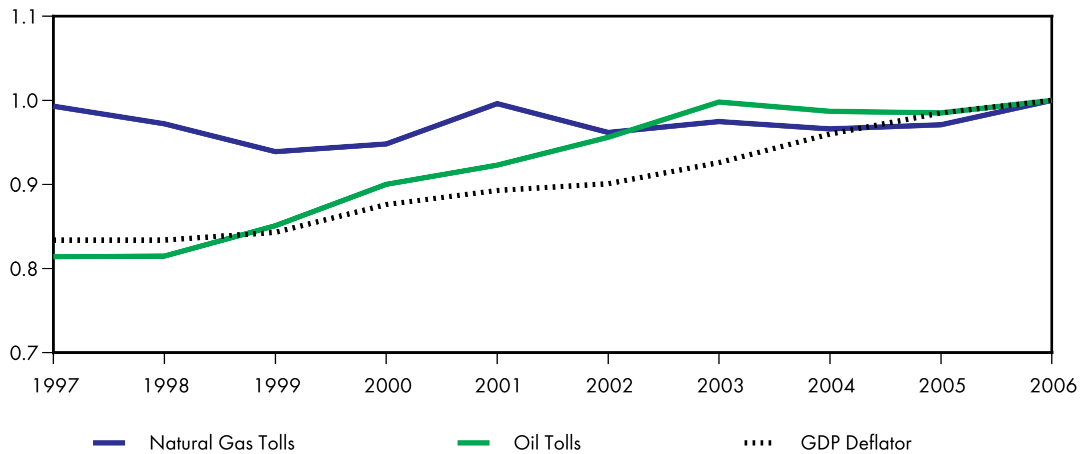
Normalized to 2006 = 1.00

* Enbridge Toll does not include terminal and tankage fees.

FIGURE 25

Oil and Natural Gas Pipeline Benchmark Tolls

Normalized to 2006 = 1.00



Comparison of Gas and Oil Pipeline Tolls

Figure 25 presents the GDP deflator with simple averages of the gas and oil benchmark pipeline tolls indices (reported in Figures 23 and 24).[8] From 1997 to 2006, average natural gas pipeline tolls have been relatively flat despite the rise in the GDP deflator. Over the same period, oil pipeline tolls increased but the net increase over the period has matched the GDP deflator. Throughput volumes have been the primary driving factor in variations during the period.

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

4.3 Shipper Satisfaction

4.3.1 NEB Pipeline Services Survey

The Board conducted its third annual Pipeline Services Survey in early 2007 to obtain direct feedback from the shippers of major NEB-regulated pipeline and midstream companies on the quality of service provided by those pipelines. The Board also used this survey to obtain feedback from shippers on the Board's regulatory performance with respect to tolls and tariffs.

To conduct this year's survey, the Board used a web-based survey tool, called Inquisite, which was sent to shippers directly via e-mail. For each survey received, shippers completed one response which reflects their company's corporate views on the services provided by the pipeline and midstream company being surveyed and on the services provided by the Board. The overall response rate for the survey was 27.0 percent, which was lower than last year's rate of 33.5 percent. The number of surveys sent out this year was 523, approximately 100 more than last year.

After analyzing the survey responses, the Board published a summary of the aggregate results on its website. They included the industry average and distribution of responses for each question and a summary of major themes. In addition, the Board provided each company and its shippers with detailed company-specific results including the average rating and distribution of responses for each question as well as the verbatim comments received from shippers, with the names of the respondents excluded.

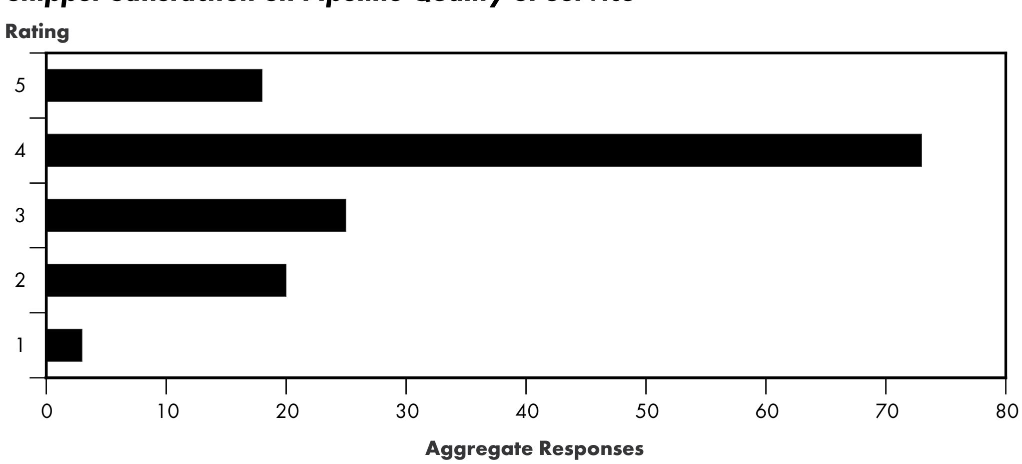
Appendix 3 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, refer to www.neb-one.gc.ca/Publications/Survey Results.

Pipeline Services

Figure 26 shows the aggregate results for the survey question that asked shippers to rate their satisfaction with the overall quality of service provided by their pipeline/midstream companies over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). The industry average score of 3.60 was slightly higher than the score of 3.57 in last year's survey. Sixty-five percent (65%) of the respondents gave their company a rating of satisfied or very satisfied on overall quality

FIGURE 26

Shipper Satisfaction on Pipeline Quality of Service



of service, compared to 58 percent last year. Based on these results, the Board is able to conclude that shippers again appear reasonably satisfied with the services provided by pipeline/midstream companies.

The three areas where shippers indicate that pipeline and midstream companies are doing very well are:

- Timeliness and accuracy of invoices and statements;
- Physical reliability of pipeline operations; and
- Satisfaction with transactional systems.

