National Energy Board
Office national de l'énergie

CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT

JUNE 2006

Canada

National Energy Board
Office national de l'énergie

CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

TRANSPORTATION ASSESSMENT

JUNE 2006

Canada

Cat. No. NE23-129/2006E
ISBN 0-662-43531-1

This report is published separately in both official languages.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-Mail: publications@neb-one.gc.ca
Fax: (403) 292-5576
Phone: (403) 299-3562
1-800-899-1265
Internet: www.neb-one.gc.ca

For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

Cover Photos:

N° de cat. NE23-129/2006F
ISBN 0-662-72019-9

Ce rapport est publié séparément dans les deux langues officielles.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courrier électronique : publications@neb-one.gc.ca
Télécopieur : (403) 292-5576
Téléphone : (403) 299-3562
1 800 899-1265
Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

Photos en page couverture :

T A B L E O F C O N T E N T S

FIGURES

TABLES

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
OEB	Ontario Energy Board
PADD	Petroleum Administration Defense Districts
PCOG	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., carrying on business as Duke Energy Gas Transmission

UNITS

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
MW	Megawatt

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 main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids (NGLs) and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas. In addition, the Board provides energy information and advice by collecting and analyzing information about Canadian energy markets through regulatory processes and monitoring.

This report, the second of its kind, provides an assessment of the Canadian hydrocarbon transportation system. To do so, it brings together data from various publicly available sources that was collected and monitored by NEB staff as well as throughput data supplied by the pipeline companies. The Board also benefited from discussion with members of the investment community with respect to capital markets and emerging issues. Prior to the release of this report, a draft was sent to the Canadian Energy Pipeline Association (CEPA) and the Canadian Association of Petroleum Producers (CAPP) for comment. Comments provided by CAPP and CEPA were taken into consideration in the preparation of this report.

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

Karen Overli
Applications Business Unit
National Energy Board
Telephone: (403) 299-3661
Email: koverli@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 Canadian public interest is all Canadians and refers to a balance of economic, environmental and social interests that change as society's values and preferences change.

INTRODUCTION

Energy is essential to our daily lives. The ability of the pipeline transportation system to deliver this energy in the form of natural gas, natural gas liquids (NGLs), crude oil and petroleum products is critical to Canada's economic well-being.

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

Pipelines have a well-deserved reputation as the safest and most energy-efficient method of moving vast amounts of fuel from producers to consumers. In 2005, approximately $120 billion worth of products flowed through Canadian pipelines to markets at home and in the U.S. The cost in 2005 of providing these transportation services is estimated to be around $5 billion, not including fuel costs paid by shippers on natural gas pipelines. This was accomplished by infrastructure that is mostly invisible to consumers and that operates with a low rate of failure and minimal environmental impact.

To assist in the delivery of its mandate and to ensure that the Board's regulatory oversight provides value to Canadians, the Board developed five goals:

1. NEB-regulated facilities and activities are safe and secure, and are perceived to be so.
2. NEB-regulated facilities are built and operated 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 processes.

Each year, the Board issues various reports that focus on different aspects of Canadian energy markets. This report, which assesses how well the Canadian hydrocarbon transportation system is working, pertains largely to Goal 3. However, for the system to function efficiently and effectively, it must operate in a safe and environmentally acceptable manner, which relates to Goals 1 and 2. Outcomes related to safety and the environment are discussed in a companion document, the Board's report, *Focus on Safety and Environment, a Comparative Analysis of Pipeline Performance.*

This report should not be read as a regulatory document. In this report, the Board is not making a determination on regulatory matters because the factors on which the functioning of the transportation system is assessed are not necessarily the same as those considered in a regulatory proceeding.

For the hydrocarbon transportation system to work well, the Board believes the following three outcomes should be achieved:

1. there is adequate pipeline capacity in place to move energy products from producers to consumers;
2. pipeline companies are providing services that meet the needs of shippers at reasonable prices; and
3. pipeline companies have adequate financial integrity 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.

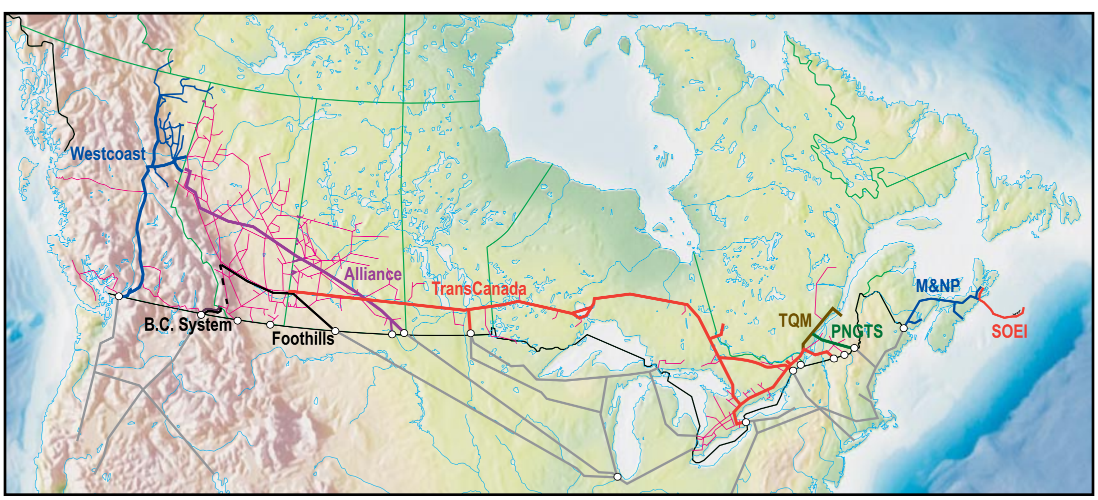
An efficient hydrocarbon transportation system needs to have the ability to be expanded on a timely basis when changing market conditions require new pipeline capacity. In order for expansion to occur in the time frame required, two things should occur. First, pipeline companies must have ready access to financial markets on reasonable terms and conditions. In addition, the regulatory process must be timely and predictable, while allowing a fair opportunity for all affected parties to provide input prior to a decision on an application being made.

In this report, the Board provides an assessment of the ability of pipeline companies to access capital on reasonable terms and conditions. The Board does not, however, provide an assessment of the efficiency and effectiveness of its regulatory processes. The Board reports on a number of regulatory efficiency measures in its *Annual Report to Parliament* and in the annual *Departmental Performance Report* that are submitted to the Treasury Board, both of which are public documents. This report, in the discussion of the Pipeline Services Survey (see Section 2.3.1), does provide information on shippers' perceptions of the Board's regulatory process. The Board recognizes that there is the potential to improve the means by which regulatory effectiveness and efficiency is measured and will be consulting with stakeholders on this topic.

For the Board's financial regulatory purposes, pipeline companies have been divided into two groups, Group 1 and Group 2. Major oil and gas pipeline companies are designated as Group 1 and are actively regulated by the NEB. All other NEB-regulated pipeline companies are classified as Group 2 companies and are subject to a lighter degree of regulation. A listing of companies regulated by the Board, as of 31 December 2005, can be found in Appendix 4.

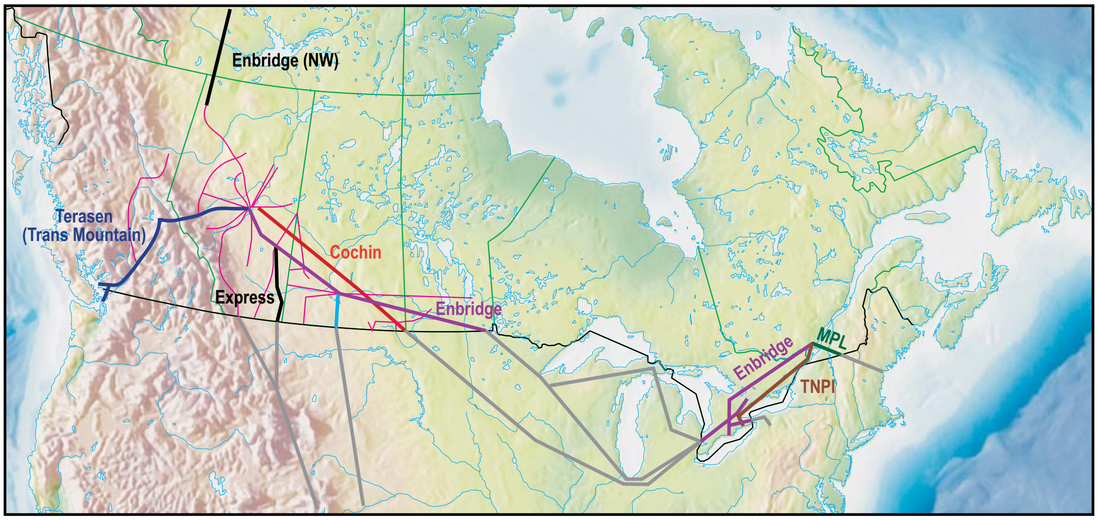
FIGURE 1

Gas Pipelines Regulated by the NEB



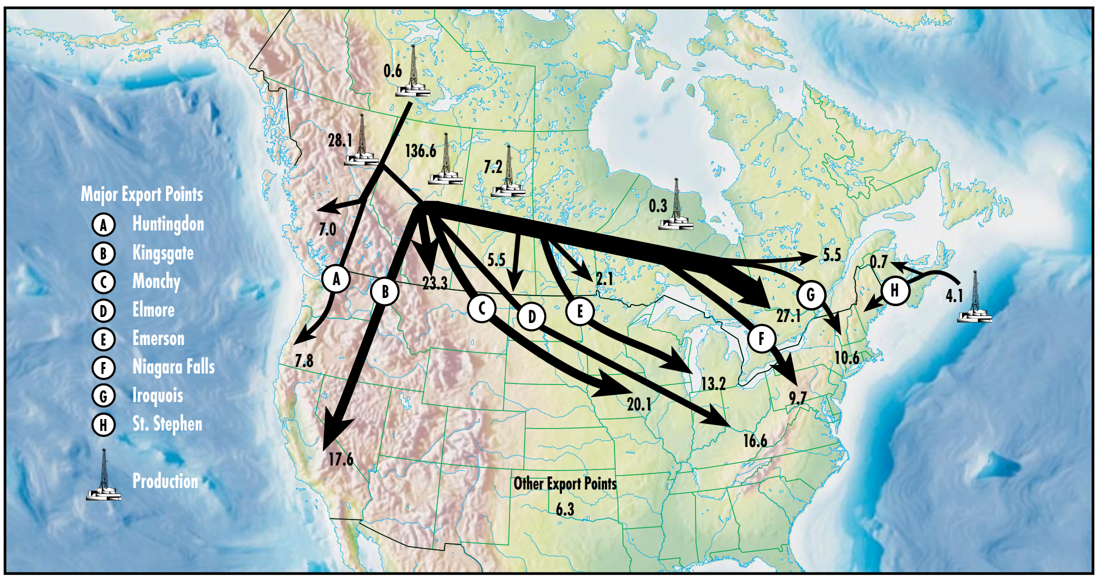
F I G U R E 2

Oil Pipelines Regulated by the NEB



F I G U R E 3

2005 Supply and Disposition of Natural Gas

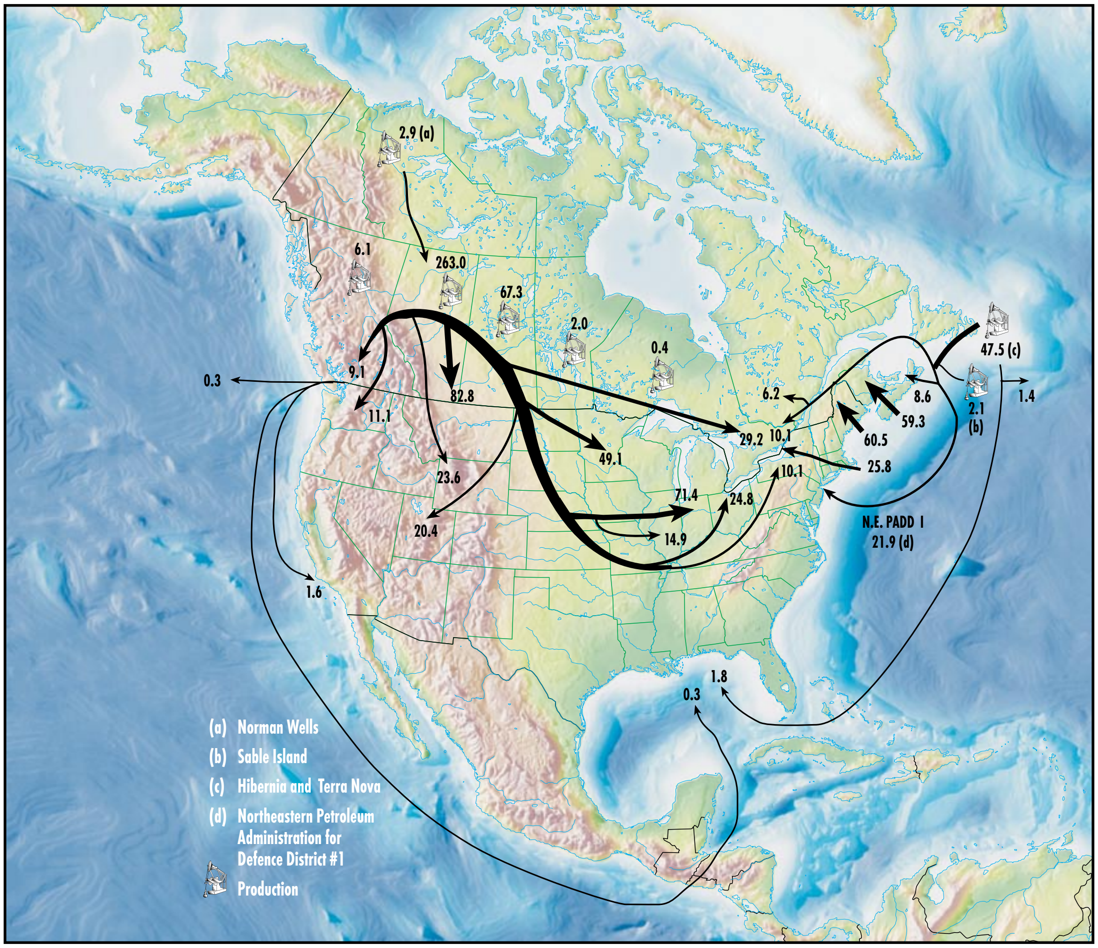


Publicly available data for Group 1 companies and Express Pipeline Limited Partnership (Express), the largest Group 2 company, was used to assess the extent to which the three outcomes identified by the Board are being achieved. These companies represent ownership of the majority of the Canadian hydrocarbon transportation system regulated by the NEB and the data from these companies provides a good view of the overall functioning of the hydrocarbon transportation system.

