National Energy Board
Office national de l'énergie

Reasons for Decision

Maritimes & Northeast Pipeline Management Ltd.

RH-4-2010

June 2011

Final Tolls for 2010 (Escrow Issue)

Canada

National Energy Board

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In the Matter of

Maritimes & Northeast Pipeline Management Ltd.

Final Tolls for 2010 (Escrow Issue)

RH-4-2010

June 2011

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Definitions and Acronyms

1999 Bonds	M&NP Limited Partnership bond debt issued in 1999.
1999 GLJ Report	Independent reservoir engineer's report on Sable Offshore Energy Project (Plus Other Significant Discoveries on the Scotian Shelf): Appraisal of Reserves and Deliverability Report – A Study Prepared by GLJ for Lenders to Maritimes & Northeast Pipeline, L.L.C. and Maritimes & Northeast Pipeline Limited Partnership, May 1999. This report was annexed to the 1999 Offering Memorandum.
1999 Offering Memorandum	Document dated 24 June 1999 describing senior secured notes to be issued by Maritimes & Northeast Pipeline Limited Partnership.
2007 Deliverability Report	M&NP Management Ltd. Deliverability Report, November 2007. An independent reservoir engineer's report prepared in accordance with procedures contained in the M&NP Financing Documents and Capital Markets Agreements to determine the forecasted production decline date.
2009 Bonds	M&NP Limited Partnership bond debt issued in 2009.
Act	*National Energy Board Act*
Applicant	M&NP Management Limited on behalf of the Limited Partners
Beck Report	Independent engineering report, prepared for Maritimes & Northeast Pipeline Limited Partnership, on the design, construction and operations of the Maritimes & Northeast Pipeline System including projected operating results. This report was annexed to the 1999 Offering Memorandum.
Board or NEB	National Energy Board
ECPG	East Coast Producer Group
Escrow Account	The account established for the purpose of holding funds until certain conditions are fulfilled, as established by written agreement.
Escrow Funds	The money held in the Escrow Account.
FSAs	Firm Service Agreements
General Partner	Maritimes & Northeast Pipeline Management Ltd.

GJ/d	Gigajoules per day
GLJ	Gilbert Laustsen Jung Associates Ltd.
Limited Partners	The entities who own a partnership share in the Pipeline.
Limited Partnership	Maritimes & Northeast Pipeline Limited Partnership
M&NP	Maritimes & Northeast Pipeline
MMBtu/d	Millions of British Thermal Units per day
Mobil Backstop Agreement	A 20-year agreement between the Limited Partnership, and Mobil Oil Canada Properties and Mobil Canada Products Ltd. under which the Mobil entities will pay for unsubscribed firm capacity on the Pipeline to a maximum amount of 184 548 GJ/d (175,760 MMBtu/d).
NSDOE	Nova Scotia Department of Energy
Operating Period Cash Waterfall	The order of priority for project cash flows during the operating period, as established in the financing documents.
OSD	Other significant discoveries in the Sable Island Area.
Pipeline	The natural gas pipeline system from Goldboro, Nova Scotia to the Canada-U.S. border near St. Stephen, New Brunswick, operated by M&NP Management Ltd.
PUAs	Pipeline Utilization Agreements
Required Escrow Amount	The amount of dollars required to be accumulated in the Escrow Account, under certain conditions described in the 1999 Offering Memorandum.
Settlement Agreement	M&NP 2010 Toll Settlement Agreement filed with the NEB on 2 March 2010.
SOEP	Sable Offshore Energy Project
Tcf	Trillion Cubic Feet

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* (Act) and the Regulations made thereunder: and

IN THE MATTER OF an application by Maritimes & Northeast Pipeline Management Ltd. on behalf of Maritimes & Northeast Pipeline Limited Partnership for approval of final tolls for 2010 pursuant to Part IV of the Act, filed with the National Energy Board (Board or NEB) on 26 July 2010, under file OF-Tolls-Group 1-M124-2010-01 01; and

IN THE MATTER OF Hearing Order RH-4-2010 issued on 13 October 2010;

Heard in Halifax, Nova Scotia on 1, 2 and 3 March 2011 and Calgary, Alberta on 23 and 24 March 2011;

BEFORE:

R. J. Harrison, Q.C.	Presiding Member
R. R. George	Member
L. Mercier	Member

Appearances	**Participants**	**Witnesses**
L. E. Smith N. Gretener	Maritimes & Northeast Pipeline Management Ltd.	M. Whalen M. Rideout C. Inskip J. Vander Weide K. McShane J. Reed
B. Armstrong	*6720471 Canada Ltd. (ATCO Midstream)	
D. Crowther	*Alliance Pipeline Ltd.	
N. Guay	*AltaGas Holdings Inc.	
C. K. Yates	East Coast Producer Group	H. W. Johnson J. D. McCormick
	- Encana Corporation	R. K. Powell
	- Imperial Oil Resources and ExxonMobil Canada Properties	R. R. Moore
	- Mosbacher Operating Ltd.	R. Dingwall
	- Pengrowth Corporation	J. MacDonald
	- Shell Canada Energy	R. Gall
I. Johnston	*Emera Energy Incorporated	
D. Davies	*Enbridge Southern Lights GP	

J. Haynes	Heritage Gas Limited
R. Block	*Kinder Morgan Canada Inc.
R. Gallant A. Trenholm	Nova Scotia Power Inc.
J. Scott	*TransCanada PipeLines Limited
J. Green	*Utility Group Facilities Inc.
B. Pydee	*Westcoast Energy Inc. (St. Clair Pipelines Management Inc. and Spectra Energy Midstream Canada Partner Corporation)
M. Rieksts B. O'Halloran	Government of Nova Scotia
R. Kolber M. Haug	National Energy Board

* Participated only on the Motion brought by the East Coast Producer Group.