The three areas where shippers believe that companies could improve the most are:

- Reducing the level of transportation tolls or midstream charges;
- Exhibiting an attitude of continuous improvement and innovation; and
- Ensuring that settlements or tariff arrangements work well.

Feedback on the Board

The 2007 survey indicated that approximately 59 percent of shippers are either satisfied or very satisfied with the Board's performance with creating an appropriate regulatory framework and 55 percent of shippers are either satisfied or very satisfied with the Board's processes to resolve disputes. Both of these results were lower than in the 2006 survey. Two areas for improvement noted by shippers were for the Board to build its internal capacity to serve Canadians better and to provide effective regulatory processes that are more accessible to stakeholders and yield more timely decisions. Both of these areas are addressed in the Board's 2007-2010 Strategic Plan, which can be found at www.neb-one.gc.ca/AboutUs/strtgcpln2007_2010_e.htm.

4.3.2 Formal Complaints

If shippers are unable to resolve concerns with the pipeline, they can bring a formal complaint to the Board. The complaint would then be dealt with through appropriate dispute resolution, a formal complaint process or, in some cases, the parties may be able to negotiate a solution to the concern. There was only one formal shipper complaint during the past year which involved the Board.

Several shippers on Cochin Pipe Lines Ltd. (Cochin)

In December 2006, Cochin filed for new rates to become effective 1 January 2007. The new rates reflected increases ranging from 91 to 580 percent across both Regular Volume Rates and Incentive Volume Rates and included a new toll segment from Detroit, Michigan to Windsor, Ontario. The Board received 11 letters from Cochin's shippers and interested parties indicating concern with the magnitude and timing of the rate increases. Shortly thereafter, Cochin initiated settlement discussions with its shippers and, in February 2007, filed a negotiated settlement and letters of support from many of its shippers. Following further negotiations with one opposing shipper, Cochin advised that it and the shipper had reached a resolution of the outstanding issue. Cochin's toll settlement was subsequently approved by the Board in May 2007.

4.3.3 *Service Enhancements*

On an ongoing basis pipelines may propose modifications to their services as circumstances and needs of their customers change or innovative ideas are brought forward. Normally, the pipeline and its shippers will discuss and agree upon proposed service enhancements in their tolls task force prior to submission to the Board and ultimate adoption. However, if the task force is unable to agree on the service, a party may still bring the issue directly to the Board.

Coral Energy Canada Inc. (Coral)

Coral applied to the Board to modify the Firm Transportation Risk Alleviation Mechanism (FT-RAM) pilot, a service enhancement proposed by TransCanada for its long haul contracts on the Mainline. In February 2006, The Board approved Coral's application which sought to extend FT-RAM credits to short-haul contracts held by the same shipper, which when combined with a long-haul contract forms a continuous long-haul on the TransCanada Mainline. The Board subsequently also approved amendments supported by an unopposed tolls task force resolution to extend the FT-RAM pilot project for an additional year.

TransCanada

In May 2006, TransCanada applied to the Board for approval of two new services on its Mainline, designed to meet the fluctuating demands of new gas-fired electric generation in Ontario. The Board has approved the implementation of these services; Firm Transportation - Short Notice (FT-SN) and Short Notice Balancing (SNB) and the proposed tolling method for FT-SN. However, the Board directed TransCanada to develop an alternate tolling method for SNB service.

Westcoast

After lengthy discussions with the Toll and Tariff Task Force on the possible decontracting on transmission facilities, Westcoast and its customers agreed to the following firm service enhancements, which were subsequently approved by the Board in RHW-1-2005 and implemented in 2006:

- Term differentiated rates (offering lower rates for longer term commitment) were taken up by about 25% of eligible volumes starting in January 2006.
- Authorized Over Run service which provides firm service customers with access to additional capacity at a higher priority than interruptible service was successfully utilized during a scheduling constraint in late 2006.
- Cross-corridor crediting was implemented on the various corridors on Westcoast's T-North system in 2006.

Moreover, to address periodic imbalance management issues, Westcoast, in collaboration with its shipper community, proposed a Supply Imbalance Management Strategy that was unanimously supported by its Toll and Tariff Task Force, and is expected to be implemented in 2007.

4.4 Chapter Summary

The following observations are made in this chapter:

- Shippers are able to resolve the majority of their tolling issues of interest with pipelines through the negotiated settlement process;

- Pipeline tolls have been relatively stable on average, although particular regional situations may cause greater variability in some areas;
- Based on responses to the NEB Pipeline Services survey; shippers again appear reasonably satisfied with the services provided by pipeline/midstream companies.
- There are few formal service complaints; and
- Development of pipeline service enhancement continues.

The Board concludes that pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). Shippers are also reasonably satisfied with the role played by the Board itself, with some suggestions incorporated into the Board's own planning.

PIPELINE FINANCIAL INTEGRITY AND ABILITY TO ATTRACT CAPITAL

Pipeline companies must have adequate financial integrity to attract capital on reasonable terms and conditions to effectively maintain their systems and build new infrastructure to meet the market's evolving needs. The following sections review and discuss a number of the factors relevant to these areas, starting with the area over which the Board has the most direct influence.

5.1 Common Equity

A common equity ratio is defined as the percentage of common equity in a company's capital structure. This ratio is often used to evaluate a company's financial risk. Higher common equity ratios increase the likelihood of a company being able to meet its obligations.

Deemed Common Equity Ratios

The Board approves a deemed common equity ratio for the Group 1 pipeline companies that it regulates.[9] When the Board approves a Group 1 pipeline company's tolls for a specified time period, it typically also approves a return on equity (ROE) and deems a common equity ratio for the regulated entity. Alternatively, some Group 1 pipeline companies successfully negotiate a comprehensive tolls settlement with their shippers, which may include capital structure and return on equity. In this instance, the Board still considers the overall settlement. Given the extent of negotiated settlements, many of the equity ratios have been determined by negotiation among the parties involved. Through this mechanism, the Board has influence over the operating profitability and financial risk of some Group 1 pipeline companies.

