National Energy Board

Office national de l'énergie

Reasons for Decision

TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd.

MH-1-2006

February 2007

Transfer of Facilities

Canada

National Energy Board | Office national de l'énergie

ERRATA

File OF-Fac-G-T241-2006-01
12 February 2007

Please note that the English and French version of the *National Energy Board's MH-1-2006 Reasons for Decision dated February 2007,* together with Order MO-02-2007 attached therein are corrected as follows:

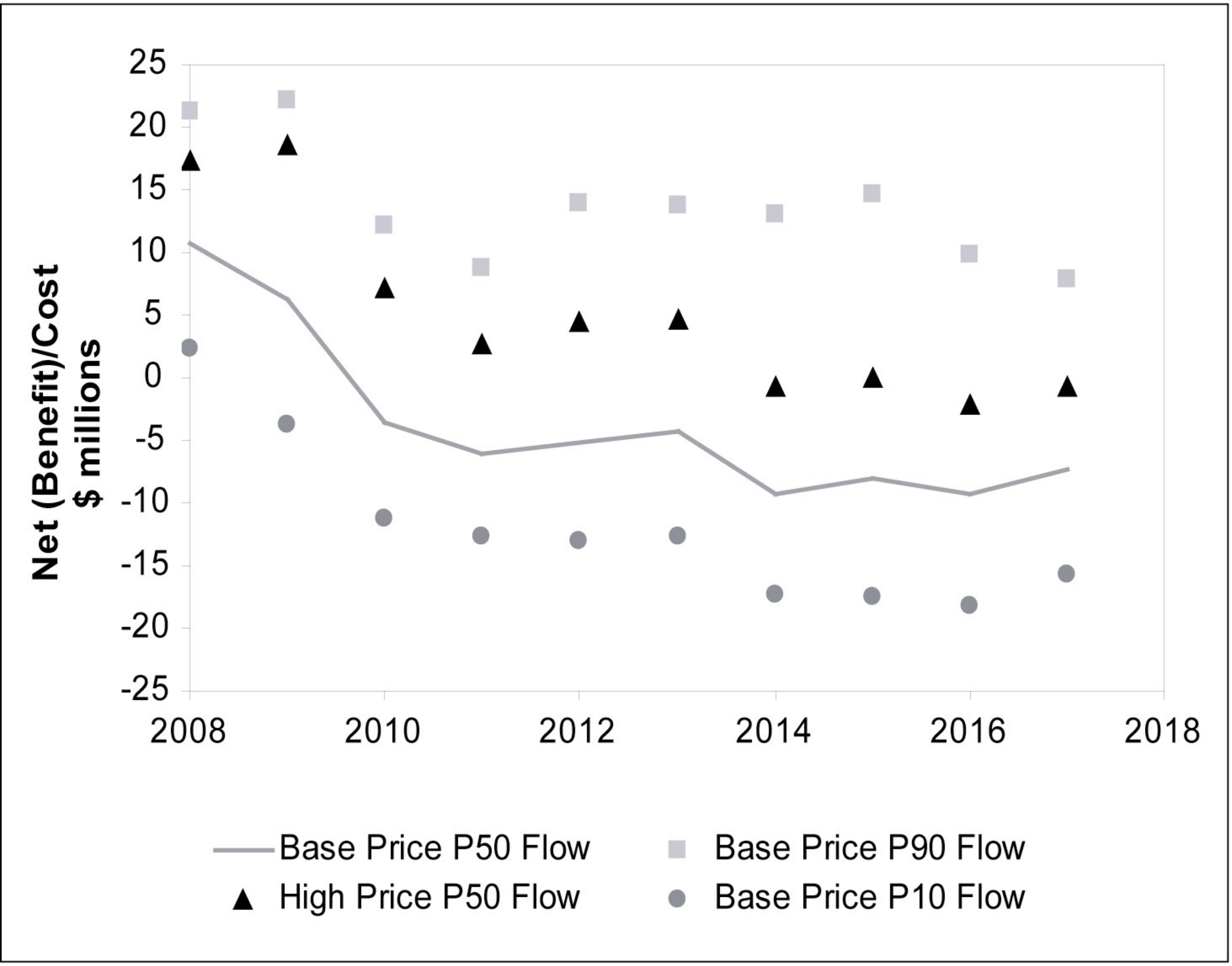
English Version:
1. Page 43, Figure 4-1 entitled "Net Benefit/(Cost) to Shippers", is hereby replaced by the attached revised Figure 4-1.

French Version:
1. Page 48, Figure 4-1 entitled "Avantage (coût) net pour les expéditeurs", is hereby replaced by the attached revised Figure 4-1.

NATIONAL ENERGY BOARD

Michel L. Mantha
Secretary

Canada


Net (Benefit)/Cost
$ millions
25
20
15
10
5
0
-5
-10
-15
-20
-25
2008
2010
2012
2014
2016
2018
Base Price P50 Flow
Base Price P90 Flow
High Price P50 Flow
Base Price P10 Flow

National Energy Board

Reasons for Decision

In the Matter of

TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd.

Application dated 5 June 2006 for leave to transfer pipeline facilities and for a determination of the transfer price

MH-1-2006

February 2007

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Abbreviations

Act or NEB Act	*National Energy Board Act*
AGUA	Alberta Gas Utilities Act
Alliance	Alliance Pipeline Ltd.
Applicants	TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd.
ATCO	*ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, [2006] 1 S.C.R. 140
BCDENS	BP Canada Energy Company, Coral Energy Canada Inc., Devon Canada Corporation, EnCana Corporation, Nexen Inc., Shell Canada Limited
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Board or NEB	National Energy Board
bpd	barrels per day
ºC	degrees Celsius
CAPP	Canadian Association of Petroleum Producers
CBM	coalbed methane
CEP	Communications, Energy and Paperworkers Union of Canada
CNR	Canadian Natural Resources Limited
COC	Council of Canadians
ConocoPhillips	ConocoPhillips Canada Limited
EUB	Alberta Energy and Utilities Board
Filing Manual	National Energy Board Filing Manual
FT	firm transportation
Gaz Métro	Société en commandite Gaz Métro
GHG	greenhouse gases
GJ	gigajoules (10^9 joules)

GJ/d	gigajoules per day
GLGT	Great Lakes Gas Transmission
GLJ	GLJ Petroleum Consultants Ltd.
GPUAR	*Gas Pipeline Uniform Accounting Regulations*
GTN	Gas Transmission Northwest
Imperial	Imperial Oil Limited
Informetrica	Informetrica Limited
IT	interruptible transportation
Keystone	TransCanada Keystone Pipeline GP Ltd.
Keystone Shippers Group	ConocoPhillips Canada Limited, Suncor Energy Marketing Inc., Canadian Natural Resources Limited
km	kilometre(s)
LNG	liquefied natural gas
m^3	cubic metres
m^3/d	cubic metres per day
MLV	mainline valve
mm	millimetre(s)
MMcf/d	million cubic feet per day
NBV	net book value
NPV	net present value
OD	outside diameter
Ontario	Minister of Energy for the Province of Ontario
OPUAR	*Oil Pipeline Uniform Accounting Regulations*
PADD	Petroleum Administration for Defense District that defines a market area for crude oil in the United States
Purvin & Gertz or P&G	Purvin & Gertz Inc.
SEMI	Suncor Energy Marketing Inc.
TJ	terajoule(s) (10^{12} joules)

TransCanada	TransCanada PipeLines Limited
TTF	Tolls Task Force
US$	United States dollars
Vector	Vector Pipeline Limited Partnership
WCSB	Western Canada Sedimentary Basin
$	Canadian dollars

Glossary of Terms

Alberta System	TransCanada's provincially-regulated natural gas transmission system in Alberta; the Alberta System gathers natural gas for use within the province and delivers it to provincial boundary points for connection with the Mainline and other gas transmission systems and pipelines
Base Case	TransCanada's best estimate of future throughput on its Mainline
capability	maximum flow rate that can be transported taking into account specific operating conditions, for example, outages, maintenance and ambient temperature
capacity	maximum flow rate that can be transported based on specific design criteria
central Canada	natural gas market region that includes Ontario and Quebec
coalbed methane	an unconventional form of natural gas that is trapped within the matrix of coal seams
condensate	a mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other gathering facilities, or at the inlet of a natural gas processing plant before the gas is processed
conventional crude oil	crude oil which can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil
conventional gas	natural gas that can be produced without the need to use different or special completion, stimulation or production techniques to retrieve the resource
Dawn Hub	a geographic location near Sarnia, Ontario where several gas pipelines intersect enabling the trading, transportation, storage, exchange, parking or loans of natural gas
eastern Canada	natural gas market region that includes Ontario, Quebec, New Brunswick and Nova Scotia
Equilibrium Model	an analytical tool used by TransCanada which uses an iterative process to assess North American natural gas supply, demand and flows amongst pipelines in order to develop TransCanada's Base Case forecast of Mainline throughput

evergreen	automatically renew a contract that in principle must be agreed to regularly
ex-basin or ex-WCSB	out of the western Canada hydrocarbon producing region
Facilities	assets to be transferred from TransCanada to Keystone
Facilities Application	an application filed with the Board by Keystone in respect of the construction and operation and tolling methodology in Canada of the proposed Keystone Pipeline
firm transportation service	natural gas transportation service under schedules that anticipate no interruptions, except for force majeure (causes that are beyond the control of the pipeline and without fault or negligence)
greenhouse gases	gaseous components of the atmosphere from natural and man-made processes that contribute to the greenhouse effect
Gulf Coast	market area that borders on the Gulf of Mexico
heavy crude oil	dense, viscous crude oil generally having a density greater than 900 kilograms per cubic metre
interruptible transportation service	natural gas transportation service that is subject to curtailment or interruption; on the Mainline, curtailment or interruption can occur at any time that TransCanada determines that deliveries would in any way interfere with or restrict TransCanada's ability to make deliveries of gas under any and all transportation services having a higher priority on TransCanada's system
Keystone Pipeline	a proposed crude oil pipeline to be constructed by Keystone that would transport heavy crude oil from Hardisty, Alberta to Wood River, Illinois
Keystone Project	the project to construct the proposed Keystone Pipeline including the conversion of Line 100-1 from gas to oil service and the construction of new pipeline in Canada and the United States
light crude oil	generally, crude oil having a density less than 900 kilograms per cubic metre; also, a collective term used to refer to conventional light crude oil, upgraded heavy crude oil and pentanes plus
light-heavy price differential	the difference in price at specified trading centres between a specific grade of light crude oil and a specific grade of heavy crude oil

Line 100-1	an 864 mm OD gas pipeline that is one of the gas transmission lines on TransCanada's Mainline
Lloydminster Blend	a benchmark heavy crude oil produced in western Canada, generally priced at Hardisty, Alberta
Mainline	TransCanada's NEB-regulated natural gas transmission system that extends 14,898 km from the Alberta/Saskatchewan border east to the Quebec/Vermont border and connects with other natural gas pipelines in Canada and the United States
Mexican Maya	a benchmark heavy crude oil produced in Mexico
Monte Carlo process	an analytical technique in which a large number of simulations are performed using random quantities for uncertain variables to generate a distribution of results
northeastern United States	United States natural gas market region that includes New York, New Jersey, New Hampshire, Maine, Vermont, Massachusetts, Rhode Island, Connecticut and Pennsylvania
oil sands	sand and other rock material that contain bitumen
Open Season	a process used to offer to potential shippers the opportunity to express interest in contracting for throughput capacity on a pipeline or to contract for firm transportation service on a pipeline
post-Alliance	the time period following the construction of the Alliance pipeline
price differential	the difference in price between two trading points or two commodities; for crude oil, the difference in price between two crude oils at their respective trading centres
probability distribution	the range of probabilities associated with each of the possible values of a random variable
rate base	the amount of investment on which a return is authorized to be earned; it usually consists of plant in service, plus an allowance for working capital
Rockies	United States producing and market region that includes Montana, Wyoming, Colorado, Utah, Nevada, Arizona and New Mexico
shale gas	a continuous low-grade accumulation of natural gas in shales

stochastic	arising from a process that incorporates random variables and involves chance or probability
Throughput Study	Canadian Mainline Throughput Study - a study submitted by the Applicants detailing TransCanada's analysis used to derive the Mainline throughput forecasts
tight gas	natural gas contained in reservoirs where gas flow is restricted because rock grains are compacted tightly together
Transfer Application	the application filed with the NEB by the Applicants for leave to transfer certain pipeline facilities presently comprising part of the Mainline from TransCanada to Keystone, and related orders
Transfer Agreement	the agreement entered into by TransCanada and Keystone that governs the transfer of the Facilities
triangular distribution	a subjective description of a population, generally used when there is only limited sample data and especially in cases where the relationship between variables is known but data is scarce
ultimate potential	the sum of all gas resources that have been discovered (including gas that has already been produced) and undiscovered resources that are expected to be discovered
unconventional gas	natural gas that is contained in difficult to produce rock formations which require different or special completion, stimulation or production techniques to retrieve the resource
upgrade	convert heavy crude oil or bitumen into synthetic crude oil
upgrader	a facility that converts heavy crude oil or bitumen into synthetic crude oil
western United States	United States natural gas market region that includes California, Oregon and Washington

Conversions

cubic metre of crude oil	6.29 barrels of crude oil
cubic metre of natural gas	35.3 cubic feet of natural gas at 14.73 pounds per square inch and 60 degrees Fahrenheit
gigajoule	0.95 thousand cubic feet at 1000 British thermal units per cubic foot
kilometre	0.62 mile
millimetre	0.04 inch

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* and the regulations made thereunder; and

IN THE MATTER OF an application dated 5 June 2006 by TransCanada PipeLines Limited (TransCanada) and TransCanada Keystone Pipeline GP Limited (Keystone) pursuant to sections 74 and 59 of the Act for leave to transfer certain pipeline facilities currently forming part of the TransCanada mainline natural gas transmission system from TransCanada to Keystone, and for a determination of the price of the transfer; and

IN THE MATTER OF National Energy Board Hearing Order MH-1-2006 dated 21 June 2006;

HEARD in Calgary, Alberta on 23, 24, 25, 26, 27 October 2006 and 9, 10 and 14 November 2006;

BEFORE:

J.S. Bulger	Presiding Member
G. Caron	Member
G.A. Habib	Member

Appearances	**Participants**	**Witnesses**
C.K. Yates, Q.C. W.M. Moreland	TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd.	G.M. Engbloom M. Feldman D.K. Ferguson R.K. Girling A. Jamal R. Jones W.A. Langford A. Leong C. Tosi T.H. Wise J.W. Zwick
P.L. Fournier	Industrial Gas Users Association	
S. Shrybman	Communication, Energy and Paperworkers Union of Canada	
D. Davies	BP Canada Energy Company, Coral Energy Canada Inc., Devon Canada Corporation, EnCana Corporation, Nexen Inc. and Shell Canada Limited	D. Robostan H. Assen A. Cheung C. Crowfoot L. Herchen K. Joslin

		A. MacBurnie L. Marks M. Romanow A. Safir
G.M. Nettleton	Canadian Natural Resources Limited	R. Cusson
G.M. Nettleton	ConocoPhillips Canada	C. Fredericks
R.R. Moore	Imperial Oil Limited	
R. Kolber	Petro-Canada Oil and Gas	
L.-C. Ratelle	Société en commandite Gaz Métro	
G. M. Nettleton	Suncor Energy Marketing Inc.	J. Van Heyst T. Paul
M. Buchinski	Union Gas Limited	
E. Sweet J.C. Turchin	Minister of Energy for the Province of Ontario	
M.A. Fowke J.A. Fisk	National Energy Board	

Written Argument

Canadian Oil Sands Limited

Centra Gas Manitoba Inc

Enbridge Gas Distribution

Husky Energy Marketing Inc.

Chapter 1

Introduction

1.1 The Application

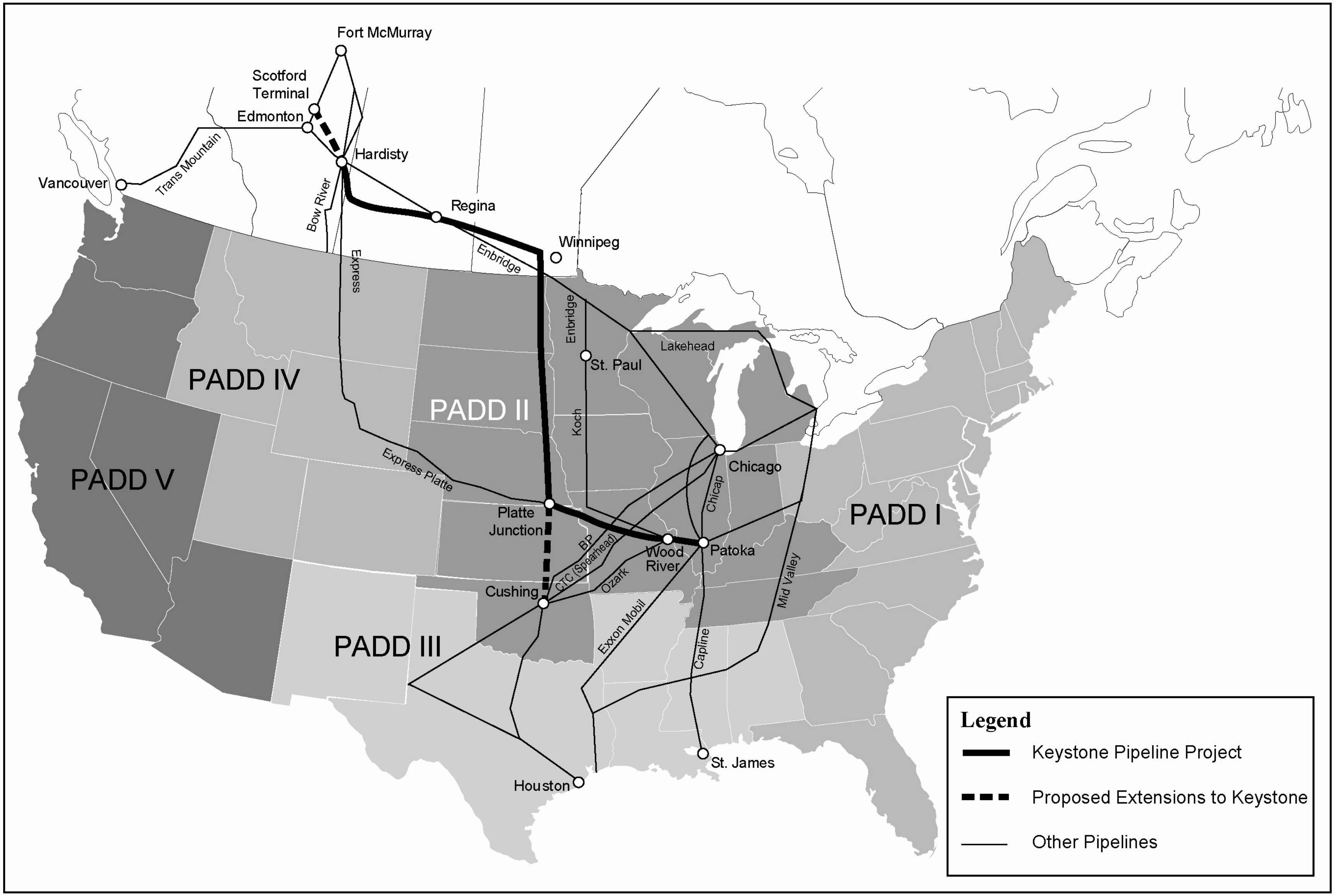
On 5 June 2006, TransCanada PipeLines Limited (TransCanada) and TransCanada Keystone Pipeline GP Ltd. (Keystone), (jointly the Applicants), applied to the National Energy Board (Board or NEB) for leave to transfer certain pipeline facilities (Facilities) presently comprising part of the TransCanada mainline natural gas transmission system (Mainline) from TransCanada to Keystone (Transfer Application) for use in Keystone's proposed new oil pipeline (Keystone Project). Keystone is a wholly owned subsidiary of TransCanada and the general partner on behalf of the TransCanada Keystone Pipeline Limited Partnership. The transfer would be governed by an agreement dated 5 June 2006 that was entered into by TransCanada and Keystone (Transfer Agreement. A summary of the Transfer Agreement, including the assets that would be transferred, is provided in Appendix I.

The transfer would involve the sale of the Facilities by TransCanada pursuant to paragraph 74(1)(a) of the *National Energy Board Act* (Act or NEB Act)[1] and their purchase by Keystone pursuant to paragraph 74(1)(b) of the Act, and would be a prerequisite to the conversion of the Facilities from gas service to oil service for use in the Keystone Project. The Keystone Project is a proposal by Keystone to construct a new oil pipeline from Hardisty, Alberta to Wood River and Patoka, Illinois (Keystone Pipeline). Initially, the proposed Keystone Pipeline would provide access for western Canada crude oil producers to the southern Petroleum Administration Defence District (PADD) II region of the United States, a major refining area which currently has minimal access for western Canada crude oil due to limited available pipeline capacity into the region. Additionally, a proposed extension to the Keystone Pipeline could eventually provide access to the PADD III refining market. Figure 1-1 shows the proposed Keystone Pipeline route, planned extensions and PADD regions. Further description of the proposed Keystone Project is provided in Appendix III.

The Transfer Application also included requests for Board approval pursuant to section 59 of the Act to: remove the net book value (NBV) of the Facilities at the date of the transfer from the Mainline rate base; include the NBV in Keystone Pipeline's Oil Plant Under Construction upon the transfer of the Facilities; and subsequently include that NBV in the Keystone Pipeline rate base when it is placed into oil transmission service.

1 For the convenience of the reader, the specific sections of the Act and other legislation referred to in these Reasons for Decision are reproduced in Appendix II.

Figure 1-1
Proposed Keystone Project



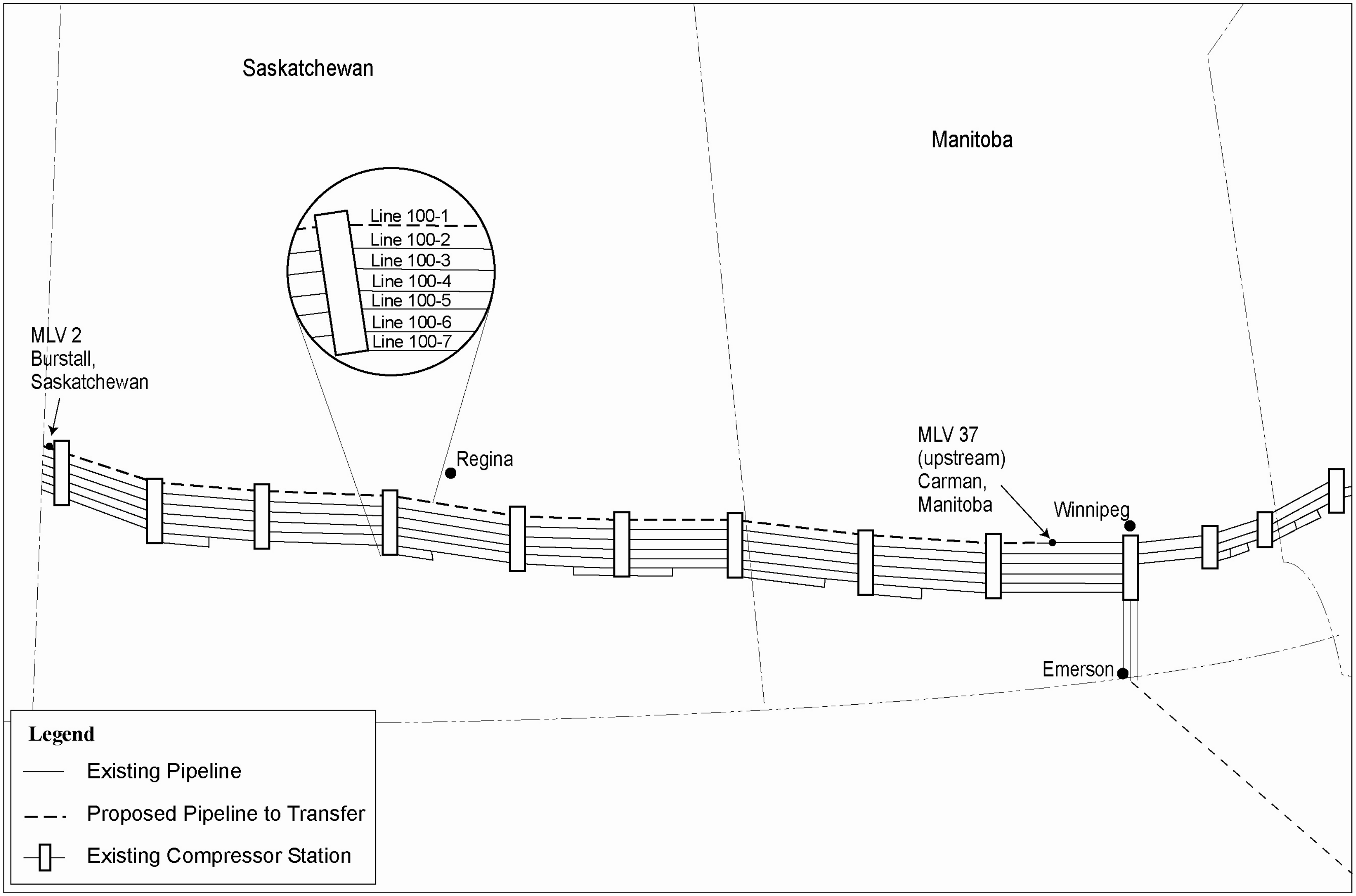
The Applicants stated that the impetus for the Keystone Project and associated Transfer Application was the request from a group of Canadian oil producers in 2003 asking TransCanada to explore the potential of utilizing spare capacity on its Alberta System and the Mainline by converting a portion of this spare capacity to oil service for the transportation of incremental oil sands production. Collaborative efforts to develop the project and examine the impacts of converting a gas pipeline to oil service culminated in the initial announcement of the Keystone Project proposal in February 2005. By December 2005, the Keystone Project had secured firm, long-term contracts from oil shippers for volumes totaling approximately 54.1 thousand m^3/d (340.0 thousand bpd), which would amount to about 78 percent of the initial pipeline capacity. The duration of the long-term contracts averaged 18 years. The Applicants considered that the securing of these binding contracts for oil shipments supported their analysis of crude oil supply and demand and their conclusion that additional oil transportation capacity is urgently required.