Chapter 1

Introduction

1.1 History

In 1996, a consortium planned to develop six natural gas fields located on the Scotian Shelf. The Sable Offshore Energy Project (SOEP) was viewed as a seed project that was expected to promote future development of offshore gas reserves on the Scotian Shelf.

In 1997, the National Energy Board (NEB or Board) approved an application by Maritimes & Northeast Pipeline Management Ltd. on behalf of Maritimes & Northeast Pipeline Limited Partnership, to construct and operate the Maritimes & Northeast Pipeline (the Pipeline). The Pipeline's purpose was to transport SOEP natural gas to Canadian and U.S. markets. It consisted of a natural gas pipeline system extending from Goldboro, Nova Scotia, through the Provinces of Nova Scotia and New Brunswick to a point on the international boundary between Canada and the U. S. near St. Stephen, New Brunswick. (See Figure 1-1.)

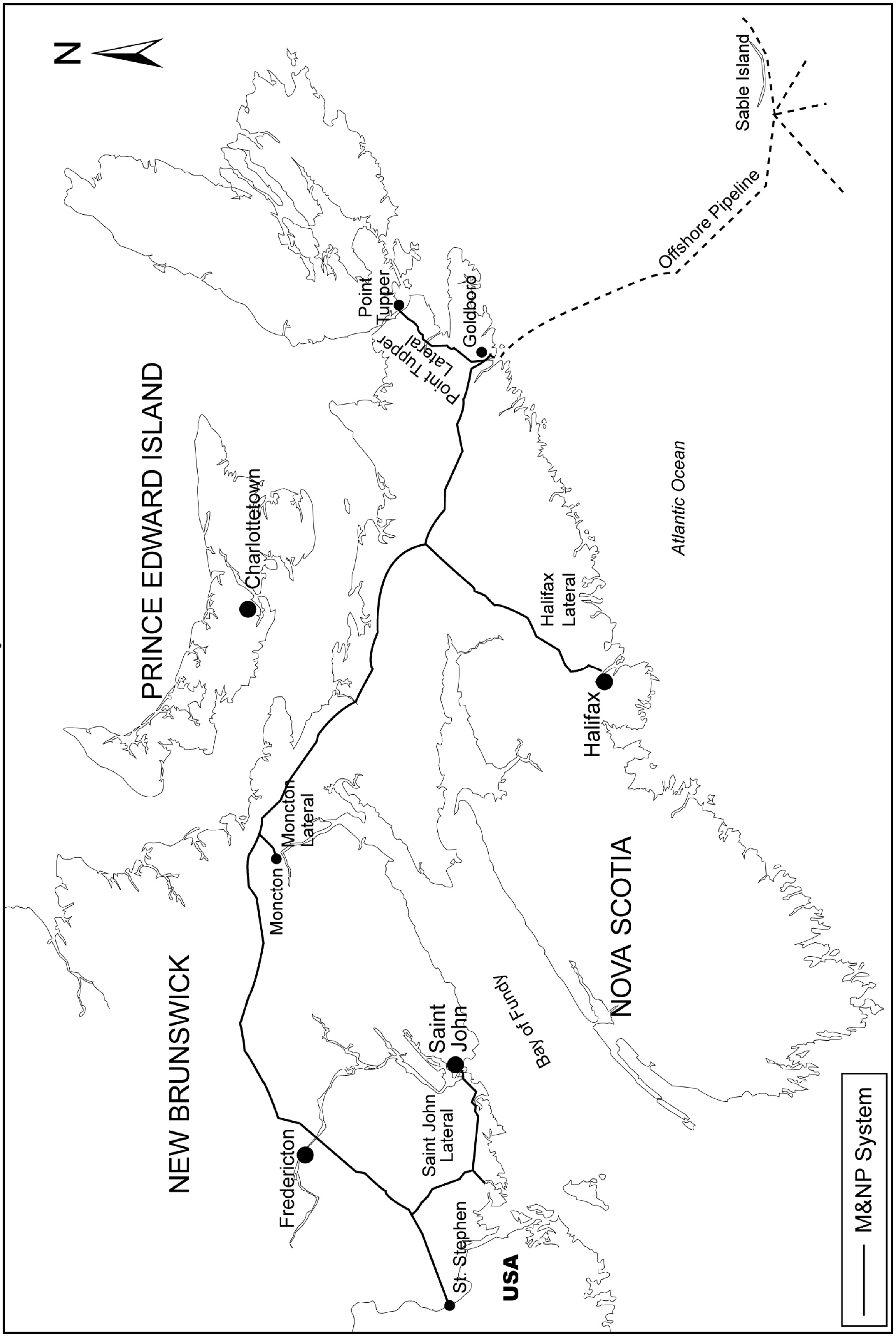
Maritimes & Northeast Pipeline Limited Partnership. a partnership of several entities (Limited Partners), developed the Pipeline.[1] Maritimes & Northeast Pipeline Management Ltd. is the General Partner that owns and operates the Pipeline on behalf of the Limited Partners. It is a company as defined in the *National Energy Board Act* (the Act). The Limited Partnership Agreement sets out the General Partner's powers, duties and obligations, including the following:

> … the General Partner has the full and exclusive right, power and authority (i) to manage, control, administer and operate the Partnership and its business and affairs, and (ii) to do any act, take any proceeding, make any decision and execute and deliver any instrument, deed, agreement or document, for and on behalf of and in the name of the Partnership, in connection with the matters described in clause (i).
>
> …

1 According to the Applicant's 2010 evidence, the General Partner has a 1% interest in the Limited Partnership. As of December 2010, the current Limited Partners and their respective interests are 38.38% Spectra Energy Midstream Holdings Limited Partnership (parent, Spectra Energy Corp.); 38.38% Spectra Energy MNEP Holdings Limited Partnership (parent, Spectra Energy Corp); 12.79% NSP Pipeline Incorporated (parent, Emera Incorporated); 9.45% ExxonMobil Canada Hibernia Finance Ltd. (parent, Exxon Mobil Corporation) and 1% M&NP Management Ltd. (General Partner).