More detailed information can be found in the Board's 2005 Annual Report.

FIGURE 4

2005 Supply and Disposition of Oil



THE CANADIAN HYDROCARBON TRANSPORTATION SYSTEM

2.1 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 NGLs from producing to consuming regions.

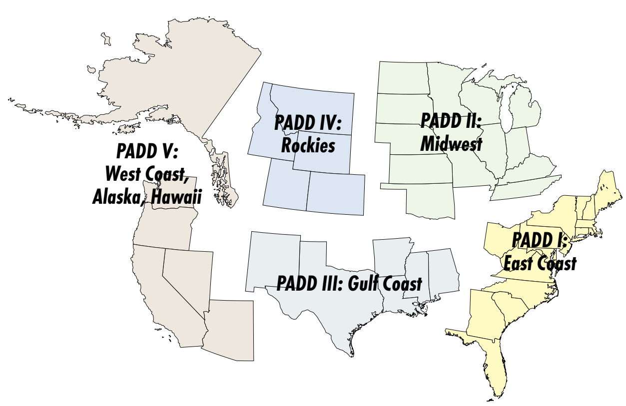
This section examines the following factors to assess the current adequacy of pipeline capacity:

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 better than not having enough. Higher tolls for shippers are a cost of having excess pipeline capacity; however, the costs associated with not having enough pipeline capacity are generally greater. Substantial revenue is lost when producers are unable to move their oil or gas to market. Not only is it important to have some excess capacity, but flexibility with sufficient access to the right markets or for the right type of product is also important.

When there is inadequate pipeline capacity to transport crude oil to the West Coast and PADD V (West Coast) producers have the option of transporting crude oil to Ontario and PADD II (Midwest) or PADD IV(Rockies). In addition, when refineries are in turnaround (maintenance) in Ontario and PADD II, crude oil volumes can be delivered to the West Coast and PADD V or PADD IV providing there is pipeline capacity.

Petroleum Administration for Defense Districts



The importance of having adequate pipeline capacity in place is highlighted by the fact that the value of natural gas and oil transported in NEB-regulated pipelines far exceeds the cost of service on those pipelines.

2.1.1 *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. Conversely, when there is inadequate pipeline capacity between two market points, the basis, that is the differential in price between the two end points, will exceed the cost of transportation. In a market with adequate capacity, sellers would generally direct their product to the market that nets the highest revenue back to the producer, thereby meeting that region's need for energy. Where inadequate capacity exists, the product cannot get to market and the price differential persists, resulting in higher prices for consumers and lost revenues for producers.

In order to use price differentials as a measure of 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 (TransCanada or TCPL) and one for transportation on Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission (Westcoast).

Figure 5 shows the basis differential between the Alberta border and the Dawn delivery point compared with the TransCanada firm service toll between the two points, including fuel costs. The basis between the Alberta border 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 basis between the two locations, natural gas pricing is very responsive to relatively small changes in flow or demand. The short-term increase in the basis differential between September 2005 and January 2006 was a result of increased demand for supply from other basins when gas supplies from the Gulf of Mexico were reduced due to hurricanes Katrina and Rita. Cold weather early in the winter also affected demand. In addition, after the hurricane-induced gas price increase, the cost of fuel for use in the pipeline compressors also increased temporarily. Very mild weather and reduced demand in response to higher prices has since moderated flows and the demand for gas and transportation.

FIGURE 5

Dawn – Alberta Basis vs. TransCanada Toll and Fuel

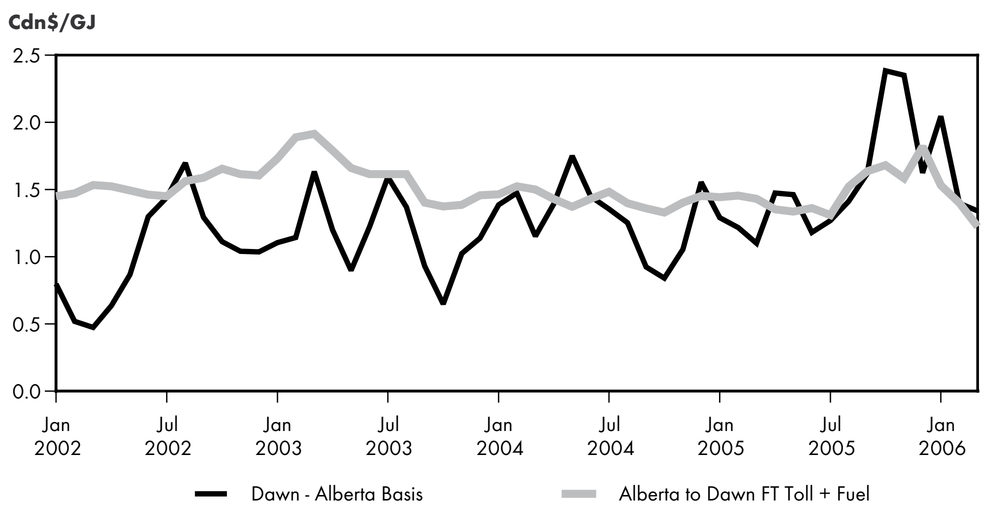
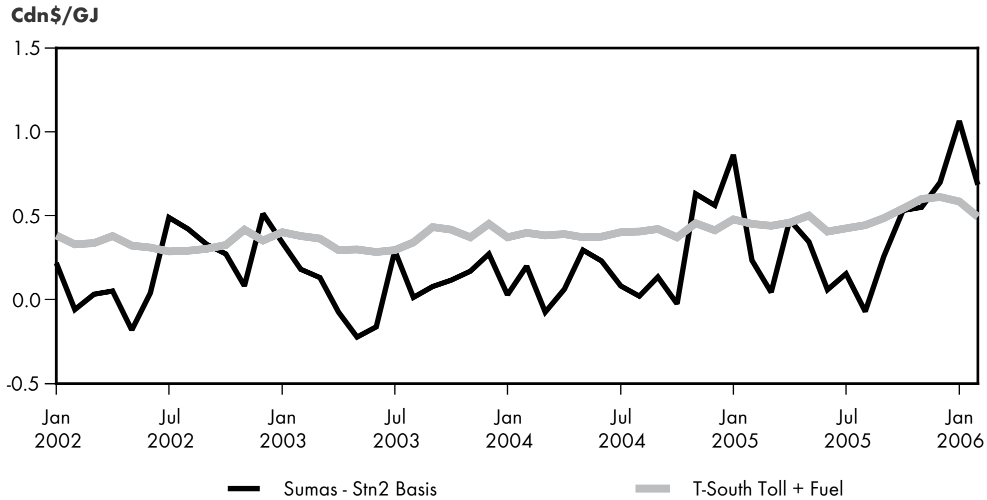


Figure 6 shows the basis between Compressor Station 2 on the Westcoast system and the Sumas export point compared with the Westcoast firm service toll between the two points (T-South or Southern Mainline), including fuel costs. Since January 2002, except for a few months, the basis has been lower than the transportation costs indicating that there has been adequate capacity in place since that time.

FIGURE 6

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



Note: 2006 - interim term-differentiated toll (5 or more years service).

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 basis between pricing points has been slightly lower than pipeline transportation and fuel costs. However, natural gas pricing is volatile. Hurricane-induced supply disruptions in the Gulf of Mexico and erratic weather impact both basis and pipeline fuel costs. Figures 5 and 6 both indicate times where the basis exceeded transportation and fuel costs. These events proved to be temporary, and gas flows and prices moderated.

Price Differentials and Tolls on Oil Pipelines

The major drivers of price differentials, amongst other things, are availability of pipeline capacity, competition, supply and demand, seasonality and the grade (quality) of crude oil. Price differentials are increasingly becoming an issue on oil pipelines because of the increase in bitumen blend crude oil supply from the oil sands. Limited access to markets, particularly those with refineries that process heavy crude oil, exerts downward pressure on heavy oil prices and widens the light-heavy differential.

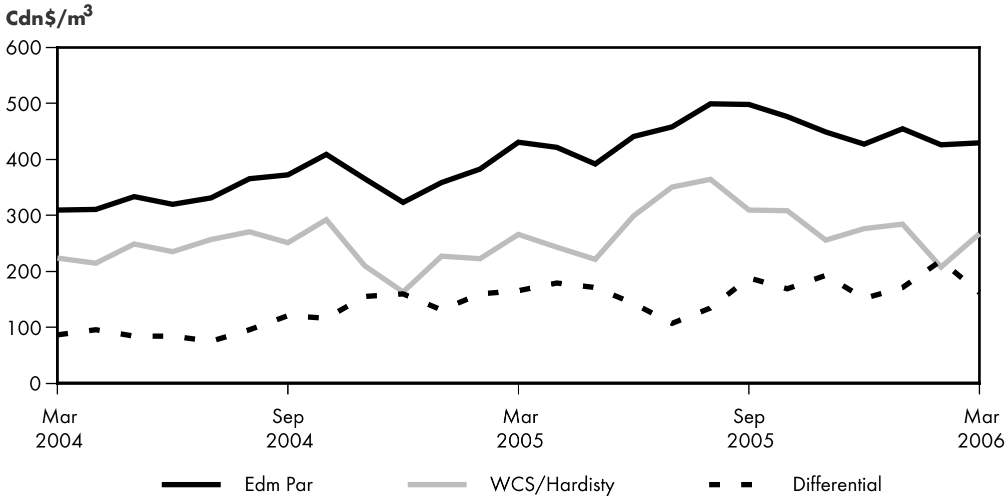
Figure 7 illustrates the wide light-heavy differential as indicated by the difference in price of Edmonton Par light crude oil and Western Canadian Select (WCS), a heavy crude oil. As shown, the average differential has been increasing during the time period shown and in recent years has averaged about 30 percent over the course of a year. Notably, in the first quarter of 2006, the price of heavy crude was, on average, 42 percent less than the price for light crude oil (the light-heavy differential).

Typically, the differential is narrower during the summer months due to the additional demand for heavier crude oil for use in the production of asphalt for paving.

Differentials have also widened as a result of supply growth from the oil sands, pipeline constraints and a lack of refinery capacity to process heavier crude oil. Wide light-heavy differentials reduce heavy oil producers' netbacks and at extreme levels could possibly result in some oil sands projects being uneconomic. Recently, the differential has narrowed because of increased market access with the delivery of western Canadian crude oil to Cushing, Oklahoma through the Spearhead Pipeline and into the U.S. Gulf Coast through the reversed Mobil Pipeline.

FIGURE 7

Canadian Crude Oil Prices and Differential



2.1.2 Capacity Utilization on Major Routes

Pricing data is available for a number of injection and delivery points on pipeline systems. Even where this data is not available, another measure of adequate capacity is obtained by comparing throughput with capacity. The Board monitors capacity utilization for most of the large pipelines it regulates.

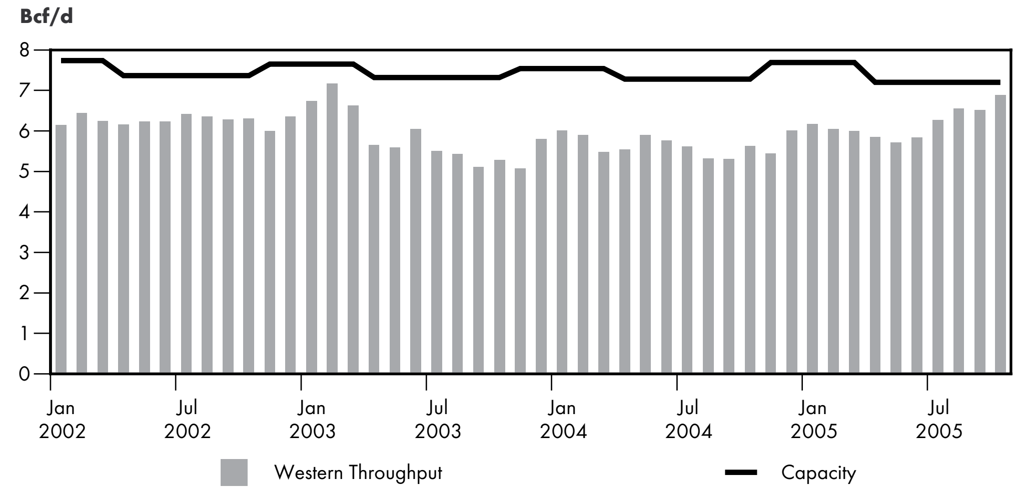
The following figures show pipeline average monthly throughput compared with capacity for some of the largest NEB-regulated pipeline systems, including the TransCanada Mainline, Foothills Pipe Lines Ltd. (Foothills), TransCanada B.C. System, Westcoast, Alliance Pipeline Ltd. (Alliance), Trans Québec & 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 8 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. It demonstrates that while the prairie line has been operating at between 70 to 80 percent of capacity since April 2003, the volumes have increased in recent months. These higher volumes reflect increased eastern demand for Canadian gas due to last year's hot summer weather and reduced gas supplies (since September) from the Gulf of Mexico following the late summer hurricanes. Overall, the indicator shows that there has been adequate pipeline capacity to move volumes to eastern markets.

FIGURE 8

TransCanada Mainline Throughput vs. Capacity



The volumes shown in Figure 9 are the average monthly throughput on TransCanada's Foothills Pipeline (Sask.) compared with capacity. This pipeline connects with Northern Border Pipeline Ltd. (Northern Border) and Monchy, Saskatchewan to flow gas to the U.S. Midwest. While the Foothills (Sask.) capacity utilization has been running at an annual average of about 94 percent since 2002, there was some decline in the spring of 2005. The lower volumes were due to a period of unsold firm capacity on the connecting Northern Border pipeline, stemming from low seasonal demand and high storage levels.