T A B L E 6

Deemed Common Equity Ratios (Percent)

	2002	2006	2007
Alliance	30	30	30
Foothills	30	36	36
M&NP	25	25	29.27
TQM*	30	30	30
TransCanada B.C. System	30	36	36
TransCanada Mainline	33	36	40
Westcoast Transmission	30	35	36

* TQM's common equity ratio was specified in its negotiated settlement that expired on 31 December 2006.

Table 6 shows the deemed common equity ratio for some NEB Group 1 pipeline companies through adjudication or negotiation. TransCanada, Westcoast Transmission, B.C. System, and Foothills have increased their deemed common equity ratios between 2002 and 2006. The market considers these increases to be credit positive, lowering the financial risk of the pipeline companies.

9 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.

Return on Common Equity

Return on equity is commonly used to assess the operating profitability of a company. Financial markets define ROE as net income divided by common equity.

For NEB-regulated pipeline companies, ROE is the return on the equity portion of the rate base that is approved by the Board and is determined either through adjudication or negotiation. A higher ROE is typically preferred by investors.

Annually, the Board establishes an approved-ROE following the method outlined in RH-2-94. It is applicable to pipelines that the Board regulates, except those that have Board approved alternative rates. Achieved ROEs can vary from NEB-approved levels for various reasons, such as incentives, profit-sharing mechanisms and cost reductions.

Table 7 shows the achieved ROE for several NEB-regulated pipeline companies from 2002 to 2006 along with the ROE approved by the NEB in accordance with the RH-2-94 Formula[10]. As per their respective negotiated settlements, Enbridge, TPTM and Trans-Northern are not required to submit their Financial Surveillance Reports to the NEB, which would include achieved ROEs. Therefore, these pipeline companies are not included in Table 7. Other companies are included in Table 8, but are not subject to the RH-2-94 Formula ROE: Alliance and M&NP have negotiated ROEs with their shippers,[11] and Westcoast's Field Services Division is financially regulated on a complaint basis as described in the Framework for Light-handed Regulation (RHW-1-98). Fees for gathering and processing services are negotiated individually with shippers. TransCanada and TQM have negotiated settlements which use the RH-2-94 Formula as a basis and allow incentives causing some variations from the Formula rate.

The RH-2-94 Formula produced an ROE of 8.88 percent for 2006, falling each year since 2003 because of low interest rates. From 2002 to 2006, for pipeline companies subject to the RH-2-94

TABLE 7

Achieved ROEs and the RH-2-94 Formula ROE (Percent)

	2002	2003	2004	2005	2006
Transmission					
Alliance	11.25	11.25	11.25	11.25	11.25
Foothills	9.53	9.79	9.56	9.46	8.88
M&NP	12.95	12.31	13.75	14.31	14.68
TQM	9.80	10.21	9.84	9.92	8.99
TransCanada B.C. System	9.53	8.21	8.51	9.46	8.47
TransCanada Mainline	9.95	10.18	9.83	9.66	8.92
Westcoast Transmission*	13.44	12.93	10.28	10.82	9.16
NEB RH-2-94 Formula	**9.53**	**9.79**	**9.56**	**9.46**	**8.88**
Midstream					
Westcoast Field Services*	14.87	6.76	11.63	12.48	10.46

Source: NEB Surveillance and Annual Reports

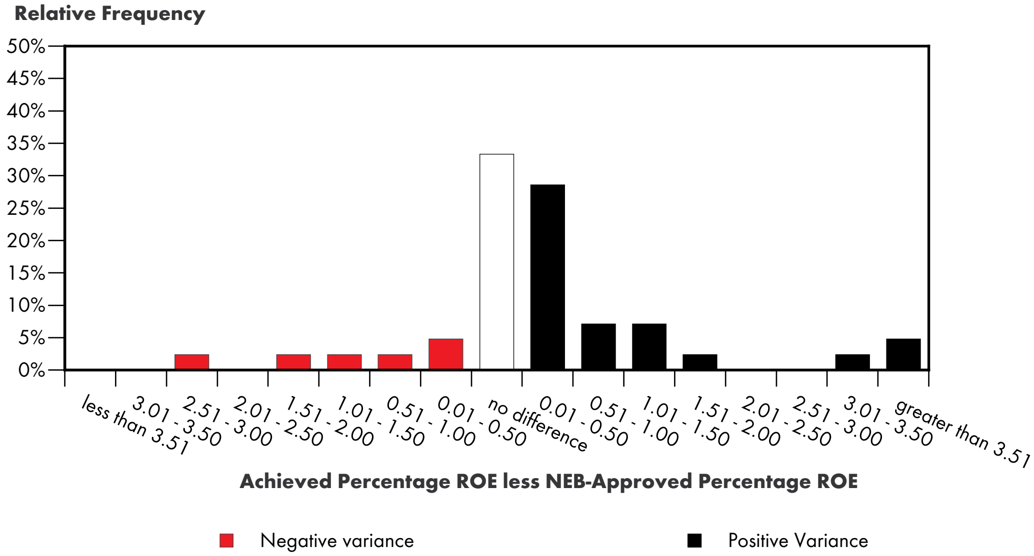
* excluding CWIP (construction work in progress) and, in the case of Transmission, deferrals.

10 The formula used to determine the ROE for certain NEB-regulated pipelines, established in the RH-2-94 Proceeding, and later amended to eliminate rounding.

11 The settlements were subsequently approved by the Board. Alliance's settlement sets its ROE at 11.25 percent over this period. M&NP has a base return on equity of 12 percent for 2007; up to and including 2006 their base rate was 13 percent, with incentive potential.

FIGURE 27

Variance from NEB-Approved ROE for the Years 2001 to 2006



Source: NEB Surveillance Quarterly and Annual Reports. Includes TransCanada Mainline and B.C. System, TQM, Westcoast Transmission system, and M&NP, as well as Foothills and Alliance which earn precisely their allowed ROE.

Formula ROE, only the TransCanada B.C. System has failed to earn an ROE at or above the Formula return in each year.