According to the 1999 Offering Memorandum, the Limited Partners and their respective interests were: 37.125% M&N PanEnergy Ltd., a wholly-owned subsidiary of Duke Capital; 37.125% Westcoast; 12.375% Mobil Resources Ltd., an indirect wholly-owned subsidiary of Mobil; and 12.375% NSP Pipeline Incorporated, a wholly-owned subsidiary of NS Power. Maritimes & Northeast Pipeline Management Ltd was the General Partner, owning 1% and in turn owned in proportionate shares by the Limited Partners.

Figure 1-1
M&NP System



> An action taken by the General Partner on behalf of the Partnership in accordance with the terms of this Agreement and the terms of the Shareholder Agreement is deemed to be the act of the Partnership and binds the Partnership, and no person dealing with the Partnership will be required to inquire into the authority of the General Partner to take such action.

1.2 The Application

On 26 July 2010, the General Partner on behalf of the Limited Partners (the Applicant) applied to the NEB under Part IV of the Act for approval of final tolls for 2010 (the Application).

On 17 December 2009, by Order TGI-05-2009, the Board approved interim tolls for 2010. On 2 March 2010, the Applicant applied to the Board for approval of its 2010 Settlement Agreement and for approval of revised interim tolls. The Applicant submitted that the Agreement fulfilled the requirements of the Board's 12 June 2002 *Revised Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs*. The Applicant noted that the Agreement addresses all issues except the issue arising out of the placement of funds in escrow under the terms of its financing.[2] As such, the toll resulting from the 2010 Settlement Agreement would continue to be interim until the escrow issue is resolved. On 17 March 2010 by Order TGI-01-2010 the Board approved the 2010 Settlement Agreement and the revised interim toll effective 1 April 2010.

In the Application, the Applicant requested approval of final tolls for 2010 which consisted of:

- the interim toll determined by the 2010 Settlement Agreement, plus
- a surcharge of $30.38 million compensation for funds held in escrow (the Escrow Funds) in 2010, including an equity return on 100 percent of the Escrow Funds and a gross-up for income taxes.

The Applicant also requested approval of an increase in the income taxes in its Income Tax Deferral Account established through the 2010 Settlement to reflect the amount of the gross-up for Escrow Funds compensation.

1.3 Hearing Process

The Board issued Hearing Order RH-4-2010 on 13 October 2010 establishing a process to consider whether the Applicant should be compensated for funds held in the Escrow Account in the 2010 revenue requirement and, if so, how the amount of compensation should be determined. (See Appendix 1 - List of Issues.)

The Board indicated that if it decided the Applicant should be compensated for funds in the Escrow Account, the Board would allow a period for parties to negotiate with respect to the appropriate level of compensation. If parties did not reach agreement, the Board would establish a further process to determine the appropriate level of compensation for these funds. If the Board decided the Applicant should not be compensated for funds in the Escrow Account, it would

2 Escrow funds are dollars held in an escrow account, usually to satisfy certain financial conditions. An agreement specifies the conditions constraining use of the funds.

proceed to set final 2010 tolls equal to the interim 2010 tolls included in the Settlement Agreement.

On 2 November 2010, at the request of parties, the Board extended the schedule set out in Hearing Order RH-4-2010. The evidentiary portion of the oral Hearing took place in Halifax, Nova Scotia from 1 to 3 March 2011. Final argument took place in Calgary, Alberta on 23 and 24 March 2011.

1.4 ECPG Motion

On 15 February 2011, the East Coast Producer Group (ECPG) filed a Notice of Motion and applied for an order dismissing the Application.[3] ECPG is composed of ExxonMobil Canada Properties, Imperial Oil Resources, Shell Canada Energy, EnCana Corporation, Pengrowth Corporation and Mosbacher Operating Ltd. Its motion was made on the grounds that the Board does not have jurisdiction to grant the relief sought in the Application, primarily because, ECPG asserted, the relief is sought by and for the Limited Partnership.

On 18 February 2011, the Board issued a letter noting that the ECPG motion raises a substantive matter of law and, in the Board's view, may have the potential to affect the business structure of some entities regulated by the Board. Accordingly, the Board invited Board-regulated pipelines and international power lines to make written submissions and to participate in oral argument on the motion.[4] Oral argument on the motion took place on 23 March 2011.

The Board has concluded that, given its decision on the application for final tolls for 2010, it is not necessary to rule on the motion.

3 The motion, written submissions, oral argument and hearing transcripts are available on the Board's website.

4 In addition to ECPG and M&NP, the following companies made submissions: Alliance Pipeline Ltd., Enbridge Southern Lights GP, Kinder Morgan Canada Inc., TransCanada PipeLines Ltd., and Westcoast Energy Inc. Also, Utility Group Facilities Inc. and 6720471 Canada Ltd. (ATCO Midstream) expressed interest in participating in the hearing of the motion but did not make submissions. The Board acknowledges the participation of these companies and thanks them for their assistance regarding the motion.

Chapter 2

Background - Development of the Escrow Issue

In its Reasons for Decision in GH-6-1996, the Board stated that the Pipeline faced circumstances substantially different than those faced by other NEB-regulated pipelines. It was a greenfield project, its only sources of gas were new and untested fields, and it would be serving an untested market in Canada and facing significant competition for its anchor market in the U.S. northeast.[5]

In structuring its project, the Applicant worked with shippers wanting to compete in the northeast U.S. gas markets and lenders concerned about the prospects in the new supply basin.