FIGURE 9

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

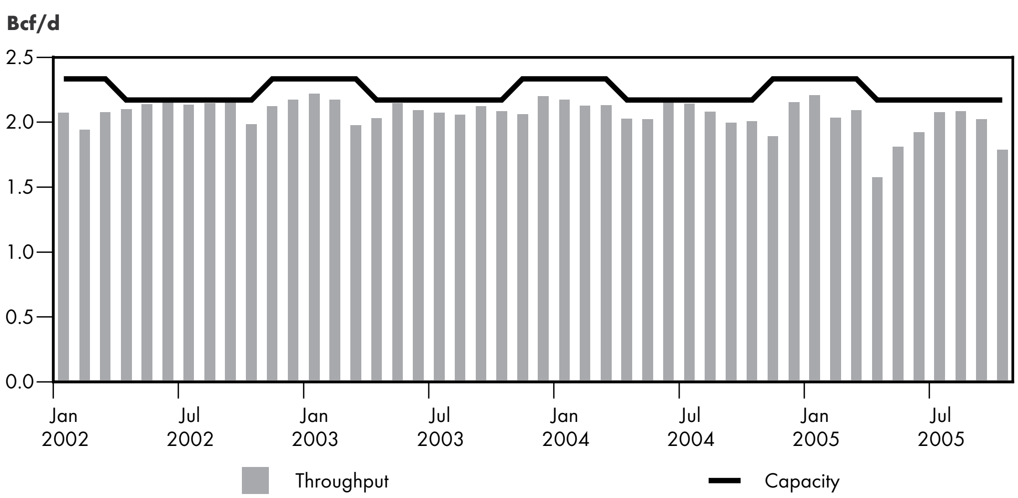


Figure 10 compares the average monthly throughput on Westcoast's Southern Mainline with the capacity on this system between Station 2 and the Sumas export point. This figure shows the seasonal nature of throughput on the Southern Mainline with higher volumes being transported during the peak winter months and less during the summer. One of the major contributors to low flows on Westcoast is the competition with production from the U.S. Rockies region which also has access to the U.S. Pacific Northwest market via Williams' Northwest Pipeline system. A warm winter and increased hydro power generation in British Columbia and the U.S. Pacific Northwest reduced gas flows on this pipeline in early 2006. In fact, the peak flow levels were lower than normal, as was the duration of the winter peak.

FIGURE 10

Westcoast Mainline Throughput vs. Capacity

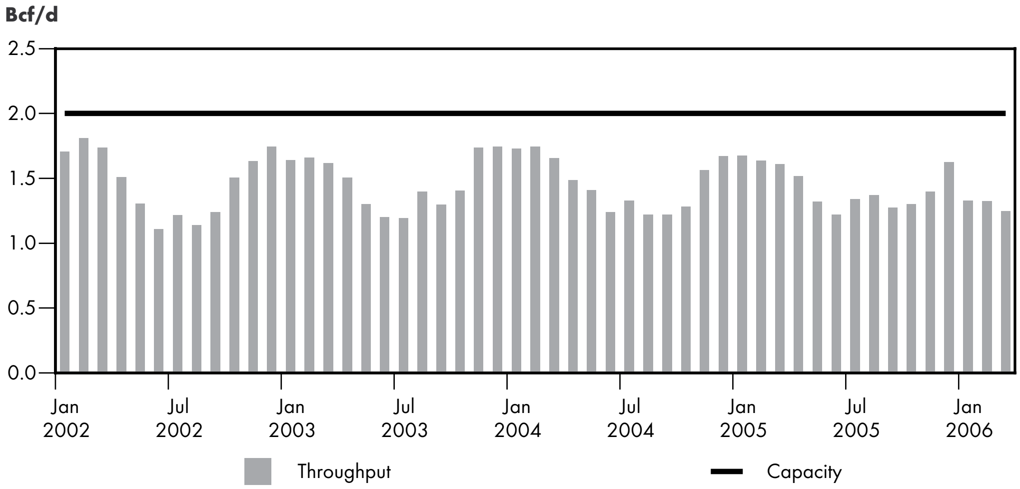


Figure 11 shows the average monthly throughput and capacity on the TransCanada B.C. System. The annual average capacity utilization dropped from about 77 percent in February 2002 to about 60 percent in March 2006, and there is spare capacity on this pipeline to export gas through Kingsgate. In California, which is the B.C. System's primary market region, 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).

FIGURE 11

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

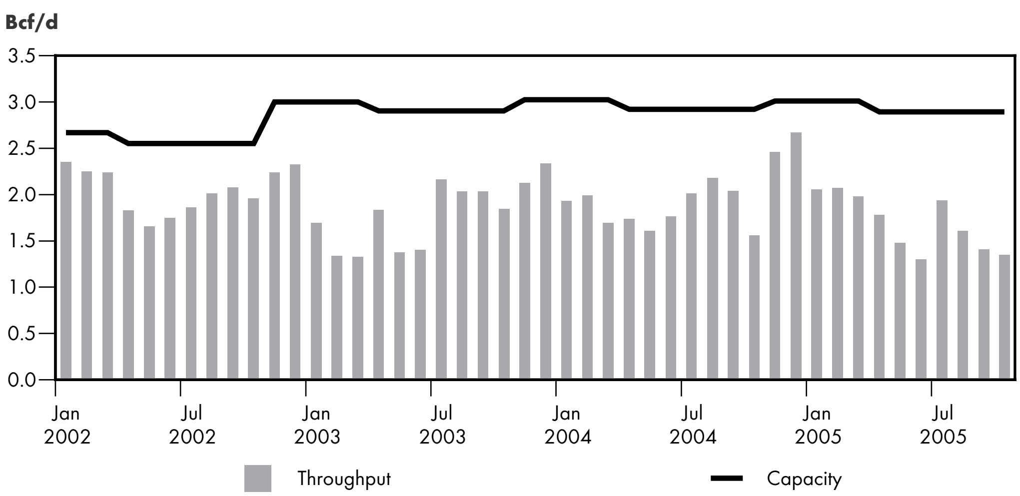


Figure 12 shows the average monthly throughput on the Alliance system relative to physically available capacity levels. Alliance offers approximately 37 534 $10^3 m^3/d$ (1.325 Bcf/d) of firm service capacity, and makes any additional capacity available to its contracted shippers pro rata as Authorized 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 12

Alliance Throughput vs. Capacity

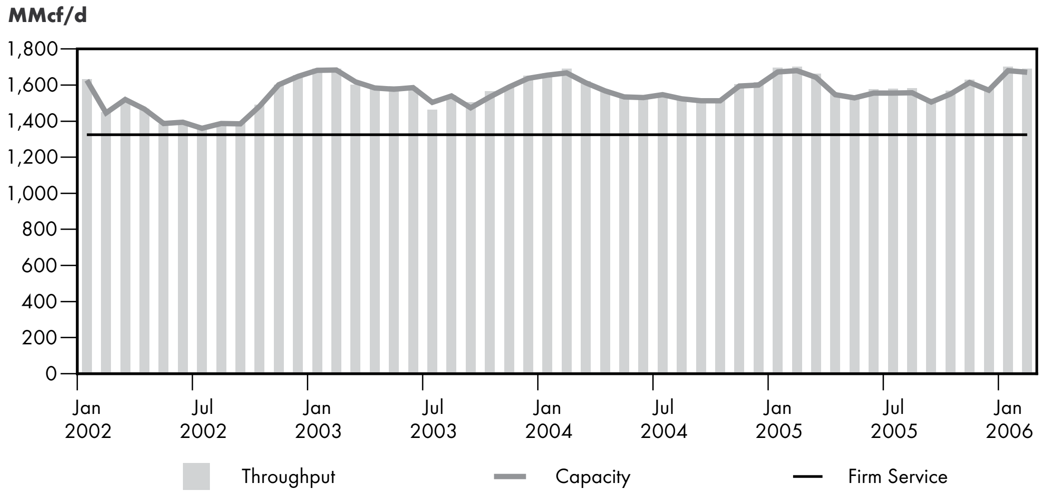


Figure 13 compares the average monthly throughput and capacity on TQM. This figure shows the seasonal nature of the throughput on this pipeline, with more volumes being transported during the peak winter months. With the annual average capacity utilization of around 60 percent, there is spare capacity on this pipeline which delivers gas between the TransCanada Mainline, connecting TQM at Saint-Lazare on the Ontario and Québec border, and TQM's endpoints at Saint-Nicolas (south shore of Québec City) and East Hereford (New Hampshire state border). 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 along the pipeline. Higher system utilization in 2005 reflects increased exports at East Hereford due to reduced gas supplies from the Gulf of Mexico following the late summer hurricanes.

FIGURE 13

Trans Québec & Maritimes Throughput vs. Capacity

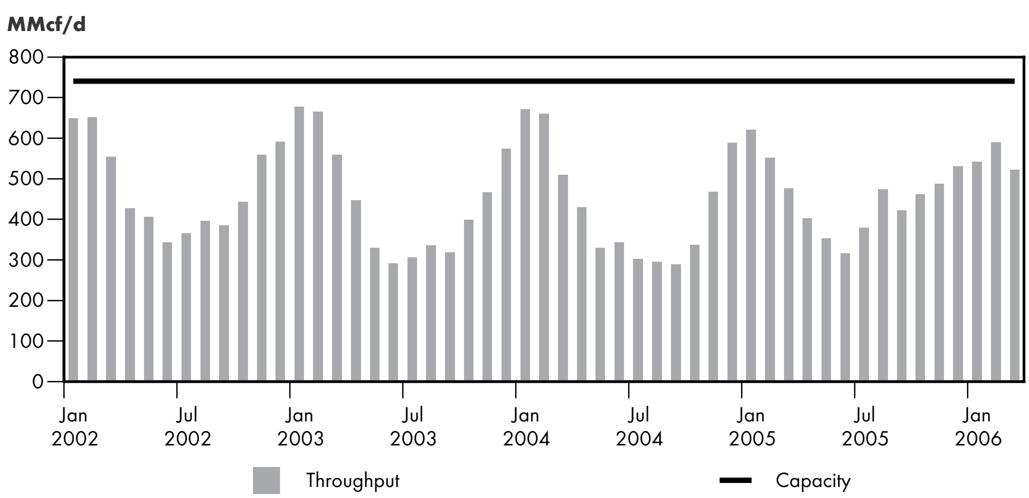
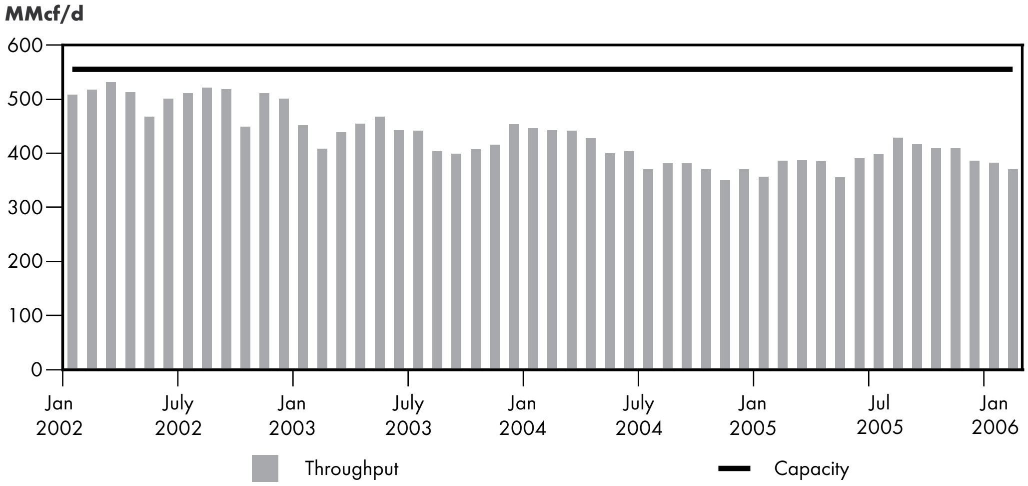


Figure 14 compares the average monthly throughput on the M&NP pipeline with its capacity. The annual average capacity utilization has been declining from about 92 percent in 2002 to an average of about 70 percent in 2005. The drop in this pipeline's utilization stems from declining natural gas production from Nova Scotia's Sable Offshore Energy Project. The variations in throughput are primarily related to changes in gas supply.

F I G U R E 1 4

Maritimes & Northeast Pipeline Throughput vs. Capacity



Although the Dawn-Parkway corridor is not regulated by the NEB, it is a key link between the Dawn hub and growing markets in eastern Canada and the U.S. Northwest. Last year the Ontario Energy Board (OEB) approved Union Gas' Phase 1 Expansion, expected to be in service by November 2006. This year, Union filed an application with the OEB for its Phase 2 Expansion. If approved, the expansion is expected to be in service by 1 November 2007. Market demand for capacity in this corridor is expected to remain robust due to the liquidity of Dawn as a transactional trading point given its market reach.

Oil

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

The Enbridge system originates in Edmonton, Alberta and extends east across the Canadian prairies to the U.S. border near Gretna, Manitoba to join 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 system consists of several lines transporting crude oil, NGLs and refined petroleum products. Figure 15 illustrates Enbridge Mainline throughput versus capacity for all lines. In 2005, Enbridge transported roughly 224 600 m^3/d (1.4 million barrels per day) of crude oil, petroleum products and NGLs. In the first quarter of 2006, Enbridge operated at around 80 percent of capacity (Figure 15). Certain lines, particularly Lines 3 and 4, which transport heavy oil, have been operating at or close to full capacity, with some apportionment (see Section 2.1.3).

In November 2005, Kinder Morgan purchased Terasen Inc., owner of the Trans Mountain pipeline system. This purchase made Kinder Morgan a major oil pipeline player in Canada. TPTM's current capacity, assuming some shipments of heavy 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 2.1.3). However, the capacity indicated in Figure 16 is 45 300 m^3/d (285 Mb/d). This higher capacity assumes no heavy crude oil shipments. On average, particularly in the last two years, 20 percent of TPTM's crude oil receipts at Edmonton are heavy and because of the increased viscosity, pipeline capacity was reduced to 35 700 m^3/d (225 Mb/d).