Most pipelines have, or have proposed, negotiated settlements. Three settlements have allowed ROEs that are different than the Formula ROE: Alliance, M&NP, and Trans-Northern. In the case of Alliance and M&NP, the ROE was fixed for an extended period. Other settlements use the RH-2-94 Formula as the allowed ROE and many of these settlements provide varying degrees of incentives to enable pipelines to earn more than the Formula ROE. As a result of the various incentives, most Group 1 pipelines have achieved actual ROEs that are greater than allowed ROEs. With the low interest rate environment, the RH-2-94 Formula produces an ROE of 8.46 percent for 2007.

Figure 27 charts the difference between achieved ROEs and NEB-approved ROEs for the TransCanada Mainline, the B.C. System, TQM, the Westcoast Transmission system, and M&NP. Also Foothills and Alliance are included; by their settlement their achieved ROEs equal their approved ROEs. From 2001 to 2006, pipeline companies (included in Figure 27) have met or exceeded their NEB-approved ROEs 86 percent of the time. The stability and predictability of returns is positive for both bondholders and equity investors. It also highlights that these pipeline companies, in many cases, have been able to meet or outperform approved levels through cost reductions, incentives and profit sharing mechanisms.

5.2 Financial Ratios

Financial ratios, based on financial statement information, can be useful in describing a company's performance and financial integrity. A financial ratio is most meaningful when the ratio of a particular company is compared with a benchmark or industry standard over time. A variety of ratios can be used to evaluate a company's liquidity, operating performance, growth potential, and risk. However, care must be exercised in the collection and interpretation of financial ratios. Reported financial information often pertains to a parent company, and includes non-regulated assets and/or assets from different industries.

The following sections specifically outline and discuss some ratios relating to the financial risk of certain companies with NEB-regulated pipelines.

Financial risk is the risk inherent in a company's use of debt and other obligations that have fixed payments. It differs from business risk which is the risk 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 increases in relation to shareholders equity. An increase in debt may obligate a company to make more and larger fixed payments in the future. From a bondholder's perspective, a company with above average financial risk could have problems making interest payments. From an equity holder's perspective, a company's level of debt coverage gives some indication of the sustainability and value of the equity, and possible ability to pay dividends.

A company's financial risk can be described by ratios such as interest and fixed-charges coverage and cash flow-to-total debt and equivalents.

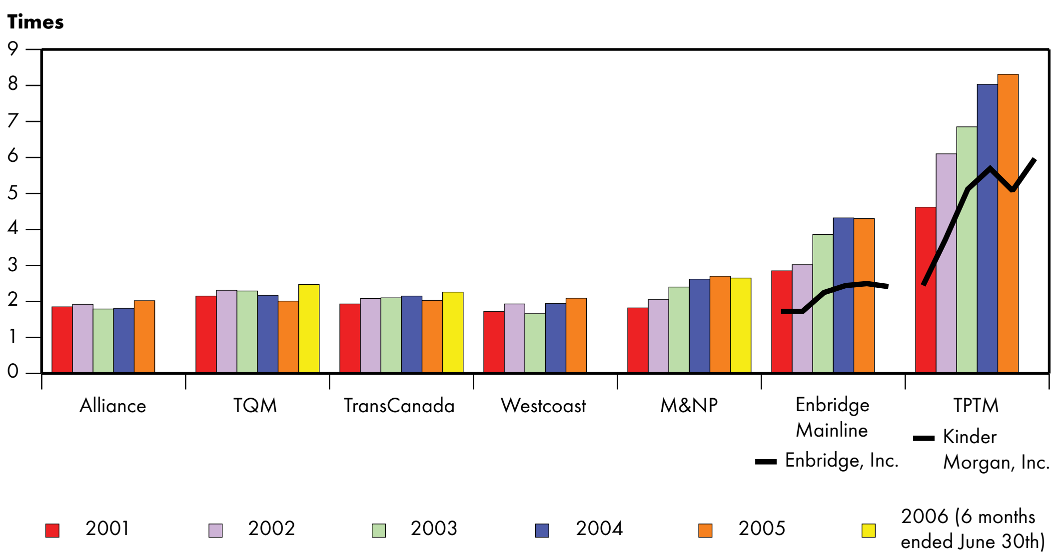
Interest and Fixed-Charges Coverage Ratios

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 (EBIT) divided by interest charges. The metric presented below is similar: the *fixed-charges coverage ratio* describes the ability to make interest payments as well as other types of fixed payments a company is obligated to make. It is defined as earnings before interest, fixed charges and taxes divided by fixed-charges, including interest. Higher ratios indicate a higher likelihood that the company will be able to meet its obligations and, if all other things are equal, could indicate that it has unused borrowing capacity.

The fixed-charges coverage ratios for some NEB-regulated pipeline companies, as calculated by the Dominion Bond Rating Service (DBRS), are shown in Figure 28. Complete data are not available consistently for all companies: the Enbridge Mainline is shown in the block data, the consolidated company Enbridge Inc. is shown as the line. TPTM information was not available on a stand-alone

FIGURE 28

Fixed-Charges Coverage Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge (Mainline) in 2006.

basis for 2006: the overlay line shown is its new owner, Kinder Morgan Inc. The average fixed-charges coverage ratio for the companies for which data is available is 2.42, which is a 6 percent increase year-over-year for those companies.[12]

No company saw its 2006 fixed-charges coverage ratio lower than its 2001 levels. From 2001 to 30 June 2006, the fixed-charges coverage ratio for the five natural gas pipeline companies shown increased modestly from a little under 2 times to around 2.2 by 2006. The two oil pipelines (Enbridge (Mainline) and TPTM, in each case representing the oil pipelines business unit) had higher ratios, which increased more rapidly. TPTM's fixed-charges coverage ratio has been higher, primarily due to a deemed common equity ratio of 45 percent (larger than its peers), which means it carried less debt, and had lower fixed payments. The continuing increases in fixed-charges coverage ratios for all companies is one metric signaling a decrease in the pipeline companies' financial risk, when considered as a group.