2.1 Contracts and Agreements

Shipper and Producer Agreements

The 1999 Offering Memorandum dated 24 June 1999 described senior secured notes to be issued by Maritimes & Northeast Pipeline Limited Partnership. According to the 1999 Offering Memorandum, the Applicant entered into the following contracts:

- Firm Service Agreements (FSAs) signed with shippers for up to 20 years,
- a Backstop Agreement signed with Mobil Oil Canada Properties and Mobil Canada Products Ltd. (Mobil Backstop Agreement),
  - for a term of 20 years during which the Mobil entities would pay for any unsubscribed firm capacity on the Pipeline up to a maximum of 184 548 GJ/d (175,760 MMBtu/d)[6], and
  - agreeing to constrain Canadian tolls to under $0.75/MMBtu for the first five years of the Pipeline operation, and
- Pipeline Utilization Agreements (PUAs) signed with Sable producers to reduce the risk of a competing pipeline being built

In combination, the FSAs and the Mobil Backstop Agreement provided contracts for nearly 20 years for 467 250 GJ/d (445,000 MMBtu/d). This is 84 percent of the Pipeline's initial design capacity of 556 500 GJ/d (530,000 MMBtu/d), noted in GH-6-96. In 1999, a report commissioned by the Applicant, annexed to the 1999 Offering Memorandum, established the capacity of the Pipeline could be 609 000 GJ/d (580,000 MMBtu/d) without compression facilities.

5 GH-6-96 p. 15

6 The evidence was submitted in imperial units of MMBtu (million British thermal units). The Board converted these units by multiplying the amount indicated in MMBtu by a conversion factor of 1.05 to provide an amount in metric GJ (gigajoules).

Original Bank Debt and 2009 Bonds

Initially, the Applicant used a combination of bank and bond debt to finance the Pipeline. The principal on the original bank debt was repaid partially over the initial 10 year term, with the balance subject to a balloon payment in 2009. The Applicant used bond debt (2009 Bonds) to pay the balloon payment in 2009. These senior secured notes were issued for $190 million at 4.34% due 2019.

1999 Bonds

The Applicant also arranged bond debt of $260 million for 20 years starting in 1999 (1999 Bonds). Through renewals of the FSAs and through additional FSAs, the Applicant expected to have firm capacity commitments for 556 500 GJ/d (530,000 MMBtu/d) from the second year of operations through to the maturity of the 1999 Bonds in 2019. The General Partner, in obtaining the original 1999 Bond financing, dealt with lenders who were reluctant to rely solely on gas contracts. The lenders preferred to rely on proved physical gas reserves or expected throughput to ensure loans would be repaid. The lenders proposed various conditions in the financial arrangements to increase the certainty of debt repayment.

Details of the terms and conditions are described in the 1999 Offering Memorandum and several related documents and, among other things, include:

- an interest rate of 6.9% on the 1999 Bonds, payable semi-annually commencing in 1999
- leverage (or a debt proportion) not exceeding 75 percent
- repayments of $13,000,000 in May and November each year from 2010 to 2019
- the Operating Period Cash Waterfall, a set order of priority for cash payments, directing cash into a series of collateral accounts, and
- provisions for advances to Partners.

The General Partner agreed to the 1999 Offering Memorandum on behalf of the Limited Partners.

The Escrow Provision and Trigger

The 1999 Offering Memorandum required an independent engineering Deliverability Report to be conducted. This Deliverability Report was to ensure that if no additional reserves or deliverability were demonstrated by the end of the eighth year, there would be sufficient time to fully cash collateralize the remaining 1999 Bond debt by the end of approximately 13 years (i.e., within the proved reserve life). Lenders were concerned that reserve life estimates were less than the 20-year financing term. Further, the lenders were concerned about the possibility that reserves would be produced quickly, up to the Pipeline’s maximum capacity of 609 000 GJ/d (580,000 MMBtu/d), potentially depleting reserves before the end of the term of the 1999 Bonds.

Certain clauses (collectively the Escrow Provision) would come into effect if gas supply could not sustain throughput of 609 000 GJ/d (580,000 MMBtu/d) until the bond maturity.

Specifically, if gas supply could not support this throughput until 2019 (the maturity of the 1999 Bonds), the Escrow Provision would “trigger”.

The Offering Memorandum defined the Required Escrow Amount which, if the Escrow Provision came into effect, is the amount of money needed to pay all future costs of the 1999 Bonds. Each year, the Required Escrow Amount declines as interest payments are made. It is expected to be $263 million in 2012 and then continue its decline until the debt is completely repaid (or refinanced).

The Operating Period Cash Waterfall requires that the Escrow Account meet the Required Escrow Amount before cash could be directed to subordinate uses. As cash is deposited, the Escrow Account balance would increase until it met the declining Required Escrow Amount. At that point the Escrow Account would be fully funded and no further cash would be swept into the Escrow Account. Then, as specified in the Operating Period Cash Waterfall, funds in the Escrow Account in excess of any year’s declining Required Escrow Amount would be available for other purposes.

If the Escrow Provision were triggered by the results of a gas test, the 1999 Offering Memorandum provided the Applicant with the opportunity to repeat the gas tests an unlimited number of times. If an additional gas test showed that the supplies could support throughput at 609 000 GJ/d (580,000 MMBtu/d) until the maturity of the 1999 Bonds, then the Required Escrow Amount would fall to zero, allowing release of the funds in the Escrow Account for other purposes.

The primary impact of the Escrow Provision being triggered is that cash distributions to equity investors cease until the Escrow Account is fully funded.