FIGURE 15

Enbridge Pipeline Throughput vs. Capacity

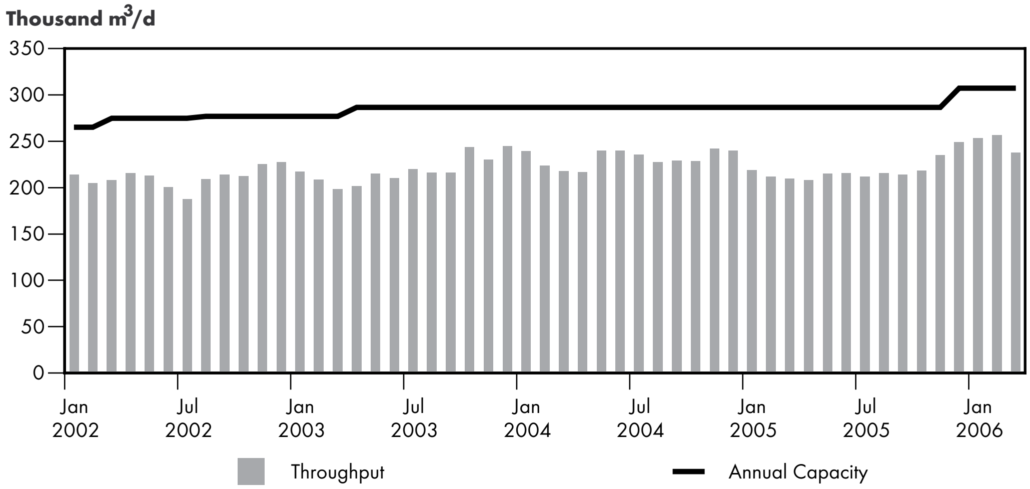
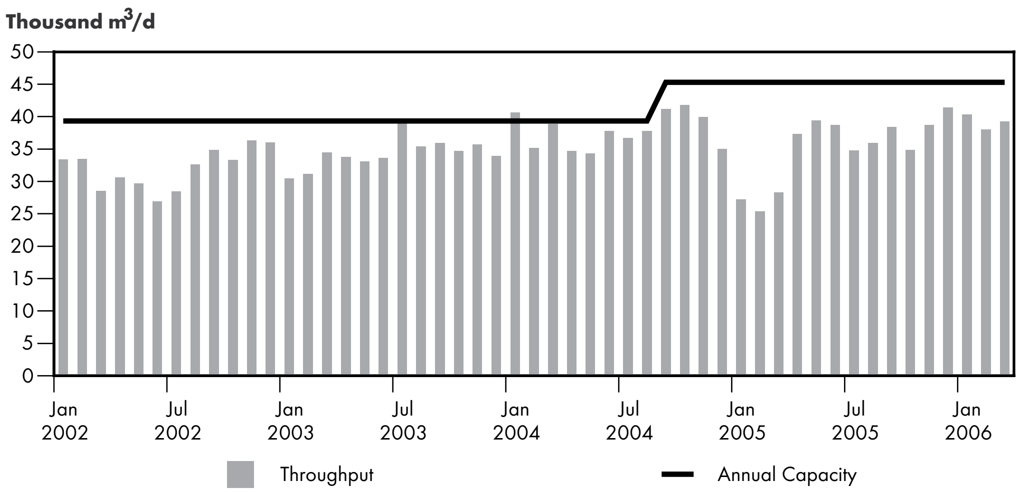


FIGURE 16

TPTM Throughput vs. Capacity[2]



On 5 July 2005, Terasen applied to the NEB for a capacity increase of 5 600 m^3/d (35 Mb/d). It was approved on 10 November 2005 and the in-service date is April 2007.

In the first quarter of 2006, TPTM operated at approximately 86 percent of capacity (see Figure 16). Though the system did not operate at capacity, TPTM was under apportionment in January, February and March of 2006. Many factors contributed to this apportionment, including growing oil sands supply coupled with increased demand from Washington State refiners and crude oil shipments off the Westridge Dock.

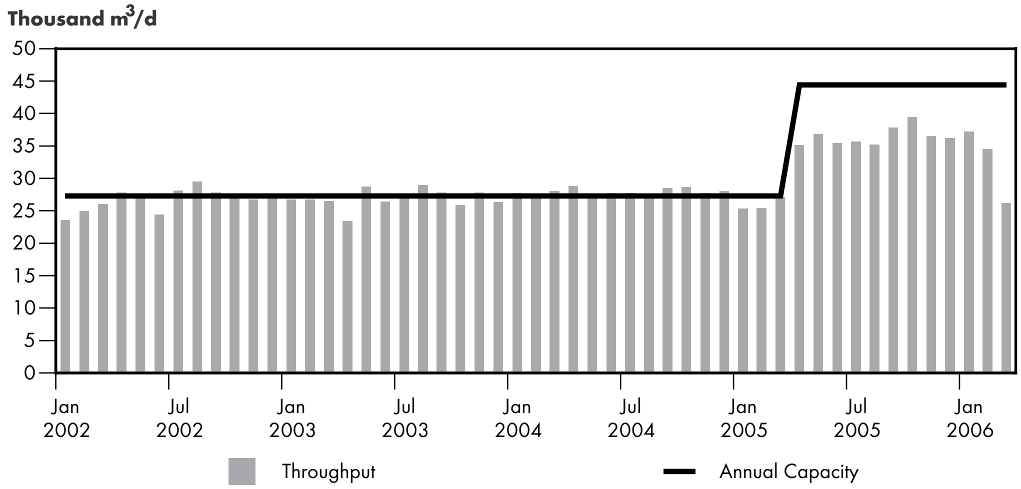
During the past several years, Express has been operating at capacity. In April 2005, Express completed its 17 600 m^3/d (100 Mb/d) expansion, bringing the total capacity to 44 900 m^3/d (280 Mb/d). Express is the only crude oil pipeline in western Canada that operates under long-term take-or-pay agreements with its shippers for the majority of its capacity.

2 Capacity shown is light crude oil only (0% heavy).

In the first quarter of 2006, Express operated at approximately 73 percent of capacity (Figure 17). Throughputs were reduced in March 2006 due to apportionment on the Platte Pipeline system in the U.S.

FIGURE 17

Express Throughput vs. Capacity



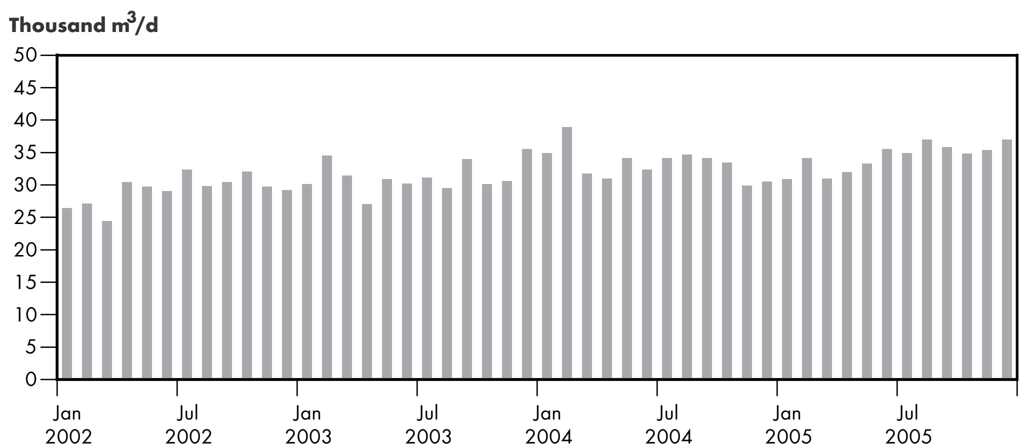
TNPI is a refined petroleum products pipeline. Historically, the pipeline system extended from Nanticoke, Ontario to Montreal, Quebec serving petroleum industry terminals along the route. In 2003, TNPI applied to the Board to increase the line capacity between Montreal and Farran's Point, Ontario from 10 500 m^3/d (66 150 Mb/d) to 21 000 m^3/d (132 300 Mb/d) and to reverse the direction of flow between Farran's Point and Metropolitan Toronto from a west-to-east direction to an east-to-west direction.

The Board approved TNPI's application to reverse the line and to accept take-or-pay obligations from Petro-Canada and Ultramar for 91 percent of the capacity. The remaining 900 m^3/d or nine percent of the capacity from Farran's Point to Toronto is available for spot shipments.

The expansion and the reversal, which took place in November 2004, were a response to declining shipments on the TNPI system and the closure of Petro-Canada's refinery in Oakville, Ontario. Increased deliveries from Montreal on TNPI serve markets in Ontario formerly served by Petro-Canada's Oakville refinery and by Ultramar by rail from Quebec (Figure 18).

FIGURE 18

Trans-Northern Pipelines Inc. Throughputs



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

2.1.3 Apportionment

Oil pipelines normally operate as common carriers, although pipelines such as Express, Enbridge Line 9 and TNPI operate with long-term shipper take-or-pay agreements. Common carriers require shippers to nominate their volumes for delivery into a pipeline on a monthly basis without a contract for the pipeline's 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 set out by the pipelines. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations and refinery maintenance. Some recent apportionment data for Enbridge, TPTM and Cochin is shown below.

Enbridge

Historically, Lines 2 and 4 were dedicated to the transportation of heavy crude oil and Line 3 was dedicated to the transportation of light and medium crude oils. In the third quarter of 2005, Enbridge completed the Terrace Phase III expansion project to facilitate the growth in heavy crude oil. By converting Line 2 from heavy to light service and Line 3 from light to heavy service, it increased its heavy capacity by 39 000 m^3/d (245 700 b/d and reduced its light capacity by 18 400 m^3/d (115 920 b/d).

As illustrated in Table 1, Line 4 was under apportionment once between August 2005 and February 2006. In February, each shipper was required to reduce its volume, resulting in a three percent reduction. There are a number of factors that caused the apportionment: increased throughput from the oil sands, apportionment on the Platte system in the U.S., increases in conventional production in North Dakota for injection at Cromer, Manitoba and Clearbrook, Minnesota; pipeline reconfiguration; and refinery maintenance.

Enbridge's Line 9 has a capacity of 38 150 m^3/d (240 000 b/d) and transports oil from Montreal, Quebec to Sarnia, Ontario. In contrast to last year, there was no apportionment on the line between August 2005 and February 2006. This was partly due to increased volumes of western Canadian light conventional crude oil being processed in Ontario refineries.

TABLE 1

Enbridge Appointment[3]

	Aug-05	Sept-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06
Line 4 Apportionment	0%	0%	0%	0%	0%	0%	3%
Throughput (10^3m^3/d)	104.3	103.4	102.4	113.0	90.4	113.9	111.0

Terasen Pipelines (TransMountain) 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 in November 2005 through to March 2006 reflects increased volumes associated with expansion in the oil sands and the higher market demand for Canadian crude. In addition, heavy crude oil volumes also increased during this time limiting capacity on the TPTM system. With improving market economics TPTM is delivering increasing volumes of western Canadian crude oil into Washington

State refineries as well as for export over the Westridge Dock which contributed to apportionment at both of these locations.

Following three notices of motion and an oral argument heard on 11 April 2006, the Board released its Decision approving the inclusion of a premium in the Tariff as a means of allocating capacity to the Westridge Dock. Further information can be found in the Board's letter decision dated 12 April 2006 and MH-2-2005.

TABLE 2

TPTM Apportionment

	Aug-05	Sept-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06
Apportionment								
Domestic	0%	0%	0%	12%	0%	16%	32%	34%
Export	0%	0%	0%	18%	15%	18%	33%	43%
Dock	0%	0%	0%	74%	0%	30%	87%	93%
Throughput (10^3m^3/d)	35.9	38.4	34.9	38.7	41.4	40.3	38.0	39.2

Cochin

The Cochin pipeline is the largest and longest NGL pipeline in Canada. It transports propane, ethane, ethylene and butane, although no butane has been transported since 2002. Ongoing maintenance work on the pipeline has affected the available capacity. The lower throughput volumes and apportionment in September 2005 was caused by unexpected downtime required for immediate repairs. Because ethylene was already in the pipeline, there was no flexibility to transport larger volumes of other products (ethylene has a higher vapour pressure than propane and ethane and reduces the capacity of the pipeline).

Effective 7 March 2006, Cochin suspended the transportation of ethylene until at least the fall of 2007 due to a defect found in the U.S. portion of the pipeline and went on a voluntary pressure restriction. The pressure is not to exceed 900 psi and applies to the whole line from Fort Saskatchewan, Alberta to Windsor, Ontario. Without ethylene in the pipeline, propane and ethane shippers are not expected to face apportionment. The average capacity will be around 10.3 to 11.9 10^3m^3/d (64 890 b/d to 79 970 b/d). Once the pressure restrictions are lifted, capacity is expected to return to 17.5 10^3m^3/d (110 250 b/d).

TABLE 3

Cochin Apportionment

	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06
Apportionment	0%	18%	0%	0%	0%	0%	0%	0%
Throughput (10^3m^3/d)	8.6	5.6	9.9	6.0	9.7	9.2	9.8	7.7

2.1.4 Summary of the Adequacy of Pipeline Capacity

Overall, the examination of throughput and capacity on NEB-regulated natural gas pipelines shows that pipeline capacity is adequate across the country although there may be limitations 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 through some Canadian pipelines can be variable as well.

[3] Line 4 was the only line on the Enbridge system out of western Canada that was apportioned during this period.

Where possible, the use of storage helps to reduce the variation in flows and allows pipeline capacity to be used more efficiently with higher annual capacity utilization.

Oil pipeline capacity, however, is tight and is expected to remain tight through 2008, even with the current expansions underway (Figure 28). This is being driven by increases in crude oil supply from the oil sands and in conventional production in North Dakota and PADD IV. In the first quarter of 2006, the price of heavy crude oil was, on average, 42 percent less than the price of light crude oil. This compares to a more typical light/heavy differential of around 30 percent. The light/heavy differential is typically wider during the winter months, reflecting reduced demand for asphalt and lower gasoline demand. However, the size of the differential in the first quarter reflects pressures building from an increase in supply, in this case from the oil sands, pipeline constraints and lack of refinery capacity to process heavier crude oil. Recently, the differential has narrowed as a result of market extension into Cushing, Oklahoma and the U.S. Gulf Coast through the Spearhead Pipeline and the Mobil Pipeline, respectively.