The Applicants indicated that an application for the Keystone Project facilities would be filed with the Board late in 2006 (Facilities Application)[2]. The Facilities Application would include requests for the conversion of the Facilities to oil service, a certificate of public convenience and necessity for the Canadian portion of the Keystone Pipeline pursuant to section 52 of the Act and approval of the pipeline's proposed toll methodology and tariff pursuant to Part IV of the Act. An application would be also made pursuant to subsection 21(2) of the Act for an order of the Board that varies Board Certificate of Public Convenience and Necessity No. GC-1, issued to TransCanada on 11 April 1960, by removing the Facilities, effective upon their transfer to Keystone. The Applicants requested the relief applied for in the Transfer Application be made conditional upon the Board's approval of the Facilities Application and the issuance of a certificate of public convenience and necessity for the Keystone Pipeline Project.

As part of its exploration of the potential of utilizing spare gas transportation capacity for oil service, TransCanada conducted a hydraulic and economic analysis of the Prairies section of the Mainline. The Prairies section comprises six full pipelines ranging in diameter from 864 mm (34 inches) to 1220 mm (48 inches) and a seventh 1220 mm diameter pipeline looped at selected locations. TransCanada concluded that the 864 mm Line 100-1 was the best option for conversion from gas to oil service. The physical features of Line 100-1 would enable the economic transportation of approximately 63.5 thousand m^3/d (400 thousand bpd) of heavy crude in turbulent flow. Line 100-1 was also selected for the transfer for operational reasons as it is located, for the most part, on the outside portion of the multi-line right of way. In addition, TransCanada observed that, of all the lines within the Prairies section, the removal of Line 100-1 would have the least impact on gas shippers. The section of Line 100-1 to be transferred is depicted in Figure 1-2.

2 The Facilities Application for the Keystone Project was filed with the Board on 12 December, 2006. On 29 January 2007 the Board issued Hearing Order OH-1-2007. The Board stated that it was issuing the OH-1-2007 Hearing Order for the purpose of resource allocation and in the interest of efficiency and that the issuing of this Order should not be taken as an indication of the Board's decision on the Transfer Application.

Figure 1-2
Mainline Prairies Section Showing Section of Line 100-1 To Be Transferred



The Applicants submitted that TransCanada had engaged its Mainline commercial stakeholders in a consultative process regarding the proposed transfer beginning in the middle of 2005. In July 2005, TransCanada provided its stakeholders with a copy of a document entitled “The Proposed TransCanada Keystone Pipeline Project” (Keystone Project Report) which provided a comprehensive overview of the impacts of the Keystone Project on the natural gas industry, as those impacts were understood by TransCanada. Additionally, the Keystone Project was discussed at nine Tolls Task Force (TTF) meetings between March 2005 and May 2006. Handout materials were provided at the TTF meetings in March, July, August and October 2005 and in March and April of 2006. Verbal status updates on the proposed Keystone Project were given at the September and December 2005 and May 2006 meetings.

In the Keystone Project Report, TransCanada listed four concerns that had been identified by its industry stakeholders regarding the proposed transfer. These related to: potential constraint of gas production in the Western Canada Sedimentary Basin (WCSB) due to the reduction in Mainline capacity; the appropriate transfer price for the assets; the overall cost savings that would be achieved by TransCanada's gas transmission customers with the transfer of the gas transmission assets; and the cost to replace lost capacity should production available for export exceed current forecasts.

Prior to submitting the Transfer Application, TransCanada undertook an extensive assessment of Mainline throughput in order to determine what capacity might be available for conversion to oil service. This analysis was submitted in the form of a report entitled “Canadian Mainline Throughput Study” (Throughput Study). TransCanada's analysis concluded that the removal of the Facilities would reduce the 100 percent design capacity of the Prairies section. However, it stated that the Mainline would still have at least 34.0 million m^3/d (1.2 Bcf/d) of capacity available above the peak winter day flow forecast, and that sufficient capacity, from both the ex-WCSB and Mainline perspectives, would remain post-transfer to serve the needs of western Canada gas suppliers. Should future transportation requirements exceed forecasts, additional capacity could be put in place by the addition of compression or other mitigating alternatives. TransCanada also concluded that the appropriate transfer price for the Facilities would be their NBV at the time of transfer. TransCanada recognized that the reduction in the revenue requirement achieved by the removal of the transfer price from the Mainline rate base would be offset by increased fuel requirements. However, based on its most likely throughput and price forecasts, TransCanada concluded that on a ten year net present value (NPV) basis, gas customers would experience a small cost savings of approximately $15 million.

The Applicants submitted that the best use of the Facilities would be in providing much needed oil transportation capacity rather than in the provision of gas transportation service. They further submitted that, while such facilities are used and useful, they are no longer necessary in gas service. The Applicants stated in their evidence that they were seeking a determination that the transfer on the terms they proposed, and the conversion of the Facilities from gas service to oil service, would be in the public interest provided the Board makes a subsequent determination that the Keystone Project is required by the present and future public convenience and necessity.

1.2 The Proceeding

After considering the Applicants' requests and supporting information in the Transfer Application, the Board decided to set the application down for public hearing. On 21 June 2006, the Board issued Hearing Order MH-1-2006 in respect of the Transfer Application. Prior to the commencement of the Hearing on 23 October 2006, the Board issued two decisions on matters brought forward by intervenors which dealt with comments on the List of Issues in the Hearing Order and a motion by the Communications Energy and Paperworkers Union of Canada (CEP) to adjourn the Hearing until the Transfer and Facilities Applications could be heard at the same time. Key points of these decisions are provided below. The complete text of the Board's decisions is attached as Appendix IV and Appendix V. Additionally, during the Hearing, the CEP argued that the Board does not have the jurisdiction to make a determination on the Transfer Application. A discussion of the CEP's argument and the Board's determination are included in section 1.2.3 of these Reasons.

1.2.1 Comments on the List of Issues

The Board received comments from three parties and reply comments from the Applicants on the List of Issues. The Council of Canadians (COC) suggested that the Applicants were fragmenting the approvals process by dealing only with the transfer of the Facilities and submitted that the Keystone Pipeline Project should be dealt with in its entirety in one process to allow for full discussion on the social, political and economic issues. The CEP suggested adding four issues, mainly relating to the operation of the proposed Keystone Pipeline. Coral Energy Canada Inc., Devon Canada Corporation, EnCana Corporation, Nexen Inc. and Shell Canada Limited, (jointly, BCDENS[3]) asked the Board to clarify its intent with regard to Issue 2[4]. The Applicants replied to the comments by letter dated 14 July 2006.

In its 17 July 2006 letter responding to the comments on the List of Issues, the Board stated that it had concluded that the social, political and economic issues in respect of the sale and purchase of the Facilities should be addressed in the MH-1-2006 Hearing and those in respect of operating the proposed Keystone Pipeline could be raised when the Facilities Application is heard. The Board considered that some elements relating to the conversion of the pipeline to oil service could be important to determinations it would have to make in regard the Transfer Application. Therefore, the List of Issues had been drafted broadly to ensure the Board would receive all relevant evidence and to allow parties to frame their cases and present their views in the manner they determined to be appropriate. Thus, while the Board was of the view that there was no need to add issues to the List of Issues, it emphasized that parties were not restricted with respect to any position that they may wish to take regarding the decisions that the Board was being asked to make. However, for greater certainty, the Board varied Issue 2 to include a reference to supply when considering the impacts of the removal of the Facilities from gas transportation service and their conversion to oil transportation service. The revised List of Issues in the MH-1-2006

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3 BP Canada Energy Company (BP) was not a member of BCDENS at the time the comments on the List of Issues were submitted; it became a member of the group on 10 October 2006. References to BCDENS elsewhere in this document include BP unless otherwise noted.

4 Issue 2 in the MH-1-2006 Hearing Order originally read: "The commercial, economic, and market impacts of the removal of the Facilities from gas transportation service and conversion to oil transportation service."

Hearing is included at the end of Appendix IV as an attachment to the Board's 17 July 2006 letter.

The Board also agreed with the Applicants' reply comments that the question of whether the section 74 and section 52 applications must be heard together was not a matter for inclusion in the List of Issues in the section 74 proceeding, but would be more appropriately dealt with by way of a motion.

1.2.2 CEP Motion

On 24 July 2006, the CEP filed a motion with the Board for orders adjourning the MH-1-2006 Hearing until such time as applications for all of the approvals required to establish the Keystone Pipeline Project were properly constituted and filed with the Board and for all public hearings regarding such applications to proceed at the same time. By letter dated 3 August 2006, the Board established a written process to hear the motion, the grounds supporting the motion and the relief sought. Seven parties, in addition to the Applicants, filed submissions.

Both the Sierra Club of Canada and the COC supported the CEP motion. The motion was opposed by the Applicants, ConocoPhillips Canada Limited (ConocoPhillips), Suncor Energy Marketing Inc. (SEMI) and Canadian Natural Resources Limited (CNR).

In its ruling on the motion issued on 25 August 2006, the Board stated that it could make decisions regarding the Transfer Application after hearing all of the evidence and argument on the matter without causing prejudice to its ability to consider the public interest in relation to the decisions it would be asked to make in the context of an eventual Facilities Application. The Board considered that the stepwise approach used by the Applicants was acceptable and lawful, and that it would not result in an abuse of process or a serious waste of time and resources by the Board or parties. The Board did not believe that the Applicants were proceeding by way of separate applications in order to avoid jurisdiction or some process, or as a form of project splitting.

The Board did not accept the suggestion that the stepwise approach would lead to the marginalization of environmental and other public interest concerns, nor that it was contrary to the requirements of the *Canadian Environmental Assessment Act*. The Board was of the view that consideration of environmental issues at a later stage of the approvals process would not prevent it from fulfilling its mandate to consider environmental issues.

The Board was not persuaded that consideration of the Transfer Application should be adjourned until such time as the Facilities Application is filed. It was also not persuaded that the risks raised in the motion warranted diverging from the Board's practice of allowing applicants to frame their applications as they determine to be appropriate, or from the accepted stepwise application process chosen by the Applicants. However, the Board reiterated comments from its letter dated 17 July 2006 that it would be open to hearing parties' positions on whether the Board has sufficient evidence to be able to make determinations on any or all aspects of the Transfer Application or whether a determination on any or all aspects of the Transfer Application would prejudge the Facilities Application.

1.2.3 CEP Argument Regarding the Board's Jurisdiction

In final argument, the CEP submitted that the Board does not have the jurisdiction to make the determination that the proponents are seeking, namely, that it is in the Canadian public interest that the Facilities be converted from gas service to oil service. The CEP made this assertion on the basis that there is no application before the Board to convert the Facilities. More specifically, the CEP argued that the Board would be expanding its jurisdiction if it imported into its consideration matters that are particular to other approvals that might be sought under the Act in the future. The CEP expressed concern that the Board might inform its decision about the Transfer Application with reference to approvals that might be given on subsequent applications, namely the section 52 and 21 applications.

Views of the Board

The Board previously determined when it ruled on the preliminary motion brought by the CEP that the Applicants' stepwise application for approvals would not cause the Board to in any way prejudge the merits of the Facilities Application nor imply that its decision on the present application is, or will be, based on applications yet to be filed. The Board continues to be of the view that a staged application to allow applicants to structure their applications as they wish, for their own business reasons, is acceptable and lawful despite the fact that there may be some overlap between proceedings, and that the Board can properly adjudicate the present application without fettering itself with respect to a future Facilities Application.

As is discussed in greater detail in these Reasons for Decision, the Board assessed the Transfer Application on its own merits to determine whether the relief sought was in the public interest. The public interest is a concept which defies exact definition; its specific boundaries may vary from case to case depending on things such as the interests involved or the section of the Act under which an application is made.

The Board is of the view that the ultimate use of the Facilities, if transferred, is relevant to the determination of the public interest with respect to the current application. At the very least, the Board must consider the use the transferred facilities will be put to, if for no other reason than to ensure that the proposed use does not in principle contravene the Act. However, approval of a transfer is not a final or complete answer to the question of whether, for example, the operation of the Facilities in oil service would be in the public interest or public convenience and necessity. Parliament drafted the Act in such a way that projects, such as this one, require Board approval under more than one section of the Act. In the Board's view, this illustrates Parliament's intention that the Board direct its mind to the particular approvals requested and conduct an analysis in relation to each, in light of the public interest. Thus, the Board is of the view that it need not receive every detail regarding the conversion of the Facilities to oil service at this time in order to be able to make a determination regarding whether the application to transfer the Facilities is in the public interest. Specific consideration of the details of the conversion and related operation in oil service may be considered upon the filing of future applications.

The Board rejects the notion that it is an expansion of its jurisdiction to consider evidence of conversion of service as it relates to the transfer of the Facilities. The Board has been granted broad discretion in determining what factual elements define the public interest. In this case, the Board views the notion of a change in service as a relevant aspect of the public interest analysis on the transfer. Similarly, considering the conversion as it relates to the Transfer Application in no way prejudges the decisions that the Board will have to make in future applications, including whether it is in the public convenience and necessity to allow the Keystone Pipeline to be constructed and operated in oil service.

Chapter 2

The Applicable Regulatory Standard

As noted by the Applicants, this is the first case that has come before the Board to deal on a contested basis with the test to be applied in determining whether facilities should be transferred. Parties spent considerable time in argument discussing what the test should be and framed their argument of the facts around their position regarding the appropriate test. Parties were generally either of the view that the Board should assess the Transfer Application on the basis of a broad public interest standard or alternatively, that the correct standard was a "no harm to customers" test. Those arguing the no harm test based their position on their interpretation of the decision of the Supreme Court of Canada in the *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*[5] (*ATCO*) case.

The Applicants took the position that the regulatory standard that the Board should use to assess the present application is the overall Canadian public interest, which they view as the Board's mandate. They argued that public interest is the standard that the Board has historically used in considering transfer applications. For example, the Board's Filing Manual indicates that the Board's "purpose is to promote safety, environmental protection and economic efficiency in the Canadian public interest through its regulation of pipelines, energy development and trade as mandated by Parliament."[6]

In the Applicants' submission, the overall Canadian public interest is inclusive of all Canadians and refers to a balance of economic, environmental and social interests that may vary with the application, the location, the commodity, the various segments of the public affected by the decision and the purpose of the section of the Act. Considering these components will, in the Applicants' view, ensure that all relevant factors, including the impact of the transfer on oil producers, shippers, consumers, governments, citizens and others, are considered by the Board in assessing the merits of the transfer. This assessment should include a weighing by the Board of the possible or expected adverse impacts of removing the Facilities from gas service against the benefits of the use of the Facilities in oil service.

The Applicants argued that the *ATCO* decision does not apply to deciding the issue of the test in respect of the application before the Board, for a number of reasons. From a preliminary standpoint, the Applicants pointed out that the issue addressed in the *ATCO* case was whether, having found that no harm would come to customers, the Alberta Energy and Utilities Board

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5 [2006] 1 S.C.R. 140. ATCO Gas and Pipelines Ltd. had filed an application with the Alberta Energy and Utilities Board (EUB) for approval of the sale of buildings and land in Calgary as the property was no longer used or useful for the provision of utility services. Persuaded that rate paying customers would not be harmed by the sale, the EUB approved the transaction. In a second decision, the EUB determined that it had jurisdiction to approve the proposed disposition of the net gain on the sale proceeds as between customers and shareholders. This second decision was appealed to the Alberta Court of Appeal, who set aside the decision and referred the matter back to the EUB to allocate the entire remainder of the proceeds of sale to ATCO. The case was then escalated to the Supreme Court of Canada which dismissed the appeal.

6 National Energy Board Filing Manual, Chapter 1 at p. 1-1.

(EUB) could nonetheless allocate some of the proceeds of the sale to ratepayers. *ATCO* did not make a decision regarding the interpretation of the NEB Act nor did it make any decision on the EUB's application of the no harm test, which was the subject of a different EUB decision altogether. The Applicants therefore submitted that the case is not binding in the present matter.

The Applicants argued that the statutory scheme being considered by the Supreme Court in *ATCO* is very different from the NEB's. They pointed out that in order to interpret a particular provision, regard must be had to the balance of the statute and then to the "context that colours the words and the legislative scheme"[7]. The Board's attention was drawn to the following passage from the *Bell Canada*[8] case, as cited in the *ATCO* case, in further support of the argument:

> The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes.

E.A. Driedger's "modern approach" set out in his book *Construction of Statutes*[9] was also relied on:

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

If the Board conducts an independent interpretation of section 74 of the Act, rather than merely assuming that the no harm test that was decided in the *ATCO* case is applicable to the Transfer Application, the Applicants submitted that the Board must decide that the applicable regulatory standard is the public interest.

The Applicants' second ground for distinguishing *ATCO* from the present application stems from the fact that the *ATCO* case specifically dealt with the interpretation of subparagraph 26(2)(d)(i) of the *Alberta Gas Utilities Act* (AGUA), within the EUB's overall legislative context and mandate, not the NEB's. Furthermore, while the Supreme Court of Canada found that the EUB's principal function under the AGUA in respect of public utilities was the determination of rates[10], it was submitted that the functions of the NEB are much broader. The NEB not only operates under a different statute but is an entirely different regulatory regime. The NEB Act is a complete statute providing for a greater variety of functions related, for example, to facilities,

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7 *ATCO, supra,* at note 5 at para 49.

8 *Bell Canada v. Canada (The Canadian Radio-Television and Telecommunications Commission),* [1989] 1 S.C.R. 1722 at para. 50.

9 Driedger, Elmer A. *Construction of Statutes*, 2nd ed. (Toronto: Butterworths, 1983), as cited in *ATCO, supra* note 5 at para 37.

10 *ATCO, supra* note 5 at para 60.

rates and environmental matters. This broad mandate, the Applicants suggested, argues in favour of construing the test more broadly. The legislative interpretation conducted by the Court in the *ATCO* case therefore cannot be directly applied to the Board.

It was further submitted by the Applicants that the courts have decided the Board has the discretion to determine which considerations are relevant to its decisions and that it is not limited to the express language of the Act when it is determining those factors[11].

The Applicants also rejected the suggestion put forth by BCDENS that Part V of the Act is different than Parts III or IV because it focuses on what pipeline companies can and cannot do rather than on Board powers to certificate facilities and set tolls and tariffs. The Applicants stated that there is no justification for treating a regulatory constraint imposed on the actions of a private corporation any differently, because it appears in Part V of the Act, rather than Parts III or IV, and further, that adopting a narrow no harm interpretation would also be contrary to the Board's otherwise broad approach. The Applicants reasoned that had Parliament intended a different standard to apply to Part V, it would have said so. As a result, the standard under Part V must be the same as that for the rest of the Act. The Applicants also relied on section 12 of the Act as providing the Board with express statutory authority to use the public interest as the standard applicable to section 74.

Finally, the Applicants pointed out that as a matter of logic, adopting a no harm to shippers test does not make sense; the impact on gas shippers cannot be the only consideration. The Applicants urged the Board to consider a situation where, while there is no harm caused to customers by a proposed sale, there might be other important environmental, socio-economic or safety issues to be weighed in the balance.

ConocoPhillips, CNR and SEMI (jointly, the Keystone Shippers Group) expressed the view that when considering the section 74 application the Board should adopt a broad flexible approach to evaluate the overall public good the request can create as well as its potential negative aspects. The Board should weigh the possible or expected adverse impacts of removing the Facilities from gas service against the benefits of using of the Facilities in oil service. The Board should also consider the relief requested by weighing all relevant facts and circumstances on the basis of what is reasonable.

The Keystone Shippers Group noted that the *ATCO* case dealt with different legislation where the utility was a local distribution company. They also noted that in the present circumstances, there is nothing remotely similar to the no harm test either within the NEB Act or prior Board decisions. In further support of their rejection of the no harm test, these intervenors relied on the Board's reasoning set out in the Trans-Northern Pipeline MH-3-2000[12] proceeding. The

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11 *Sumas Energy 2, Inc. v. Canada (National Energy Board),* [2005] F.C.J. No. 1895 (F.C.A.); *Nakina (Township) v. Canadian National Railway Co.,* [1986] F.C.J. No. 426 (F.C.A.) and *Quebec v. Canada (National Energy Board),* [1994] 1 S.C.R. 159.

12 National Energy Board MH-3-2000 Reasons for Decision, Trans-Northern Pipelines Inc. (Suspension of Service), November 2000. The Keystone Shippers Group stated that in this case, the Board approved an application to suspend certain services despite apprehensions that it would likely cause economic harm to a shipper. The Keystone Shippers Group argued that this case is an example of how the Board has approved operational changes to pipelines after weighing relevant factors to determine the public interest.

Keystone Shippers Group agreed with the submissions made by the Applicants as to why the *ATCO* case was distinguishable from the case at hand.

While the CEP argued that the Board lacked the jurisdiction to decide the application based on the evidence before it, it also argued that the regulatory threshold that would have to be met was the Canadian public interest. The CEP also urged the Board to resist equating the interests of the oil and gas industry with that of the Canadian public interest.

BCDENS asked the Board to find that the proper test for considering the application to sell Line 100-1 facilities is no harm to Mainline shippers.

BCDENS took the position that Part V of the Act, pursuant to which the application presently before the Board is made, does not explicitly set out the standard by which the application should be considered and that Part V applications are subject to a different standard than those made under Parts III or IV of the Act.

With respect to Part III of the Act, BCDENS recognized that Parliament has conferred a very wide discretion upon the Board. The courts have confirmed that the only apparent limit on the power bestowed upon the Board in respect of facilities applications is that it must act in good faith.[13] BCDENS similarly argued that the Board is also vested with a wide discretion with regard to tolls and tariff applications made under Part IV of the Act.[14]

BCDENS argued that Part V of the Act is quite different from Parts III and IV, in that it focuses on the powers of pipeline companies rather than on the Board's powers to certificate facilities and set rates. However, the Board does have a role to play in relation to Part V: in some circumstances, leave or approval of the Board is required before a pipeline company can exercise a power. BCDENS submitted that unlike Parts III and IV, where Parliament intends that the Board consider applications in light of the public interest, Parliament has only conferred upon the Board the power to approve a sale under Part V for a specific purpose, namely to protect utilities' customers from adverse results. They argued that this "specific public interest mandate" has been confirmed by the Supreme Court of Canada in the *ATCO* case.

It was submitted by BCDENS that the Court in *ATCO* considered subparagraph 26(2)(d)(i) of the AGUA, and this is, for all intents and purposes, the same as paragraph 74(1)(a) of the NEB Act. BCDENS argued that the Court determined that regulatory approval of the sale of a utility asset is required in order to protect the utility's customers from harm. They noted that the issue in the *ATCO* case was whether a regulator, in considering an application to sell land, could allocate the profit of the sale between shareholders and customers. However, in deciding that issue, BCDENS contended that it was necessary for the Court to ascertain the legislature's intention when it conferred upon the regulator the power to approve the sale of a utility asset. BCDENS urged the Board to accept that it is the lawmaker's intention that the fundamental purpose for requiring regulatory approval of a sale is to ensure no harm to the utility's customers; it is the test

13 *Memorial Gardens Assn. (Can.) Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353; *Canadian National Railways v. Canada Steamship Lines Limited*, [1945] 3 D.L.R. 417 (P.C.).

14 National Energy Board OH-1-79 Reasons for Decision, Trans Mountain Pipe Line Company Ltd., January 1980; *Transcanada Pipelines Ltd. v. Canada (National Energy Board*), [2004] F.C.J. No. 654 (F.C.A.); *Flint Hills Resources, Ltd. v. Canada (National Energy Board)*, [2006] F.C.J. No. 1489 (F.C.A.).

that applies to subsection 26(2) of the AGUA and that it is the test that should apply to an application made pursuant to paragraph 74(1)(a) of the NEB Act.

BCDENS further submitted that a review of the Board's Filing Manual leads to exactly the same conclusion as a reading of the *ATCO* case, namely, that the test for considering the sale of the Line 100-1 facilities is no harm to the Mainline shippers. Guide R of the Filing Manual deals with Transfer of Ownership, Lease or Amalgamation, in three scenarios: NEB regulated to non-NEB regulated (stand-alone section 74(1)(a) leave to sell), non-NEB regulated to NEB regulated (stand-alone section 74(1)(b) leave to purchase) and NEB regulated to NEB regulated. They submitted that the test for a transaction where assets are at the time of the application NEB regulated but would become non-NEB regulated following the transaction, is the no harm test set out in the *ATCO* case. In contrast, in a situation where the asset was not NEB regulated but would come within the Board's jurisdiction following a sale, the test is the public interest because it involves a consideration of whether it would be in the public interest to continue to operate the facilities, and because the application for leave to purchase might be paired with a concurrent application under Part III of the NEB Act to operate the facilities under the Board's supervision. With respect to a transaction from NEB regulated to NEB regulated, the tests that apply to a request for leave to sell and for leave to purchase are the same: paragraph 74(1)(a) attracts a no harm standard while paragraph 74(1)(b) attracts a public interest standard.

Thus, BCDENS took the view that with respect to paragraph 74(1)(a), the Board does not have the option to apply any test but the no harm test and to do otherwise would constitute an error of law.

The Minister of Energy for the Province of Ontario (Ontario) argued that a section 74 application should be considered on the basis of the public interest, despite the fact that the section does not contain those words. In its view, the link between the standard of public interest and section 74 is through the granting of the Board's general jurisdiction set out in section 12 of the Act. However, it interpreted public interest more narrowly than the Applicants did. In reliance on *ATCO*, Ontario submitted that if the transfer presented some harm or risk of harm in the broadest sense, the Board should act in the public interest to prevent the risk from being visited on customers, which includes not only Mainline shippers but also ultimate consumers.

Views of the Board

The parties advocating a no harm test suggested that the Board would be committing an error of law unless it applied the Court's conclusions in the *ATCO* case to the present application. However, the Board is not persuaded that the decision in *ATCO* is applicable to determine the test that should be applied when considering an application pursuant to section 74 of the Act.

The *ATCO* case was an appeal of an EUB decision which had decided to allocate the proceeds of the sale of land between the utility's shareholders and its customers. The test applied to determine whether to grant leave to sell the land was not at issue before the Supreme Court. That aspect of the EUB's process was decided by the regulator in an earlier proceeding; the decision was never appealed. Accordingly, the Board is of the view that the Supreme Court did not in *ATCO* have before it or decide the issue of the test applicable to an application under paragraph 74(1)(a) of the Act.