As part of the financial arrangements, the Applicant is permitted to lend funds from the Escrow Account to any of the Limited Partners if the Partner meets certain credit rating hurdles or issues a letter of credit. However, these loaned funds could be demanded by the Applicant following an event of default. The intent of this option was to minimize the impact on the Limited Partners of the Escrow Account mechanism if it triggered.

2.2 Original Supply and Market Outlook

Lenders and underwriters wanted comfort that there would be sufficient supply to adequately or effectively use capacity of 609 000 GJ/d (580,000 MMBtu/d) throughout the life of the 20-year bonds, regardless of contract levels. In 1999, the Applicant commissioned a report by Gilbert Laustsen Jung Associates Ltd. (GLJ) to provide lenders with an independent appraisal of petroleum resources and deliverability associated with SOEP fields and other significant discoveries (OSD).

This report, the 1999 GLJ Report, estimated the number of years that reserves from SOEP fields and OSD could support a base demand scenario of 467 250 GJ/d (445,000 MMBtu/d) demand in the first year and then 556 500 GJ/d (530,000 MMBtu/d) demand thereafter. The Applicant supplied this base demand scenario to GLJ. The Applicant also asked GLJ to examine an alternative demand scenario of 609 000 GJ/d (580,000 MMBtu/d), the maximum physical capacity of the Pipeline.

The 1999 GLJ Report estimated the likelihood of reserve life under the two demand scenarios for a range of probabilities. Specifically, the report focused on the number of years the reserves could support each demand scenario from proved reserves, probable reserves, possible reserves, or probability-weighted expected reserves.[7] As overall production declined from the SOEP fields, supply shortfalls were expected to be met by development of OSD including "deep gas" in the SOEP fields, for which limited data was available, and "undiscovered reserves" on the Scotian Shelf.

Using information for the SOEP fields and the most prospective OSD fields, GLJ estimated that reserves would be capable of meeting the demand requirements for the time periods shown in Table 2-1.

Table 2-1
Estimated Reserve Life[8]

	Demand Assumption	Years Capable of Meeting Demand	
Reserve Category	**MMBtu/d**	**SOEP Alone**	**SOEP Plus OSD**
Proved	530,000	12	15
Expected Value	530,000	15	19
Expected Value	580,000	13	17

The 1999 GLJ Report estimated that proved reserves could meet the base demand scenario for 15 years. With expected value reserves, the base demand scenario could be met for 19 years.

The alternative demand scenario involved throughput matching the base demand scenario in the first two years and then 609 000 GJ/d (580,000 MMBtu/d) thereafter. For this scenario, the 1999 GLJ Report estimated roughly 17 years from expected value reserves from the six SOEP fields plus OSD. The 1999 GLJ Report noted that this scenario was prepared without review of pipeline or facility limitations, or economics.

The 1999 Offering Memorandum also included a forecast of tolls and total operating revenues for both the base demand scenario and the alternative demand scenario. Tolls expected for the early years of the Pipeline's operating life are shown in Table 2-2.

7 The GLJ Deliverability Report used "proved reserves" to mean those with an 80% or greater probability of being produced; "probable reserves" having less than 80% but greater than 40% probability of being produced; and "possible reserves" having less than 40% but more than 10% probability of being produced. Expected value reserves are the probability weighted average or mean value determined using probabilistic methods. Expected value reserves are approximately equivalent to a proved plus probable reserves estimate.

8 Data from the 1999 GLJ Deliverability Report, p. C-3.

Table 2-2
Throughput and Charges[9]

	Base Demand Scenario		Alternative Demand Scenario	
Case:	**Throughput**	**Usage Charge**	**Throughput**	**Usage Charge**
Year	**MMBtu/d**	**$/ MMBtu**	**MMBtu/d**	**$/ MMBtu**
2001	530,000	0.7384	530,000	0.7415
2002	530,000	0.7332	580,000	0.7158
2003	530,000	0.7247	580,000	0.7084
2004	530,000	0.7169	580,000	0.7017
2005	530,000	0.7186	580,000	0.7038

2.3 The 2007 Deliverability Report

In 2007, the Applicant commissioned a second report by GLJ. As required by the financial arrangements, the report assessed deliverability at the specified 609 000 GJ/d (580,000 MMBtu/d) level for the next eight years. The purpose of the report was to determine the date at which the gas supply would no longer meet the throughput rate (called the Forecasted Production Decline Date in the financial arrangements).

In November 2007, GLJ provided an updated forecast of Pipeline utilization. According to this 2007 Deliverability Report, the combined production capacity of the SOEP fields, McCully Field, Deep Panuke and OSD offshore did not meet the throughput level of 609 000 GJ/d (580,000 MMBtu/d), and would not be capable of meeting this throughput rate in the future. As a result, the Escrow Provision triggered.

2.4 The Escrow Account

When the provision triggered in 2007, the Applicant began sweeping cash received from toll revenue into the Escrow Account. The balance of the Escrow Account was $58 million at the end of 2008 and $133 million at the end of 2009. At the end of 2010, the Escrow Account balance reached $190 million, for a 2010 average of $161 million.

The issue in this proceeding is whether the tolls charged by the Applicant should include compensation for funds in the Escrow Account, and if so, how the amount of compensation should be determined.

The trust indenture restricts the Escrow Funds to low-risk investments, including chartered bank time deposits and Canadian treasury securities, to meet certain credit quality and liquidity requirements. The Escrow Funds earned less than one percent average return in 2009.

The Escrow Account will be fully funded when its balance equals the (declining) Required Escrow Amount. The Escrow Account is expected to be fully funded in the second quarter of 2012 at a balance of $263 million.