2.2 Pipeline Tolls

2.2.1 *Pipeline Tolls Index*

Another indicator of a hydrocarbon transportation system's efficiency is whether pipeline companies are providing services that meet the needs of shippers at stable and reasonable prices (tolls). One of the factors the Board uses to analyze this is year-to-year variations in a 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. The following sections review variations and trends of some NEB-regulated pipeline tolls since 1997.

Natural Gas Pipeline Tolls

The benchmark tolls[4] for TransCanada's Mainline, Westcoast, Foothills, the TransCanada B.C. System (B.C. System), TQM, M&NP, Alliance, and the GDP deflator[5] normalized to the year 2001 are shown in Figure 19.

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 the toll fell, primarily due to increased contract demand and is below the level that it was in 2000.

Westcoast's tolls have increased moderately except for two years, 2000 and 2005. In 2000, Westcoast's benchmark toll increased more than 10 percent from the previous year primarily due to a large amount of non-routine pipeline integrity costs and in 2005, this toll increased by over 15 percent due to decontracting of firm services.

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.

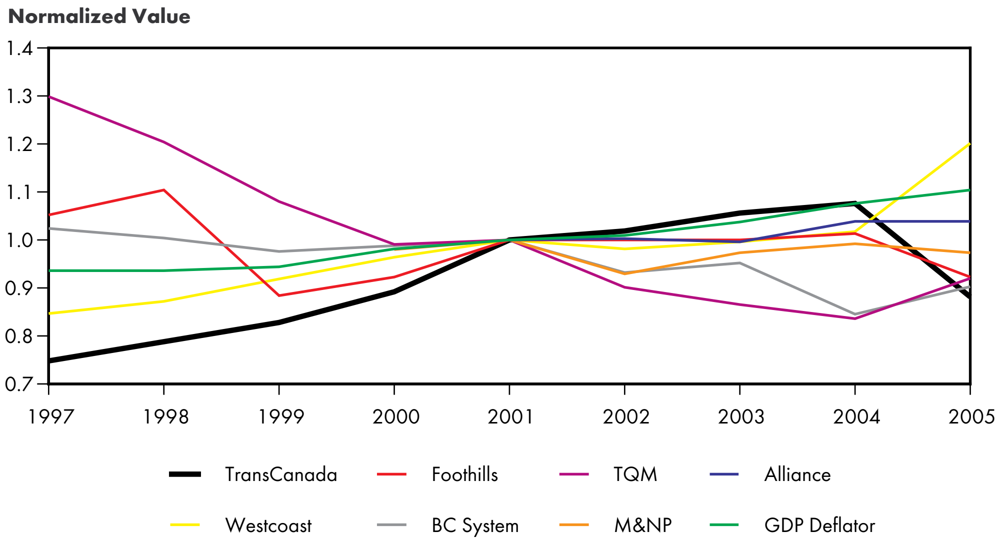
5 The GDP deflator for 2005 is an estimate using actual data for the first half or the year and data estimated by Infometrica for the second half of the year.

The B.C. System, Foothills and TQM's benchmark tolls were lower in 2005 than in 1997. The B.C. System's benchmark toll decreased in 2004 primarily because of an increase in throughput volumes (over 10 percent) from 2003. Foothills benchmark toll dropped in 1999 as a result of a cost-effective expansion of its system. TQM's benchmark toll has decreased since 1997, although it increased somewhat in 2005. The decline was due, in part, to the Portland Natural Gas Transmission System (PNGTS) extension in 1999, which increased throughput over 30 percent from 1998.

M&NP and Alliance's benchmark tolls have been relatively constant since beginning operations at the end of 1999 and 2000 respectively.

FIGURE 19

NEB-Regulated Gas Pipeline Benchmark Tolls



Oil Pipeline Tolls

The benchmark tolls for Enbridge, TPTM, TNPI, Express and the GDP deflator, normalized to the year 2001[6], are shown in Figure 20.

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 2002. The tolls increased the most in 2000 and 2004. The increase in 2000 was due to unforeseen lower throughput levels in the previous year. Under its negotiated settlement, Enbridge was able, in the following year, to recapture the revenue shortfall due to the lower throughput. The 2004 increase was primarily due to operating at lower capacity utilization as a result of 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 two years. There was a large increase in 1999 due to low forecast throughput. 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 2003 deferrals for higher revenue. TNPI and Express's benchmark tolls moved in line with the GDP deflator from 1997 to 2005.

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

FIGURE 20

NEB-Regulated Oil Pipeline Benchmark Tolls

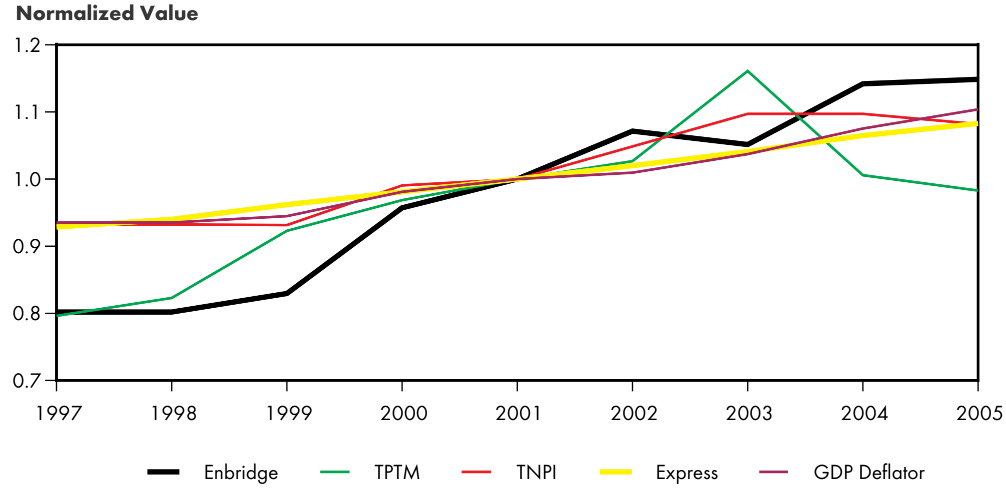
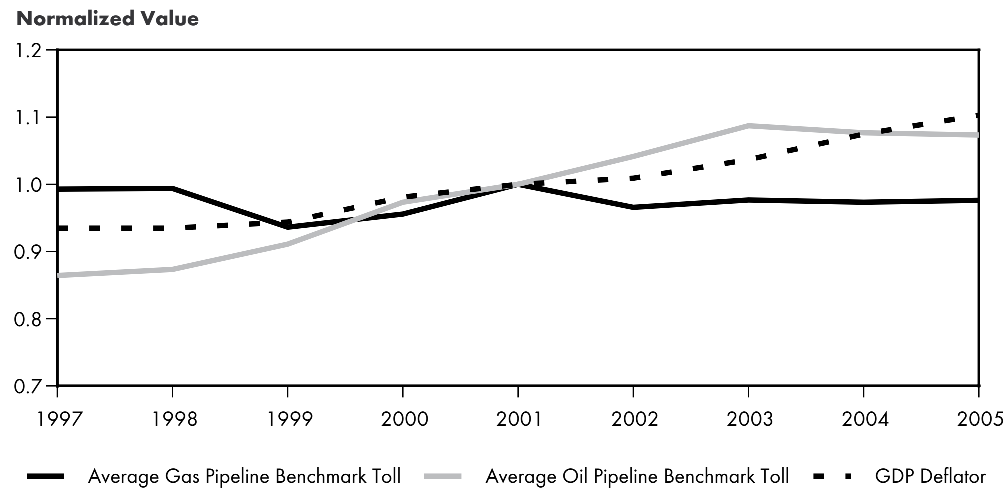


FIGURE 21

Oil and Gas Pipeline Benchmark Tolls



Comparison of Gas and Oil Pipeline Tolls

The average gas and oil benchmark pipeline tolls (reported in Figures 19 and 20) and the GDP deflator are graphed in Figure 21. From 1997 to 2005, oil pipeline tolls increased on average more than gas pipeline tolls, whereas gas pipeline tolls experienced more variation than oil pipeline tolls.

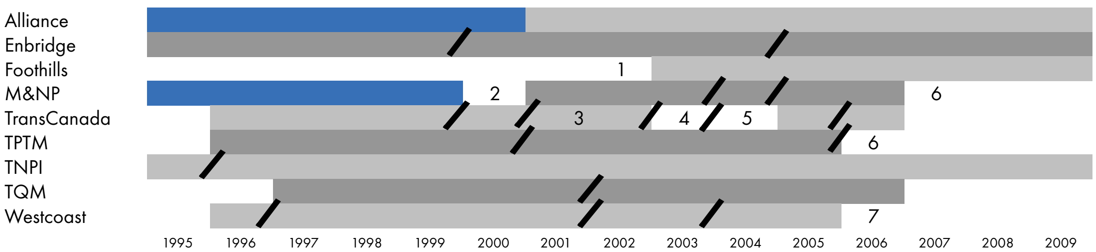
2.2.2 Negotiated Settlements

To improve the effectiveness of the regulatory process, the Board has supported the use of negotiated settlements as an alternative to toll hearings since the mid-1980s. 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.

Most of the major Group 1 companies have successfully negotiated multi-year settlements with their shippers. Beginning in 1995, the Board approved a succession of multi-year settlements. These agreements generally included incentives to reduce costs and provisions to share savings between the pipeline company and its shippers. Several of these multi-year settlements have been renegotiated upon their expiry. For example, Enbridge Pipelines has negotiated three consecutive five-year settlements covering the period 1995 to 2009. Similarly, TPTM and TQM have had two successive five-year settlements and are in the process of renegotiating new ones. Refer to Figure 22 which shows, for each pipeline company, the years that were covered by negotiated settlements.

FIGURE 22

Negotiated Settlements Timeline



Notes:
1 - Foothills is regulated under an actual cost of service methodology
2 - RH-1-2000 Hearing for tolls from 1 December 1999 to 30 September 2000
3 - RH-1-2001 Hearing to consider contested settlement for 2001 and 2002 tolls
4 - RH-1-2002 Hearing for 2003 tolls
5 - RH-2-2004 Hearing for 2004 tolls
6 - In negotiations
7 - Westcoast and its shippers have negotiated a 2-year settlement
Alliance and M&NP were not in service during these years

Negotiated settlements have contributed to a significant reduction in the regulatory burden for all parties with less time spent participating in hearings and a corresponding reduction in costs associated with the hearing process. This may be somewhat offset by the increased time spent by pipeline companies and their shippers in task force meetings. Parties note that the greater use of task forces and settlements has increased the collaboration between pipeline companies and shippers and resulted in a better alignment of interests.

Some settlements have included various innovative performance mechanisms such as incentives for cost control and performance improvement standards. Examples of the latter include the service standards in Westcoast's 1997–2001 settlement and the service and reliability metrics in Enbridge's 2005–2009 incentive agreement.

Negotiated settlements have also increased the length of period for which tolls are set. Rather than annual toll proceedings, a number of agreements have terms of five years or longer, which provides greater predictability and stability.

2.3 Shipper Satisfaction

2.3.1 *NEB Pipeline Services Survey*

The Board conducted its second Pipeline Services Survey in early 2006 to obtain direct feedback from the shippers on the level of service provided by major NEB-regulated pipeline companies. The Board also uses this survey to obtain feedback from shippers on the Board's regulatory performance with respect to tolls and tariffs.

This year, the Board used a web-based survey tool to send the survey directly to shippers via e-mail. Shippers were sent one survey for each pipeline the shipper utilized during the past year. Each survey asked the shippers to provide their company's corporate views on the services provided by the pipeline being surveyed and on the services provided by the Board. The overall response rate of 33.5 percent was a significant improvement over last year's rate of 23 percent.

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 pipeline company and its shippers with detailed company-specific results. These results include the pipeline company's average rating, distribution of responses for each question as well as the verbatim comments received from shippers, excluding the names of the respondents.

The Board follows up on the survey results, including feedback on the Board, by meeting with pipeline companies and shippers.

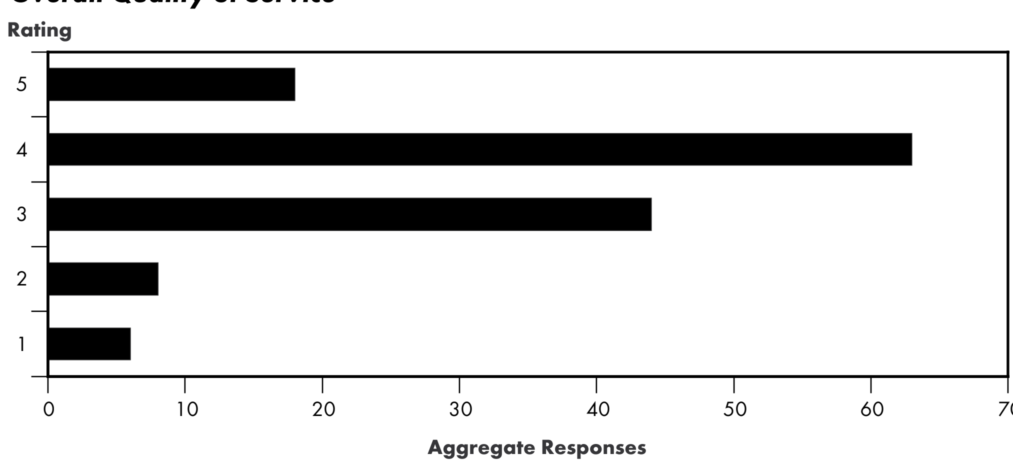
Appendix 2 provides the aggregate scores on all survey questions. For the complete report on the aggregate results, refer to www.neb-one.gc.ca/Publications/SurveyResults.

Pipeline Services

Figure 23 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 companies over the last year (1 indicates "very dissatisfied" and 5 indicates "very satisfied"). While the average score of 3.57 was lower than the score of 3.78 in last year's survey, shippers still appear reasonably satisfied with the services provided.