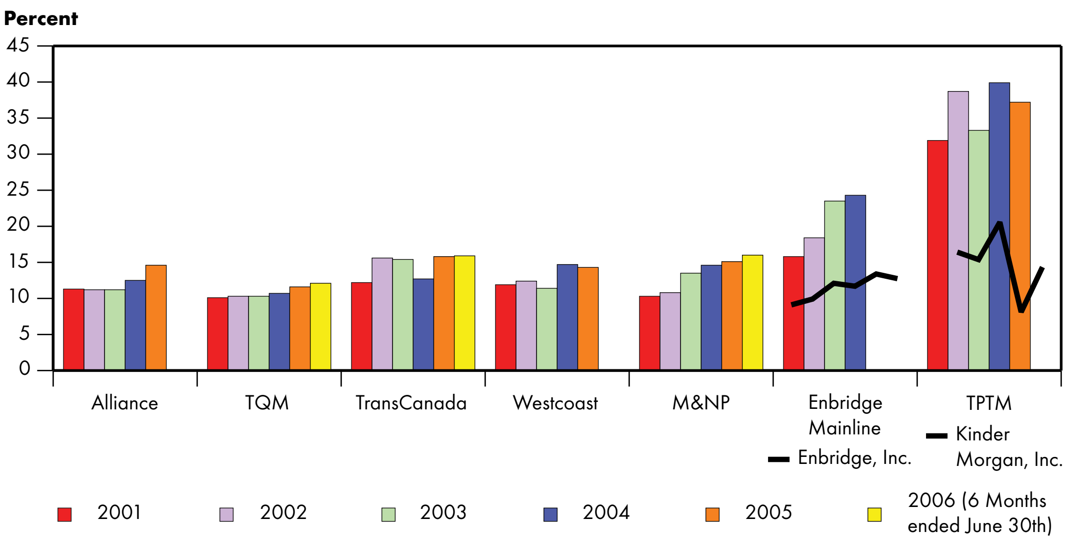
Cash Flow-to-Total Debt and Equivalents Ratio

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 that it has greater borrowing capacity.

The cash flow-to-total debt and equivalents ratio for some NEB-regulated pipeline companies, as calculated by DBRS, are shown in Figure 29. As earlier noted, this ratio is not available for the pipeline units. The average cash flow-to-total debt and equivalents ratio for these companies was 14.2 percent for the partial year ending June 2006, a slight increase from the year before.[13] TPTM's cash

FIGURE 29

Cash Flow-to-Total Debt and Equivalents Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge (Mainline) in 2005 and 2006.

12 This average includes only Alliance, M&NP, TransCanada and Enbridge Inc.; this group had a simple average of 2.28 in 2005 and 1.93 in 2001. In last year's report, the average of 3.22 cited included other pipelines, such as TPTM.

13 The ratio is heavily influenced by the availability of TPTM data. In the 2006 report, the average ratio was 17 percent including data available for TPTM. Without TPTM the ratio was much more modest. Using only the companies which have data available this year, the average is 14.2 for 2006, slightly up from 14.0 for 2005 and up notably from 10.0 in 2000.

flow-to-total debt and equivalents ratio was higher than its peers for the same reason that its fixed-charges coverage ratio was higher.

On average, the cash flow-to-debt and equivalents ratio for these pipeline companies has grown by more than 20 percent from 2000 to 2006. The increase has been steady without any noteworthy periods of deterioration. The increase in this coverage ratio, and the consistent increase in cash flow-to-total debt and equivalents support the observation from the fixed-charges coverage that, on average, these pipeline companies' financial risk has been decreasing.

5.3 Credit Ratings

In Canada, pipeline credit ratings are determined by three independent credit rating agencies, Dominion Bond Rating Service (DBRS), Standard & Poor's (S&P), and Moody's. In general, credit ratings provide an assessment of the probability that a debt issuer will live up to its obligations and as such are an indication of the financial integrity of the rated company. Credit ratings assigned to a company generally reflect the consolidated operations of the entire company and not solely the regulated portion. Consequently, the credit rating for companies such as Enbridge, TransCanada and Westcoast that have both regulated and non-regulated operations may be influenced by its non-regulated operations. In addition, the credit ratings may be influenced to some extent by a parent company. Credit ratings are somewhat subjective in that a company's ratings are the expert opinion of the credit rating agency, which may result in different ratings by different agencies. See Appendix 4 for a comparison of the rating scales for DBRS, S&P, and Moody's.

DBRS

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

For pipelines, the following specific factors are also considered in deriving the credit ratings: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities. The credit ratings for most Group 1 pipeline companies shown in Table 8

TABLE 8

DBRS Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Current
Alliance	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
Enbridge Pipelines	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)/Stb
Express[1]	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
M&NP	A	A	A	A	A	A/Stb
TQM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb
TransCanada	A	A	A	A	A	A/Stb
Trans Mountain	A(low)	A(low)	A(low)	A(low)	repaid	repaid
Trans-Northern	NR	NR	NR	A(low)	A(low)	A(low)/Stb
Westcoast[2]	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)/Stb

1 Senior secured
2 Unsecured debentures
NR Not rated

indicates that the ratings have remained stable from 2002 to the present, varying from A(low) to A(high), and there have been no recent rating changes.

Standard & Poor's

An S&P credit rating reflects a borrower's capacity and willingness to meets 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.

In S&P's rating methodology, a company rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than companies in higher-rated categories. A company rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the company to meet its financial commitments.

The rating histories for several Group 1 pipeline companies are provided in Table 9. The table illustrates that the ratings have remained stable from 2002 to the present, varying from 'BBB+' to 'A-'. There have been two recent rating changes. First, the credit rating on the long-term debt of Westcoast Energy Inc. was upgraded to 'BBB+' in January 2007 from 'BBB', which had been in place since February 2004. The rating change was based on the ownership change at the parent company level that occurred effective 2 January 2007 when Duke Energy Corporation completed the spin-off of its natural gas business (including Westcoast) to Spectra Energy Corporation, a new publicly traded company. Second, in April 2007, S&P revised its outlook on TranCanada from 'negative' to 'stable'. The negative outlook on TransCanada's credit rating had been in place since December 2002, and was initially associated with TransCanada's acquisition of a significant interest Bruce Power in February 2002. S&P noted that TransCanada's recent acquisition of ANR and its investment in the Keystone oil pipeline project provide a stabilizing offset to the declining rate base and lower return on equity from its traditional business.