9 Exhibit B5-2, 1999 Offering Memorandum, Annex B, Independent Engineer's Report (Beck Report), p. B-42 for the base demand scenario and p. B-58 for the alternative demand scenario.

Chapter 3

Business and Financial Risks

The Board has separated the topics in this proceeding into the following chapters. Chapter 3 focuses on supply, risk and responsibility for financing. Chapter 4 focuses on the characterization of the Escrow Funds, and the impact on interest and fair return.

3.1 Financial Concepts

To understand the issues in this case, it is helpful to restate some general principles related to business and financial risks.

The term ‘business risk’ describes any risk that may impact the income-generating capability of assets. ‘Financial risk’ describes the risks added by financial arrangements. Financial risks can originate from the amount of debt in the capital structure, the interest rates, and any provisions included in the debt financing agreements. Equity investors are impacted by business risks through income uncertainty and are also impacted by financial risk.

Business risks of pipeline assets include market, supply, competitive, operational and regulatory risks, each of which may affect the income-generating ability of the pipeline. Several of these risks can affect throughput. There are various means to mitigate the business risks from throughput to the income-generating capability of the pipeline. For example, where volumes are uncertain, firm service contracts can increase the certainty of pipeline revenue and income regardless of the actual gas volumes shipped.

The productive assets of an enterprise, including pipeline assets, are usually financed by a combination of debt and equity. Income uncertainty poses some risk to debt. However, debt holders are paid before equity investors because cash payments to equity investors are not made until other cash flow commitments have been met. As a result, financial risks can compound the business risks borne by equity investors.

Financial arrangements allocate income uncertainty among the providers of financial capital (i.e., between the debt and equity). If an arrangement increases the certainty of debt repayment, equity investors are exposed to greater income uncertainty.

3.2 Supply Uncertainty

It is common to speak of two distinct aspects of risk: first, the uncertainty or the probability of an event occurring; and second, the impact if the event were to happen. This section addresses the first aspect of risk, specifically supply uncertainty. Supply uncertainty originates from the unknown size and features of reserves, and from the rates of production that the reserves can deliver. Section 3.3 addresses the impact or burden from this uncertainty.

Views of the Parties

The Applicant

The Applicant submitted that there was a material change in the gas supply risk from that identified by the Pipeline owner in the GH-6-96 Hearing.

The 1999 GLJ Report presented a probability curve of reserve estimates showing approximately 92.07 10^9m^3 (3.25 Tcf) of proved reserves, 116.14 10^9m^3 (4.1 Tcf) of expected reserves and more than 141.64 10^9m^3 (5 Tcf) of proved, probable and possible reserves.[10] The Applicant asserted that, according to publicly reported reserve data, estimates of proved reserves for the original fields fell from an estimated 99.15 10^9m^3 (3.5 Tcf) in 1999 to 39.66 10^9m^3 (1.4 Tcf) in 2003. Mr. Inskip observed that the reserve and deliverability estimates were fundamentally different in 2007 than in the 1990s.

In 1999, GLJ estimated that production from existing reserves plus expected discoveries would be capable of filling the Pipeline for the 556 500 GJ/d (530,000 MMBtu/d) base demand scenario. In 1999, despite uncertainty about gas reserves, the Applicant considered throughput of 609 000 GJ/d (580,000 MMBtu/d) to be realistic, because other discoveries were expected in the area.

Mr. Inskip noted that in 1999 lenders were concerned that proved reserves would support less than 15 years of production at 609 000 GJ/d (580,000 MMBtu/d). In the lenders' view, this created more than a minor gas supply insufficiency relative to the term of the 1999 Bonds.

Nova Scotia Department of Energy (NSDOE)

NSDOE submitted that what the Applicant considered to be a supply risk is more accurately a risk from choosing an "unreasonable and an imprudently negotiated" trigger benchmark of 609 000 GJ/d (580,000 MMBtu/d).

ECPG

The 1999 GLJ Report presented reserves in a probabilistic manner, for example defining the proved gas reserves as having an 80 percent probability of being produced. ECPG asserted that the proved reserves were insufficient to support the 20-year debt. Further discoveries or reserve enhancements were needed to be able to sustain production of 609 000 GJ/d (580,000 MMBtu/d). Mr. McCormick submitted that the Applicant would have needed further discoveries or reserves enhancements beyond the OSD to sustain this level.

ECPG noted that the 2007 Deliverability Report shows cumulative production of 33.99 10^9m^3 (1.2 Tcf) from the SOEP reserves by 2007, and projects a further 48.16 10^9m^3 (1.7 Tcf) to 2025 from the estimated remaining recoverable reserves from SOEP, other significant discovery licences, Deep Panuke, McCully, and certain onshore coalbed methane potential. In combination, these numbers account for 82.15 10^9m^3 (2.9 Tcf) of reserves.

10 The evidence was submitted in imperial units of Tcf (trillion cubic feet). The Board converted these units by dividing the amount indicated in Tcf by a conversion factor of 35.301 and multiplying by 1000 to provide an amount in to metric units of 10^9m^3 (billion cubic metres).

ECPG argued that this 82.15 $10^9 m^3$ (2.9 Tcf) total was within the range estimated in the 1999 GLJ Report at the 90 percent probability level. ECPG interpreted that to mean that the supply estimated in 2007 remained within the range of reserve probabilities known and considered in 1999. ECPG argued that supply risk has not increased over what was considered by the Board in the GH-6-96 proceeding, and by the Applicant and its lenders in 1999.

Mr. McCormick referred to the alternative demand scenario of 609 000 GJ/d (580,000 MMBtu/d), that was provided in Appendix II to the 1999 GLJ Report. He noted that even proved and probable reserves could not meet this demand scenario for the term of the 1999 Bonds. Producers would not have thought the deliverability of 609 000 GJ/d (580,000 MMBtu/d) could have been met. ECPG argued that shippers and producers were not consulted on the reasonableness of 609 000 GJ/d (580,000 MMBtu/d).