FIGURE 23

Overall Quality of Service



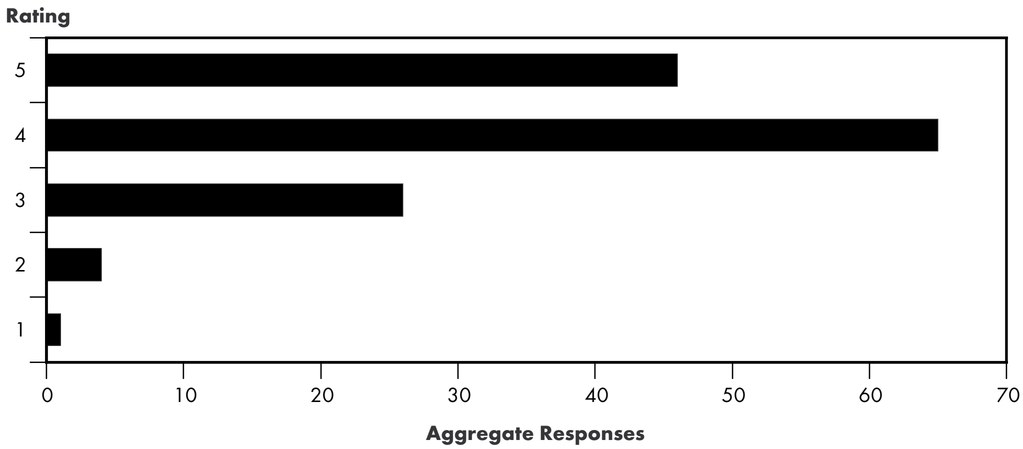
The three areas where the pipeline companies rated the highest were the same areas as in last year's survey, as demonstrated by the scores on the following questions:

1. How satisfied are you with the physical reliability of the pipeline company's operations?
2. How satisfied are you with the timeliness and accuracy of the pipeline company's invoices and statements?
3. How satisfied are you with the timeliness and usefulness of operations information (outages, available capacity, scheduled maintenance, flows, etc.) provided by the company?

The high level of satisfaction with the physical reliability of pipeline operations indicates that energy products are reliably being delivered to markets (see Figure 24).

FIGURE 24

Physical Reliability of Operations



The three areas where shippers believe that pipeline companies could improve the most are very similar to the areas in last year's survey. The questions where the pipeline companies rated lower were:

1. How satisfied are you that this pipeline company's tolls are competitive?
2. How satisfied are you with the degree to which the pipeline company demonstrates an attitude of continuous improvement and innovation?
3. How satisfied are you with the collaborative process (negotiations or task force meetings) utilized by this pipeline company?

Performance of the Board

The survey also indicated that approximately two-thirds of shippers are either satisfied or very satisfied with the Board's performance in creating an appropriate regulatory framework and with the Board's processes to resolve disputes. While this was a slight improvement over the previous year's survey, shippers did identify areas where the Board could improve its processes and performance.

2.3.2 Formal Complaints

If shippers are unable to resolve concerns with the pipeline, they can bring a complaint to the NEB. It can then be dealt with through appropriate dispute resolution (ADR), through a formal complaint process or the parties may continue to negotiate towards resolution. There were two shipper complaints this past year requiring a formal process before the Board:

Abitibi Consolidated Company (Abitibi) and Boise White Paper, L.L.C. (Boise)

Centra Transmission Holdings Inc., a Group 2 company, applied to the Board to increase its tolls. Subsequently two shippers, Abitibi and Boise wrote to the Board requesting additional time to examine Centra's application. The Board subsequently initiated a written process to deal with the matter. The Board approved Centra's application for increased tolls, subject to certain amendments. Additional information can be found in the Board's Reasons for Decision RHW-3-2005.

Petro-Canada Oil and Gas (PCOG)

PCOG applied to the Board requesting the issuance of an order requiring Westcoast to grant the permanent firm service relocation of PCOG's Transportation North Long Haul firm service without the requirement to extend its existing service agreement by two years. On 4 May 2006, the Board issued its decision on PCOG's application. The Board found that the practice of requiring a term extension does not constitute unjust discrimination and that permanent relocation may be considered a service. The Board was also of the view that not enough information concerning the appropriate level of consideration was included in the submissions. The Board directed Westcoast to bring the matter of permanent firm service relocation and the appropriate level of consideration back to the Board after discussion with the Tolls and Tariff Task Force. Further, the Board advised that PCOG's term extension, if any, will reflect the final Board decision in this matter. Additional information can be found in the Board's file, 4775-W005-1-17.

2.3.3 Service Enhancements

Pipeline companies modify their services on an ongoing basis as circumstances change or innovative ideas are brought forward. Normally, the pipeline or its shippers bring these proposed service enhancements to their tolls task force for discussion and review prior to submission to the Board and ultimate adoption. This past year, for example, Westcoast applied to the Board to introduce firm service enhancements of term differentiated rates and authorized over run service in Zones 3 and 4 and cross corridor crediting in Zone 3. The Board approved Westcoast's application. More information can be found in the Board's Reasons for Decision RHW-1-2005.

If the task force is unable to resolve the issue, a party may bring the issue directly to the Board. This past year, one such enhancement was brought to the Board and subsequently approved.

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 Mainline. The Board approved Coral's application and directed TransCanada to modify its Mainline Transportation Tariff to reflect this decision. Additional information can be found in the Board's Reasons for Decision RHW-2-2005.

2.3.4 Summary of Shipper Satisfaction

This past year, it was found that shippers are reasonably satisfied with the services provided by the pipeline companies and the Board's performance in creating an appropriate regulatory framework and the Board's processes to resolve disputes. For both the pipeline companies and the Board, shippers identified areas for improvement in service. Areas of improvement for the pipeline companies are outlined in the previous section. Shippers also noted that the Board could improve its processes through which tolls and tariffs are determined by streamlining those processes and actively engaging stakeholders so that it better understands the market context in which it makes decisions. The Board is taking this feedback into consideration. For example, in its Strategic Plan for 2006 – 2009 the Board identified the objective for its regulatory processes to be efficient, seamless and responsive to all stakeholders.

2.4 Pipeline Financial Integrity and Ability to Attract Capital

In order for a hydrocarbon transportation system to be efficient, pipeline companies must have adequate financial integrity to attract capital on reasonable terms and conditions. This enables them 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 used to assess these areas.

2.4.1 Financial Ratios

Financial statement information can be used to create financial ratios that are used for assessing a company's performance and financial integrity. Evaluating a financial ratio is most meaningful when the ratio of a particular company is compared with a benchmark or industry standard over time. These 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. Some reported financial information may pertain to a parent company, which may include non-regulated assets and/or assets from different industries.

The following sections specifically outline and discuss some of the ratios used to assess the financial risk and operating profitability of certain NEB-regulated pipeline companies. The final section outlines and discusses some NEB-approved financial ratios.

Financial Risk

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 financial risk gives some indication of its financial viability.

Ratios used to evaluate a company's level of financial risk include interest coverage, fixed-charges coverage, and cash flow-to-total debt and equivalents.

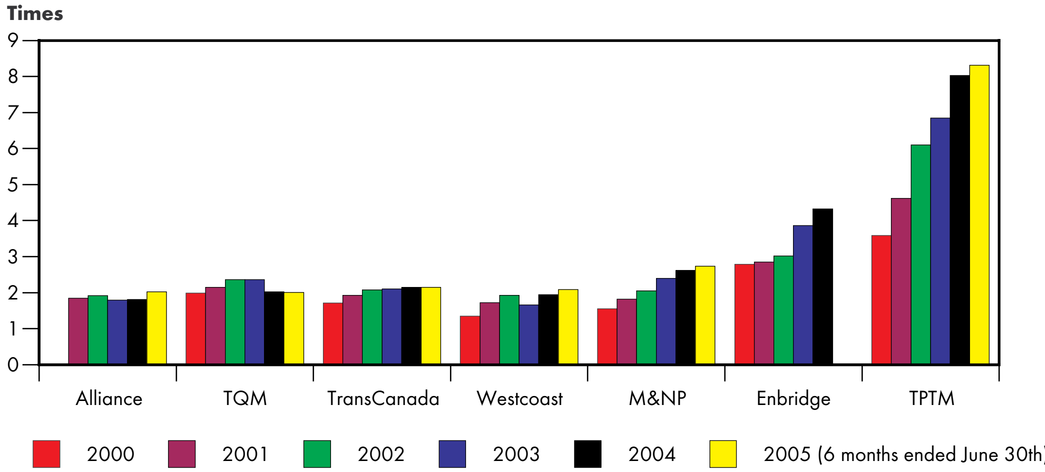
Interest and Fixed-Charges Coverage Ratios

An interest coverage ratio assesses 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. A fixed-charges coverage ratio also assesses the ability to make interest payments and repay debt obligation; however, it also takes into consideration other types of fixed payments a company is obligated to make. It is defined as EBIT less other fixed-charges divided by interest and other fixed-charges. Higher ratios indicate an increased likelihood that the company will be able to meet its obligations and may 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 25. The average fixed-charges coverage

FIGURE 25

Fixed-Charges Coverage Ratios



Source: DBRS

N.B. There was no fixed-charges coverage ratio reported for Enbridge in 2005.

ratio for these companies for the six months ending June 2005 is 3.22 times. TPTM's fixed-charges coverage ratio is higher, primarily due to a deemed common equity ratio of 45 percent (larger than its peers), which means it carries less debt and, therefore, has lower fixed payments.

From 2000 to 30 June 2005, the fixed-charges coverage ratio for these pipeline companies increased on average by 49 percent[7]. This growth was primarily driven by M&NP, Enbridge and TPTM. No company saw its fixed-charges coverage ratio decline from its 2000 level. The consistent increases in fixed-charges coverage ratios is one metric signaling a decrease in these 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 assessing a company's ability to meet its debt obligations and fixed payments. It is defined as operating cash flow divided by total debt and 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.

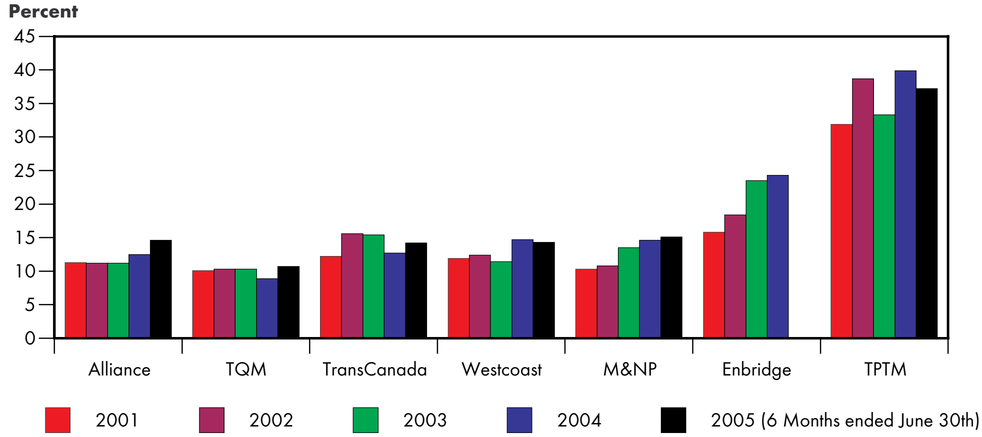
The cash flow-to-total debt and equivalents ratios for some NEB-regulated pipeline companies, as calculated by DBRS, are shown in Figure 26. The average cash flow-to-total debt and equivalents ratio for these companies was 17.68 percent for the 6 months ending June 2005. TPTM's cash flow-to-total debt 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 20 percent from 2000 to 2005. The increase has been steady without any noteworthy periods of deterioration. Similar to the fixed-charges coverage ratio, the consistent increase in cash flow-to-total debt and equivalents ratios is another metric which signals that, on average, these pipeline companies' financial risk has been decreasing.

7 Historically, Enbridge's fixed-charges and cash flow-to-debt and equivalents ratios were much higher than the average of the other pipeline companies in Figures 20 and 21. Since these ratios were not provided for Enbridge in 2005, the pipeline company average for 2005 and the percentage increase since 2000 and 2001 respectively, may be biased downward.

FIGURE 26

Cash Flow-to-Total Debt and Equivalents Ratios



Source: DBRS

N.B. There was no cash flow-to-total debt and equivalents ratio reported for Enbridge in 2005.

Operating Profitability

Return on Common Equity

ROE is commonly used to assess the operating profitability of a company. ROE is defined as net income divided by common equity. For NEB-regulated pipeline companies, this is the return on the equity portion of the rate base that is approved by the Board. A higher ROE is typically preferred by both bondholders and, even more so, by equity investors.

Table 4 shows the achieved ROE for several NEB-regulated pipeline companies from 2000 to 2005 along with the NEB-approved ROE in accordance with the RH-2-94 Formula[8] (RH-2-94 Formula ROE). Alliance, Enbridge, M&NP and TPTM are not subject to the RH-2-94 Formula ROE as they have all negotiated an ROE with their shippers[9]. As per their respective negotiated settlements, Enbridge and TPTM are not required to submit their achieved ROE to the NEB. Therefore, neither of these pipeline companies are included in Table 4. Westcoast's Field Services Division is also not subject to the ROE formula as it is under light-handed regulation[10]. Its tolls for gathering and processing services are negotiated individually with shippers.

From 2000 to 2005, most pipeline companies subject to the RH-2-94 Formula ROE have consistently had ROEs in the mid-to-high nine percent range (except for Westcoast Transmission which has achieved higher ROEs). The RH-2-94 Formula ROE for 2006 is 8.88 percent.

NEB-Approved Ratios

When the Board approves a Group 1 pipeline company's tolls for a specified time period, it typically also approves a ROE and deems a common equity ratio for the regulated entity. Therefore, the Board has influence over the operating profitability and financial risk of some Group 1 pipeline companies.

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

9 These pipelines settlements are subsequently approved by the Board.

10 Light-handed regulation is essentially regulation on a complaint basis with rules. Additional information can be found in RHW-1-98.