The Board does, however, agree with the approach to legislative interpretation adopted by the Court in *ATCO* and when it made reference to the *Bell Canada* case and Driedger, and stated that it is necessary to:

> examine the context that colours the words and the legislative scheme. The ultimate goal is to discover the clear intent of the legislature and the true purpose of the statute while preserving the harmony, coherence and consistency of the legislative scheme.[15]

Bearing in mind the parameters for determining the meaning of a provision, the Board cannot accept the argument urged upon it by BCDENS that the interpretation of subparagraph 26(2)(d)(i) of the AGUA in the *ATCO* case could apply interchangeably to paragraph 74(1)(a) of the NEB Act. This is so despite the fact that there may be similarities in language between the two provisions; the overall context of section 74 and the NEB Act is very different from that of section 26 and the AGUA. While the Court found that the principal function under the AGUA is the determination of rates, the NEB Act is not so limiting. The Board has a broader mandate as set out in the Act to examine not only economics and tolls, but also safety, engineering, environment and landowner rights, to name but a few factors. All of these are issues relating to public interest.

BCDENS also argued that Part V of the Act did not include a standard pursuant to which the Board should assess applications. They submitted that the *ATCO* case supplied that standard, which is no harm to customers. The Board, however, does not see any justification for the suggestion that Part V of the Act is different from Parts III or IV with respect to the standards to be used for Board decisions. Furthermore, the Board does not subscribe to the suggestion that even though paragraph 74(1)(b) is also in Part V, it should attract a public interest standard because it might, for example, be paired with an application under Part III of the Act but paragraph 74(1)(a) should not. In addition, the Board finds the submissions that its mandate might be limited, based on the guidance it has provided in the Filing Manual for preparing applications under section 74, to be unconvincing.

The Board is of the view that Parliament has provided it with explicit guidance in the Act as to the test it should apply to requests for relief under section 74. Part I of the NEB Act establishes the Board and sets out the Board's powers. The Board is of the view that section 12, when

15 *ATCO, supra* note 5, at para 49.

considered in accordance with the principles of legislative interpretation suggested by Driedger and the Supreme Court, requires the Board to assess the Transfer Application on the basis of the public interest. To achieve this mandate, it is therefore necessary for the Board to consider matters beyond adverse results to gas pipeline shippers.

Furthermore, adopting the proposed no harm test would be contrary to the long list of Board and Court authorities that have decided that the Board has wide discretion to determine what is relevant to the exercise of its mandate. If the Board adopted the narrow interpretation urged by the parties in favour of the no harm test, it would oblige the Board to automatically favour the interests of shippers, excluding other persons and other public interest factors, thus sterilizing the broader mandate granted the NEB by Parliament[16]. While gas shippers' interests are very important in this case, it is not the only factor that the Board must consider. The Board is charged with considering all of the factors that are relevant to the public interest, in each case. As the Board said in its Sumas Energy 2, Inc. Decision:

> In the Board's view, under the NEB Act, the factors to be considered and the criteria to be applied in coming to a decision on public interest or public convenience and necessity may vary with the application, the location, the commodity involved, the various segments of the public affected by the decision and the purpose of the applicable section of the NEB Act.[17]

Therefore, contrary to the submission of BCDENS that the Board would be committing an error of law unless it applies the no harm test, the Board is of the view that restricting itself to that sole consideration would have it commit an error of law, as it would amount to a failure to exercise its jurisdiction to consider the broader elements described in section 12 of the Act and implied in its overall jurisdiction.

Accordingly, the Board finds that the regulatory standard Applicable to the Transfer Application is the public interest.

16 *Bell Canada, supra* note 8.

17 National Energy Board EH-1-2000 Reasons for Decision, Sumas Energy 2, Inc. (Facilities), March 2004, at page 11.

Chapter 3

Energy Supply, Markets and Pipelines

As part of their evidence, information on western Canada supply and North American markets and pipeline transportation for both crude oil and natural gas was submitted by the Applicants and intervenors in support of their respective positions.

Evidence submitted relating to crude oil markets centered around crude oil production in western Canada, notably the forecast increase in heavy crude oil supply from the oil sands in northern Alberta. Evidence was also put forward on the ability of refineries in markets in both western Canada and the United States to absorb the projected increase in crude oil production, and on the need for additional pipeline capacity out of the WCSB to transport the expected additional crude oil volumes to export markets.

Evidence on gas markets included forecasts of natural gas supply that would be available in western Canada to the Mainline, including conventional and unconventional production in the WCSB as well as potential future production from northern Canada and Alaska. Evidence was also submitted on natural gas demand in western Canada and in other markets served by the Mainline in eastern Canada and the United States. Based on their analyses of natural gas supply and demand in the regions served by the Mainline, parties provided their views on ex-WCSB natural gas flow and its allocation to the various natural gas pipelines exiting the basin, including the Mainline.

3.1 Western Canada Crude Oil

In support of their application, the Applicants submitted a report by Purvin & Gertz Inc. (Purvin & Gertz or P&G) dated 2 June 2006 entitled "Outlook for Crude Oil Exports and Pipeline Capacity from Western Canada". The report provided Purvin & Gertz's outlook for crude oil production in the WCSB from 2005 to 2016. It also included a discussion on markets for western Canada crude oil supply, oil transportation issues, and the potential impacts of transportation and market constraints on western Canada crude oil producers. It concluded that without additional pipeline capacity to export crude oil out of the WCSB by the end of 2009, the price for western Canada crude oil, especially heavy crude oil, would generally have to be discounted due to transportation constraints, and that crude oil production levels could be negatively impacted. Based on the evidence presented in the Purvin & Gertz report and the status of currently proposed oil export pipeline projects, the Applicants argued that the Keystone Pipeline was the only proposal that could provide the needed new oil pipeline capacity by the end of 2009.

The Purvin & Gertz report indicated that while conventional crude oil production was expected to decrease over the forecast period, this decline would be more than offset by the anticipated increase in production from the oil sands. As shown in Table 3-1, it projected that total crude oil production in western Canada would increase by nearly 37 percent above the 2005 level to an estimated 467.9 thousand m^3/d (2.9 million bpd) by 2010. The Canadian Association of Petroleum Producers (CAPP) 2006 forecast is shown for comparison as it was the only other forecast submitted with the same level of detail as the Purvin & Gertz forecast.

Table 3-1
Western Canada Crude Oil Production Forecasts - 2005-2010
(thousand m^3/d (thousand bpd))

Crude Oil Source	2005		2010		Change	
	P&G	**CAPP**	**P&G**	**CAPP**	**P&G**	**CAPP**
Conventional crude oil and condensate	191.7 (1,206)	192.8 (1,213)	172.7 (1,086)	169.2 (1,064)	- 19.1 (-120)	-23.7 (-149)
Oil sands	150.4 (946)	157.4 (991)	295.2 (1,857)	342.0 (2,151)	+ 144.8 (+911)	+184.6 (+1,561)
Total	**342.1 (2,152)**	**350.4 (2,204)**	**467.9 (2,943)**	**511.1 (3,215)**	**125.8 (791)**	**160.9 (1412)**

Note: numbers may not add due to rounding

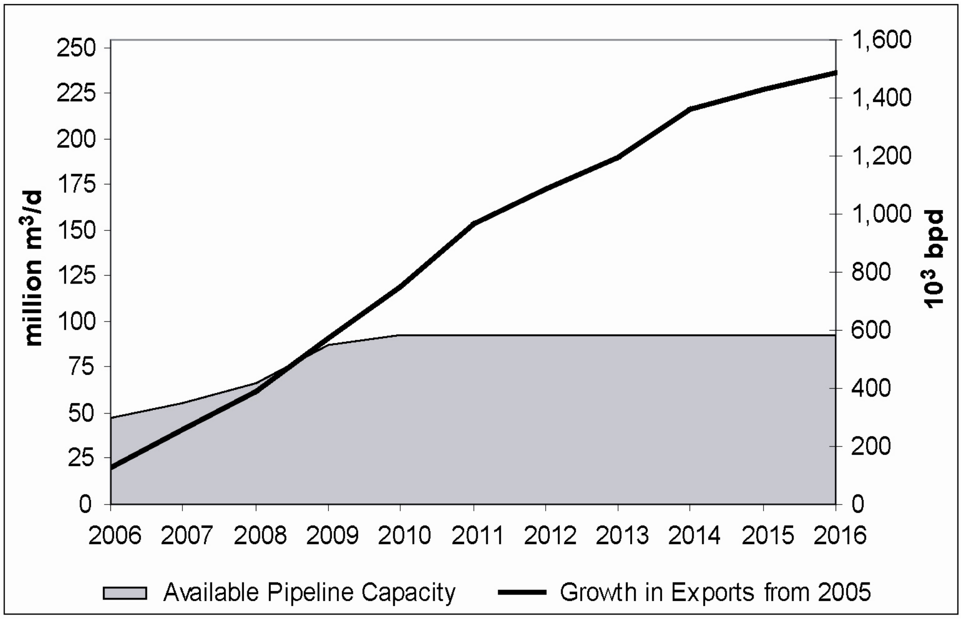
In comparing its oil sands production forecast with those published by CAPP, Enbridge Inc. and the EUB, Purvin & Gertz noted that there was general consensus that conventional production would decline through to 2016. Similarly, all forecasts showed substantial growth in crude oil production from the oil sands but beyond 2010, a wider range among the outlooks was observed. While there was some uncertainty around forecasts beyond 2010, Purvin & Gertz submitted that since many of the oil sands projects scheduled to come on stream by 2010 are known, growth in oil sands production is almost certain until then.

The disposition of total available crude oil supply from the WCSB is divided between domestic demand and the export market. According to Purvin & Gertz, the eight refineries in western Canada, which currently have a total crude capacity of 96.1 thousand m^3/d (604.7 thousand bpd), accounted for approximately 92.8 thousand m^3/d (584.0 thousand bpd) of domestic crude oil demand in 2005. Based on its estimate of an average 1.5 percent per year increase in domestic runs over the forecast period, Purvin & Gertz concluded that most of the forecast growth in oil sands would need to be absorbed by the export market. The Purvin & Gertz report identified six refineries in southern PADD II, with a combined crude oil processing capacity of 183.1 thousand m^3/d (1.2 million bpd), as Keystone Pipeline's target market and noted that the processing capacity in this market area could expand as several of the refiners are constructing or planning to add facilities to use more Canadian crude oil. It also noted that Keystone Pipeline could facilitate market penetration into the PADD III region with a planned extension from Platte Junction, Nebraska to Cushing, Oklahoma (see Figure 1-1).

Purvin & Gertz estimated total spare crude oil pipeline capacity ex-western Canada to be about 47.7 thousand m^3/d (300 thousand bpd) in 2005, of which 28.9 thousand m^3/d (182.0 thousand bpd) was available for heavy crude oil. Based on this estimate and its forecast of western Canada crude oil supply and demand, Purvin & Gertz suggested that additional oil pipeline export capacity would be required by 2009. This need was expected to exceed 63.6 thousand m^3/d (400.0 thousand bpd) by 2012 and increase to 143.0 thousand m^3/d (900.0 thousand bpd) by 2016.

Figure 3-1 illustrates Purvin & Gertz's view of the expected future imbalance between forecast western Canada crude exports and estimated available export pipeline capacity.

Figure 3-1
Forecast Crude Oil Export Growth from 2005 Compared to Available ex-WCSB Pipeline Capacity



Purvin & Gertz submitted that excess crude oil supply over available export pipeline capacity generally results in price discounts. It suggested that Canadian crude oil was undervalued against the competition because of saturation in currently accessible markets, reflecting constraints in both refining and pipeline capacities. In support of this statement, Purvin and Gertz noted that in early 2006 when limited light crude oil pipeline capacity was available, the price for Canadian light crude oil was discounted relative to West Texas Intermediate, the benchmark light crude oil price at Cushing, Oklahoma. It also noted that in 2005 and early 2006, the price for Lloydminster Blend at Hardisty, Alberta, a benchmark Canadian heavy crude oil, was deeply discounted relative to the price paid for a similar heavy crude oil, Mexican Maya, priced at Wood River, Illinois. During the same period, the Canadian light-heavy price differential was significantly wider than the light-heavy differential on the United States Gulf Coast.

Purvin & Gertz also suggested that once capacity to ship crude to preferred markets is full, shippers can choose to use pipelines which deliver crude oil to other less desirable markets, but if all pipeline capacity is full, crude oil must be shut in.

The Applicants submitted that the Purvin & Gertz report demonstrated the need for additional crude oil pipeline capacity exiting the WCSB by the end of 2009, and that with insufficient export oil pipeline capacity, oil sands development would likely slow, some crude oil production could be shut in and prices for western Canada crude oil would be weaker than in an environment with adequate pipeline capacity. They submitted that because the Keystone Pipeline had committed shipper support and the regulatory process for the project had already commenced, it would be the most imminent pipeline able to alleviate the tight oil pipeline capacity predicted by Purvin & Gertz. They argued that no other proposed project had shown the same potential ability to meet the anticipated in-service date of late 2009.

SEMI identified itself as a contract shipper on the proposed Keystone Pipeline. It submitted forecasts by CAPP that were consistent with the Applicants' conclusion that additional crude oil pipeline capacity out of the WCSB would become short by the beginning of 2010, and supported the view that the Keystone Pipeline would provide shippers with guaranteed access to United States markets with refining capacity capable of processing crude oil from the oil sands. It further stated that even with the addition of the Keystone Pipeline capacity, other projects such as TMX-2[18], an expansion of the Keystone Pipeline and TMX-3[19], would be required to meet export pipeline capacity demands through the beginning of 2013. SEMI added that alternatively, or eventually in addition, other proposed projects such as Enbridge Pipelines Inc.'s Gateway project[20] and Alberta Clipper project[21], Altex Energy Ltd.'s Altex Pipeline System project[22] and a northern leg[23] of the Trans Mountain Pipeline System would be required in order to satisfy demand for pipeline capacity exiting the WCSB.

ConocoPhillips also identified itself as a shipper on the proposed Keystone Pipeline. It submitted that it intends to process much of the incremental production from the Surmont Oil Sands project[24] in markets that would be accessed by the Keystone Pipeline and confirmed that it intends to increase the ability of its Wood River refinery to process Canadian crude oil if the Keystone Pipeline is built as proposed. CNR, another intervenor in support of the Transfer Application, stated that it was not a contract shipper on the Keystone Pipeline but intends to ship oil on the pipeline if it is approved and built.

No parties contested the Applicants' crude oil supply forecast or the need for new export oil pipeline capacity based on that forecast. However, the COC noted that the fast pace of oil sands development in Fort McMurray, Alberta has resulted in citizens facing housing shortages and a

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18 TMX-2 is Kinder Morgan Canada Inc.'s (formerly Terasen Pipelines) proposed expansion to add 15.9 thousand m^3/d (100.0 thousand bpd) of capacity to the Trans Mountain pipeline system by 2010. The project consists of two pipeline loops: one from Edmonton to Edson, Alberta and another from Hargreaves to Darfield, British Columbia.

19 TMX-3 would further expand the Trans Mountain pipeline system by looping the line between Kamloops and Sumas, British Columbia. This expansion would add another 47.7 thousand m^3/d (300.0 thousand bpd) of pipeline capacity to the system by 2012.

20 The proposed Gateway Pipeline would extend from Strathcona County, Alberta to a marine terminal located at Kitimat, British Columbia. The transported crude would then be shipped by tanker to China, other Asia-Pacific markets, and California. The anticipated in-service date is between 2012 and 2014.

21 Alberta Clipper is a proposed crude oil pipeline providing service between Hardisty, Alberta, and Superior, Wisconsin with an estimated capacity of 63.6 thousand m^3/d (400.0 thousand bpd). The anticipated in-service date is late 2009.

22 The Altex Pipeline System would be a new oil pipeline system from northern Alberta to the United States Gulf Coast with an estimated capacity of 39.8 thousand m^3/d (250.0 thousand bpd).

23 The TMX-North would be a new pipeline between Valemont and Kitimat, British Columbia that would further increase ex-WCSB capacity on the Trans Mountain Pipeline system by 63.6 thousand m^3/d (400.0 thouasnd bpd).

24 The Surmont Oil Sands Project is located near Fort McMurray, Alberta. Production of up to 4.3 thousand m^3/d (27.0 thousand bpd) is expected to begin late 2006 and is expected to reach 15.9 thousand m^3/d (100.0 thousand bpd) by 2012.

lack of infrastructure. It concluded that the scale of production from the oil sands should be cut back and the pace of development should be reduced.

Although the Purvin & Gertz forecast of domestic demand was not challenged, in the COC's view, shipping raw crude oil to the United States for refining and then shipping higher priced refined product back to Canada put Canadians at the mercy of the United States oil and gas industry. On a related note, the CEP submitted that the Keystone Project could truncate supplies available to domestic refineries and petrochemical companies, thereby inhibiting further development of these industries in Canada. The CEP also argued that approval of the Transfer Application could lead to the loss of an opportunity for value-added processing of Canadian energy resources before they are exported to United States markets. It submitted evidence, prepared for it by Informetrica Limited (Informetrica), which suggested that allowing the transfer could lead to the export of crude oil that might otherwise be processed at new upgraders and refineries in Canada. Informetrica suggested that this could represent a loss of 18,000 potential jobs per year to Canada.

While no party challenged the Applicants' claim that additional crude oil pipeline capacity would be needed by 2009, BCDENS and the Province of Ontario argued that there were options other than the proposed Keystone Project, such as Alberta Clipper or the construction of a new oil pipeline by TransCanada, that did not require the removal of the Facilities from gas transportation service. They noted that a press release by Enbridge Pipelines Inc. and its subsequent Preliminary Information Package filed with the Board on 24 October 2006, indicated a targeted in-service date for Alberta Clipper in the fourth quarter of 2009, the same proposed in-service date for the Keystone Project.

Views of the Board

The Board considers the oil supply forecasts submitted by the Applicants to be reasonable as is their conclusion that the oil sands projects scheduled to commence production by 2010 are likely to proceed given their current progress and that oil sands supply will likely continue to grow significantly beyond that date. No party challenged the assumption made by Purvin & Gertz with respect to limited growth in the western Canadian refining industry. The Board, therefore, accepts the conclusion that additional pipeline capacity to transport crude oil out of western Canada will be required towards the end of 2009.

The Board notes the concerns expressed by the CEP and COC related to the potential impacts of expanding oil sands production on Alberta communities and potential impacts related to the export of non-upgraded heavy oil production on domestic industries. However, the Board is of the view that these are matters of broad public policy that are properly under the purview of the Federal and Provincial governments and hence, in the Board's view, not relevant to the Board's consideration of this transfer and rate base application.

3.2 Natural Gas

The Throughput Study submitted by the Applicants provided an estimate of the range of excess Mainline and ex-basin pipeline capacity that would be available should the Facilities be transferred to Keystone. It consisted of two analyses, the first of which was a Base Case forecast of throughput for the Mainline. The second analysis used a statistical approach to incorporate the uncertainty in WCSB supply, western Canada demand and the Mainline's share of total ex-basin flows to arrive at a conclusion about the impact of taking capacity out of service on the Mainline. The key considerations in the Throughput Study were the amount of gas available to leave western Canada based on western Canada gas supply and demand, and its allocation amongst pipelines leaving the region.

For the first analysis, TransCanada used its Equilibrium Model to develop its Base Case WCSB forecast to 2015. This model considers supply and demand on a regional basis across North America taking into account liquefied natural gas (LNG) imports. It also incorporates pipeline capacities and transportation costs between each major market region. The model solves for each year in the projection to reach an equilibrium solution that balances flows and prices in each region. The Applicants submitted that this forecast, which is done annually as part of TransCanada's general corporate forecast, represents TransCanada's best estimate of future throughput.

For the statistical analysis, TransCanada prepared alternative forecasts for western Canada supply, demand and pipeline allocation to represent a range of uncertainty regarding these variables. Judgemental probabilities were assigned to the alternative forecasts of supply, demand and allocation. Assumptions were made on the estimated distribution of the variables, with a normal distribution (bell-shaped) assigned to most variables. A Monte Carlo[25] process was applied to populate the distribution, which filled in values between, above and below the alternative forecasts. From the distribution, values were selected at points where only ten percent of the distribution was below the value (P10), where 50 percent of the distribution was above and below the value (P50), and where 90 percent of the distribution was below the value (P90). When individual components that had been assigned a probability range were considered in combination with other components that had also been assigned a probability range, a mathematical technique (stochastic addition, subtraction or multiplication) was used by the Applicants to recognize the increased uncertainty that results when uncertain components are combined. This stochastic addition, subtraction or multiplication of elements with individual probability distributions resulted in a revised probability distribution for the combination.

3.2.1 Western Canada Gas Supply

The Throughput Study submitted in the Transfer Application provided a Base Case forecast and a probability distribution for gas supply available to western Canada. The analysis of western Canada gas supply included conventional and unconventional gas in the WCSB, and Mackenzie Delta gas. Alaska gas was considered too speculative to include as a supply source available to the Mainline and was addressed separately. The key supply parameters and assumptions utilized by the Applicants to determine gas supply available in western Canada were:

25 The Monte Carlo analysis performed by TransCanada relied on @Risk™ software with 10,000 iterations.

- WCSB conventional gas supply was forecast to remain relatively flat in the short term and show a sustained decline in the mid to longer term;
- unconventional gas supply from coalbed methane (CBM) and tight gas was forecast to increase significantly by 2020; and
- shale gas was forecast not to be materially significant for a considerable period of time as shale gas research is in its infancy, and as a result, shale gas was not included in the WCSB gas supply forecast.

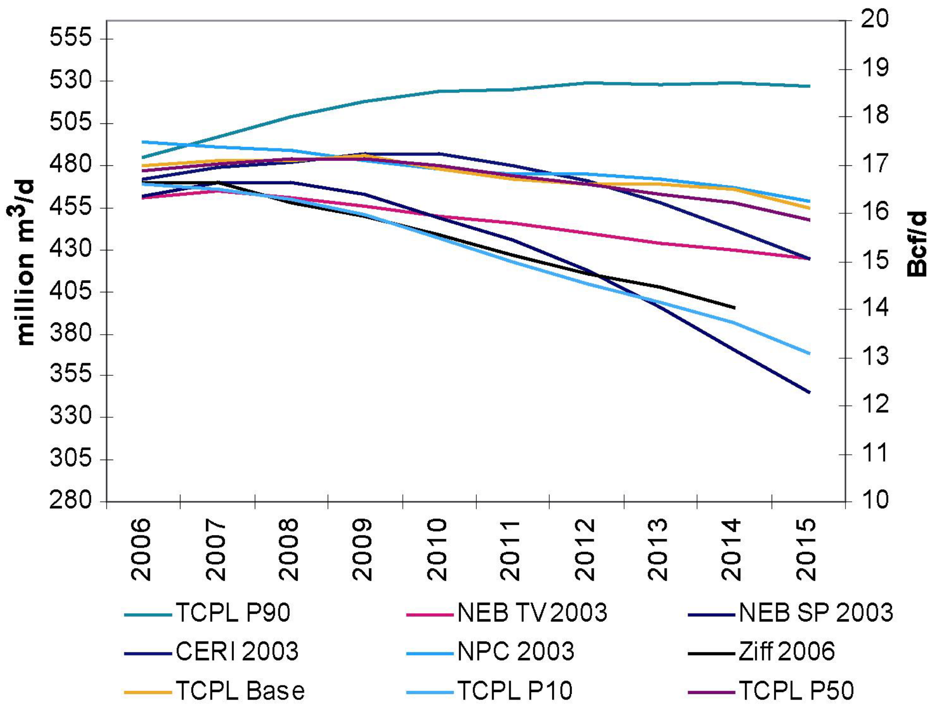
The Applicants stated that the Base Case WCSB supply forecast in the Throughput Study was based on both short-term and long-term considerations. The key factor used to determine the amount of supply that could be generated in the short term was industry activity levels. In addition to their own analysis, the Applicants considered third party forecasts and information gained from discussions with gas production companies and drilling companies. The Applicants were of the view that the sustainability of the WCSB supply in the long term is primarily dependent on ultimate resource potential and long term gas prices. In addition to conventional gas resources, the Applicants also considered future unconventional resource additions from Mannville and Horseshoe Canyon CBM and tight gas to develop the forecast of total gas supply from western Canada.

For WCSB conventional gas supply, the Applicants prepared high, base and low estimates of ultimate potential and high, base and low projections of natural gas prices. The high and low values were each assigned a 25 percent probability and the base values were each assigned a 50 percent probability. All combinations of price and ultimate potential were input to the Applicants' long-term supply model to generate nine (3 x 3) supply forecasts. The Applicants assumed that variations in long term supply would conform to a normal (bell-shaped) distribution defined by the probabilities of the nine forecasts. The Monte Carlo process described previously was applied to populate the normal distribution. From the distribution, P10, P50 and P90 supply forecasts were selected

A similar probability distribution was developed for WCSB unconventional supply by adding distributions for Horseshoe Canyon and Mannville CBM and tight gas. Conventional and unconventional supply were then combined using stochastic addition.

The Throughput Study compared TransCanada’s WCSB supply estimates to a range of publicly available gas supply forecasts covering roughly the same period. The Applicants noted that TransCanada’s Base Case forecast of WCSB gas production was generally higher than third party forecasts. The Applicants’ Base Case, P10, P50 and P90 WCSB gas supply forecasts and the comparative third party forecasts identified in TransCanada’s Throughput Study are shown in Figure 3-2.

Figure 3-2
WCSB Gas Supply Forecasts (Conventional and Unconventional)



Sources: 1. NEB Canadian Energy Supply and Demand to 2025, Figure 5.21 and Figure 5.23
2. Potential Supply and Costs of Natural Gas in Canada, Figure 6.6
3. Balancing Natural Gas Policy - Fuelling the Demands of a Growing Economy, Figure 4-21
4. Western Canada Forecast to 2014, Figure 1.

Note: Forecasts presented in Figure 3-2 are as originally provided by third parties and were not rebased to 2004 as in the Applicants' Figure 4.12.