ECPG submitted that the essence of risk is that things may turn out differently than anticipated. However, this makes the outcome a realization of a risk that was undertaken, not a new risk. Supply uncertainty is the realization of a risk considered in the GH-6-96 proceeding, undertaken and borne by the Applicant, and for which it has been paid since the outset.

3.3 Impact of Supply Uncertainty

In discussing who bears the impact from supply uncertainty in this case, there was some confusion with terminology in the evidence. The acronym M&NP was variously used to describe the Pipeline, the General Partner, the Limited Partners, the Limited Partnership, or the General Partner on behalf of the Limited Partners or on behalf of the Limited Partnership.

For example, the Applicant indicated that “revenues were no longer to be paid out to M&NP” and “M&NP is not receiving any revenue return from the project”. However, the Applicant later clarified its use of the acronym, and further clarified that its Application related to return on capital invested in the Pipeline and not to cash distributions to equity investors. The Applicant indicated its request was for incremental revenue requirement for the Pipeline-related business, and that the relief sought related to the tolls charged by the Applicant for use of the regulated Pipeline.

Views of the Parties

The Applicant

The Applicant submitted that it was not earning a fair return on its invested capital. In its view, the total invested capital grew by the amount of funds retained in the Escrow Account since 2007.

Dr. Vander Weide stated that “M&NP was unable to earn its allowed returns on equity in 2008 and 2009 primarily because the escrow balances raise its actual equity ratio significantly above the deemed equity ratios used to establish its revenue requirement.” He further described the impact on the equity on the balance sheet of the Limited Partnership from the inability to pay partner distributions, noting that deemed equity ratio in 2008 was 31.98 percent while the actual equity ratio was 35.90 percent in 2008 and 41.33 percent on average for 2009.
Dr. Vander Weide’s evidence asserts that, “to earn a fair return, M&NP Partners must be compensated for the impact of the escrow provisions on their equity investment in M&NP.”

Mr. Reed submitted that funding of the Escrow Account with no recognition in tolls has made it impossible for “M&NP to earn its allowed return on equity.” The Applicant later clarified that such references were to the Limited Partnership.

Ms. McShane suggested that the triggering of the Escrow Provision represented a crystallization of gas supply risk, a higher risk than was evident in GH-6-96. Asked to compare her use of the term supply risk to the Board’s definition of the term, Ms. McShane stated that the Applicant is not seeking a higher return to compensate for increased supply risk, but rather the Applicant is seeking relief for the “return ability of the equity holders”.

The Applicant acknowledged that it is firm contracts that are relevant to revenues, rather than gas volumes. The Applicant expects to fully recover its revenue requirement through to 2019.

NSDOE

NSDOE submitted that the Applicant’s decision to establish the Escrow Account addressed risks for which the Applicant was responsible as part of its management of the Pipeline. NSDOE argued that producers and shippers should not bear the impact of the realization of that risk.

ECPG

ECPG advised that the income-earning capability of the pipeline was not at risk from supply uncertainty, because the pipeline continues to receive revenues. ECPG noted that the income-earning capability of the Pipeline depends not on reserves, but on FSAs, PUAs and the Mobil Backstop Agreement. ECPG stated that the various transportation agreements mitigated the supply risk accepted by the Applicant.

Further, Mr. Johnson suggested that the earning capability of the Limited Partners was not impacted in any substantial way, since the Partners could borrow against the Escrow Account assets at a very nominal interest rate. Mr. Johnson stated that if the Escrow Funds belong to the Limited Partners, then the opportunity cost would be that of the Limited Partners not the Limited Partnership.

ECPG asserted that the escrow issue is a matter relating to the Limited Partnership, and is irrelevant to regulated pipeline operations. Citing the stand-alone principle, ECPG noted that the disposition of funds after collection from shippers through NEB-approved tolls is a partnership matter.

3.4 Responsibility for Risk

Views of the Parties

The Applicant

The Applicant was persuaded to accept the Escrow Provision as part of the financing, including the lenders’ requirement to set the supply benchmark at 609 000 GJ/d (580,000 MMBtu/d). The Applicant stated that the Escrow Provision was part of the financial package required to build the

Pipeline. Further, the Applicant said that an alternative of 15 year debt was not workable as the resulting rates would not have met the toll constraint required by the Mobil Backstop Agreement. Mr. Reed stated that this financial package was necessary to achieve the high degree of leverage, the low-cost of debt and the 20-year term of the debt, all of which were important to achieving the toll objective.

The Applicant stated that the parties representing the Applicant during the financing negotiations considered there to be a low probability that the second gas test would fail. The Applicant did not expect the Escrow Provision to trigger. Mr. Inskip added that lenders generally expect gas supply risk to be borne by equity rather than debt.

NSDOE

The NSDOE argued that management is to be held responsible for certain risks to ensure that costs are reasonably and prudently incurred. Holding management responsible ensures its motivation to be reasonable and prudent.

ECPG

ECPG believed that the Applicant had other financing options (for example, a lower bond rating). Further, ECPG observed that the Escrow Provision was very likely to trigger. However, ECPG was not concerned about the likelihood, since it had no idea the Applicant would propose treating the Escrow Account as equity in rate base.

ECPG stated that at no time before committing to the Escrow Provision in the 1999 financing did M&NP seek or obtain agreement of shippers to the Escrow Provision. None of the members of the ECPG were advised of or agreed to the 1999 financing.