TABLE 4

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

	2000	2001	2002	2003	2004	2005
Alliance	11.21	11.25	11.25	11.25	–	–
Foothills	9.90	9.61	9.53	9.79	9.56	9.46
M&NP	13.80	14.20	12.95	12.31	13.75	14.31
TQM	9.96	10.21	9.80	10.21	9.84	9.92
TransCanada	9.99	9.72	9.95	10.18	9.83	9.66
B.C. System	9.90	6.86	9.53	8.21	8.51	9.46
Westcoast Field Services	–	13.62	14.87	6.76	11.63	12.48
Westcoast Transmission	12.68	15.84	13.44	12.93	10.28	10.82
NEB RH-2-94 Formula	**9.90**	**9.61**	**9.53**	**9.79**	**9.56**	**9.46**

Source: NEB Surveillance and Annual Reports; dash indicates not available

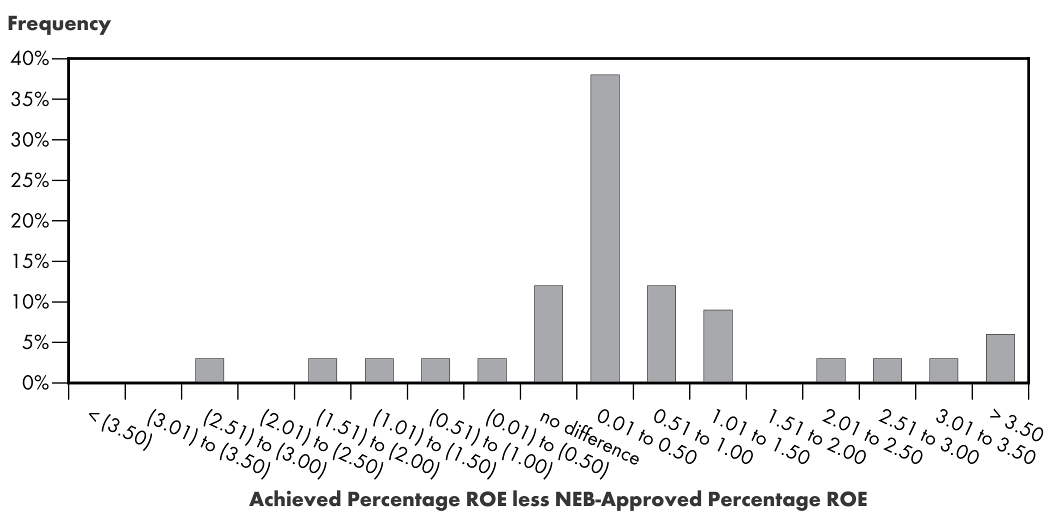
NEB-Approved Return on Common Equity

NEB-approved ROEs have great influence over the ROEs that are actually achieved. Achieved ROEs can vary from NEB-approved levels for various reasons, such as incentive and profit sharing mechanisms and cost reductions over the year.

Figure 27 charts the difference between achieved ROEs and NEB-approved ROEs for TransCanada, B.C. System, TQM, Westcoast Transmission system, and M&NP[11]. Enbridge and TPTM are not required to submit their achieved ROEs to the Board as per their negotiated settlements. Westcoast Field Services is not included as it is subject to light-handed regulation. Foothills and Alliance are not included in Figure 27 as neither is able to over- or under-perform on ROE in accordance with their respective cost-of-service methodologies.

FIGURE 27

Achieved and NEB-Approved ROE for the Years 1999 to 2005



11 TransCanada, B.C. System, TQM and Westcoast Transmission system have NEB-approved ROEs subject to the RH-2-94 Formula ROE, whereas M&NP has a NEB-approved ROE of 13 percent.

From 1999 to 2005, pipeline companies (included in Figure 27) have met or exceeded their NEB-approved ROEs 85 percent of the time. This stability and predictability of their operating profitability is positive for both bondholders and equity investors. It also highlights that these pipeline companies, in many cases, have been able to meet and outperform approved levels through cost reductions, incentive and profit sharing mechanisms.

NEB-Approved Deemed Common Equity Ratios

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. The Board approves a deemed common equity ratio[12] for most of the Group 1 pipeline companies that it regulates.

TABLE 5

Deemed Common Equity Ratios (Percent)

	2000	2006
Alliance	30	30
Foothills	30	36
M&NP	25	25
TQM	30	30*
TransCanada	30	36
B.C. System	30	36
Westcoast Transmission	30	31*

* TQM and Westcoast Transmission's 2006 deemed common equity ratios are interim.

Table 5 shows the deemed common equity ratio for some NEB Group 1 pipeline companies. TransCanada, Westcoast Transmission, B.C. System and Foothills have had their deemed common equity ratios increased between 2000 and 2006. These increases are credit positive and lower the financial risk of the pipeline companies.

2.4.2 Credit Ratings

In Canada, pipeline credit ratings are determined by three independent credit rating agencies: DBRS, Standard & Poor's (S&P), and Moody's Canada Inc. (Moody's). A comparison of the rating scales for DBRS, S&P and Moody's can be found in Appendix 1. Credit ratings, like stock prices, generally reflect the consolidated operations of the entire company and not solely the regulated portion. Thus, using these ratings as an accurate measure of the creditworthiness of a NEB-regulated pipeline owned by a company with both regulated and non-regulated operations, such as TransCanada and Enbridge, must be interpreted with some care. In addition, 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.

Dominion Bond Rating Service

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. While key considerations will vary from industry to industry, some of the common factors considered for most ratings are: core profitability, asset quality, strategy and management strength, and financial and business risk.

The following factors are also important considerations in deriving the credit ratings for pipelines and electric and gas utilities: regulatory factors, competitive environment, supply and demand considerations, and regulated versus non-regulated activities. DBRS credit ratings for several NEB-regulated pipeline companies are shown in Table 6. As indicated, these ratings have remained stable from 2000 to the present, varying from BBB (high) to A (high).

[12] 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.

Standard & Poor's

A credit rating from S&P reflects its current opinion of a company's overall capacity to pay its financial obligations. 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. S&P's opinion may also apply to specific financial obligations.

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 weaken the company's capacity to meet its financial commitments.

S&P credit ratings for several NEB-regulated pipeline companies are shown in Table 7. This table indicates that these ratings have been relatively stable from 2000 to the present, ranging from BBB (stable) to A (negative).

Both DBRS and S&P have, at various times, expressed an opinion that the ROE awarded through the RH-2-94 Formula and the deemed equity ratios awarded by the Board are low by international standards. Notwithstanding these comments, the ratings assigned by both of these agencies for the NEB-regulated companies are all investment grade.

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 questions:

1. What is the risk to the debt holder of not receiving timely payment of principal and interest on this specific debt security?
2. How does the level of risk compare with that of all other debt securities?

Like S&P, Moody's credit rating is its current opinion of a company's overall capacity to pay its financial obligations and focuses its ratings on the overall creditworthiness of a consolidated entity. In so doing, Moody's measures the ability of an issuer to generate cash in the future. This determination is built on an analysis of the strengths and weaknesses of the individual issuer compared with those of its peers worldwide. Moody's also takes into consideration factors external to the issuer, including industry or nation-wide trends that could impact the entity's ability to meet its debt obligations. Of particular concern is the ability of company management to sustain cash generation in the face of adverse changes in the business environment.

The rating histories for several NEB-regulated pipeline companies are provided in Table 8. All of Moody's ratings place these pipelines in the investment grade category, ranging from "medium grade" to "upper-medium grade".

TABLE 6

DBRS Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
Alliance	BBB(high)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
M&NP	A	A	A	A	A	A	A
TQM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
TransCanada	A	A	A	A	A	A	A
Westcoast[1]	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
Enbridge	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)	A(high)
Express[2]	NR	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)
TPTM	A(low)	A(low)	A(low)	A(low)	A(low)	A(low)	discontinued /debt repaid
TNPI	NR	NR	NR	NR	NR	A(low)	A(low)

Notes: (1) Unsecured debentures; (2) Senior secured

NR Not reported

TABLE 7

S&P Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
TQM	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable	BBB+/Stable
TransCanada	A-/Stable	A-/Stable	A-/Watch Negative	A-/Watch Negative	A-/Watch Negative	A-/Negative	A-/Negative
Westcoast	A-/Negative	A-/Stable	A/Negative	BBB/Stable	BBB/Positive	BBB/Watch Negative	BBB/Stable
Enbridge	A-/Stable	A-/Negative	A-/Negative	A-/Stable	A-/Stable	A-/Stable	A-/Stable
TPTM	BBB+/Stable	BBB+/Stable	BBB+/Watch Negative	BBB/Stable	BBB/Stable	BBB+/Stable	discontinued / debt repaid

TABLE 8

Moody's Credit Rating History

Pipeline	2000	2001	2002	2003	2004	2005	Current
Alliance[1]	Baa1	A3	A3	A3	A3	A3	A3
M&NP[2]	A1	A1	A1	A1	A1	A2	A2
TransCanada[1]	A2	A2	A2	A2	A2	A2	A2
Enbridge	NR	NR	NR	NR	NR	NR	NR
Express[2]	A3	Baa1	Baa1	Baa1	Baa1	Baa1	Baa1

Notes: (1) Senior unsecured; (2) Senior secured

2.4.3 Comments by Investment Community

As noted previously, pipeline companies must be able to access capital markets to maintain and, potentially, expand their systems as the needs of the transportation market change. Board staff met with credit rating analysts, equity analysts (sell-side analysts), and suppliers of capital such as insurance and pension funds (buy-side analysts) 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. This section reflects the views expressed in those meetings.

All parties expressed the view that there was no problem accessing debt markets at this time. In fact, utilities frequently enter the market to refinance their debt and, given the current liquidity in the markets, they have been able to do so at favourable spreads relative to government bonds.

Several analysts noted that Canadian regulation, including the ROE formula approach, provides transparency, predictability and stability, which are seen as highly beneficial. However, a number of analysts felt that the ROE generated by the NEB ROE formula and the formulas of other Canadian regulators were "a little too low" and not supportive of dividend growth or credit metrics. Although most analysts felt that utilities have good access to equity markets, the current level of ROEs was seen by some as impeding this access. As there has been, in most cases, adequate pipeline capacity from the WCSB in recent years, the ability of pipeline companies to access equity markets has not been significantly tested.

Many equity analysts publish their assessments of various companies for investors. Most of the analysts currently rate major NEB-regulated pipeline companies in the "Hold" or "Buy" categories. A number of equity analysts commented that where they have "Buy" ratings on Canadian utility stocks, they tend to reflect the prospects of the companies' non-regulated businesses. A number of analysts also noted that companies have reduced costs and taken other steps to support corporate profit and dividend growth for several years, and they questioned how long this can continue.

It was noted that pipeline stocks are part of the interest-sensitive segment of the equity market and as such, low interest rates have been positive for valuations and the price-to-earnings ratio. The price-to-earnings ratios of Canadian utilities have been higher than their U.S. and European counterparts. The reasons given for this difference included greater growth opportunities in Canada given oil sands, northern gas, power infrastructure development, a more stable regulatory environment, as well as strong foreign interest in Canadian stocks in general.

2.4.4 *Summary of Pipeline Financial Integrity and Ability to Attract Capital*

The financial information and observations by the investment community are summarized as follows:

- Fixed-charges and cash flow-to-total debt and equivalents coverage ratios have increased since 2000.
- Deemed common equity ratios have increased since 2000.
- Achieved ROEs have, in most cases, been greater than or equal to their NEB-approved levels between 1999 and 2005.
- Achieved ROEs have been stable and predictable.
- Credit ratings continue to be strong.
- The investment community is of the view that NEB-regulated companies should have no problems accessing the capital markets at this time.

These observations signal that, currently, NEB-regulated pipelines have adequate financial integrity to attract capital on reasonable terms and conditions.

2.5 Proposed Pipelines

Many proposals to expand pipeline capacity or build new pipeline systems have been announced, applied for or recently approved. These include gas pipelines to growing markets in Canada and the U.S. and pipelines to ship western Canadian crude oil to the West Coast for delivery to Washington State and offshore markets, the U.S. Midwest and southern PADD II and the U.S. Gulf Coast (PADD III). More specifically, these project proposals include:

- new pipelines connecting northern gas supplies to existing gas infrastructure;
- natural gas expansions in the east to facilitate market development in eastern Canada and the U.S. Northeast; and
- pipeline laterals connecting existing infrastructure to proposed LNG receiving terminals in Nova Scotia and New Brunswick; and
- oil pipeline expansions and new pipeline proposals to facilitate the expected growth in the next decade in oil sands production.

Natural Gas

In the coming decade, demand for natural gas in North America is expected to exceed the growth in North American domestic supplies. In Canada, there are two sectors of growth that bear noting: oil sands projects in Alberta and electricity generation in Ontario.

The Canadian oil sands projects are a large and growing market for natural gas. Today, these projects consume about 0.7 Bcf/d. Natural gas is used to generate power, generate steam for in situ oil production and upgrade bitumen into synthetic blends. Gas demand for oil sands is expected to more than double to perhaps 2 Bcf/d over the next decade depending on the number of oil sands projects that proceed and the technology used.

In addition, Ontario's policy to remove 7 500 MW of coal-fired electrical generation by 2009 may require significant supplies of natural gas for power generation While refurbishment of existing nuclear generation and the addition of renewable power sources may meet part of the requirement, it is possible that new electrical generation will primarily be fired by natural gas.

Table 9 summarizes currently announced Canadian natural gas pipelines and expansion proposals.

TABLE 9

Announced Canadian Natural Gas Pipelines and Expansions

Pipeline	Location	Capacity Increase (Bcf/d)	Proponents' Estimated Completion Date	Market to be Served
TransCanada PipeLines Limited – 2006 Eastern Mainline Expansion	Ontario, Québec	.310[13]	Late 2006	Central Canada, Northeastern U.S.
TransCanada PipeLines Limited– 2007 Eastern Mainline Expansion	Ontario, Québec	.377[14]	2007	Central Canada, Northeastern U.S.
Mackenzie Gas Pipeline	Mackenzie Delta, Northwest Territories to Alberta	1.2	2011	North America
Maritimes & Northeast Pipeline – Brunswick Pipeline	New Brunswick	0.75	2008	Atlantic Canada, Northeastern U.S.
Maritimes & Northeast Pipeline – Bear Head Pipeline	Nova Scotia	.813	N/A	Atlantic Canada, Northeastern U.S.

N/A Not Available

[13] TCPL Eastern Mainline Expansion: Montreal/North Bay Shortcut to Iroquois delivery point.

[14] TCPL Eastern Mainline Expansion: Montreal/North Bay Shortcut to Les Cèdres (148 MMcf/d), Philipsburg Extension to Philipsburg (12 MMcf/d) and Kirkwall/Niagara Line to Chippawa (217 MMcf/d).

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. Furthermore, advances in liquefaction and transportation technologies have lowered the unit cost of LNG by 30 percent over the past decade, enabling the use of LNG as a cost competitive source of gas supply in North America. In anticipation of growing natural gas requirements, expansions of some existing U.S. terminals and numerous new receiving facilities have been proposed, including sites in Canada as shown in Table 10.