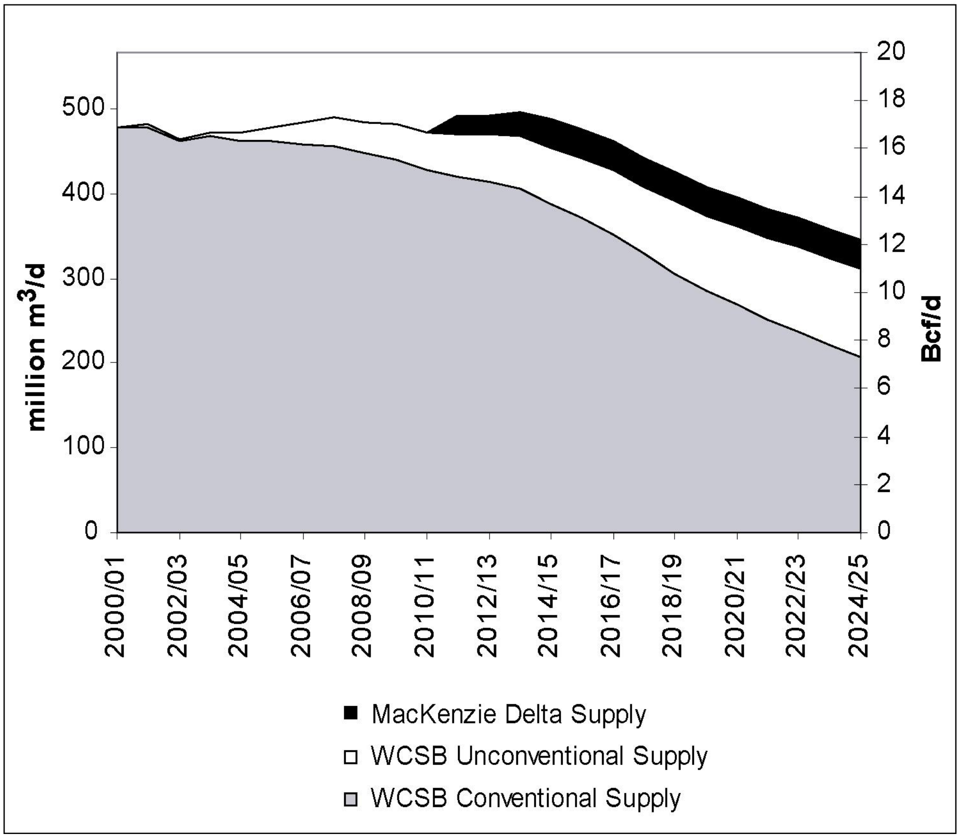
The Applicants also provided forecasts for Mackenzie gas supply that could become available in western Canada. Under the various forecasts, Mackenzie production was estimated to begin in the 2011 to 2012 time period, increase until 2014 to 2016 and thereafter maintain a constant rate. Two levels for the constant rate were considered to cover a range of uncertainty: 34.0 and 51.0 million m^3/d (1.2 and 1.8 Bcf/d).

It was assumed that the WCSB and the Mackenzie supply distributions were statistically independent and therefore, could be stochastically added to create a probability distribution for total supply available in western Canada. The Applicants indicated that the P50 total gas supply in western Canada was very similar to the Base Case total gas supply forecast developed using TransCanada's Equilibrium Model.

Although TransCanada indicated in its Throughput Study that Alaska gas was considered too speculative to include as a supply source available to the Mainline, upon request, the Applicants provided a scenario for its Base Case that included Alaska gas volumes beginning in November 2015 at 113.0 million m^3/d (4.0 Bcf/d) and increasing to 156.0 million m^3/d (5.5 Bcf/d) by November 2019. No peak flow forecasts or probability distributions including Alaska gas were available.

The Applicants' Base Case gas supply forecast for gas available to western Canada is shown in Figure 3-3.

Figure 3-3
TransCanada Base Case Western Canada Gas Supply Forecast



SEMI, the only other party to submit a gas supply forecast, stated that its supply analysis was consistent with the Applicants' analysis.

GLJ Petroleum Consultants (GLJ) submitted that it was contracted by BCDENS[26] to examine the analyses submitted by the Applicants and other available data as well as make its own interpretations of that information. GLJ confirmed that it did not prepare its own probabilistic analysis and that its assessments were qualitative. To prepare its comments on the Applicants' supply outlook, GLJ reviewed gas connections and supply for the entire WCSB by reviewing data from the EUB and the NEB. It proposed that declines in average well productivity were the result of increased development of small or low productivity pools and CBM that was enabled by higher commodity prices and advances in technology. It also submitted that a growing proportion of CBM production would mitigate the required increase in supply additions due to the lower decline rates for CBM wells. GLJ expected gas related activity to remain strong and to allow total supply to be maintained. Under these assumptions, GLJ considered that the P90 Case supply level would have a higher probability of occurring than the 10 percent probability

26 BP was not a member of BCDENS when GLJ was originally contracted to perform its examination.

assigned by TransCanada in its Throughput Study, and therefore adopted the P90 supply for its analysis of net flow out of the WCSB.

During the hearing, the members of BCDENS discussed their plans for future gas development, especially with respect to CBM and stated that they considered the Applicants had underestimated the total gas supply. The Applicants replied that their forecasts had included abundant CBM.

In its comments on the Applicants' supply forecast, Société en commandite Gaz Métro (Gaz Métro) expressed a concern about the expected timing of Alaska gas volumes entering western Canada and due to the possible impact of Alaska volumes. This was one of the reasons for which Gaz Métro proposed the application be denied.

3.2.2 Western Canada Gas Demand

In the Throughput Study, the Applicants provided TransCanada's Base Case estimate for western Canada demand as its most likely view of future demand. The Throughput Study also included a probability distribution for western Canada gas demand using similar ranges and similar statistical approaches as were used to create the supply distribution. This demand distribution was based on judgemental ranges for gas consumption by end use sector.

The Base Case projection showed western Canada demand rising with the increased use of gas in oil sands and electric power generation between 2005 and 2015. The Applicants noted that the gas demand forecast for oil sands projects was built from a project-by-project assessment of timing, size and the nature of the projects combined with TransCanada's forecast of the amount of gas that would be required to produce a barrel of oil (gas intensity). Based on this assessment, it was forecast that gas demand for oil sands in Alberta would increase by 2015 and that gas intensity would decline later in the outlook period as improved technology increased extraction and processing efficiency, resulting in a levelling off of gas consumption in this sector beyond 2015. A comparison of TransCanada's oil sands production forecast to other forecasts showed that it was similar to FirstEnergy Capital Corporation's 2006 forecast, lower than CAPP's 2006 forecast, and higher than five others at 2015[27]. The Applicants noted that TransCanada's gas intensity assumption was midway between the EUB's 2005 and the NEB's 2006 forecasts for 2010 and equivalent to the EUB's 2005 forecast for 2015. Figure 3-4 shows TransCanada's forecast range of gas demand.

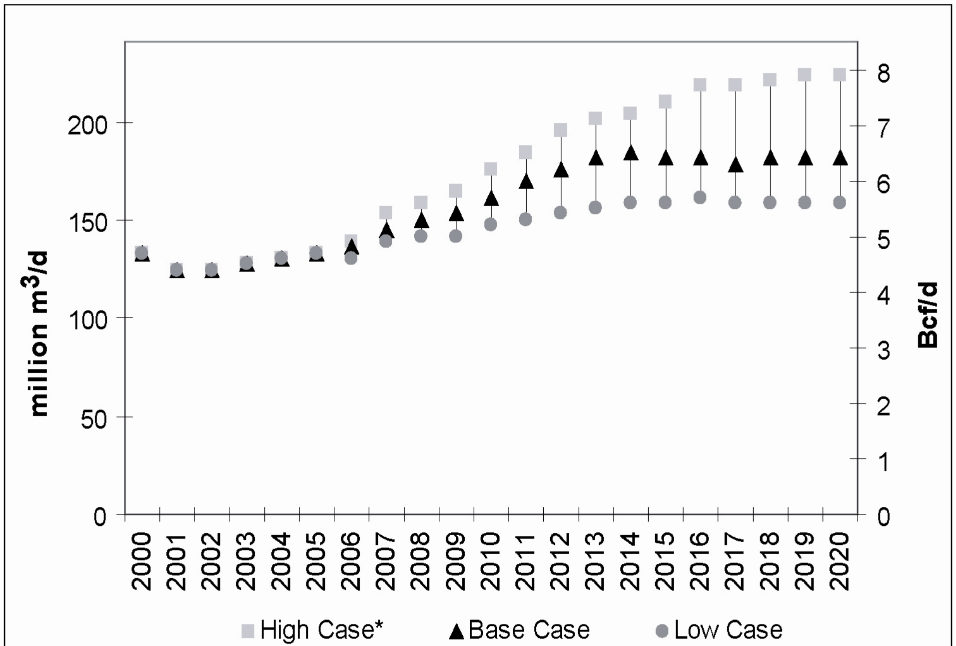
SEMI, the only other party to submit a gas demand forecast for Alberta, showed a similar robust natural gas demand for the province, led by strong oil sands gas requirements.

GLJ submitted that there is uncertainty in future levels of western Canada gas demand and that realistic alternative forecasts of lower demand exist. It suggested that the wide range of forecasts by industry experts illustrated significant uncertainty regarding natural gas demand in the oil sands sector and submitted that a large number of factors can influence the outcome of gas demand for oil sands projects, including production levels, the timing of new projects, natural

27 Other forecasts included were Purvin & Gertz 2006 forecast, Canadian Energy Resources Institute 2005 High forecast, EUB 2005 forecast, NEB 2006 forecast and Canadian Energy Resources Institute Reference forecast 2005.

gas and crude oil prices, and technological improvements. On the basis of these uncertainties, GLJ prepared its sensitivity case using the TransCanada Low Case for western Canada gas demand.

Figure 3-4
TransCanada Western Canada Gas Demand Forecast Range



* Revised from Original published in Throughput Study, response to BCDENS Information Request 49 and 50, 22 August 2006

In addition, GLJ noted that a proposed LNG regasification terminal at Kitimat, B.C., which could be in service in 2009, could satisfy a portion of oil sands natural gas demand and thereby lower the WCSB gas demand requirements. The Applicants submitted that a Kitimat LNG facility to supply Alberta oil sands producers with natural gas was improbable as the economics of that particular project were poor due to the distance from the oil sands region and other markets.

3.2.3 Potential Gas Flow Out of Western Canada

Net gas flow available to leave western Canada was calculated as the difference between total gas supply available to western Canada and western Canada demand. For the statistical analysis, it was assumed that WCSB supply and WCSB demand were statistically independent and therefore, that a probability distribution for total volume of gas available for delivery out of the WCSB could be calculated as the stochastic difference between the basin supply distribution and the basin demand distribution. The Applicants clarified that it would be normal to expect a negative correlation between supply and demand in that an increase in gas price would elicit higher gas supply and lower gas demand. However, they submitted that this would likely not be the case in western Canada. In the Applicants' view, higher gas prices would be indicative of higher oil prices, thereby leading to increased oil sands production and a corresponding increase in western Canada gas demand. Since they were of the view that a normal correlation between supply and demand would not apply in western Canada, the two components were considered to have zero correlation, or to be independent. The Applicants' forecasts of gas leaving western Canada are shown in Tables 3-5 and 3-6.

The Applicants noted that TransCanada's forecast of WCSB gas production was generally higher than the third party forecasts that were provided. They submitted that if WCSB production were to ultimately perform as suggested by these other forecasts, ex-basin flows would be lower than forecast by TransCanada, in turn yielding more excess pipeline capacity out of the western Canada than projected in TransCanada's Throughput Study.

The Throughput Study discussed the ex-WCSB pipelines and their current design capacity (see Figure 3-7). The Applicants stated that currently ex-WCSB pipelines have capacity available to transport additional gas volumes from the region. The Applicants did not include any new WCSB gas pipeline capacity in their forecast for the period from 2006 to 2017. However, they considered that there is the potential for expansions of existing capacity, including, but not limited to, increases of roughly 5.67 million m^3/d (0.2 Bcf/d) on the Northwest Pipeline system and roughly 2.83 million m^3/d (0.1 Bcf/d) on the Alliance Pipeline Ltd. (Alliance) system.

Figure 3-5
TransCanada Forecasts of Gas Leaving Western Canada - Average Annual Flows

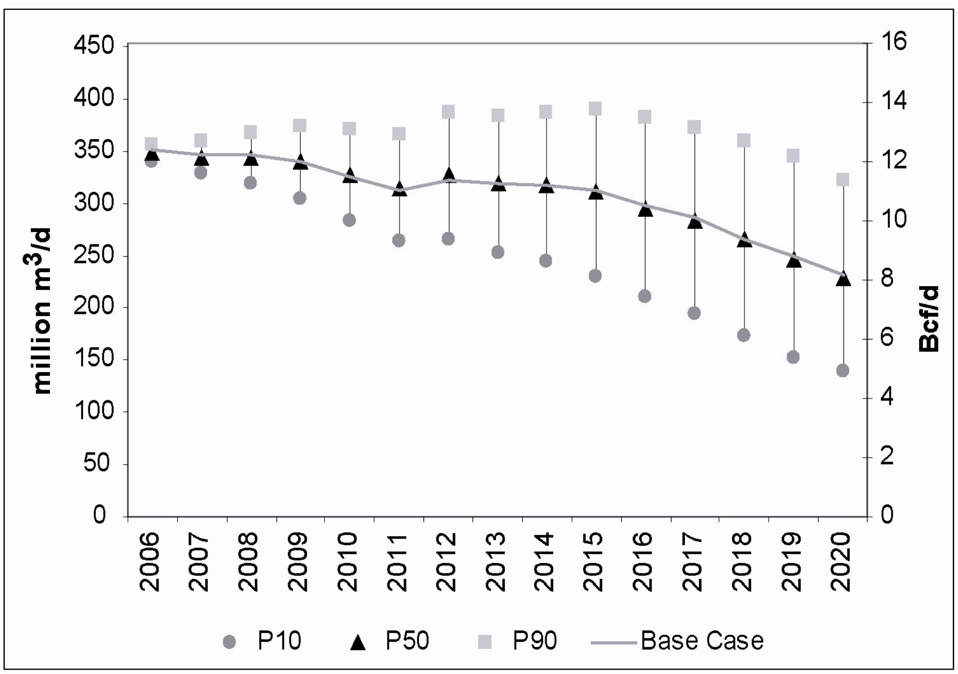
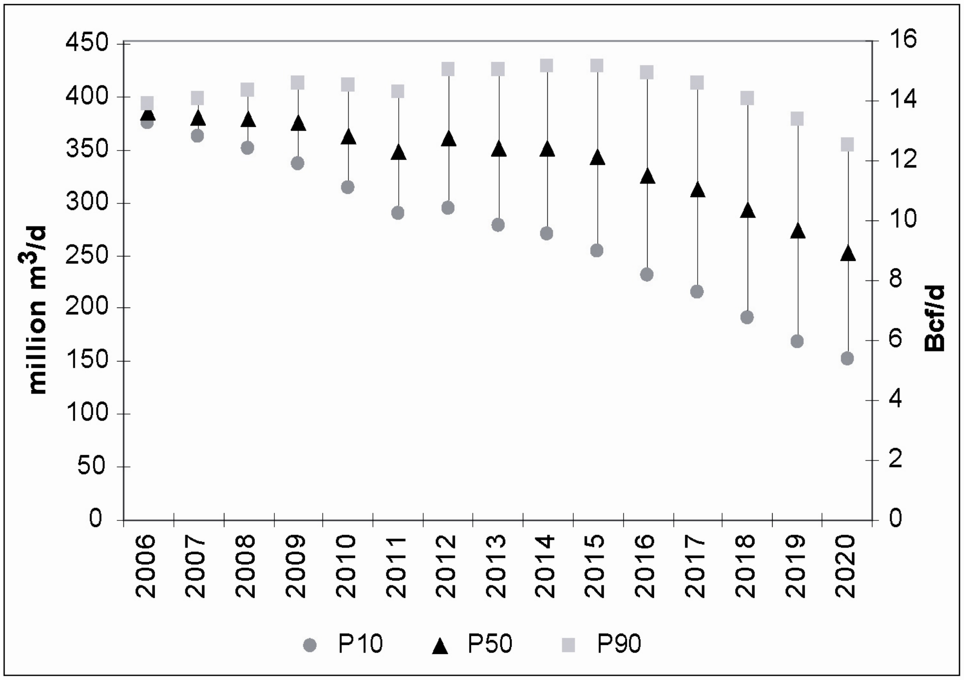


Figure 3-6
TransCanada Forecasts of Gas Leaving Western Canada - Annual Peak Flows



SEMI’s estimate of ex-basin gas flows and available pipeline capacity was similar to the Applicants’ forecast.

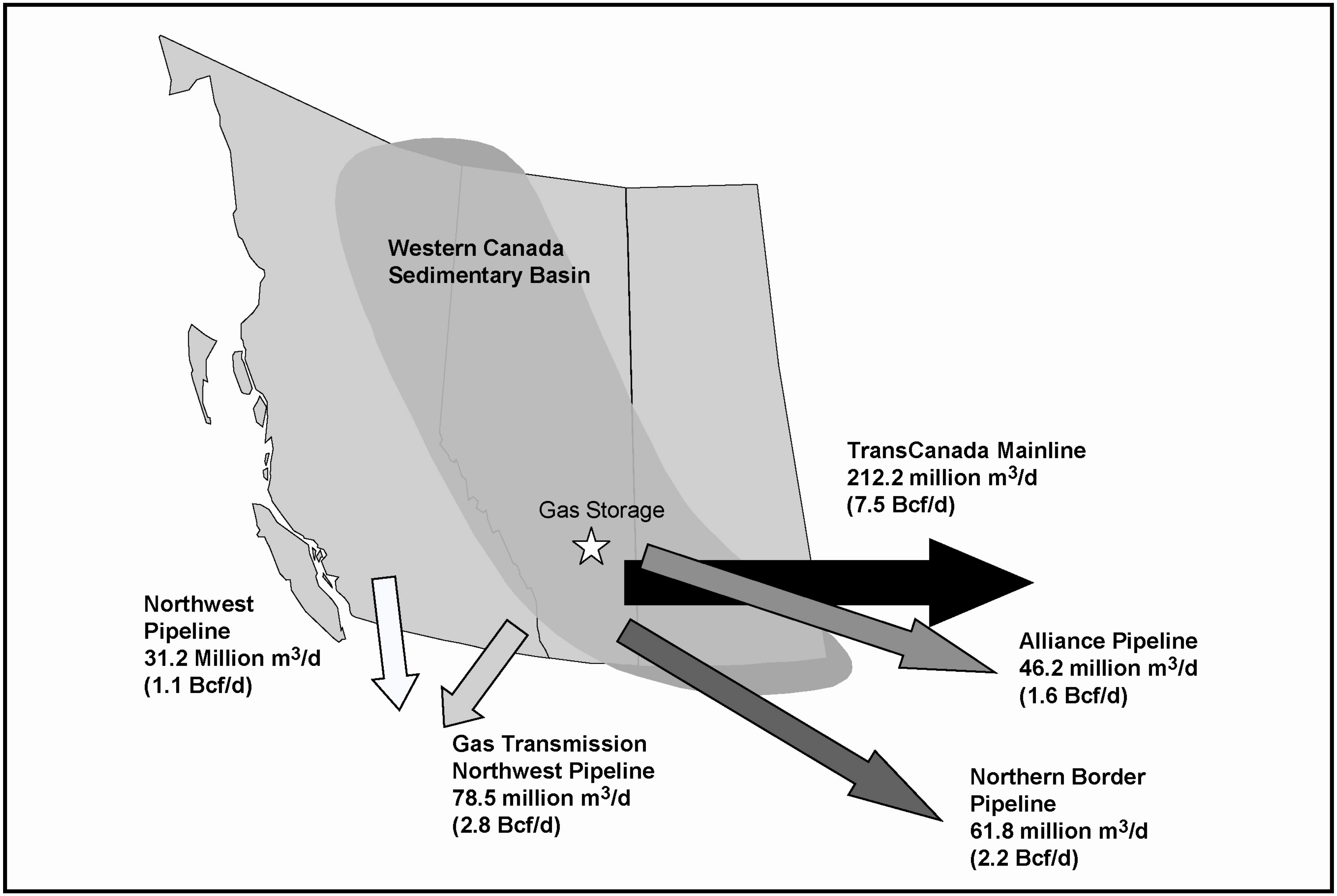
The only other party to comment on ex-basin gas flows was GLJ on behalf of BCDENS. Based on GLJ’s assumptions that the Applicants' P90 supply case and low demand case would have a higher probability of occurring than indicated by the Applicants, GLJ presented a sensitivity case whereby the low demand probability distribution was deducted from the P90 supply distribution for each year of the projection to represent the annual volume available to leave the basin. Using this approach, GLJ’s estimates of ex-basin volumes were higher than the volumes which had been forecast in the Throughput Study.

The Applicants submitted that GLJ’s compilation of the P90 WCSB supply, P90 Mackenzie supply and P10 western Canada demand was not a reasonable alternative scenario. They estimated the probability of the compilation of these P90 and P10 elements over the entire 20-year period of the scenario to be 10^{-20}. During the hearing, GLJ stated that it did not calculate the probability for the scenario to occur, but was of the view that the scenario had sufficient probability to be worthy of consideration.

3.2.4 Allocation of Flows to Pipelines Leaving Western Canada

Having assessed the total volumes of gas available to leave western Canada and the potential ex-basin pipeline capacity, consideration can be given to the allocation of the available volumes among the major pipelines leaving the region. From the allocation, potential throughput on the Mainline can be evaluated relative to available capacity. Key gas pipelines and market regions for western Canada gas supply are shown in Figure 3-8.

Figure 3-7
Ex-WCSB Pipeline Capacity



TransCanada developed the Base Case forecast and P90, P50 and P10 probability distributions for the share of ex-basin volumes that would be allocated to the Mainline. Rather than prepare a number of alternative scenarios upon which to apply Monte Carlo simulations and develop a normal distribution for allocations, TransCanada constructed a simplified triangular distribution that used the Base Case allocation as its mean. The triangular distribution was truncated at 10 percent from its upper and lower limits to serve as P90 and P10 allocation shares.

Ex-basin flows among pipelines were allocated according to the initial condition giving consideration to firm transportation (FT) contracts. After FT contract volumes were satisfied, the Equilibrium Model then considered netbacks[28] for gas shippers in each region to determine the volumes of gas that would flow to those markets and the resulting utilization of pipeline capacity.

In the Throughput Study, TransCanada stated that the Equilibrium Model incorporated numerous tolls and transportation routes. The Applicants noted that netbacks from the various regions can vary depending on the demand for WCSB gas and market conditions. They stated that a feature of the Equilibrium Model is that it uses annual changes in relative netbacks between regions to adjust annual flow allocations, rather than annual changes in absolute netbacks. This feature reflects the assumption that a supply region does not concentrate all of its available output to the single market with the highest absolute netback. Rather, it recognizes the historical variability in regional netbacks, and distributes flows among the regions to reduce the overall risk to shippers. When western Canada ex-basin gas flows begin to decline, throughput on all pipelines not protected by long-term firm transportation contracts is projected to decline proportionally to their share of ex-basin flows.

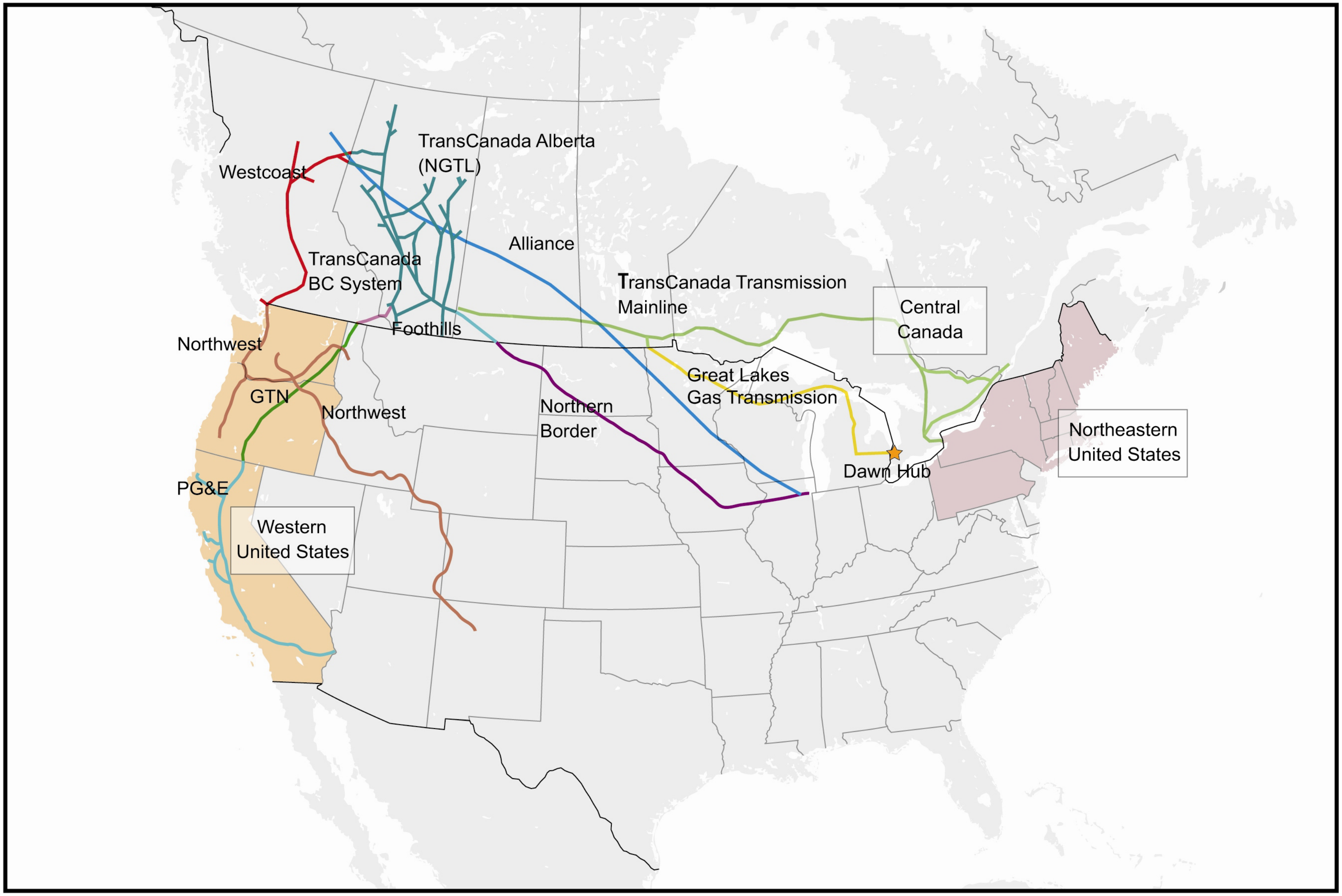
Western United States Markets

The Applicants forecast that gas demand in the western United States market (see Figure 3-8) would grow by 2010 driven by the growing gas demand for electricity generation in that region. This market is currently served by the Rockies, San Juan and California supply basins in the United States and by exports from the WCSB. The Applicants also expected that LNG imports at Baja, California will begin to serve the western United States market beginning in 2009.