Both DBRS and S&P have expressed an opinion at various times that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Nonetheless, the ratings assigned by these credit rating companies indicate that NEB-regulated companies are all rated investment grade.

TABLEAU 9

S&P Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Cote actuelle
Pipelines Enbridge	A-/Neg	A-/Stb	A-/Stb	A-/Stb	A-/Stb	A-/Stb
M&NP[1]	A/Stb	A/Stb	A/Stb	A/Stb	A/Stb	A/Stb
TQM	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb	BBB+/Stb
TransCanada	A-/Watch/Neg	A-/Watch/Neg	A-/Watch/Neg	A-/Neg	A-/Neg	A-/Stb
Trans Mountain	BBB+/Neg	BBB/Stb	BBB/Stb	BBB/Stb	debt repaid	debt repaid
Westcoast[2]	A/Stb	BBB+/Stb	BBB+/Stb	BBB/Watch/Neg	BBB/Stb	BBB+/Stb

1 Senior secured
2 Unsecured debentures

Moody's

Moody's 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.
- 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 so doing, 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.

The rating histories for several Group 1 pipeline companies are provided in Table 10. All of Moody's ratings placed the pipelines in the investment grade category, specifically rated 'medium grade' to 'upper-medium grade'.

There has been one recent rating change by Moody's. In March 2007 Moody's downgraded the ratings on the senior unsecured debt of Enbridge Inc. one notch to Baa1 from A3.[14] Moody's stated that the one notch downgrade was based on concerns relating to the company's weak financial profile, the complexity of its organizational and capital structure, and the scope and financial impact of the company's substantial organic growth plans.

5.4 Comments by the Investment Community

Access to capital market is necessary for pipeline companies to maintain and, potentially, expand their systems as the needs of the transportation market changes. Board staff met with credit rating analysts, equity analysts, and suppliers of capital such as insurance and pension funds to discuss their views on the ability of NEB-regulated pipeline companies to access capital markets as well as their views on transportation markets and the current regulatory environment in Canada.

TABLE 10

Moody's Credit Rating History

Pipeline	2002	2003	2004	2005	2006	Current
Alliance[1]	A3	A3	A3	A3	A3	A3
Embridge Inc.	A2	A3	A3	A3	A3	Baa1
Express[2]	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1
M&NP[2]	A1	A1	A1	A2	A2	A2
TransCanada[1]	A2	A2	A2	A2	A2	A2

1 Unsecured debentures
2 Senior secured

14 Enbridge Inc. is the parent company of Enbridge Pipelines Inc., which owns the Enbridge Mainline. Unlike DBRS and S&P, Moody's does not rate the debt issued by Enbridge Pipelines Inc.

There was a consensus among parties that there is substantial liquidity in both domestic and export global capital markets. Solid economic growth in recent years, low interest rates, the accumulation of capital in pension funds and the ability of private equity funds to borrow large sums at low rates from finance companies were among the reasons cited for the current situation, which was characterized as ‘a lot of money chasing too few assets’. Regulated businesses, along with infrastructure and real estate, were seen as particularly attractive investments. It was noted that the federal tax changes made in October 2006 with respect to income trusts and increases in the dividend tax credit also increased demand for shares of dividend paying companies like financials, utilities and pipelines, at least temporarily.

Given this environment, there was agreement that NEB-regulated pipelines have not had difficulty accessing equity or debt markets. The parent companies of TransCanada PipeLines Limited and Enbridge Pipelines Inc. recently went to the equity market and collectively raised more than $2 billion. Both companies have also had substantial debt issues recently. However, some parties expressed concern that on a stand-alone basis the regulated entities themselves might have difficulty attracting capital given low ROEs. Others felt that the regulated entities would be able to attract capital but that the terms under which they did so may be more costly than for the consolidated entity.

Again this year the investment community noted that price-to-earnings ratios of utilities in Canada have been higher than those in the U.S. because of large energy infrastructure investment opportunities, a more stable regulatory environment and global interest in Canadian stocks. While there is currently substantial liquidity, it was noted that capital markets could change and this could happen very quickly and result in considerable volatility.

Many analysts expressed support for a formulaic approach to determining ROEs because of the transparency, stability and predictability that this method provides. However, a number expressed the view that the ROE resulting from the formula was too low, and contend that they are much lower than regulated ROEs in the U.S. and U.K. While views ranged widely on this issue, some felt that the typically lower ROEs in Canada were not justified by the differences in risk for Canadian companies compared to FERC-regulated pipelines. Some parties suggested it was time for the Board to revisit the ROE Formula.

5.5 Chapter Summary

The observations made in this chapter may be summarized as follows:

- Fixed-charges and cash flow-to-total debt and equivalents coverage ratios have increased since 2001;
- Deemed common equity ratios have increased since 2001;
- Achieved ROEs have in most cases been greater than or equal to their NEB-approved levels since 2001;
- Approved ROEs have been predictable, but declining and may now be too low;
- Credit ratings continue to be investment grade; and
- The investment community views NEB-regulated companies as having access to capital markets at this time of significant liquidity, but noted that market conditions can change rapidly and that on a stand-alone basis the regulated entities themselves may have difficulty attracting capital given current ROEs.

In general, these observations signal that, currently pipelines companies have adequate financial strength to attract capital on reasonable terms and conditions.

CONCLUSIONS

Based on the criteria identified in the Introduction to this report, the Board believes that the Canadian hydrocarbon transportation system continues to work effectively.

1. **There is adequate capacity in place on existing natural gas pipelines.** The price differentials and capacity utilization charts indicate that most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. The existence of some excess capacity out of the WCSB has provided suppliers with the flexibility to access markets of their choice at most times. Proposed pipeline projects are mainly directed towards providing connection to new supplies or addressing bottlenecks in the market area.