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. As discussed above, pipeline laterals will be required to connect LNG receiving terminals to existing natural gas pipeline infrastructure in order to deliver the gas to market.

TABLE 10

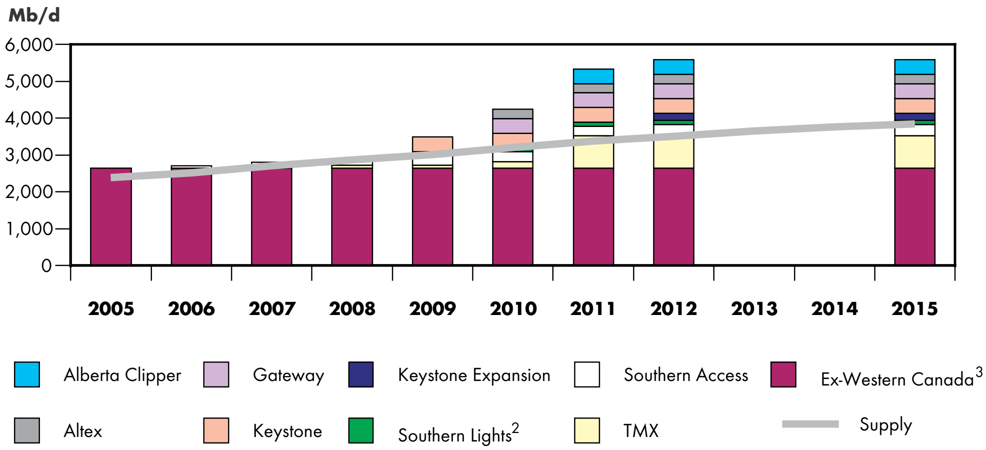
Proposed Canadian LNG Terminals

Terminal	Company	Location	Capacity (Bcf/d)	Proponents' Estimated Completion Date	Market to be Served
1 Bear Head	Anadarko Petroleum Company	Point Tupper, Nova Scotia	0.750 to 1.00	N/A	Atlantic Canada, Northeast U.S.
2 Keltic Goldboro	Keltic Petrochemicals Inc.	Goldboro, Nova Scotia	1.00	Late 2009	Atlantic Canada, Northeast U.S.
3 Cacouna Energy	TransCanada PipeLines Limited and Petro-Canada	Gros Cacouna, Québec	0.50	2010	Québec, Ontario, Northeast U.S.
4 Rabaska	Gaz Metro Limited Partnership, Gaz de France and Enbridge Inc.	Beaumont, Québec	0.50	2010	Québec, Ontario
5 Canaport	Irving Oil Limited and Repsol YPF	Saint John, New Brunswick	1.0	Late 2008	Atlantic Canada, Northeast U.S.
6 WestPac Prince Rupert	WestPac Terminals Inc.	Ridley Island, British Columbia	0.15 to 0.50	2009	Westcoast North America
7 Kitimat	Galveston Energy	Port of Kitimat, British Columbia	0.61	2009	Westcoast North America
8 Statia	Statia Terminals Canada Partnership	Canso Strait, Nova Scotia	0.50	N/A	Atlantic Canada, Northeast U.S.

N/A Not Available

FIGURE 28

NEB Supply Forecast and Proposed Pipeline Projects and Timing



1 The pipeline projects are listed alphabetically. In-service dates are proposed by the project sponsors

2 Edmonton to Cromer

3 Total pipeline capacity out of the WCSB

TABLE 11

Announced and Proposed Canadian Oil Pipelines and Expansions

Pipeline	Potential Filing Date	Capacity Increase (Mb/d)	Proponents' Estimated Completion Date	Market
Terasen (TPTM)		**75**		PADD V
Phase One TMX1	Filed July 2005	35	April 2007	Offshore/Far East
Phase Two TMX1	Filed February 2006	40	Nov. 2008	
Southern Option		**700**[1]		PADD V
TMPL TMX2	01Q2007	100	Jan. 2010	Offshore/Far East
TMPL TMX3	N/A	300	Jan. 2011	
Northern Option (TMX)	N/A	**450**	2011	PADD V Offshore/Far East
Enbridge Gateway (oil/diluent)	Fall 2006	**400/150**	Mid-2010	PADD V Offshore/Far East Alberta (diluent line)
Pembina Spirit (diluent)	N/A	100	April 2009	Alberta
Enbridge Southern Lights	N/A			
Southern Lights (diluent)		**180**		
Line 2 Expansion (oil)		**169**	2009	Alberta
Edmonton to Cromer		103		PADD II
Cromer to Clearbrook		33		PADD II
Clearbrook to Superior		33		PADD II
TCPL Keystone	June 2006	435	2009	Southern PADD II/ PADD III
Alberta Clipper	N/A	**400**	2010/11	Southern PADD II
Altex Energy	N/A	250	4Q2010	PADD III
Enbridge (Southern Access)		**315**		Midwest/Southern PADD II
Phase I	May 2006	120	Oct. 2006 and Feb. 2007	
Phase II	N/A	148	2008/09	
Phase III	N/A	47	N/A	

N/A Not Available

1 The 700 mb/d includes the existing capacity of 300 mb/d and the capacity additions from TMX2 and TMX3.

Oil

High crude oil prices and strong global demand are key drivers in the expansion of the oil sands. In this regard, many proposals to expand existing pipelines or build new facilities have been announced. Figure 28 shows that pipeline capacity out of western Canada could be tight in 2008.

Table 11 illustrates announced and potential expansions by Canadian pipelines. Additional details about these proposals are found in the EMA entitled *Canada's Oil Sands Opportunities and Challenges to 2015: An Update*, released in June 2006.

The proposals for pipeline expansion and construction of new pipelines indicate that the market is responding to increases in supply and demand.

2.6 Emerging Issues

While the transportation system is currently working well, there are a number of challenges facing the industry.

The demand for natural gas in North America is expected to increase by about two percent per year over the next decade. Conventional sources of supply for natural gas in North America are not likely to meet the increased demand. LNG is the fastest growing fuel source worldwide, and LNG's market share in North America is estimated to grow to about 15 percent within the decade. Although there is uncertainty around the number of LNG terminals that will be built in North America and the potential effects that imported LNG will have on the supply, demand and pattern of natural gas flow, LNG could become an important component of gas supply in Canada.

The construction of LNG terminals could have implications for existing pipeline transportation systems. For some pipelines, such as the TransCanada Mainline, this could result in volumes from the WCSB being displaced. For others, such as PNGTS and M&NP on the east coast, there is the possibility of higher capacity utilization on their systems. Direction of flow and toll design may also be affected. The PNGTS pipeline system has the potential for backhauls or reversal to import gas into Canada. There are also possibilities for expansion, reversals or backhauls in Quebec on TQM. Northern gas projects such as the Mackenzie Valley Pipeline or a pipeline from Alaska, if approved, and constructed, would also affect flows on existing systems.

If the expected increase in natural gas demand for power generation in Ontario materializes, it will impact the balance of supply and demand and consequent gas flows. The impact of this power generation on pipeline infrastructure will depend on the total amount of generation built and its location. New pipeline services may also be required to satisfy the needs of the power generation customers.

The expected growth in oil sands production is forcing industry to address questions such as which incremental markets to serve and how to expand the pipeline system to access them efficiently. Options include expanding existing systems and constructing new systems to access new markets in the U.S. and/or Asia. Given the large capital outlay and the relative irreversibility of the investment, market participants want to ensure that the optimal decisions are made.

There is concern in industry and in the financial community about the potential for insufficient pipeline capacity, particularly oil capacity, and conversely, the potential for excess capacity if too many projects go ahead. Other issues include the financial implications of increasing levels of competition among oil pipelines and the manner in which the regulatory process would unfold if numerous competing applications come before the NEB.

The challenge for the pipeline transportation industry is to have appropriate pipeline capacity in service to correspond to increases in production and growing market needs. For this to happen, there must be recognition of adequate lead times to achieve sufficient market support from amongst competing proposals, obtain regulatory approvals, arrange financing, mobilize labour and materials, and construct. A key component is that the regulatory process continues to be fair and effective with clear timelines and clear requirements.

Some of the above-noted issues will be settled among market participants; others may be examined in formal proceedings before the Board. The Board will continue to consult with stakeholders and seek input if and when any regulatory initiatives are pursued.

CONCLUSIONS

In the Introduction to this report, the Board identified its assessment criteria. Based on these criteria the Board continues to believe that, at the present time, the Canadian hydrocarbon transportation system is working effectively.

1. **There is adequate capacity in place on existing natural gas pipelines.** The basis differentials and capacity utilization charts show that most NEB-regulated gas pipelines have some excess capacity, even during the peak winter season. Some excess capacity out of the WCSB and the unprecedented high prices for energy has provided producers with the flexibility to access markets of their choice at most times. However, there are constraints at the market end of some pipelines as indicted by expansions currently underway.

   Capacity is tight on oil pipeline transportation systems. While the capacity utilization charts show that there is spare capacity on some of the pipelines, additional capacity is required to meet the growing demand, provide flexibility and enhance market penetration. The need for additional capacity is best shown by the number of announced and proposed pipelines and expansions.

2. **Shippers continue to indicate that they are reasonably satisfied with the services provided by pipeline companies.** The results of the NEB Pipeline Services Survey again rate the physical reliability of pipeline operations very highly, while satisfaction with toll competitiveness was again identified as the area where shippers most had concerns.

3. **NEB-regulated pipeline companies are financially sound** and able to attract capital on reasonable terms and conditions. While it is recognized that some of the data and indicators reviewed is for the consolidated operations of pipeline companies, discussion with the investment community indicated that, at this time, NEB-regulated pipeline companies should have no difficulty raising capital. Extensive investment will be required in the future to provide needed infrastructure and the financing for those facilities will depend upon the characteristics of the projects and the financial markets at that time.

As identified in Section 2.5 there are a significant number of proposals to build or expand Canadian pipelines to deliver additional volumes of oil and natural gas to growing markets. Some of these proposals may be competing for the same sources of supply and perhaps the same markets.

The 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 coordinating with other jurisdictions. Investors desire clear regulatory processes with predictable timelines. New investment can be frustrated when timelines stretch out and unexpected regulatory hurdles materialize during the process. 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.

The Board recognizes that this report is 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.

Debt Rating Comparison Chart

This chart provides a comparison of the rating scales used by DBRS, S&P and Moody's when rating long-term debt.

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.

S&P'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.

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
1	4	26	65	46	4.06

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
1	4	26	65	46	4.06

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

1	2	3	4	5	Average
9	10	24	60	36	3.75

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
4	12	37	73	16	3.60

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
6	7	43	69	17	3.59

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
8	29	62	31	10	3.04

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
14	19	39	49	17	3.26

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	19	47	49	11	3.30

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

1	2	3	4	5	Average
4	17	51	55	10	3.37

10. How satisfied are you that this pipeline company's transportation tolls are competitive?

1	2	3	4	5	Average
14	29	45	38	11	3.02

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
8	12	51	42	8	3.25

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
7	11	48	47	6	3.29

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
6	8	44	63	18	3.57

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

Improved	19	13%
Remained the Same	110	78%
Decreased	13	9%
Total	**142**	**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
7	7	30	72	8	3.54

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
3	7	23	54	4	3.54

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

Stakeholder Consultation

Alliance Pipeline Ltd.
BMO Nesbitt Burns
Canadian Association of Petroleum Producers
Canadian Energy Pipeline Association
CIBC World Markets
Cochin Pipe Lines Ltd.
CPP Investment Board
Credit Suisse First Boston
Dominion Bond Rating Service
Enbridge Pipelines Inc.
Express Pipeline Limited Partnership
First Energy Capital
Foothills Pipe Lines Ltd.
Kinder Morgan Canada Inc.
Maritimes and Northeast Pipeline
Moody's Canada Inc.
Ontario Teachers' Pension Plan
RBC Capital Markets
Standard & Poor's
Sun Life Financial
TD Newcrest
Terasen Pipelines Inc.
Trans Mountain Pipe Line
Trans-Northern Pipeline Inc.
Trans Québec & Maritimes Pipeline Inc.
TransCanada PipeLines Limited
Union Gas Limited
Westcoast Energy Inc., carrying on business as Duke Energy Gas Transmission

Group 1 and Group 2 Pipeline Companies Regulated by the NEB

As of 31 December 2005

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., carrying on business as Duke Energy Gas Transmission

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
AltaGas Suffield Pipeline Inc.
AltaGas Transmission Ltd.
Apache Canada Ltd.
ARC Resources Ltd.
Bear Paw Processing Company (Canada) Ltd.
BP Canada Energy Company
Canadian Hunter Exploration Ltd.
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.
Devon Energy Canada Corporation
Echoex Energy Inc.
EnCana Border Pipelines Limited
EnCana Ekwan Pipeline Inc.
EnCana Oil & Gas Co. Ltd.
EnCana Oil & Gas Partnership
EnCana West Ltd.
ExxonMobil Canada Properties
Forty Mile Gas Co-op Ltd.

Huntingdon International Pipeline Corporation
Husky Oil Operations Ltd.
KEYERA Energy Ltd.
Many Islands Pipe Lines (Canada) Limited
Mid-Continent Pipelines Limited
Minell Pipeline Limited
Murphy Canada Exploration Company
Murphy Oil Company Ltd.
Nexen Inc.
Niagara Gas Transmission Limited
Northstar Energy Corporation
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.
Regent Resources Ltd.
Renaissance Energy Ltd.
St. Clair Pipelines Management Inc.
Samson Canada, Ltd.
Shiha Energy Transmission Ltd.
Sierra Production Company
Suncor Energy Inc.
Taurus Exploration Canada Ltd.
Union Gas Limited
Vector Pipeline Limited Partnership
County of Vermilion 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
PrimeWest Energy Inc.
Provident Energy Pipeline Inc.
Renaissance Energy Ltd.
SCL Pipeline Inc.
Shell Canada Products
Shell Canada Products Limited
Sun-Canadian Pipe Line Company
Taurus Exploration Canada Ltd.
Yukon Pipelines Limited
1057533 Alberta Ltd.

GOAL 3

Canadians benefit from efficient energy infrastructure and markets.