The Applicants estimated that flows from the United States Rockies into the western United States would increase by 2012, to partially offset the expected decline in production from the San Juan and California basins. However, the proposed Rockies Express Pipeline would have the capacity to transport 50.1 million m^3/d (1.8 Bcf/d) of gas from the Rockies producing region to eastern markets. Following from this analysis, the Applicants forecast that gas flows from the WCSB into the western United States market along the Gas Transmission Northwest (GTN) and the Williams Northwest Pipeline systems would increase by 2010. However, they also indicated that a delay in the in-service date of the Rockies Express Pipeline or smaller flows would both have a negative impact for flows on GTN and therefore, more gas would be available to flow eastward on the Mainline.

28 Netback indicates the price at the inlet of a pipeline determined by subtracting the cost of transmission from the market price at the outlet of the pipeline.

Figure 3-8
Key North American Natural Gas Pipelines and Market Regions



BCDENS proposed that supply growth in the western United States from substantial growth in Rockies production and LNG receipts was forecast to exceed demand growth in the western United States, and questioned the Applicants' expectation that additional volumes would flow into that region from the WCSB. They also submitted that the Applicants’ expectation that volumes would flow first on systems underpinned by firm contracts ignored historical pipeline flows that show that shippers sell gas to the highest netback market, irrespective of firm transportation contract obligations. Based on the Applicants’ forecast of netback prices, they argued that the Malin, California market would provide netback prices that are below the WCSB prices and inferior to all other routes and markets, and suggested the volume assigned to the GTN pipeline might therefore be overstated.

The Applicants clarified that the Equilibrium Model was used to estimate flows, not contract utilization, and therefore, it was assumed that not all firm contracts would be utilized, depending on the economic outcome for any given time period. They explained that GTN flows are expected to improve over time because the annual average netbacks for that market reflect the expectation that in 2010 there will be more time periods during which transportation to that region would be attractive when compared to 2006. They also submitted that the improvements in flows on the GTN system reflect an improving netback in western markets relative to eastern routes on the Mainline.

Central Canada and Northeastern United States Markets

While the Applicants projected strong demand growth in central Canada (see Figure 3-8), driven by Ontario’s plan to replace some of the coal-fired generation in the province with natural gas by 2009, they considered that this market area would enjoy a large surplus of available pipeline capacity for the foreseeable future. The Applicants noted that pipeline capacity into the central Canada market currently exceeds total Ontario and Quebec demand. They also noted that this market is currently served by WCSB gas supplies through TransCanada’s Northern Ontario Line (which is supplied by the Mainline), as well as by gas supplies from the United States Gulf of Mexico, Rockies, Texas and Oklahoma through connections with several pipelines delivering into the St. Clair, Ontario region, and described planned projects that could increase supply into the region.

The Applicants suggested that increased gas supply in the United States Rockies through the Rockies Express Pipeline would send additional Rockies gas to the Chicago, Illinois area, and forecast an increase in pipeline capacity into Ontario from Chicago by 2015. This corridor is currently served by the Vector Pipeline Limited partnership (Vector) and Union Gas pipeline systems. They also submitted that the Dawn Hub is currently accessible by several United States pipelines and storage facilities pipelines.

In addition to the pipeline expansions, the Applicants were of the view that some of the growth in central Canadian gas demand would be met by LNG imports into Canada through two new facilities, one in Quebec and one in Atlantic Canada. These facilities were expected to begin supplying these markets in 2008. As a result of these expected pipeline expansions and prospective LNG developments, the Applicants projected that Mainline capacity would exceed Ontario and Quebec demand in 2015.

Similar to the western United States markets, the Applicants forecast that natural gas demand in the northeastern United States (see Figure 3-8) would grow by 2015, driven primarily by the electric power generation sector. Currently, this region is served by many North American gas sources and LNG delivered through numerous pipelines into this area. The Applicants submitted that the Canadian LNG projects would serve the northeastern United States market in the future and suggested that there were a number of other sources of expected supply growth into the region including United States LNG imports and Rockies gas. LNG imports into the United States were forecast to grow by 2015, mostly through the Gulf of Mexico. The Applicants also expected one new LNG terminal would be built in the northeastern United States to serve local markets.

Based on their analysis of these markets, the Applicants forecast a 44 percent decline in Canadian Mainline gas exports to the northeastern United States through central Canada. The volumes that would continue to be delivered to the northeastern United States were expected to flow under a variety of services, including new FT contracts. The Applicants noted that there are currently only 5.7 million m^3/d (0.2 Bcf/d) of FT contracts to the northeast United States that have an expiry date later than 2015.

The Applicants acknowledged that there is uncertainty surrounding the forecasts and expected timing of LNG imports and flows of gas from the United States Rockies and the consequent reduced demand for WCSB gas transported on the Mainline to the northeastern United States. They conceded that delays in LNG projects or imports or delays in the timing or reductions in volumes of gas to be delivered on the Rockies Express Pipeline would be supportive of other gas sources into the northeastern United States, including the Mainline.

In support of the Applicants' views, SEMI submitted that the construction of one LNG terminal on the east coast of North America could potentially back out WCSB gas and lessen the economic incentive to flow gas on the TransCanada Mainline.

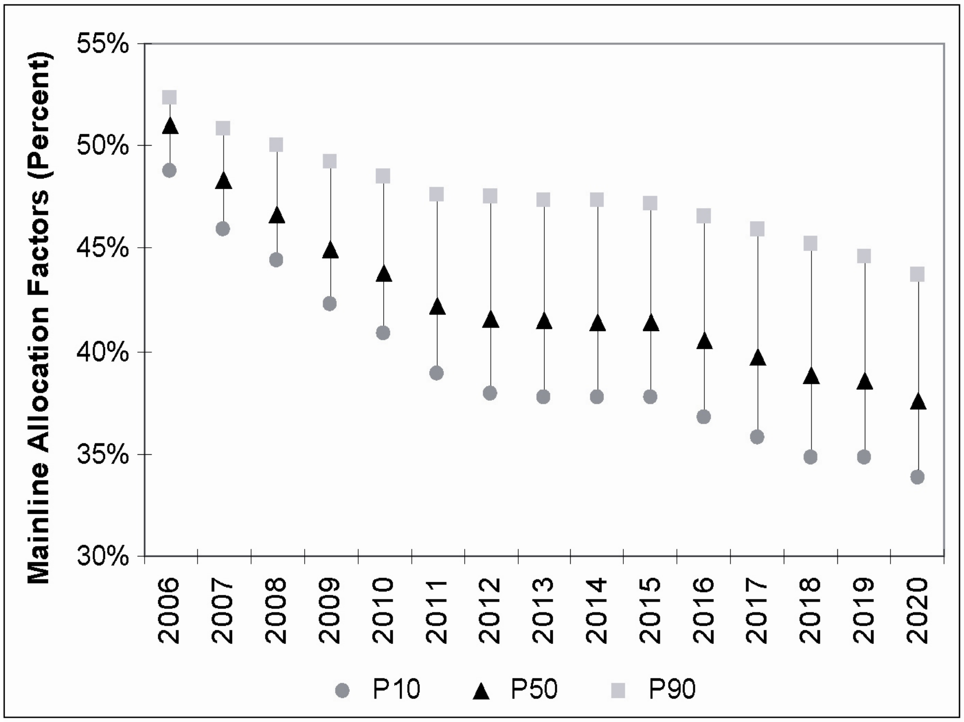
Ontario submitted that the Applicants' forecast relied too heavily on growing LNG imports which are not supported by current events, noting the difficulty of finding sites for LNG facilities in North America and of securing the necessary LNG supply. Therefore, it considered the Applicants' LNG forecast to be unrealistic.

In addition, Ontario had concerns regarding the assumption that potential shortfalls in gas deliveries to Ontario and other eastern markets would be met by new natural gas pipelines, such as the proposed Rockies Express Pipeline. Ontario noted that these proposed natural gas pipelines have not yet been constructed and may not provide competitive tolls. Ontario considered reliance on prospective pipelines to replace transferred capacity to be too speculative.

3.2.5 Allocation to the Mainline

The Throughput Study submitted by the Applicants indicated that the Mainline's share of total ex-basin flows would decline from roughly 52 percent in 2005/2006 to 40 percent in 2015/2016 in the P50 Case as indicated in Figure 3-9. The Applicants noted that the Mainline's 52 percent market share in 2005/2006 was the highest that has been observed in the post-Alliance period and reflected strong eastward flows from the WCSB in response to hurricane-related supply disruptions in the Gulf of Mexico.

Figure 3-9
TransCanada Mainline Share of Total Ex-Basin Gas Flows

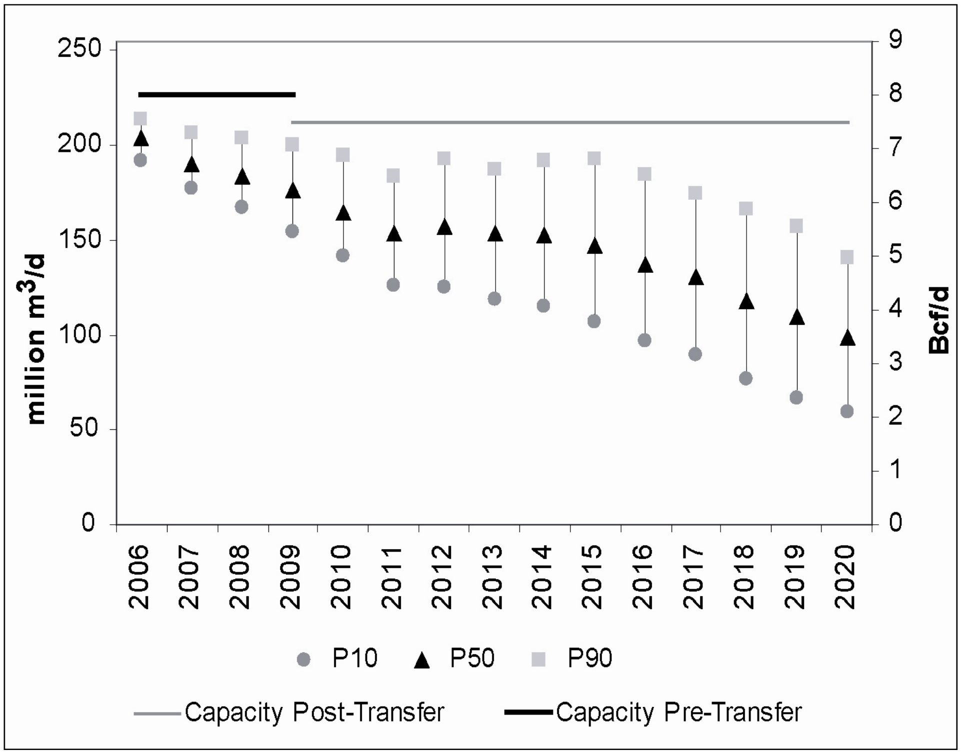


The Applicants determined the Mainline average annual flow based on ex-basin flow distribution forecasts and the allocation distributions. They indicated that for any given annual average flow, there would be a range of daily flows that would at times either exceed or be less than the average flows. To estimate the volatility of daily flows, the Applicants assessed daily flows on the export pipelines and the Mainline for the 2001/2005 post-Alliance period, and applied these to the forecast period. The peak flow curves, defined as the 99 percentile of the daily flows for each year, as shown in Figure 3-10, accounted for this historical daily volatility.

In response to concerns about the poor performance of the Equilibrium Model in predicting the flow allocation on the Mainline over the 2005/2006 period, the Applicants suggested that flows were unusually high for the 2005/2006 year and, while they considered it to be possible that these flows could be reached again[29], it was improbable that such flows could be maintained consistently for another 20 years. They noted that in 2005, Hurricanes Katrina and Rita caused the loss of over 15.6 billion m^3 (550.0 Bcf) in offshore Gulf of Mexico production. With pipeline capacity from the western United States to eastern markets already highly utilized, Mainline flows were strongly supported by the loss of the Gulf of Mexico production. The Applicants claimed that with TransCanada's Base Case forecast, a Mainline flow at the 2005/2006 level for 20 years would result in all other export pipelines being virtually empty by the end of that period.

29 TransCanada stated there is an 11% probability that the 2005/2006 factor will be reached or exceeded in 2007.

Figure 3-10
TransCanada Mainline Throughput Peak Flow Forecast



BCDENS, in their report prepared by GLJ, proposed alternative forecasts of capacity utilization on the Mainline based on its sensitivity case for gas volumes available to exit western Canada (see section 3.2.3) and the TransCanada post-Alliance Mainline allocation. The impact of this sensitivity case resulted in higher Mainline capacity utilization. Several sensitivity cases created by GLJ, incorporating the Mainline share of ex-basin flows reported by TransCanada for the 2005/2006 year, resulted in peak and annual average flows exceeding the current Mainline capacity.

BCDENS[30] also submitted evidence prepared by A.S. Cheung & Associates that expressed concern with the Applicants' assumptions regarding non-renewal of FT contracts on the Mainline. Ms. Cheung noted that during a period of expansions of the Mainline system in the 1980s and 1990s, TransCanada had FT contracts that would expire within the planning horizon, and that for the purposes of those facilities expansions, TransCanada had assumed evergreening of most of those FT contracts as the basis for the proposed expansions. In this Application, however, Ms. Cheung stated that the Applicants assumed no renewal of any of the FT contracts. Ms. Cheung expressed the view that by increasing the level of firm service demands, for example by assuming evergreening of some FT contracts or including some short-term FT, the baseline used for the purposes of allocating gas supply to the Mainline would be higher and this would result in a higher throughput forecast for the Mainline.

30 BP was not a member of BCDENS when A.S. Cheung & Associates was originally contracted to perform its examination.

The Applicants responded that rather than assume current contract levels to remain constant, they based their analysis on the fact that shipping decisions and contract renewals are purely underpinned by their economics.

Ontario and GLJ also raised concerns about the accuracy of the TransCanada throughput analysis. Based on a comparison of Mainline flows for 2003/04 and 2004/05, Ontario concluded that TransCanada's recent forecasts using its Equilibrium Model (for example, in the 2004 Tolls and Tariff Application RH-2-2004) had proven to be a poor predictor of Mainline throughput and urged the Board not to rely on the forecasts.

Views of the Board

Key considerations for the Board in assessing the need for the Facilities in gas service are gas supply and demand in western Canada, markets served by gas from western Canada, and the allocation of those gas flows amongst the various pipelines leaving western Canada, including the Mainline. The Board recognizes that future levels for each of these elements and how they may impact each other are unknown and, therefore, gas market and Mainline throughput forecasts will involve some degree of uncertainty. In previous applications before the Board that included an estimate of the expected future usage of Mainline facilities, a frequently used approach for addressing uncertainty involved the preparation of a Base Case forecast throughput on the Mainline and a discussion of a reasonable range around this Base Case to address the uncertainty. For this application, the Applicants submitted the Base Case forecast and prepared probability distributions from alternative forecasts for western Canada supply, demand and pipeline allocation to represent a range of uncertainty regarding these variables.

The Board observes that TransCanada has used its Equilibrium Model to forecast gas flows on the Mainline in the past and the Board has been satisfied that it is a reasonable method for forecasting the Base Case. The Board agrees with TransCanada that forecasts cannot be expected to take into account unusual circumstances that are beyond normal expectations and it is not prepared to discount the Equilibrium Model methodology for forecasting Mainline throughput based on its inability to account for the severe weather in 2004-05.

The Board considers that the probability-based forecasts of supply, demand, and pipeline allocations presented by the Applicants in this case provided a thorough and systematic means of assessing potential flows on the Mainline over the next 10 to 15 years. In the Board's view, this approach provided quantitative confirmation that the range of flows provided by the Applicants encompasses a reasonable range to address the uncertainty. The approach also provided a quantitative means of assessing the degree of risk being assumed. The Board finds the concept of a statistical analysis with associated probabilities to be a helpful tool in assessing the likelihood of various scenarios. The Board agrees that this type of analysis in this case is an improvement over single-line evaluations.

While the Board finds that this new statistical approach is useful for the purposes of this application, the Board notes that its implementation presented some challenges with respect to the evaluation of the forecasts produced. For example one misunderstanding centered around whether the P10, P50 and P90 distributions could be interpreted as meaningful scenarios. The Board suggests that if TransCanada employs a statistical analysis in the future, it may wish to consider providing further information on the preparation of probability distributions of variables, the Monte Carlo process and the process of combining separate distributions.

The Board finds that the Applicants' analysis of the supply and demand fundamentals to be comprehensive based on current data. In the Board's view, the Applicants' forecasts of gas supply and demand in western Canada are centered on an acceptable Base Case. Additionally, the P10 to P90 cases provide for gas supply and demand that address the uncertainty. The Board notes that comparisons with third party forecasts provided further comfort that the Applicants' forecast is not outside the bounds of expectations as seen by others.

In the Board's view, the Applicants submitted a sound assessment of conditions in markets served by gas supply from western Canada and allocations of gas flows to these markets. Accordingly, the Board finds the Applicants' analysis and probability distributions of ex-basin gas flow allocation and Mainline throughput to be reasonable.

GLJ proposed a scenario that combined high supply and low demand in western Canada and a Mainline allocation based on a period experiencing hurricane-related supply disruptions. No quantitative substantiation regarding the validity of combining these factors into a scenario or their likelihood of occurrence was submitted. The Board is of the view that this set of market conditions was not shown to be sufficiently credible to serve as a basis for long-term planning of Mainline utilization. Furthermore, in the event that such conditions were to occur, it appears that average day flows could still be accommodated without the Facilities in gas service and that no FT service forecast volumes would be impacted under peak day conditions.

Chapter 4

Potential Impacts of the Transfer

During the hearing a number of potential impacts of the transfer of the Facilities on gas shippers were identified. The main impacts discussed were adequacy of the Prairies section capacity, fuel costs, potential loss of commercial revenue, the value of spare capacity and the effects of the transfer on Mainline operations.

4.1 Adequacy of Prairies Section Capacity

The Applicants stated that the Mainline is an integrated system operated to ensure that the aggregate needs of both firm and discretionary service requirements are met in the most efficient, safe and reliable manner. The Applicants expected that the impact of the removal of the Facilities on the operation of the integrated system would be marginal.

The 100 percent design capacity of the Mainline, which was determined to average approximately 220.1 million m^3/d (7.8 Bcf/d) pre-transfer and 205.7 million m^3/d (7.3 Bcf/d) post-transfer, assumes all facilities are available under average seasonal temperatures.

While the original evidence in the Application compared average day flow to winter 100 percent design capacity, the Applicants indicated in reply evidence that the more appropriate comparison, as pointed out by BCDENS, should have been with capacity adjusted for planned and unplanned maintenance. They submitted that if capability factors were assigned to the 100 percent design capacity to take into consideration the need for ongoing maintenance, on an average day, the capability of the system would be less than the 100 percent design capacity. The capability factors used and applied to the 100 percent design capacity, 96.2 percent in the summer season and 96.7 percent in the winter season, were based on a capability factor study undertaken by TransCanada. As shown in Table 4-1, the adjustment to the average annual design capacity decreased the excess capacity post-transfer by 7.4 million m^3/d (0.3 Bcf/d).

Table 4-1
Average Annual Design Capacity Adjusted by Capability Factor Pre- and Post-Transfer[31]
(million m^3/d (Bcf/d))

	Annual 100% Design Capacity	Annual 100% Design Capability Adjusted by Capacity Factors	Difference
Pre-Transfer	220.0 (7.77)	212.2 (7.49)	7.9 (0.28)
Post-Transfer	205.7 (7.26)	198.3 (7.00)	7.4 (0.26)

The Applicants confirmed that the most critical design condition for the Prairies section is the summer peak day with loss of unit. This design condition is consistent with TransCanada's past practices and was used in considering firm service requirements pre- and post-transfer of the Facilities.

31 Exhibit B-21c

In the Applicants' view, the Throughput Study demonstrated that in the Base Case, the Mainline would have sufficient capacity to transport all forecast volumes after taking into account the capacity effects associated with the transfer. They submitted that the statistical analysis demonstrated that the Mainline would have sufficient capacity to meet transportation requirements over a wide range of probabilities of supply, demand and the Mainline's share of flows on both an average annual and peak day basis.

In response to the testimony of BCDENS' witness, Ms. Cheung, the Applicants indicated that consideration was given to fuel requirements in the current contract expiry profile. They explained that 8.5 million m^3/d (0.3 Bcf/d) had been assigned to allow for downstream fuel requirements and indicated that fuel requirements had been taken into consideration when calculating excess capacity on the Mainline. The Applicants concluded that there would still be excess capacity on the Mainline post-transfer.

As shown in Table 4-2, the Applicants forecast that there would be an excess of capacity of 44.2 to 72.5 million m^3/d (1.6 to 2.6 Bcf/d) in the throughput Base Case scenario over the ten year study period, based on average annual flows.

Table 4-2
Mainline Excess Capacity (Under Average Annual Flow Conditions) Post-Transfer[32,33]
(million m^3/d (Bcf/d))

Forecasts	**2007**	**2009**	**2010**	**2015**
10 Percentile	56.9 (2.0)	63.2 (2.2)	75.4 (2.7)	104.5 (3.7)
50 Percentile	45.9 (1.6)	45.3 (1.6)	55.0 (1.9)	69.7 (2.5)
Base Case	44.5 (1.6)	44.2 (1.6)	54.1 (1.9)	72.5 (2.6)
90 Percentile	34.6 (1.2)	24.9 (0.9)	30.6 (1.1)	31.2 (1.1)

In assessing the Mainline's capability available for peak service requirements (including both firm and discretionary service volumes), the Applicants submitted that it was reasonable to compare those requirements to the 100 percent design capability calculated on a winter season basis. Based on peak flows shown in Table 4-3, the Applicants forecast that there would be an excess capacity of 35.7 to 64.3 million m^3/d (1.3 to 2.3 Bcf/d) over the study period, in a scenario that would have a 50 percent probability of occurring. In their analysis, the lowest amount of peak flow excess capacity could occur in 2009 at 11.3 million m^3/d (0.4 Bcf/d). However, there was only a ten percent probability that excess capacity would be this low or lower.

32 Application, Appendix B, page 26, Table 3, Revised 7 November 2006 (Exhibit B-21c)

33 Flow-in (includes Prairies fuel)

Table 4-3
Mainline Excess Capacity (Under Peak Flow Conditions) Post-Transfer[34]
(million m^3/d (Bcf/d))

Forecasts	2007	2009	2010	2015
10 Percentile	48.7 (1.7)	57.2 (2.0)	69.7 (2.5)	104.3 (3.7)
50 Percentile	35.7 (1.3)	35.7 (1.3)	47.0 (1.7)	64.3 (2.3)
90 Percentile	20.1 (0.7)	11.3 (0.4)	17.3 (0.6)	18.7 (0.7)

The Applicants' analysis showed that when the current FT expiry profile (including fuel) is compared to the most critical capability conditions (summer peak day with loss of critical unit basis post-transfer) there would be at least 147.9 million m^3/d (5.2 Bcf/d) of excess capacity available. They also submitted that if the current FT contract levels were annually renewed post-transfer, there would still be at least 36.8 million m^3/d (1.3 Bcf/d) of excess capacity available to meet FT demand including fuel.

For the period 1 January 2000 to 1 April 2006, the Applicants confirmed that there have been no days when it would not have been able to meet firm service requirements if the Facilities had been removed. During the same period, theoretically, 79 days would have had limits on interruptible service. After the construction of Alliance and as of 1 January 2001, 54 days would have had limits placed on interruptible service. Of the 54 days, 25 would have occurred in October and November 2005 due to a prolonged compressor outage with a high demand for western receipts to satisfy eastern storage injections and eastern exports as a result of the 2005 hurricanes.

Mr. Engbloom of Confer Consulting Ltd., acting on behalf of the Applicants, stated that the Applicants' supply analyses showed that the quality of contracted firm gas transmission service from the WCSB, including the Mainline, is not reduced by the Facilities being in oil service. A secondary conclusion is that there is a very low probability that the quality of interruptible service will be reduced.

In circumstances where additional capacity might be required, the Applicants stated that TransCanada would consider changes to its operating strategies and maintenance planning activities. Furthermore, in the event that all shipper-requested volumes could not be met, TransCanada would look to restrict the interruptible transportation (IT) volumes first, which would be consistent with the IT priority of service.

In response to a request regarding the possible impact of an Alaska gas pipeline coming into service in 2016, the Applicants stated that no new export capacity would be required for the movement of gas. If Alaska gas commences before 2016, new ex-WCSB capacity would likely be required whether or not the Facilities were transferred. However, TransCanada submitted that Alaska gas was not included in its forecasts due to the high degree of uncertainty around its timing.

CNR also submitted that the likelihood of a shortfall in gas transmission capacity appeared to be very small. SEMI's evidence supported the Applicants' analysis. It showed that there would be

34 Application, Appendix G, page 15, Table 3.4

sufficient capacity available on the TransCanada Mainline to meet forecast gas flows out of the WCSB.

On behalf of BCDENS, Ms. Cheung submitted that FT contracts should not be looked at alone in determining how much capacity is required to transport volumes. She suggested that by looking at recent historical use of the system, the Facilities could well be required for gas service in the future.

Gaz Métro stated that users of an integrated system benefit by being able to utilize all of the TransCanada assets to maximize gas delivery efficiency. It argued that removing the Facilities from service would disrupt the system's balance, reduce flexibility and put TransCanada in the position of having insufficient capacity at certain times of the year.