   Capacity remains very tight on oil pipeline systems. While the capacity utilization indicators show that there was spare capacity on some of the pipelines in 2006, this was partially due to facility outages reducing the amount of crude oil or products to be transported. It is likely that export crude oil pipelines out of Western Canada may experience periods of apportionment by the fourth quarter 2007, and this may continue for the next 18 months. As indicated by Figure 21, no significant pipeline capacity is expected to be added between now and 2009. The industry and the pipeline companies are working together to develop a number of initiatives to reduce and/or eliminate the impacts of apportionment.

   The number of announced and proposed pipeline and expansions, and the transfer of under-utilized gas pipeline facilities on the TransCanada Mainline to transportation of crude oil, illustrates that the hydrocarbon transportation systems are responding and have the ability to make adjustments to pipeline capacity as market conditions change.

2. **Shippers continue to indicate that they are reasonably satisfied with the services provided by pipelines.** Once again, shippers rate the physical reliability of pipeline operations highly and express the most concern around the level of pipeline tolls.

3. **NEB-regulated pipeline companies are financially sound and have been able to attract capital on reasonable terms and conditions.** While it is recognized that some of the data and indicators reviewed are for the consolidated operations of pipeline companies, the investment community views NEB-regulated companies as having access to capital markets at this time of significant liquidity. However, the investment community also noted that market conditions can change rapidly and that on a stand-alone basis the regulated entities themselves may have difficulty attracting capital given current ROEs.

As identified in Chapter 3, there are a significant number of pipelines proposed to ensure that the Canadian transportation system has sufficient capacity to deliver the additional volumes of oil and natural gas to serve new and growing markets. The challenge for the pipeline transportation industry is to put appropriate capacity in service corresponding with changes in production and market requirements. For this to happen there must be adequate and predictable lead times to achieve sufficient market support from amongst competing proposals, obtain regulatory approvals, arrange financing, mobilize labour and materials, and construct facilities.

A key component and ongoing challenge from the NEB's perspective is to provide, in a timely manner, a fair and effective process that does not distort the market place investment decisions. This may involve ongoing efforts to coordinate regulatory activities with other jurisdictions and to provide clear regulatory processes with predictable timelines. New investment can be frustrated when unexpected regulatory hurdles create delays or unpredictable timelines which may introduce uncertainty from changing supply and market conditions and business risk. Further, unnecessary construction delays, for both expansions and new pipelines, can be costly to both energy consumers and producers as the development of new supplies is constrained. Given the large capital outlay and the long-term nature of these investments, market participants seek to ensure that the optimal decisions are made.

The Board recognizes that this report represents only a snapshot in time and does not include a comparison with or to pipeline transportation systems in other jurisdictions. As part of its mandate, the Board will continue to monitor the effectiveness of the transportation system and will continue to meet with parties to gain an understanding of all perspectives on this issue. The Board welcomes feedback on the measures and conclusions in this report and also welcomes suggestions for improvements to future reports.

The Board thanks those companies and organizations that directly or indirectly provided the information found in this report, including those that actively participated in the Pipeline Services Survey.

STAKEHOLDER CONSULTATION

Alliance Pipeline Ltd.
BMO Nesbitt Burns
Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association
Canadian Gas Association
Canaccord Adams
Caisse de dépôt et placement du Québec
CIBC World Markets
Cochin Pipe Lines Ltd.
Dominion Bond Rating Service
Enbridge Pipelines Inc.
Express Pipeline Limited Partnership
Foothills Pipe Lines Ltd.
Industrial Gas Users Association
Kinder Morgan Canada Inc.
Maritimes and Northeast Pipeline
Moody's Investor Services
Ontario Teachers' Pension Plan
RBC Capital Markets
Scotia Capital
Standard & Poor's
Sun Life Financial
Terasen Pipelines Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipeline Inc.
Trans Québec & Maritimes Pipeline Inc.
TransCanada PipeLines Limited
Union Gas Limited
Westcoast Energy Inc.

GROUP 1 AND GROUP 2 PIPELINES

Regulated by the NEB As of 31 December 2006

Group 1 Gas Pipelines

Alliance Pipeline Ltd.
Foothills Pipe Lines Ltd.
Gazoduc Trans Québec & Maritimes Inc.
Maritimes & Northeast Pipeline Management Ltd.
TransCanada PipeLines Limited
TransCanada PipeLines Limited, B.C. System
Westcoast Energy Inc.

Group 1 Oil and Products Pipelines

Cochin Pipe Lines Ltd.
Enbridge Pipelines Inc.
Enbridge Pipelines (NW) Inc.
Terasen Pipelines (Trans Mountain) Inc.
Trans-Northern Pipelines Inc.

Group 2 Natural Gas and Natural Gas Liquids Pipelines

AltaGas Pipeline Partnership
Apache Canada Ltd.
ARC Resources Ltd.
Bear Paw Processing Company (Canada) Ltd.
BP Canada Energy Company
Burlington Resources Canada (Hunter) Ltd.
Canada Customs and Revenue Agency
Canadian Natural Resources Limited
Canadian-Montana Pipe Line Corporation
Centra Transmission Holdings Inc.
Champion Pipeline Corporation Limited
Chief Mountain Gas Co-op Ltd.
DEFS Canada L.P.
Delphi Energy Corporation
Devon Canada Corporation
Devon Energy Canada Corporation