4.2 Potential Costs to Gas Shippers

The Applicants argued that, based on their forecast, the cost impact of the removal of the Facilities from the Mainline combined with the impact of the removal of the NBV of the Facilities from the TransCanada rate base would result in a small net benefit to gas shippers. BCDENS submitted that harm could result to gas shippers from the transfer of the Facilities in two ways: the first, if fuel costs are higher than TransCanada's forecast; and the second, due to the loss of substantial producer revenue if throughput on the Mainline is higher than TransCanada has predicted.

4.2.1 Compressor Utilization and Fuel Cost Risks

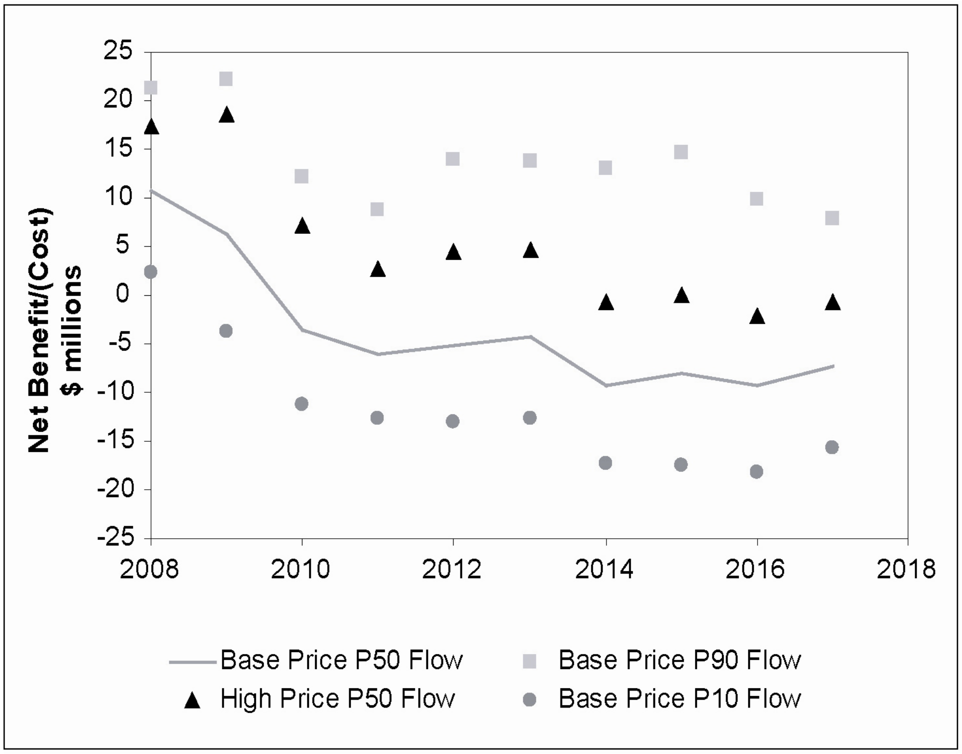
The Applicants stated that in order to transport the forecasted Prairies section flows, TransCanada's existing compressors would have to operate at a higher utilization rate which would result in increased fuel consumption. It was anticipated that the transfer of the Facilities would increase Eastern Zone fuel ratios by 0.15 percent to 0.21 percent in the years 2009 to 2013.

The Applicants indicated that TransCanada had evaluated and would continue to evaluate a number of potential changes to the compressors in order to increase efficiencies and reduce forecasted fuel requirements resulting from the transfer. They added that TransCanada had considered replacing older less efficient units, but given the low forecasted utilization of these units, the higher capital cost of new compression would not generate enough fuel savings to justify replacement, as changes to compression equipment would only yield significant fuel savings on the more highly utilized newer units, many of which already incorporate more efficient technology.

The Applicants submitted that if the Facilities were to be removed from gas service, the resulting increase in fuel costs would be more than offset by the decrease in the Mainline revenue requirement. They provided a forecast of the impact of the removal of the Facilities on the revenue requirement and fuel costs. The decrease in the revenue requirement is discussed in Chapter 5.

Mainline fuel is provided in kind by shippers. The proposed removal of the Facilities would cause fuel requirements to increase at all flow levels assuming no changes are made to compressor efficiencies. The Applicants provided analyses which showed a range of net costs or savings to shippers depending on different throughput and gas price forecasts. Various fuel cost and net benefit scenarios are shown on Figure 4-1.

Figure 4-1
Net Benefit/(Cost) to Shippers



In the hearing, parties discussed the question of who should bear the risk of increased fuel costs. The Applicants submitted that their forecast net benefit was based on a very thorough assessment. However, TransCanada would not be willing to accept the risk should the increase in fuel costs exceed the revenue requirement reduction. The Applicants stated that accepting risks for gas forecasts is not the type of risk that TransCanada would normally assume and that industry has decided that it is best for the company not to take on short-term volatility in order to ensure the lowest possible cost of capital which in turn results in the lowest possible tolls. Taking on such risks could alter the risk profile of the company and in turn affect the return on equity. Furthermore, should the Board decide that the Keystone oil shippers are to bear the risk of increases in fuel costs in excess of the reduction in the revenue requirement, the Applicants would have to determine if its oil shippers would accept those terms and conditions. This could result in a delay of the project or possibly it not going forward.

The Keystone Shippers Group submitted that the Applicants' forecast of a modest net positive benefit is reasonable. Nevertheless, their witnesses testified that as oil shippers, they were not prepared to accept the risk if the increase in fuel costs were to be higher than the Applicants' forecasts. They considered that determining such costs would be very complex, the amount would be immaterial in the context of tolls on the system, the concept would be contrary to the cost causation principle, and it would be inappropriate for oil shippers to assume an undetermined, undefined liability. The Keystone Shippers Group also stated that they have accepted risk by signing transportation agreements as well as potentially owning 50 percent of the Keystone pipeline and that they should not be asked to take on more risk on behalf of the industry.

Ontario submitted that, if it is unreasonable for TransCanada and the oil shippers to assume the fuel gas price risk, it is equally unreasonable for Mainline customers to assume the same. Ontario argued that it would be unfair to allow those who benefit from the conversion and who cause the increased risk to shift the risk to others. In Ontario's view the risk should follow the benefit. In an effort to substantiate the level of risk, Ontario observed that one only has to substitute the Sproule Associates Limited 2006 gas price forecast in place of the Applicants' fuel gas price forecast and the predicted overall economic impact for the conversion goes from a net positive benefit to a net negative effect.

Enbridge Gas Distribution Inc. stated that if the Board approves the Application, it should condition its approval so as to hold Mainline shippers harmless. Gaz Métro also expressed concern about the increased fuel volumes and the price forecasts applied to the increased volumes. It stated that if the Board were to approve the Application, it should, in its decision, order the implementation of a mechanism which would protect gas shippers.

Centra Gas Manitoba Inc. and Imperial Oil Limited (Imperial) supported the sale of the Facilities but submitted that it would be inappropriate for existing and committed Mainline gas shippers to carry the risks of increased fuel costs.

The CEP argued that one ground for dismissing the Application is that there will not only be increased fuel costs but also an increase in emissions of greenhouse gases (GHG) due to increased compressor utilization.

4.2.2 Potential Loss of Commercial Revenue

According to BCDENS, the loss of gas sales revenue, which the Group said could result if throughput on the Mainline is higher than what TransCanada has predicted, is another potential harm to gas shippers.

The Applicants, through the evidence of Mr. Gordon Engbloom submitted that an improbable situation of inadequate capacity would need to occur in order for there to be any impact on commercial revenues. This submission was based on TransCanada's throughput forecasts to the year 2020, which showed that firm capacity out of the WCSB would always be available without capacity constraints and there is only a very small probability that interruptible service would be unavailable to shippers.

According to the Applicants, in the improbable event that supply exceeded capacity, any loss of commercial revenue would be minimal and short-lived since gas not able to exit the WCSB on a given day could do so soon afterward, possibly the next day.

Mr. Engbloom quantified the revenue impact by calculating the difference in revenue from selling gas on a peak day versus selling it a day or two later. In his example, if the gas supply that was unavailable due to capacity constraints was 14.2 million m^3/d (0.5 Bcf/d) for four days per year, then the cost in lost revenue would be $2 million per day or $8 million per year. Applying a one percent probability of four peak days of excess supply occurring, Mr. Engbloom estimated a cost impact of less than $0.1 million. Intervenors did not submit any estimates in dispute of this figure.

By contrast, the revenue that might be lost due to constraints to oil markets caused by inadequate oil pipeline capacity could be in the billions, according to the Applicants. Based on a $5 per barrel widening in the light-heavy crude oil price differential, Mr. Engbloom calculated that the annual revenue loss could be $3 billion. Using price differentials observed since 2004, including the first eight months of 2006, the revenue loss could be in the order of $9 billion annually.

BCDENS rejected the Applicants' estimate that $9 billion in oil revenue could be lost, citing problems with TransCanada's analysis. Specifically, BCDENS noted that TransCanada had not provided any support for the price differentials used in the analysis and that no consideration had been given to the possibility of another oil pipeline being constructed, thereby reducing the duration of pipeline constraints. In response, TransCanada cited the study underlying the analysis, specifically, the Purvin & Gertz report

4.2.3 The Value of Spare Capacity

The Applicants submitted that it is desirable to maintain excess capacity on the Mainline to ensure that the WCSB does not become disconnected from North American gas prices, and that gas production is not shut in. Mr. Engbloom expressed the opinion that economically efficient spare capacity is designed to meet transportation requirements under firm, long-term transportation contracts, even when some of its total capacity is not available due to maintenance. It was the Applicants' view that such spare capacity was designed into the Mainline system even with the removal of the Facilities. In the absence of the proposed Keystone Project opportunity, TransCanada stated that it would leave the Facilities in place with the result that excess capacity on the system would have to be addressed in the future.

According to Dr. Andrew Safir of Recon Research Corporation, acting on behalf of BCDENS, the Applicants paid insufficient attention to the economic benefits of excess capacity, especially those related to the functioning of a competitive system as a whole. He submitted that one of the reasons that the Facilities are economically necessary to the transportation of natural gas is the benefit of having a degree of spare capacity to allow gas from the WCSB to flow in response to demand surges in the North American market. In his view, pipeline excess capacity of 10 to 20 percent is required to ensure smoothly coordinated markets. When capacity utilization exceeds the 80 to 90 percent level, capacity constraints become apparent and natural gas prices are affected. Dr. Safir also suggested that the appropriate indicator to use in analyzing pipeline requirements is peak throughput in relation to actual capacity, as, in his view, this would provide better information on actual pipeline demand and a more realistic measure of capacity bottlenecks than TransCanada’s equilibrium model. He considered capacity to be abundant only if it is available to serve peak customer needs without distorting price signals in the natural gas commodity market.

Dr. Safir stated that his examination of the relationship between capacity utilization on the Mainline and the Dawn-Alberta basis over the January 2003 through March 2006 period revealed that capacity constraints had affected natural gas prices. He said that once capacity utilization surpassed 85 percent, the price differential between basin and market delivery location began to climb significantly above transportation costs, which, in his view, was a very good indicator of historical instances of relative scarcity of capacity leaving the WCSB for eastern Canada. His examination of recent historical flows on the Mainline indicated that capacity utilization frequently exceeded 85 percent. The resulting effect of periods of high utilization on basin-market differentials illustrated the economically important benefit of having spare capacity to accommodate surges in demand.

Dr. Safir contended that shippers are willing to continue to pay for spare capacity on the Mainline as a component of rate base. He submitted that “willingness to pay” is demonstrated by the fact that the BCDENS shippers, who have FT contracts for volumes that account for about 30 percent of the total throughput, have indicated that they are willing to continue to pay for the Facilities. Dr. Safir recommended that the BCDENS position should carry considerable weight with the Board because they are committing financial resources to the Mainline.

Mr. Engbloom replied that it was wrong to relate spare capacity to peak-day demand and incorrect to suggest that when rare daily price spikes occur, there is insufficient pipeline capacity. He argued that such an approach was not a common utility practice as it would be too expensive to have pipeline capacity such that there would never be spikes in daily prices. In Mr. Engbloom’s view, there ought to be a trade off between the basis price differential and transportation costs that reflects periods of relative abundance and tightness in pipeline capacity. He suggested that Dr. Safir did not recognize that this trade off is normal for the industry and thus, missed the reason that shippers avoid the cost of additional surplus pipeline capacity to meet occasional spikes in daily prices.

The Applicants submitted that Dr. Safir’s examination of the relationship between capacity utilization on the Mainline and the Dawn-Alberta basis was flawed. They stated that they had corrected Dr. Safir’s errors relating to the appropriate segment of the transportation route and the corrected data showed that using daily prices and exchange rates resulted in a market-basin price differential rarely exceeding transportation costs by more than US$0.50. Their corrected data also did not support Dr. Safir's contention that once capacity utilization surpassed 85 percent the market-basin price differential climbed significantly higher than transportation costs.

In the Applicants’ opinion, BCDENS seemed to be suggesting that TransCanada should be required to retain capacity, not only for reasonable aggregate flows, but for peak flows under discretionary services and to retain the option of moving gas volumes to a particular market. In the Applicants’ view, the value of the option of moving gas to the eastern market is substantially higher than the cost which gas shippers pay.

The Applicants maintained that a firmer indication of BCDENS’ preparedness to pay for this option would have been for them to contract for service to the level of capacity inclusive of the

Line 100-1 Facilities for some period of time beyond the start of Keystone. They submitted that there was almost 56.6 million m^3/d (2.0 Bcf/d) of capacity available through the winter of 2006/2007 which BCDENS had not contracted for. In addition, some of the individual companies comprising BCDENS had not renewed 221.1 thousand GJ/d (210.0 MMcf/d) of long-haul capacity as of 1 November 2006. While this was offset by new contracts totaling 238.1 thousand GJ/d (226.0 MMcf/d), only 73.4 thousand GJ/d (70.0 MMcf/d) of the new contracts were long haul with the remaining volumes contracted for capacity from Emerson, Manitoba downstream. A further 210.2 thousand GJ/d (200.0 MMcf/d) of contract capacity would expire by the end of April 2007. The Applicants argued that the members of BCDENS had reduced their willingness to pay on the Prairies section by a total of almost 355.0 thousand GJ/d (337.0 MMcf/d), which is more than the amount of winter capacity that would be lost to them if the transfer were to be approved.

4.3 Impact of the Transfer on Mainline Operations

4.3.1 Discharge Temperature

The Applicants submitted that there would be a minimal increase in the discharge temperature in the gas exiting the existing compressors. It was anticipated that the average Prairies section discharge temperature would increase by approximately 0.5 ºC at the expected flows, to a temperature well within the maximum design temperature limit of 50 ºC. The Applicants stated that the discharge temperature increase would have no material impact on pipeline integrity.

BCDENS submitted that the higher utilization of existing compression equipment could increase the discharge temperature beyond the anticipated 0.5 ºC at higher throughput levels and suggested that further investigation should be conducted on this aspect to ensure pipeline integrity is not compromised.

4.3.2 Capacity Mismatch

The Applicants noted that, while the transfer of the Facilities would reduce the maximum amount of gas that can be supplied by the Prairies section to the downstream facilities, the capabilities of the Northern Ontario section, Great Lakes Gas Transmission Pipeline (GLGT), and other downstream pipelines would not change. Thus, post-transfer, the downstream pipelines would still be able to take away 5.7 to 8.5 million m^3/d (0.2 to 0.3 Bcf/d) more than the Prairies section could supply (see Table 4-5). The Applicants indicated that for this to become an issue, all downstream pipelines would need to be flowing near capacity at the same time. They noted that currently the Northern Ontario section peaks in the winter and the GLGT section peaks in the summer and therefore were of the view that this mismatch in capacities would not present an issue post-transfer.

Table 4 -4
Design Capacity Comparison Post-Transfer ($10^6 m^3$/d (Bcf/d))[35]

	100 percent Design Capacity Post-transfer	
	Winter	Summer
Prairies Summary		
Prairies Section at Empress (SK)	212.5 (7.5)	201.1 (7.1)
less deliveries & and fuel	28.3 (1.0)	22.7 (0.8)
net leaving Prairies	**184.1 (6.5)**	**178.5 (6.3)**
Ontario Summary		
Northern Ontario Section	121.8 (4.3)	119.0 (4.2)
Great Lakes at St. Clair	70.8 (2.5)	65.2 (2.3)
total entering Ontario	**192.6 (6.8)**	**184.1 (6.5)**
Capacity Mismatch	**-8.5 (-0.3)**	**-5.7 (-0.2)**

4.3.3 Replacing Capacity

The Applicants indicated that should gas production exceed all current forecasts such that additional capacity is required in the future, it could be accommodated with the addition of compression facilities. The Applicants submitted that approximately 7.9 million m^3/d (0.25 Bcf/d) of capacity during the winter season could be added with the addition of two compressor units at a cost of approximately $65 million, the estimated NBV of the Facilities on 1 May 2008. They were of the view that this would eliminate the majority of the capacity mismatch with the downstream facilities. Alternatively, the addition of three compressor units for an approximate cost of $100 million could replace 8.5 million m^3/d (0.3 Bcf/d), all of the capacity mismatch in the winter season. The Applicants further suggested that a number of other alternatives exist to mitigate the loss in capacity if and when deemed necessary, including but not limited to new looping, storage, transportation services, increasing the maximum operating pressure, replacement of ageing compression, or combinations of any of these.

Imperial submitted that, if there is a need to replace the capacity lost by the transfer of the Facilities, the cost of any new facilities should be borne by TransCanada and Keystone.

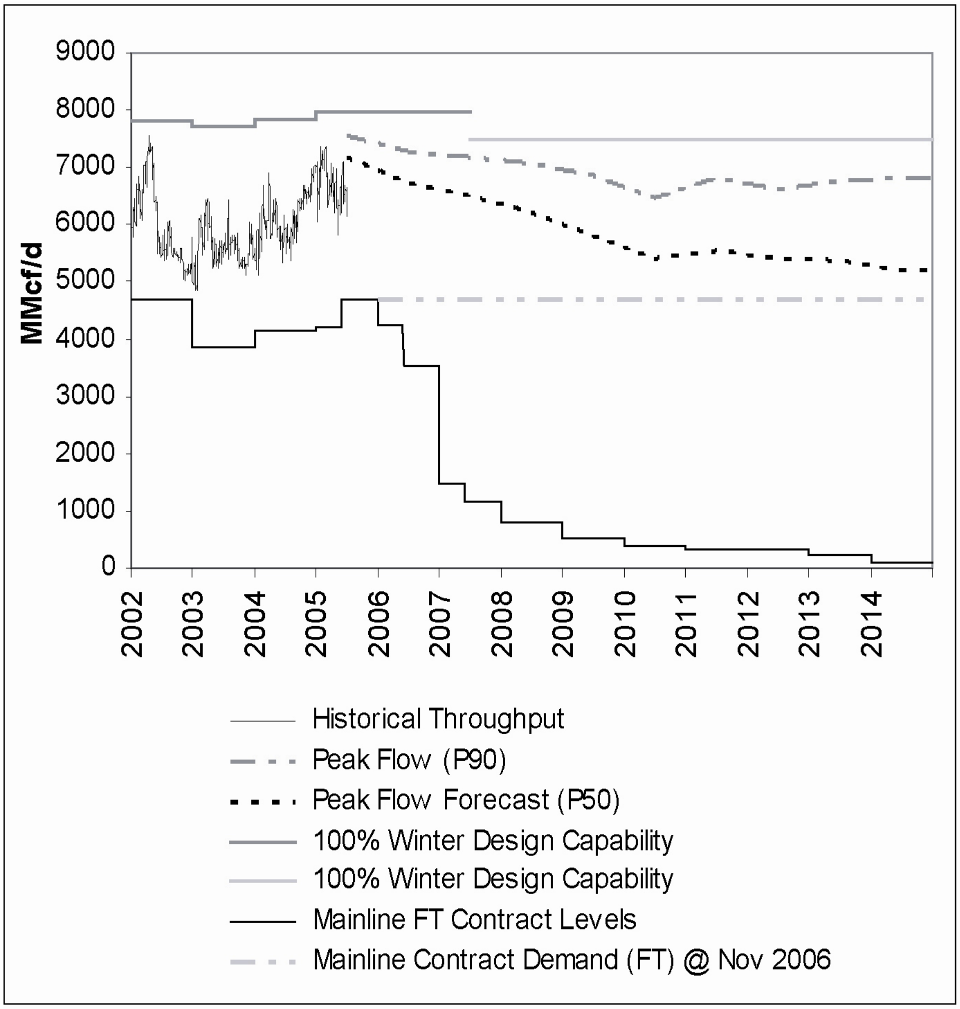
Views of the Board

The Applicants' analysis of both average annual and peak flows demonstrated that there would be adequate capacity on the Mainline under the P10, P50 and P90 throughput forecasts. The Board is of the view that the relevant consideration for determining adequate capacity for the Mainline is the pipeline's ability to meet anticipated requests for firm service. The Applicants' statistical analysis and the Throughput Study

35 TransCanada's response to BCDENS Information Request 12(b)

incorporated a plausible range of possibilities for flows on the Mainline, including both FT and discretionary services. Based on these studies, the Applicant has demonstrated to the Board's satisfaction that even with removal of the Facilities from gas service the system could meet currently contracted firm demand. Further, the system could continue to meet firm demand even if it were evergreened at the existing level. Finally, in the Board's view, the ability of the system to meet the forecasted P90 and P50 peak flow demonstrates that discretionary services would be provided at an acceptable level (see Figure 4-2).

Figure 4-2
Mainline Capacity and Peak Flow Forecast with FT Contract Levels (excluding fuel)



The Board notes BCDENS' submission that the Facilities are not only used and useful but that they are necessary because they provide spare capacity enabling WCSB prices to be connected to prices in the premium markets served by the Mainline. The Board also notes BCDENS' expressed opinion that adequacy of Mainline capacity should be assessed in relation to peak throughput and that the Facilities should be retained in gas service as long as gas shippers are willing to pay for them.

In these circumstances, the Board does not believe that the capacity of the Prairies section should be related to peak requirements. This would be wasteful and an inefficient use of resources. Neither does the Board agree with BCDENS alternative scenario combining high supply and low demand in western Canada in conjunction with a Mainline allocation based on a period of extreme market conditions to be sufficiently credible to warrant adoption for long-term planning of Mainline utilization. Even if such rare conditions were to occur such as that experienced in the 2005 hurricane season, the evidence shows that average day flows could be accommodated without the Facilities, and that under peak day conditions, no FT service volumes would be impacted.

The Board is of the view that a key measure of the efficient operation of natural gas markets is that there is adequate pipeline capacity to transport natural gas from producing regions to market areas. One measure of adequacy is based on the principle that if adequate capacity exists, the price differential (or basis) between two points on a pipeline should be equal to or less than the cost of transportation. As long as the price differential is less than the firm service toll plus fuel, the market is demonstrating that there is adequate pipeline capacity between two pricing points. When there is inadequate pipeline capacity between two market points, the basis will exceed the cost of transportation. As a result, gas prices in a particular region can disconnect from those in an integrated market. For a number of years in the mid-1990s, WCSB gas prices were disconnected and lower than those in most market areas of North America. Until additional takeaway pipeline capacity was added, western gas producers lost revenue. However, given the discussion above, the Board does not believe in this case that should the Facilities be removed from gas service, gas prices of the WCSB production would be disconnected from prices in premium markets served by the mainline.

A careful assessment of capacity utilization on the Mainline and the Dawn-Alberta basis from January 2003 through March 2006 showed that there were few instances when the basis exceeded transportation costs. These instances corresponded to extraordinary events for which it would not be prudent to have additional gas infrastructure. BCDENS submitted that they required the capacity represented by Line 100-1 to ensure that the WCSB remains part of an integrated market, to be able to respond to demand surges and to prevent revenue losses. The Board accepts that the Applicants' analysis demonstrates that there will likely be a similar amount of spare capacity on the Mainline in 2015 as there is in 2006. The Board believes that this level of spare capacity should keep gas prices in the WCSB connected to North American markets.

As to BCDENS' assertion that Line 100-1 is demonstrated to be necessary given that shippers are willing to pay for the Facilities as part of the rate base, the Board believes that shippers are entitled to receive the service for which they contract and notes that the recent pattern of contract non-renewals does not strongly support BCDENS' contention that the capacity associated with the Facilities is required.

The Board notes that TransCanada examined a wide range of possibilities employing different fuel cost and throughput forecasts in order to assess fuel cost impact. The Board accepts the Applicants' submission that the probability of the P10 or P90 cases occurring in any one year are low and the probability of these cases occurring in more than one year are even lower. As a result, the Board finds the Applicants' analysis of fuel costs to be reasonable.

The Board is of the view that the risk with respect to the fuel costs is not likely to be large and is the type of risk which is normally assumed by gas shippers. It is the Board's view that gas shippers do not have acquired rights to be protected from cost increases. Mainline gas shippers will benefit from the removal of the Facilities through a reduction in revenue requirement and will assume the risk of increased fuel costs due to higher gas prices as they have in the past.

The Board also notes that no cost estimates were put forward to challenge the Applicants' estimates of any potential adverse impacts on commercial revenues. The Applicants asserted such impacts are improbable given the low probability of capacity constraints. The Board concurs.

The Board has considered Imperial's suggestion that in the event there is a need to replace the capacity that will be lost due to the removal of the Facilities, TransCanada can add the necessary compression at its own cost or at the cost of the Keystone beneficiaries. In the Board's view, there is no compelling reason to suggest that the Mainline shippers should not be responsible for costs due to future changes in system configuration as is normally the case. In any event the allocation of the cost of new facilities is a matter to be discussed when an application is received.

In final argument, the CEP raised concerns with respect to GHG emissions as a result of increased compressor utilization. The Board notes that when it grants approvals for the construction and operation of the existing Mainline facilities, it considers the suitability of proposed pipeline pressures and related equipment, including compressor units. As a result, existing orders allow TransCanada to operate the Mainline and compressors within approved limits, even if this involves operating the compressors more frequently or at a higher level than recent utilization (due to operational requirements). As the Applicants have not sought amendment to existing operational approvals, TransCanada remains authorized to operate the compressors as previously authorized by the Board.

The Board is aware that if the Facilities are removed from gas service, compressors on the Mainline would be running at a higher utilization rate, thus impacting the fuel requirement and ultimately the compressor repair and overhaul costs. However, the Board is of the view that these impacts are acceptable and in all likelihood no new facilities will be required to maintain gas service on the Mainline, nor will any upstream or downstream facilities be stranded by the transfer of the Facilities.