DR Four Beat Energy Corp.
Echoex Energy Inc.
EnCana Border Pipelines Limited
EnCana Ekwan Pipeline Inc.
EnCana Oil & Gas Co. Ltd.
EnCana Oil & Gas Partnership
Enermark Inc.
ExxonMobil Canada Properties
Forty Mile Gas Co-op Ltd.
Huntingdon International Pipeline Corporation
Husky Oil Operations Ltd.
Kaiser Exploration Ltd.
KEYERA Energy Ltd.
Many Islands Pipe Lines (Canada) Limited
Marauder Resources West Coast Inc.
Mid-Continent Pipelines Limited
Minell Pipeline Limited
Murphy Canada Exploration Company
Murphy Oil Company Ltd.
Nexen Inc.
Niagara Gas Transmission Limited
Northstar Energy Corporation
NuVista Energy Ltd.
Omimex Canada, Ltd.
Paramount Transmission Ltd.
Peace River Transmission Company Limited
Pengrowth Corporation
Penn West Petroleum Ltd.
Petrovera Resources Ltd.
Pioneer Natural Resources Canada Inc.
Portal Municipal Gas Company Canada Inc.
Prairie Schooner Limited Partnership
Profico Energy Management Ltd.
Renaissance Energy Ltd.
St. Clair Pipelines Management Inc.
Shiha Energy Transmission Ltd.
Suncor Energy Inc.
Sword Energy Limited
Talisman Energy Inc.
Taurus Exploration Canada Ltd.
Union Gas Limited
Vault Energy Inc.
Vector Pipeline Limited Partnership
County of Vermillion River No. 24 Gas Utility
2193914 Canada Limited
806026 Alberta Ltd.
1057533 Alberta Ltd.

Group 2 Oil and Products Pipelines

Amoco Canada Petroleum Company Ltd.
Aurora Pipe Line Company
Berens Energy Ltd.
BP Canada Energy Company
Dome Kerrobert Pipeline Ltd.
Dome NGL Pipeline Ltd.
Duke Energy Empress L.P.
Enbridge Pipelines (Westspur) Inc.
Ethane Shippers Joint Venture
Express Pipeline Limited Partnership
Genesis Pipeline Canada Ltd.
Glencoe Resources Ltd.
Husky Oil Limited
Imperial Oil Resources Limited
ISH Energy Ltd.
Montreal Pipe Line Limited
Murphy Oil Company Ltd.
NOVA Chemicals (Canada) Ltd.
PanCanadian Kerrobert Pipeline Ltd.
Paramount Transmission Ltd.
Penn West Petroleum Ltd.
Plains Marketing Canada, L.P.
PMC (Nova Scotia) Company
Pouce Coupé Pipe Line Ltd. (as agent and general partner of the Pembina North Limited Partnership)
Provident Energy Pipeline Inc.
Renaissance Energy Ltd.
SCL Pipeline Inc.
Shell Canada Products Limited
Sun-Canadian Pipe Line Company
Taurus Exploration Canada Ltd.
Yukon Pipelines Limited
1057533 Alberta Ltd.

PIPELINE SERVICES SURVEY

Aggregate Results

Below are the aggregate responses for each question in the survey. Respondents were asked to rate their satisfaction with the services they receive on a scale of 1 to 5, where 1 indicates "Very dissatisfied" and 5 indicates "Very satisfied". See the Board's website for the complete details

1. How satisfied are you with the physical reliability of the pipeline company's operations?

1	2	3	4	5	Average
4	18	12	74	31	3.79

2. How satisfied are you with the quality, flexibility and reliability of the pipeline company's transactional systems (nominations, bulletin boards, reporting, contracting, etc)?

1	2	3	4	5	Average
0	24	16	75	22	3.69

3. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?

1	2	3	4	5	Average
7	7	14	75	31	3.87

4. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc) provided by the pipeline company?

1	2	3	4	5	Average
3	17	21	79	19	3.68

5. How satisfied are you with the timeliness and usefulness of commercial information (tolls, service changes, new services, contract information, etc) provided by the pipeline company?

1	2	3	4	5	Average
7	13	34	70	15	3.53

6. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?

1	2	3	4	5	Average
10	30	36	51	11	3.17

7. How satisfied are you with the accessibility and responsiveness of the pipeline company to shipper issues and requests?

1	2	3	4	5	Average
9	22	32	54	21	3.41

8. How satisfied are you that the pipeline company works towards fair and reasonable solutions when resolving issues?

1	2	3	4	5	Average
6	20	37	54	19	3.44

9. How satisfied are you with the suite of services offered by the pipeline company?

1	2	3	4	5	Average
4	13	40	67	10	3.49

10. How satisfied are you with the level of this pipeline company's tolls in relation to the transportation services your company receives?

1	2	3	4	5	Average
7	26	42	53	4	3.16

11. How satisfied are you with the collaborative processes (negotiations or task force meetings) utilized by this pipeline company?

1	2	3	4	5	Average
11	16	38	45	14	3.28

12. How satisfied are you that the current negotiated settlement agreement or tariff arrangements work well to provide fair outcomes?

1	2	3	4	5	Average
11	8	47	52	5	3.26

13. How satisfied are you with the OVERALL quality of service provided by the pipeline company over the last calendar year?

1	2	3	4	5	Average
3	20	25	73	18	3.60

14. On an overall basis, has the pipeline company's quality of service in the last year:

Improved	18	13%
Remained the Same	100	72%
Decreased	20	15%
Total	**138**	**100%**

15. What are the things that this pipeline company does well?

16. What are the things that this pipeline company could do better?

17. How satisfied are you that the NEB has established an appropriate regulatory framework in which negotiated settlements for tolls and tariffs can be reached?

1	2	3	4	5	Average
4	10	39	67	9	3.52

18. When toll and tariff matters are not resolved through settlement, how satisfied are you with the Board's processes to resolve disputes?

1	2	3	4	5	Average
4	6	39	53	7	3.49

19. What could the Board be doing to improve its processes through which tolls and tariffs are determined?

DEBT RATING COMPARISON CHART

This chart provides a comparison of the rating scales used by Dominion Bond Rating Service (DBRS), Standard and Poor's (S&P), and Moody's when rating long-term debt.

Standard & Poor's also provides a Rating Outlook that assesses the potential direction of a long-term credit rating over the intermediate to longer term. A 'Positive' outlook means that a rating may be raised; a 'Negative' outlook means that a rating may be lowered; and a 'Stable' outlook means that a rating is not likely to change.

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
			C

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

GOAL 3

Canadians benefit from efficient energy infrastructure and markets.