The Board notes that the capacity reduction on the Prairies section of 14.2 million m^3/d (0.5 Bcf/d) would result in a capacity mismatch with the downstream facilities of 5.7 to 8.5 million m^3/d (0.2 to 0.3 Bcf/d). The Board accepts the Applicants' view that a capacity mismatch would not be a concern due to the different timing of flow peaks on downstream pipelines and the resulting unlikelihood that all downstream facilities would be operating at their full capacity at the same time.

While concerns were raised by parties regarding the increase in the gas discharge temperature from the compressors at the higher utilization rates, the Board notes that the increase in the gas discharge temperature is within the design temperature range.

Chapter 5

The Transfer at Net Book Value

The Applicants proposed that the price for the assets to be transferred from TransCanada to Keystone should be the NBV at the time the transfer is to take place in May 2008. The NBV of the assets is $76.3 million as at 31 December 2005 and would be approximately $65.1 million at the time of transfer. The NBV would be calculated as the book cost of the Facilities of $169.5 million, less the estimated accumulated depreciation of $104.4 million. The Applicants stated that the NBV is a fair and reasonable price from the perspectives of both the purchaser and seller, and that it facilitates cost-based, competitive tolls that have been tested in the market. They also stated that it would be consistent with original cost rate making, Board regulations, and regulatory precedent.

The Open Season process for the Keystone Project was premised on tolls which reflect NBV for the Facilities. The Applicants stated that a higher transfer price and consequent higher tolls could jeopardize the contract commitments that are the basis for the commercial viability of the Keystone Pipeline. In addition, a transfer at NBV from one regulated utility to another ensures that one customer group is not being favoured at the expense of another, and ensures that the consolidated entity is not making an excessive return through the transfer of assets to an affiliate at greater than NBV. The Applicants further stated that the transfer of the Facilities at NBV accords with the National Energy Board *Oil Pipeline Uniform Accounting Regulations* (OPUAR) and the National Energy Board *Gas Pipeline Uniform Accounting Regulations* (GPUAR) which stipulate that where facilities are purchased from an affiliated company, the original cost of the facilities and accumulated depreciation is recorded in the accounts of the purchasing company.

The NBV calculation of $65.1 million assumed no capital cost additions or line replacements from 31 December 2005 until the time of transfer and employed the currently approved depreciation rate for pipeline of 2.8 percent over the same period. The book cost and accumulated depreciation balances applicable to the Facilities were determined by applying a pipeline distance ratio to the book cost and accumulated depreciation balances for the provinces of Saskatchewan and Manitoba. The pipeline distance ratio is the result of dividing the Facilities' segment distance by the total pipeline distance for 864 mm O.D. pipe in each province.

The Transfer Amount is subject to adjustments for expenditures of a capital nature, less adjustments for depreciation between 31 December 2005 and the closing date. The forecast for capital expenditures relating to pipeline integrity for the years 2006 to 2008 inclusive is $0.9 million. These expenditures would increase the NBV. TransCanada stated that it did not foresee any other circumstances which would affect the Transfer Amount. TransCanada further stated that a change in the NBV of $10.0 million would not have a material effect on shippers.

None of the intervenors objected to the use of the NBV as the transfer price.

The Applicants forecast that the removal of the Facilities would result in a reduction in TransCanada's revenue requirement in the amount of $112.6 million on a NPV basis over a ten year period. The forecast reduction in the revenue requirement is mainly due to lower depreciation, taxes, operations and maintenance costs, lower return on rate base, as well as lower pipeline integrity costs. No parties filed evidence or expressed concern with respect to the forecast reductions to the revenue requirement.

Views of the Board

The Board notes that the proposal to transfer the Facilities at NBV was uncontested. The Board is of the view that NBV is the appropriate transfer amount in this situation as it accords with existing practices and principles and the OPUAR and GPUAR. The Board accepts the Applicants' proposed method to reduce TransCanada's rate base by the NBV of the Facilities on the date of the sale and also is prepared to authorize Keystone's inclusion of the NBV of the Facilities in the Oil Plant Under Construction of the Keystone Pipeline on the date of the transfer, and subsequently in the rate base of the Keystone Pipeline if and when it is placed in oil transmission service.

Chapter 6

The Board's Views on the Transfer and the Public Interest

As determined in Chapter 2, the Board finds that the regulatory standard applicable to the Transfer Application is the public interest. The Board must consider all of the factors that are relevant to the public interest in this case, including, but not limited to, the interests of gas and oil shippers, producers and consumers.

Canada relies on competitive markets to determine prices for oil and natural gas. Since market deregulation in the 1980s, Canadian and United States oil and natural gas markets have increasingly evolved into an integrated North American market. This integrated market is supported by a complex network of interconnecting pipelines between sources of supply and regional markets.

Transportation paths are often determined on the basis of price signals at supply and market regions throughout North America. Producers are continuously seeking to maximize the value received for the commodity they produce, while consumers seek to obtain the lowest cost alternative to meet their requirements. Economically efficient outcomes are achieved when both producers and consumers are able to effectively achieve these goals.

To obtain economically efficient outcomes, there must be adequate transportation infrastructure to connect supply to markets. When there is a lack of sufficient pipeline capacity between two locations, crude oil or natural gas supplies can become “trapped” in one region, causing a disconnect from those prices reflected in the larger integrated market. In a disconnected region, the price of the commodity can be significantly higher or lower than the rest of the market. Prices in a disconnected region will tend to move to the point where the price would be determined based on the available supply and demand in that particular region, rather than the requirements and prevailing price of the larger integrated market.

In Chapters 3 and 4 the Board has clearly established that the Facilities are not required for gas transmission purposes. The Board considers that the detailed analysis done by the Applicants of North American supply and demand demonstrates the Mainline’s ability to meet firm service commitments and that the Mainline will continue to have spare capacity over a wide range of supply and demand estimates. This, in the Board’s view, would be accomplished without causing any disconnect between gas prices of the WCSB from that of premium markets served by the Mainline. The Board notes that even when it became clear that there was a potential that some capacity from the Mainline would be removed, certain BCDENS gas shippers did not contract for firm long-term capacity, although they had the opportunity to do so. Gas shippers are only entitled to service for which they have contracted; they are not entitled to specific facilities. Nonetheless in assessing this application the Board has considered the Mainline's ability to meet both current and projected firm service requirements as well as projected throughput. Having regard to the evidence submitted, the Board concludes that if approval were to be granted there will remain sufficient capacity for current and projected firm and interruptible gas service requirements.

While Mainline gas shippers will benefit from the removal of capacity through a reduction in revenue requirement they will continue to be responsible for costs due to changes in system configuration or possibly higher fuel prices as is normally the case. Shippers are not protected from higher than forecast fuel prices, whether or not the Facilities remain in service.

None of the hearing participants disputed the need for additional oil pipeline capacity. There was also a general consensus that western Canadian crude oil production will continue to grow significantly due to the development of the oil sands while there would likely be limited growth in the western Canadian refining industry. The Board concludes, therefore, that exports will also grow significantly. The Board notes that the rapid development of the oil sands has fundamentally transformed Canada's oil industry. High oil prices coupled with technological advancements have made oil sands extraction economically possible but, among other challenges, this strong growth has led to stress on the pipeline sector. It has become clear that, to facilitate market efficiency, more crude oil pipeline capacity is needed to provide new market access for growing oil sands output. Since they went into service in early 2006, the high capacity utilization of both Enbridge Pipelines Inc.'s Spearhead pipeline, which delivers to Cushing, Oklahoma, and that of Exxon Mobil Pipeline Company, which delivers heavy Canadian crude oil to the United States Gulf Coast, testify to this.

The Board has considered a number of factors in its assessment of the oil-related aspects of the Application. These include the level of shipper support, growing oil sands production, availability of markets for the increasing supply, and timeliness of market access. The Board observes the willingness of shippers to sign long-term transportation service agreements on the Keystone Pipeline, totalling 54.1 thousand m^3/d (340.0 thousand bpd) with an average contract duration of 18 years. This is strong evidence that they are willing to make financial commitments to support their assessment and identification of potential profitable markets for western Canadian crude oil.

The Board is of the view that incremental oil pipeline capacity will be needed as early as late 2009 to accommodate the forecast growth in oil sands production. The Board recognizes that if there is insufficient pipeline capacity to connect the growing crude oil supply to potential markets, the risk of apportionment (which is currently happening on some pipelines) and shut-in oil is increased. In addition, constrained access to markets capable of processing the heavier Canadian grades could exert downward pressure on heavy oil prices thus widening the light-heavy price differential, leading to economically inefficient outcomes.

For much of its operating history, the TransCanada Mainline has been the major transporter of gas from the WCSB to eastern markets in Canada and the United States. As supply continued to grow, TransCanada received approval from the Board to expand the Mainline a number of times. In the 1990s, the regulatory environment encouraged competition and market-based outcomes. The commencement of service in 2000 on the Alliance and Vector pipelines created a new and competitive path to take significant WCSB gas to markets that had traditionally been served by the Mainline.

A critical aspect of the approval of the Alliance pipeline was the conclusion that off-loading of the incumbent pipelines would be temporary and that supply growth would refill them. During this proceeding, the Applicants stated that the Mainline had, in fact, lost about 42.5 million m^3/d (1.5 Bcf/d) of contracted volumes, which have not come back. In the RH-1-2001[36] Decision, the Board suggested that a review of TransCanada's business and regulatory framework was necessary. The message the Applicants correctly took from the RH-1-2001 Decision was that TransCanada needed to become more competitive in the future.

Since the end of 2001, TransCanada has come to the Board with various proposals to increase its competitiveness. Some were successful in getting Board approvals while others were not. All demonstrate TransCanada's attempt to respond to competition. For example, TransCanada filed a request for discretion in IT pricing[37,] which was opposed by stakeholders, and was denied by the Board. TransCanada filed the Southwest Zone application[38] and the North Bay Junction application[39] for a new receipt and delivery point, both of which were approved by the Board. Also, an application to increase depreciation rates[40], so that tolls could be more competitive in the future, was approved by the Board. The Board approved biddable FT-NR[41] (non-renewable firm transportation), although the biddable aspect was later overturned on review[42]. The recent application for Firm Transportation-Short Notice and Short Notice Balancing[43] services was approved in general (although not the tolling proposal for Short Notice Balancing).

The Board recognizes that TransCanada's efforts were driven by the new competitive environment. They were attempts to make the Mainline more competitive and to maximize utilization of facilities. The proposed project is no exception. The concept for the Keystone Pipeline Project originated in late 2003, when a group of oil shippers requested TransCanada to explore the potential of using a portion of the capacity on its Alberta natural gas system and the Mainline, for conversion to oil service. The Applicants stated that they were seeking the highest and best use for Facilities that currently provide excess capacity. They indicated that while such facilities are used and useful they are no longer necessary and that their transfer would provide much needed oil capacity and hence would provide a higher value.

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36 TransCanada PipeLines Limited, Tolls and Tariff, 2001 and 2002 Tolls and Tariff Application, Reasons for Decision dated November 2001, p.14

37 RH-1-99, TransCanada PipeLines Limited, Tolls and Tariff, Interruptible Transportation and Short Term Firm Transportation Tariff Amendments, Reasons for Decision dated April 2000

38 RH-1-2002, TransCanada PipeLines Limited, Tolls and Tariff, 2003 Tolls and Tariff Application, Reasons for Decision dated July 2003

39 RH-3-2004, TransCanada PipeLines Limited, North Bay Junction Application, Application for approval to establish a new receipt and delivery point, the North Bay Junction, and for the corresponding tolls for services to and from the point, Reasons for Decision dated December 2004

40 RH-1-2002, *supra* note 38

41 RH-2-2004 Phase I, TransCanada PipeLines Limited, Tolls and Tariff, 2004 Mainline Tolls and Tariff Application, Reasons for Decision dated September 2004

42 RH-R-1-2005, Canada Association of Petroleum Producers, Review of RH-2-2004 Phase I Decision, Application dated 12 November 2004 requesting a review of Board Decision RH-2-2004 Phase I, Reasons for Decision dated May 2005

43 RH-1-2006, TransCanada PipeLines Limited Application for approval of Short Notice Service and related tolls, Reasons for Decision dated November 2006

The Applicants argued that this application would provide an opportunity for TransCanada to right-size its Prairies section for expected flows and to respond to the impact of the competition it faces. TransCanada and Keystone maintained that it would be economically efficient to transfer Line 100-1 from gas service to oil service, and that this was an opportunity to deal with the issue of excess capacity in a manner consistent with the move to a more market-oriented and lighter regulation. They also expressed the view that the oil and gas industry would benefit by letting TransCanada respond to competitive market situations by reducing unnecessary capacity and moving it into a service that is in the greater public interest. They submitted that the transfer is what would have happened in an unregulated, competitive market.

The Board is supportive of the oil and gas industry exploring innovative solutions to address issues such as insufficient pipeline capacity. At the same time, the Board is cognizant that the potential adverse effects on the gas shippers need to be examined before determining the benefits of conversion. The Board believes that regulation should not be an impediment to achieving benefits that otherwise would have been reached in the absence of regulation in a well-functioning market. In fact the Board believes that regulation should emulate competition and should encourage actions and decisions that would enhance efficiency, improve competition, respond to market needs but in doing so should also be in keeping with the public interest.

The Board realizes that its decision does not come without certain risks. However, in exercising its mandate it is the duty of the Board to consider all factors and to ensure that potential risks are carefully measured in order to satisfy itself that the outcome of assuming such risks is superior to the alternative. Circumstances that could have a negative impact on the transfer include a steep decline in oil prices and consequent reduced oil sands production resulting in underutilization of Keystone. Significant volumes of northern gas coming on sooner than forecast, WCSB supply substantially higher than forecast, the absence of operating LNG terminals in eastern Canada, and fewer LNG imports than expected to supply eastern United States markets could also be unfavourable, resulting in additional capacity required to transport gas volumes. However, the Board is of the view that these events are not likely to occur in a combination such that there is a reasonable probability that the pipeline will be required in gas service.

The Board believes that there is a high probability of positive consequences arising from the approval of the Application. The Board is of the view that the transfer of Facilities with the proposed rate base treatment is in the public interest for several reasons. The Board notes the broadly held view that additional oil pipeline capacity is needed in the near future. Also, the Board recognizes that the transfer could provide a productive alternate use of underutilized assets. If the underutilization is not dealt with now, it may have to be dealt with later, perhaps at a cost to gas shippers rather than providing the small benefit projected by TransCanada in this case. The Board does not believe that it would be in the public interest to direct TransCanada to continue to keep the Facilities in gas service when the Applicants have demonstrated that they are not necessary and has proposed an alternative use for them which the Board has found to be in the public interest.

Thus, having regard to the finding that the appropriate test in this case is the public interest and having weighed the potential benefits of the transfer against the potential negative impacts, the Board is of the view that it is in the public interest to approve the transfer of the Facilities to oil service.

However, if the Board is incorrect in construing the applicable regulatory standard as the Canadian public interest rather than as the no harm test, the Board finds, on a careful review of the evidence before it, that the Transfer Application will not cause harm to the gas shippers. The Applicants demonstrated to the Board's satisfaction that the Mainline would be able to meet firm service commitments over a ten year period, and that there is a high likelihood of ongoing sufficient spare capacity. However, passing the no harm test is not the same as the Application passing a no **risk** of harm test as Ontario suggested, which would be impossible and could result in no regulatory approvals ever being granted. Approving this Application, as with any application, is not risk free.

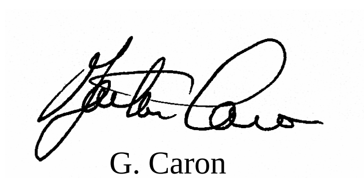
The Board notes that this approval of the Transfer Application, including the rate base treatment, has no effect unless further regulatory approvals, including those required for the section 52 and 21 applications by TransCanada Keystone Pipeline GP Ltd. are received.

Chapter 7

Disposition

The foregoing chapters together with Order MO-02-2007 constitute our Reasons for Decision in respect of the application considered by the Board in the MH-1-2006 proceeding.

J.S. Bulger
Presiding Member



G. Caron
Member

G.A. Habib
Member

Calgary Alberta
February 2007

Appendix I

Summary of the Transfer Agreement Dated 5 June 2006 Between TransCanada and Keystone

The assets to be transferred would include: 864.26 kilometres (km) of Mainline, Line 100-1 864 mm outside diameter (OD) pipeline commencing at Mainline Valve (MLV) 2 near Burstall, Saskatchewan and terminating at a point 3.49 km upstream of MLV 37 near Carman, Manitoba. The Facilities comprise a total of 612.30 km and 251.96 km of line in Saskatchewan and Manitoba respectively; related pipeline facilities; and interests in and to the portion of the rights of way directly relating to the ownership, operation and maintenance of the Keystone Pipeline. The remaining lengths of Line 100-1 would remain as part of the Mainline (see Figure 1-2). The transferred assets would also include:

- 29 MLV assemblies;
- 9 drip assemblies;
- 1 681 metres of casing pipe;
- 25 pipe fittings;
- 1,688 river weights; and
- 8,481 saddle weights.

Additionally, as part of the transfer, Keystone would acquire 100 percent ownership in the northern half of TransCanada's original easement where applicable. TransCanada would retain 100 percent ownership in the remaining half.

The Facilities, would be transferred from TransCanada to Keystone on 1 May 2008 (closing date) at a price that reflects their NBV at that time. The final transfer amount would be the base transfer amount (NBV of the Facilities of $76,259,000 as at 31 December 2005) plus adjustments for expenditures of a capital nature and minus adjustments for depreciation between 31 December 2005 and the closing date of the transfer. It was estimated that the NBV at the time of the transfer would be $65.1 million.

During the time between the date of the Transfer Agreement and the closing date, TransCanada would conduct business in the ordinary course, continue insurance on the Facilities and give Keystone prompt notice of any material adverse changes in respect of the transferred assets. All taxes, fees and charges in respect of the transferred assets would be borne by Keystone. In addition, Keystone would be liable for any Goods and Services Tax in connection with the purchase and sale of the transferred assets and would pay the costs to isolate, cut and cap the Facilities, and the cost for connections to permanently disconnect the Facilities from TransCanada's remaining facilities. Regulatory costs related to the Facilities transfer would be shared equally between TransCanada and Keystone.

Prior to the closing date, TransCanada and Keystone would be required to negotiate in good faith and enter into agreements relating to the operation, maintenance and sharing of services in respect of the Facilities and interaction with TransCanada's other facilities, and jointly determine the most reasonable location for pump stations in respect of the proposed Keystone Pipeline system.

Appendix II

Relevant Legislation

National Energy Board Act

12. (1) The Board has full and exclusive jurisdiction to inquire into, hear and determine any matter

> *(a)* where it appears to the Board that any person has failed to do any act, matter or thing required to be done by this Act or by any regulation, certificate, licence or permit, or any order or direction made by the Board, or that any person has done or is doing any act, matter or thing contrary to or in contravention of this Act, or any such regulation, certificate, licence, permit, order or direction; or
>
> *(b)* where it appears to the Board that the circumstances may require the Board, in the public interest, to make any order or give any direction, leave, sanction or approval that by law it is authorized to make or give, or with respect to any matter, act or thing that by this Act or any such regulation, certificate, licence, permit, order or direction is prohibited, sanctioned or required to be done.

(1.1) The Board may inquire into any accident involving a pipeline or international power line or other facility the construction or operation of which is regulated by the Board and may, at the conclusion of the inquiry, make

> *(a)* findings as to the cause of the accident or factors contributing to it;
>
> *(b)* recommendations relating to the prevention of future similar accidents; or
>
> *(c)* any decision or order that the Board can make.

(2) For the purposes of this Act, the Board has full jurisdiction to hear and determine all matters, whether of law or of fact.

R.S., c. N-7, s. 12; 1990, c. 7, s. 5.

21. (1) Subject to subsection (2), the Board may review, vary or rescind any decision or order made by it or rehear any application before deciding it.

(2) The Board may vary a certificate, licence or permit but the variation of a certificate or licence is not effective until approved by the Governor in Council.

(3) This section does not apply to

> *(a)* a decision, operating licence or authorization to which section 28.2 or 28.3 applies; or

(b) an approval of a development plan under section 5.1 of the Canada Oil and Gas Operations Act.

R.S., c. N-7, s. 21; 1990, c. 7, s. 10; 1994, c. 10, s. 21.

52. The Board may, subject to the approval of the Governor in Council, issue a certificate in respect of a pipeline if the Board is satisfied that the pipeline is and will be required by the present and future public convenience and necessity and, in considering an application for a certificate, the Board shall have regard to all considerations that appear to it to be relevant, and may have regard to the following:

(a) the availability of oil, gas or any other commodity to the pipeline;

(b) the existence of markets, actual or potential;

(c) the economic feasibility of the pipeline;

(d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline; and

(e) any public interest that in the Board's opinion may be affected by the granting or the refusing of the application.

R.S., 1985, c. N-7, s. 52; 1990, c. 7, s. 18; 1996, c. 10, s. 238.

59. The Board may make orders with respect to all matters relating to traffic, tolls or tariffs.

R.S., c. N-6, s. 50.

74. (1) A company shall not, without the leave of the Board,

(a) sell, transfer or lease to any person its pipeline, in whole or in part;

(b) purchase or lease any pipeline from any person;

(c) enter into an agreement for amalgamation with any other company; or

(d) abandon the operation of a pipeline

(2) For the purposes of paragraph (1)(b), "pipeline" includes a pipeline as defined in section 2 or any other pipeline, and, for the purposes of paragraph (1)(c), "company" includes a company as defined in section 2 or any other company.

(3) Despite paragraph (1)(a), leave shall only be required if a company sells, transfers or leases any part or parts of its pipeline that are capable of being operated as a line for the transmission of gas or oil.

R.S., c. N-6, s. 63; R.S., c. 27(1st Supp.), s. 19; 2004, c. 25, s. 155.

Alberta Gas Utilities Act

26(1) The Lieutenant Governor in Council may by regulation designate those owners of gas utilities to which this section and section 27 apply.

(2) No owner of a gas utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or

(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them,

unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,

(ii) a right, franchise or privilege in excess of the amount actually paid to the government or a municipality as the consideration for it, exclusive of any tax or annual charge, or

(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of it or them, and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

1984 c66 s1

Appendix III

Proposed Keystone Project

The proposed Keystone Project would entail the construction of a 2 960 km (1,830 mile) oil pipeline from Hardisty, Alberta to Wood River and Patoka, Illinois (Figure 1-1). The pipeline would be capable of transporting a range of crude oil types and its single bullet pipe design would enable large batch sizes or batch trains that require fewer and smaller interfaces between products. The total cost of the proposed Keystone Project is estimated to be US$2.1 billion.

The Keystone Pipeline, with an initial design capacity of approximately 69.2 thousand m^3/d (435.0 thousand bpd), could be further expanded to 93.8 thousand m^3/d (590.0 thousand bpd) through the addition of pump facilities. Significant interest has also been received for both the Keystone Heartland and Cushing Extension expansion projects. The Heartland extension would provide a connection from Scotford Terminal, north of Edmonton, Alberta to Hardisty. The Cushing Extension would provide a connection from Platte Junction, Nebraska to Cushing, Oklahoma. Interest in the order of approximately 79.0 thousand m^3/d (260.0 thousand bpd) in the Heartland Extension has been received and interest in the order of approximately 75.9 thousand m^3/d (250.0 thousand bpd) has been received in the Cushing Extension.

The Canadian portion of the Keystone Pipeline would be constructed, owned and operated by Keystone. This segment would require the conversion of the Facilities from natural gas to oil transmission service and the construction of approximately 370 km of 762 mm OD new pipeline. New pipeline construction in Canada would comprise 260 km from Hardisty to Burstall, Saskatchewan and 110 km from Carman, Manitoba to the border between Canada, near Haskett, Manitoba and the United States. The total estimated capital cost of the Canadian portion would be approximately $664 million. The Keystone Project would also include the construction of approximately 1 730 km (1,070 miles) of new pipeline in the United States.

The initial Keystone Project proposal was announced to the public in February 2005. On 3 November 2005, TransCanada and ConocoPhillips Company announced that they had entered into a Memorandum of Understanding that gave ConocoPhillips Pipeline Company, a wholly-owned subsidiary of ConocoPhillips Company, the option to acquire up to a 50 percent ownership interest in the Keystone Pipeline.

Appendix IV

Board Letter dated 17 July 2006 with the Revised List of Issues

File OF-Fac-G-T241-2006-01 (3400-T241-1)
17 July 2006

To: All Parties to Hearing Order MH-1-2006

TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd. - Application for Leave to Transfer Pipeline Facilities and related Orders
List of Issues and List of Parties

On 5 June 2006, TransCanada PipeLines Limited (TransCanada) and TransCanada Keystone Pipeline GP Ltd. (Keystone) (jointly the Applicants) filed an application for the transfer of certain facilities, presently comprising part of the TransCanada mainline natural gas transmission system (the Facilities), from TransCanada to Keystone, for use in the Keystone project that is proposed to transport crude oil from Hardisty, Alberta to Wood River and Patoka, Illinois.

On 21 June 2006, the Board issued Hearing Order MH-1-2006. Interventions were required to be filed by 11 July 2006. The Board has received 26 interventions of which three discuss the List of Issues in the Hearing Order. The Board has considered these submissions along with the reply comments from the Applicants dated 14 July 2006.

Submissions of Parties

The Council of Canadians stated that its concerns are not covered in the List of Issues. Its suggested issue is:

> TransCanada is fragmenting the approvals process by dealing only with the conversion of the 860 km of existing pipeline facilities currently being used to transport natural gas. The Keystone Pipeline Project should be dealt with in its entirety in one process. This would allow for full discussion on the social, political and economic issues regarding this proposal.

Coral, Devon, EnCana, Nexen and Shell provided comments with respect to the second issue which is as follows:

> The commercial, economic and market impacts of the removal of the Facilities from gas transportation service and conversion to oil transportation service.

These intervenors stated that if the second issue as framed means that the Board intends to examine the commercial, economic and market impacts of not having the Facilities in gas transportation service, then they concur with it. However, if the second issue as framed means that the Board also intends to examine the commercial, economic and market impacts of operating the Facilities in oil transportation service, then they do not concur with it. They state that the determination of whether the conversion would be in the public interest can only be made in conjunction with the section 52 application which Keystone expects to file in late 2006.

The Communications Energy and Paperworkers Union of Canada (CEP) stated that the issues on the List of Issues are broadly framed and that it is particularly interested in:

i) the effects of the proposal on the availability of adequate feedstock to the petrochemical industry and refineries in Canada;
ii) the effects of the proposal on greenhouse gas emissions, and Canada's international obligation to reduce such emissions;
iii) the effects of the proposal on Canadian energy security, particularly in light of Canada's obligations under the *North America Free Trade Agreement*; and
iv) the nature of the public interest test that should be applied by the Board to these applications.

Views of the Board

With respect to the issue raised by the Council of Canadians, the Board is of the view that the social, political and economic issues in respect of the sale and purchase of the Facilities can be addressed in this application and those in respect of operating the pipeline can be raised when the section 52 application is heard. The Board also agrees with the Applicants that the question of whether the section 74 and 52 applications must be heard together is not a matter for inclusion in the List of Issues in the section 74 proceeding, but would be more appropriately dealt with by way of a motion.

With respect to the comments by Coral, Devon, EnCana, Nexen and Shell in their intervention, the Board is of the view that matters relating to the operation of the pipeline in oil service, such as environmental and engineering issues, will be addressed in the section 52 hearing. However, there are elements relating to the conversion of the pipeline to oil service that may well be important to determinations that the Board has to make in relation to the application which has been filed. The List of Issues is intended to be broad in order to ensure that the Board receives all relevant evidence and to allow parties to frame their case and present their views in the manner they determine to be appropriate. Thus, while the Board is of the view that there is no need to vary the List of Issues as a result of these intervenors' comments, the Board emphasizes that parties are not restricted with respect to any position that they may wish to take regarding the decisions that the Board is being asked to make.

The Board is of the view that issues (i) and (iv) raised by the CEP are encompassed by the List of Issues. Specifically, issue 1 in the List of Issues is broad enough to include the matters raised by the CEP in its issue (iv). As well, CEP's issue (i) is contemplated by issue 2 in the List of Issues. However, for greater certainty, the Board varies issue 2 to read:

> The commercial, economic, **supply** and market impacts of the removal of the Facilities from gas transportation service and conversion to oil transportation service.

Issues (ii) and (iii) raised by the CEP are, in the Board's view, not relevant to this application. The sale of the Facilities has no effect on emissions and as this application does not request approval to operate a pipeline, there is no effect on Canadian energy security. These are matters which could be raised in connection with the section 52 application.

A revised List of Issues, noting the change to issue 2 indicated by the Board in response to the CEP's comments, is attached.

Pursuant to paragraph 7 of Hearing Order MH-1-2006, please find attached the List of Parties. Parties are to advise the Secretary of any change in their contact information. The List of Parties will be amended for any such changes. On receipt of this List of Parties, intervenors are to serve their written interventions on the Applicant and all other intervenors to the hearing.

Yours truly,

Michel L. Mantha
Secretary

Attachments

Board letter dated 17 July 06
Appendix I

Revised List of Issues

The Board has identified but does not limit itself to the following issues for discussion in the proceeding:

1. The tests to be used in assessing the application, including the test for the sale and the test for the purchase of the Facilities.

2. The commercial, economic, **supply** and market impacts of the removal of the Facilities from gas transportation service and conversion to oil transportation service.

3. If the sale and purchase are approved, the terms of the transfer, including the assets to be transferred.

4. The price which should be assigned to the Facilities for the purposes of:
   a. removal from TransCanada's rate base; and
   b. inclusion in Keystone's rate base.

5. The terms and conditions, if any, that should be included in any approval the Board may issue.

Appendix V

Board Ruling on the CEP Motion

File: OF-Fac-G-T241-2006-01
25 August 2006

Mr. Steven Shrybman
Counsel
Sack Goldblatt Mitchell
Suite 500, 30 Metcalfe Street
Ottawa, ON K1P 5L4

Mr. Fred Wilson
Assistant to the President
Communication, Energy and Paperworkers
Union of Canada
301 Laurier Avenue West
Ottawa, ON K1P 6M6

Dear Messrs. Shrybman and Wilson:

TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd.
Application for Leave to Transfer Pipeline Facilities and Related Orders
Communications, Energy and Paperworkers Union of Canada Notice of Motion
Ruling Number 1

Background

The National Energy Board has set down for hearing the application by TransCanada PipeLines Limited (TransCanada) and TransCanada Keystone Pipeline GP Ltd. (Keystone) (collectively, the Applicants) for an order to transfer certain facilities, presently comprising part of the TransCanada Mainline natural gas transmission system, from TransCanada to Keystone, and related orders (Transfer Application).

The Applicants stated that Keystone expects to file an application late in 2006 for other approvals required for the Keystone Pipeline which would be used to transport crude oil from Hardisty, Alberta to Wood River and Patoka, Illinois (Facilities Application). The Facilities Application will include an application pursuant to section 52 of the *National Energy Board Act* (Act) for a certificate of public convenience and necessity and a subsection 21(2) application to vary the certificate issued to TransCanada.

The Transfer Application asks that the transfer orders be made conditional upon the Board's approval of the Facilities Application and the subsequent issuance of a certificate of public convenience and necessity to Keystone.

On 21 June 2006, the Board issued Hearing Order MH-1-2006 which called for the submission of interventions and comments on the List of Issues to be filed by 11 July 2006. Three parties provided comments on the List of Issues in the Hearing Order. Among them, the Council of Canadians (COC) and the Communications, Energy and Paperworkers Union of Canada (CEP) suggested that TransCanada was fragmenting the approvals process. They submitted that the project should be dealt with in its entirety in one process to allow for full discussion on the social, political and economic issues regarding this proposal.

In its letter dated 17 July 2006, the Board stated that it

> is of the view that the social, political and economic issues in respect of the sale and purchase of the Facilities can be addressed in this application and those in respect of operating the pipeline can be raised when the section 52 application is heard. The Board also agrees with the Applicants that the question of whether the section 74 and 52 applications must be heard together is not a matter for inclusion in the List of Issues in the section 74 proceeding, but would be more appropriately dealt with by way of a motion.
>
> … [T]he Board is of the view that matters relating to the operation of the pipeline in oil service, such as environmental and engineering issues, will be addressed in the section 52 hearing. However, there are elements relating to the conversion of the pipeline to oil service that may well be important to determinations that the Board has to make in relation to the application which has been filed. The List of Issues is intended to be broad in order to ensure that the Board receives all relevant evidence and to allow parties to frame their case and present their views in the manner they determine to be appropriate. Thus, while the Board is of the view that there is no need to vary the List of Issues as a result of these intervenors' comments, the Board emphasizes that parties are not restricted with respect to any position that they may wish to take regarding the decisions that the Board is being asked to make.

CEP Motion

On 24 July 2006, the CEP filed a motion with the Board for orders adjourning the MH-1-2006 Hearing until such time as applications for all of the approvals required to establish the Keystone Pipeline Project are properly constituted and filed with the Board; and providing for all public hearings convened with respect to such applications to proceed at the same time.

The CEP stated that the orders requested are needed first, in order to avoid unnecessary overlap and duplication of Board approvals processes. It pointed out that the "public interest test for the sale and the purchase of the facilities (Issue No. 1) involves a consideration of issues that are similar or identical to those that will be considered in subsequent applications under s. 21(2) and 52 of the Act." The CEP pointed to the Board's comments in its 17 July 2006 letter in support of its assertion that there will be overlap in the hearings with respect to the conversion of the existing pipeline facilities from gas to oil transportation service.

Second, the CEP argued that the relief it seeks would avert the potential for inconsistent Board determinations of public interest issues. It suggested that if the Board grants approvals in distinct proceedings, there is a risk that it could make inconsistent findings regarding public interest matters. Because the Transfer Application raises neither specific nor exclusive public interest considerations to the Transfer Application, the CEP is concerned that the Board may in fact, if not in law, arrive at different conclusions regarding the public interest at a subsequent stage of the approvals process.

As its third point, the CEP argued that granting the relief it seeks would prevent any perception that approvals for the Keystone Project subsequent to the Transfer Application are *pro forma*. The CEP's fourth submission was that a bifurcated approval process comports a risk of marginalizing environmental and other public interest concerns such as the issue of energy security and the obligation to give effect to *North American Free Trade Act* proportional sharing requirements. Finally, the CEP also suggested that the Board ought to grant the relief sought to ensure the convenience of intervenors for whom intervention before the Board is neither routine nor a cost of doing business.

The Board considered the CEP's request and in a letter dated 3 August 2006 established a written process to hear the Motion, the grounds supporting the Motion, as well as the relief sought. The Board received submissions from three parties in support of the Motion and from five parties opposing the Motion.

Parties Supporting the Motion

The Sierra Club of Canada submitted that, as a Responsible Authority under the *Canadian Environmental Assessment Act* (CEAA), the Board must define the scope of the Keystone Project for the purposes of carrying out an environmental assessment and ultimately deciding whether a certificate should be granted. It argued that the Board should define the environmental scope of the Keystone Project to include the transfer of the facilities as this is one, not two distinct projects. The Sierra Club also echoed the CEP's concern that a fragmented hearing process increases the burden on public interest intervenors.

It was argued by the COC that it would be a serious mistake to consider the Transfer Application in advance of knowing the full dimensions of the Keystone Project, including its environmental implications and impacts. It stated that it is crucial that the Board ensure that the full implications of the Keystone Project be assessed before any approval, whether conditional or not, is accorded.

Coral Energy Canada Ltd., Devon Canada Corporation, EnCana Corporation, Nexen Inc. and Shell Canada Limited Group (the Industry Group) submitted that there are two issues to be considered:

1. whether TransCanada should be permitted to sell the facilities and remove them from the Mainline rate base; and
2. whether Keystone should be authorized to convert the facilities to oil service provided that TransCanada is permitted to sell the facilities to Keystone and remove them from the Mainline rate base.

The Industry Group stated that while the Board should consider the first issue in the MH-1-2006 proceeding, it should not decide the second issue until the public interest in the whole of the Keystone Project can be assessed. The Industry Group characterized the Transfer Application as requesting that the Board "make a finding that it is in the Canadian public interest that the Facilities be converted from gas service to oil service", based only on "economic aspects of the public interest". In their view, this is a piecemeal approach to assessing the public interest that is clearly inappropriate.

Parties Opposing the Motion

In response to the CEP and parties supporting the Motion, the Applicants reiterated that it is not necessary that all requisite applications for the Keystone Pipeline Project be considered together. In this respect, the Applicants as well as ConocoPhillips Canada Limited relied on Guide R in the *Filing Manual* as explicit recognition that a transfer application can properly precede a section 52 application. These three parties also argued that a "stepwise" approach is not only commercially reasonable but also lawful. Further, the approach accords with the Board's practice to consider applications as they are filed and that it is the Applicants' right to determine the relief they seek.

The Applicants and ConocoPhillips raised a number of examples where the Board considered applications in a stepwise manner.[44] They argued that in such cases, the Board's Reasons for Decision explicitly state that approvals obtained by applicants in a stepwise manner should not construed as an indication that the Board would approve subsequent applications related to the same project.

44 The parties referred to the following cases: GH-4-93 (Intercoastal Pipe Line Inc. and Interprovincial Pipe Line Inc., Facilities, Tariff & Toll Methodology, dated Apr. 1993); OH-4-96 (Interprovincial Pipe Line Inc., Facilities, dated Apr. 1996); GH-3-97 (Alliance Pipeline Ltd. on behalf of the Alliance Pipeline Limited Partnership, Facilities and Tolls & Tariffs, dated Nov. 1998); GH-6-96 (Sable Offshore Energy Project and Maritime & Northeast Pipeline Project, Facilities, dated Dec. 1997); and OH-1-2003 (Trans-Northern Pipelines Inc. , Facilities, dated July 2003).

In response to the concerns raised by the CEP on the matter of the Board's consideration of the public interest, the Applicants submitted that the Transfer Application asks "…the Board to make a decision on the public interest of the *transfer*, *not the* public interest of the *proposed Keystone Pipeline* [emphasis in the original]". They also took the position that the determination of the relevant factors and criteria to consider in coming to a decision on the matter of public interest may vary depending on the purpose of the applicable section of the Act. ConocoPhillips echoed these views in submitting that the Board is mandated to consider the public interest as it relates to each application before it. The mere fact that the public interest is considered in relation to each application before the Board does not, in and of itself, create a risk of overlap, inconsistent determinations nor would it necessarily undermine the independence of subsequent processes.

For its part, Suncor Energy Inc. submitted that granting the CEP Motion would delay the Keystone project. In its view, no party would be prejudiced by adopting a stepwise regulatory application process. Canadian Natural Resources Limited also subscribed to this argument and further suggested that a combined hearing for all approvals required would cause a tremendous waste of effort in preparation on all issues, in the event that the transfer of the facilities were not approved. The Motion was also opposed by Husky Energy Marketing Inc.; it urged the Board to keep the Transfer Application and the Facilities Application separate.

CEP's Reply

In reply, the CEP asserted that the Applicants had failed to respond to either of its two fundamental concerns: first, that the Applicants' stepwise approach would fragment and limit the Board's consideration of the public interest issues raised by the project and second, that it would result in a multiplicity of public hearings and approval processes that may also overlap.

The CEP argued that the Applicants' submissions confirmed the CEP's position that the Transfer Application conflates the public interest considerations of the Transfer Application with those that might arise in the context of the Facilities Application. Although it recognized that the Board Decisions the Applicants cited were instances where the Board proceeded to consider applications in a staged fashion, it distinguished these cases on their facts. Finally, it also indicated that Guide R of the *Filing Manual* was merely a guide, not a directive and that in any event, it neither supported the notion that applications under section 74 and 59 could be joined, nor that a section 74 application could be decided on a public interest rationale underlying a subsequent application.

In response to ConocoPhillips and Suncor Energy Inc., the CEP argued that several of their assertions regarding delay and economic prejudice and their speculation that the CEP was attempting to expand the environmental review, were unsupported.

On this last point, the CEP also argued that ConocoPhillips was wrong in stating that section 74 of the Act is not a CEAA trigger; it argued that the Transfer Application could be interpreted as a request to “abandon” the operation of the facilities for the purpose for which they were approved and to re-licence them for oil service.

Views of the Board

The question raised by the CEP and now before the Board is whether it ought to, in this case, order that consideration of the relief sought by the Applicants in the Transfer Application be delayed until such time as applications for the balance of the orders necessary to the Keystone Pipeline Project are also filed with the Board.

As the CEP stated in its reply, it essentially argues two main reasons why the Board should grant its motion. The first type of argument presented by the CEP relates to the perceived fragmentation and limiting of the Board’s consideration of public interest issues raised by the project if a staged application process is allowed to proceed. The CEP argues that one of the potential consequences of this is a risk of inconsistent findings on public interest issues.

It is clear that in making decisions under the Act, the Board is mandated to do so with regard to the public interest. As a result, the Board has often considered what this implies. For instance, in its Reasons for Decision, Sumas Energy 2, Inc.[45] the Board stated that when making a decision pursuant to the Act, the factors it considers and the criteria it applies in coming to a decision in the public interest can vary depending on the facts of the case and the “purpose of the applicable section of the NEB Act”.

With respect to the CEP’s suggestion that the Applicants confuse the public interest considerations that relate to the Transfer Application and other possible approvals, the Board notes that ultimately, the determination of the parameters of the public interest relating to the transfer is exclusively within the Board’s purview, albeit with regard to parties’ submissions. As the Board has expressed previously, the List of Issues was purposefully kept broad to allow all parties to submit evidence considered relevant to the matter of the transfer. It is open to all parties to make submissions regarding the scope of the public interest of the transfer, as they deem appropriate.

Furthermore, the Board is of the view that if it decided that some or all of the relief sought in the Transfer Application was in the public interest, a later decision that relief sought in the Facilities Application was not in the public interest would not necessarily imply any inconsistency. That is, the sale might be in the public interest while the facilities might not be, having regard to, for example, environmental or safety reasons.

45 EH-1-2000 Sumas Energy 2, Inc., Facilities, dated March 2004, at page 11.

Finally, the Board observes that the Applicants have specifically asked that any transfer approval be granted conditionally on the approval of the Facilities Application. Again, if a conditional transfer approval were granted but evidence presented on the Facilities Application demonstrated that other aspects of the Keystone Pipeline Project were not in the public interest and the section 52 application was refused, the transfer would not occur. In the circumstances, this further attenuates the risks raised in the Motion.

Therefore, the Board believes that should it decide to make any decisions regarding the Transfer Application after hearing all of the evidence and argument on the matter, it may do so without causing prejudice to its ability to consider the public interest in relation to the approvals it will be asked to give in the context of an eventual Facilities Application.

The second category of concerns raised by the Motion centers on the perceived overlap or duplication caused by the Applicants' decision to apply for Board approvals in stages, rather than all at once.

As is evident from the number of cases cited by intervenors on this Motion, there is ample precedent for submitting applications for staged approval. The Board typically allows applications to proceed in stages, unless there are cogent reasons not to. The Board's support of this practice is confirmed by the guidelines laid out in the *Filing Manual*. While the Board agrees with the CEP that this document is only a guide and is not mandatory, in the Board's view, the *Filing Manual* does reflect the Board's judgment that the practice is acceptable and lawful.

The CEP's and its supporters' submissions that a staged approach to the approvals process will cause duplication and overlap relies in part on the argument that the Applicants have raised the same facts in the Transfer Application as will be considered in an eventual Facilities Application, especially regarding the change in service from gas to oil. Given the nature of this industry, the Board notes that there is often some overlap between hearings. If the Board were of the view that proceeding by way of separate applications would result in an abuse of the process or a serious waste of time and resources by the Board and all parties, it may require them to be heard together. However, the Board is not of the view that such is the case here. The Board does not believe that the Applicants are proceeding by way of separate applications in order to avoid jurisdiction or some process, or as a form of project splitting. Rather, in the Board's view, it is a legitimate delineation of two applications with two different purposes, based on commercial requirements. Further, the Board has already stated which subject matters should be addressed in respect of the Transfer and the Facilities Applications. In the Board's view, parties should be able to adhere to these instructions and thus not incur any significant amount of duplication of work.

Related to the concerns of overlap and duplication, the CEP submitted that a staged approach might also encourage the perception that subsequent approvals for the project are *pro forma*. Although an applicant may seek approvals from the Board in a stepwise manner, this does not mean that the Board has prejudged in any way the merits of any anticipated or future applications that may come before it. In previous cases where a staged approach was adopted, the Board has been careful to warn that the first decision is without prejudice to any decision the Board may make on a related subsequent application. The Board believes that explicit comments such as have in the past been included in its decisions assist in guarding against the perception that it might have prejudged a matter. In the Board's view the concerns expressed by the CEP amount to a questioning of whether the Board can properly adjudicate in this case without fettering itself with regard to future applications, without any evidence to show that this is likely. Should the Board do so, the CEP and other parties will have avenues for legal remedies available to them at that time.

With respect to the CEP and supporting parties' suggestion that a staged process may lead to a marginalization of environmental and other public interest concerns and that the Transfer Application should be part of the scope of the CEAA assessment, the Board continues to be of the view expressed in its letter of 17 July 2006 that such concerns relate to the construction and operation of the pipeline and as such will be considered in the context of the Facilities Application. In the Board's view, the conditional approval of a transfer is not a project or activity within the meaning of the CEAA, nor does it need to be scoped in to an assessment in order to conduct an appropriate environmental assessment in relation to the Facilities Application. The Board does not accept that a consideration of these issues at a later stage of the approvals process means that the issues are any less important than those being considered first. As set out above, though the Board might grant part or all of the relief requested in the Transfer Application, from a practical perspective, any approval granted is conditional on the granting of relief that might be requested in the Facilities Application. Accordingly, the Board is of the view that a stepwise approach will not prevent it from fulfilling its mandate to consider environmental issues.

Finally, it is also worthwhile clarifying that if the Board were to grant permission for the transfer, but in a subsequent related proceeding refused another approval necessary to the Keystone Pipeline Project, it would not, as was suggested by the CEP, mean that a further hearing would be required to "undo" the transfer approval, thus causing a proliferation of hearings. The Applicants have requested that any transfer approval be conditional on approval of the Facilities Application. In addition and in any event, subsection 74(1) provides for the Board to grant leave; the Board typically issues an order permitting a transaction rather than requiring it.

If the Board decided that the Transfer Application was not in the public interest and therefore denied an approval essential to the Keystone Pipeline Project, then it would be unlikely that a Facilities Application would be filed at all. In this scenario, a staged approach realizes economies in terms of preparation and hearing time for all involved, including public interest intervenors. Accordingly, the Board is not persuaded that a "comprehensive" approach to the Keystone Pipeline Project applications would necessarily be more advantageous than a staged one.

The Board agrees with the Applicant and parties who submitted that applicants are generally entitled to frame their application as they determine to be appropriate. The Board has a legal obligation to hear an application so long as it is complete, and is not being brought forward in a piecemeal fashion for inappropriate purposes. The Board has dealt with the concept of project splitting earlier and finds this not to be the case with respect to this Application. The Board has found the Application for the sale and purchase of the facilities and the rate base considerations to be complete, and no party has made a case that it is not.

Therefore, based on the arguments made before it, and for the reasons given in this Ruling, the Board is not satisfied that consideration of the Transfer Application should be adjourned until such time as the Facilities Application is filed. The Board is not persuaded by the submissions of the CEP and parties in support of the Motion that the risks raised in the Motion warrant diverging from the Board's practice that applicants are entitled to frame their applications as they determine to be appropriate, or from the accepted stepwise application process chosen by the Applicants in this case.

However, as noted in the Board's letter of 17 July 2006, it would still be open to parties to take a position during, and argue at the end of the Hearing, that the Board does not have sufficient evidence to be able to make determinations on any or all aspects of the Application or that making a determination on any or all aspects of the Application would prejudge the Facilities Application.

Having denied the Motion by the CEP, no changes to the procedural schedule are required. The Board notes in a letter from the CEP dated 24 August 2006 that it is having difficulty preparing its evidence in the absence of this Ruling. Therefore, the Board extends the deadline, for the CEP only, to file its evidence to Friday, 8 September 2006.

Sincerely,

Michel L. Mantha
Secretary

cc: All Parties to Hearing Order MH-1-2006

Appendix VI

Order

ORDER MO-02-2007

IN THE MATTER OF the *National Energy Board Act* and the regulations made thereunder; and

IN THE MATTER OF an application made pursuant to section 59 and paragraphs 74(1)(a) and 74(1)(b) of the Act by TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd. for leave to transfer certain pipeline facilities and related orders, filed with the National Energy Board under File OF-Fac-G-T241-2006-01.

BEFORE the Board on 5 February 2007.

WHEREAS TransCanada PipeLines Limited (TransCanada) owns the TransCanada mainline natural gas transmission system (Mainline) pursuant to Certificate of Public Convenience and Necessity GC-1 dated 11 April 1960;

AND WHEREAS the Board received an application from TransCanada and TransCanada Keystone Pipeline GP Ltd. (Keystone) (jointly the Applicants) dated 5 June 2006 relating to the transfer of certain Mainline facilities (Transfer Application);

AND WHEREAS TransCanada requested an order of the Board:

(a) granting leave to TransCanada pursuant to paragraph 74(1)(a) of the Act to sell the facilities described in the attached Schedule A (Facilities) to Keystone; and

(b) authorizing TransCanada pursuant to section 59 of the Act to reduce the Mainline rate base by the net book value (NBV) of the Facilities on the date of the transfer;

AND WHEREAS Keystone requested an order of the Board:

(a) granting leave to Keystone pursuant to paragraph 74(1)(b) of the Act to purchase the Facilities from TransCanada; and

(b) authorizing Keystone, pursuant to section 59 of the Act, to include the NBV of the Facilities in the Oil Plant Under Construction of the proposed Keystone Pipeline on the date of the transfer and subsequently in the rate base (Oil Plant in Service) of the Keystone Pipeline when it is placed in oil transmission service;

AND WHEREAS the Applicants requested that the relief be made conditional upon the approval of an application by Keystone with respect to a proposed new pipeline (Keystone Pipeline) and the Facilities (Facilities Application), and the subsequent issuance of a certificate of public convenience and necessity to Keystone for the proposed Keystone Pipeline;

AND WHEREAS an oral public hearing was held commencing 23 October 2006 in Calgary, Alberta at which the Board heard evidence and argument presented by the Applicants and interested parties;

AND WHEREAS the Board's decisions on the Application are set out in its MH-1-2006 Reasons for Decision dated February 2007, and in this Order;

AND WHEREAS the Board has examined the Application and considers it to be in the public interest to grant the application recognizing that the Applicants will not transfer the Facilities until and unless Keystone receives approval of the Facilities Application and a certificate of public convenience and necessity for the proposed Keystone Pipeline;

IT IS ORDERED, pursuant to paragraphs 74(1)(a) and 74(1)(b) of the Act, that the sale and purchase of the Facilities from TransCanada to Keystone is approved.

IT IS FURTHER ORDERED, pursuant to section 59 of the Act, that TransCanada may reduce the Mainline rate base by the NBV of the Facilities upon their transfer to Keystone, and that Keystone may include the NBV in Keystone Pipeline's Oil Plant Under Construction upon the transfer of the Facilities and subsequently include the NBV in the rate base of Oil Plant in Service if the Keystone Pipeline is placed in oil transmission service.

NATIONAL ENERGY BOARD

Michel L. Mantha
Secretary

Schedule A
National Energy Board Order MO-02-2007

TransCanada/Keystone Application for leave to transfer pipeline facilities and for a determination on the transfer price
File OF-Fac-G-T241-2006-01

- 864.26 kilometres of TransCanada Mainline, Line 100-1 864 mm outside diameter pipeline commencing at Mainline Valve (MLV) 2 near Burstall, Saskatchewan and terminating at a point 3.49 km upstream of MLV 37 near Carman, Manitoba, comprising a total of 612.30 km and 251.96 km of line in Saskatchewan and Manitoba respectively, and related pipeline facilities
- 29 MLV assemblies
- 9 drip assemblies
- 1 681 metres of casing pipe
- 25 pipe fittings
- 1,688 river weights
- 8,481 saddle weights
- interests in and to the portion of the rights of way directly relating to the ownership, operation and maintenance of the Keystone Pipeline
- 100 percent ownership in the northern half of TransCanada's original easement where applicable