3.5 Views of the Board

Supply Risk

The Board defines supply risk as "risk that the physical availability of economical natural gas volumes could affect a pipeline's income-earning capability".[11] Although the Applicant referred to supply risk, its use of the term differed from the Board's definition of the term.

There has been, and continues to be, uncertainty about the reserves and production of gas supply that would support throughput on the Pipeline. That supply uncertainty has a variety of impacts. The Applicant did not submit evidence demonstrating that the Pipeline's income-earning ability was at risk because of either supply uncertainty or because of the Escrow Provision. Moreover, the Applicant indicated that the income-earning capability of the Pipeline assets is not at risk. The Applicant described impacts from uncertainty of supplies to debt holders and to equity investors and not to the income earning ability of the Pipeline.

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11 Reasons for Decision RH-1-2008 Trans Québec & Maritimes Pipelines Inc., Cost of Capital, p. 13. This definition built on earlier usage. See for example, RH-4-2001, where the Board said "Supply risk may be defined as the risk that availability of supply could impact on the Mainline's income-earning capability. Supply risk relates to the physical availability of natural gas."

The Board notes that this was not a fully developed supply risk application. If it had been, parties would have brought forward supply experts directly, and possibly depreciation experts. The Board finds that, while there was some evidence related to reserves and deliverability, there was an inadequate evidentiary basis to conclude there was a change in supply risk to the Pipeline.

Type of Risk

When setting a pipeline's revenue requirement, the Board considers how much compensation to provide for the business risks that impact the income-earning capability of the assets. The Board recognizes business risk from a variety of sources and allows a regulated pipeline the opportunity to earn higher returns where there is higher risk. Just and reasonable tolls provide the opportunity for debt and equity investors to earn a fair return in a cost of service regime. The articulation of how the Board determines fair returns has evolved over time.[12]

The Board finds that the design of the Escrow Provision incorporated supply uncertainty into the financial arrangements. The Board finds that the Escrow Provision in the 1999 Offering Memorandum did not alter the *business* risks of the Pipeline. The Escrow Provision increased the *financial* risks to equity investors and decreased the financial risks to lenders compared to what the risks otherwise would have been, all else equal. As a result, the triggering of the Escrow Provision is not a supply risk, as defined by the Board.

Responsibility for Decisions

Subject to some limitations, financial arrangements are the responsibility of management. In the regulatory context, as articulated in RH-2-2004 Phase II,[13] management is better positioned than the regulator to make creative choices about managing its business. That NEB decision also implied management must take responsibility for the choices made. The regulator is involved to the extent that those arrangements impact just and reasonable tolls and the opportunity for fair returns.

The Applicant asserted that to meet the objective of low tolls it had to accept financial arrangements with the Escrow Provision. The Board finds there was insufficient evidence to support this position. Moreover, the toll forecasts from the Beck Report were below the toll limits agreed-to in the Mobil Backstop Agreement in either the base or alternative demand case. There were alternatives to address the concerns of debt holders. The Applicant could have employed combinations of: more equity; higher interest rates; shortened payback time to more closely match proved and expected gas reserves; and other terms and conditions. The General Partner was responsible for choosing among such options. The Board is not persuaded that the Applicant could not have met the low-toll target with the available alternative financial arrangements.

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12 The Board has described its approach to setting fair returns in various Reasons for Decision including RH-2-94, RH-1-2002, RH-2-2004 and RH-1-2008. The Act does not require the Board to use a specific methodology to determine fair returns. Tolls must be just and reasonable, whatever methodology the Board employs. See *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, p. 33-4.

13 Reasons for Decision RH-2-2004 Phase II, TransCanada PipeLines Limited, Cost of Capital, Chapter 3.

The General Partner agreed to the financial arrangements, including the Escrow Provision that increased the financial risk for equity investors. Without these financial arrangements, supply uncertainty might have impacted payments on the 1999 Bonds. However, the financial arrangements isolated the bond holders from that risk. The agreed-to financial arrangements transferred some of the impact of supply uncertainty from lenders to equity investors. The Escrow Provision benefits primarily the lenders. The financial arrangements and associated risks are within the Applicant's management responsibility.

Transparency

The General Partner has proposed that the shippers, not the Applicant, are responsible for the consequence of the triggering of the Escrow Provision, and should pay additional tolls as a result. If that were the case, the Board is of the view that the shippers and producers should have been provided explicit information in order to make informed decisions.

The Applicant assigned a low probability to the triggering of the Escrow Provision. However, producers and shippers had better information to advise on the probability of it triggering. During this proceeding, producers responded that they believed that the Escrow Provision had a high probability of being triggered. This belief was based on the information available in the 1999 GLJ Report.

Shippers typically understand that they are exposed to changes in market conditions at refinancing points. Shippers and/or producers cannot be presumed to have known that the Applicant would consider them responsible to compensate the Applicant for the Escrow Funds. The producers provided reserves data to the Applicant to support financial arrangements. The Applicant asserted this meant producers should have known shippers would be responsible to compensate the Applicant for the Escrow Funds. The Board disagrees.

In previous decisions on transparency, the Board has articulated the principle that shippers are to know in advance of negotiations the terms and conditions of access to the pipeline. This ensures transparency and allows market participants to make informed supply and market decisions, contributing to efficient functioning of the market.[14] The Board is of the view that this perspective on transparency should apply equally where pipeline management decisions may shift significant risks from a pipeline to shippers. Shippers must be aware of the shift of such risks to make informed decisions about participating in a project.

14 Reasons for Decision RH-3-2004 TransCanada PipeLines Limited North Bay Junction top of p. 9, including footnote 1.

Chapter 4

Treatment of the Escrow Account

Supply, risk and responsibility for financing were discussed in Chapter 3. Chapter 4 focuses on the characterization of the Escrow Funds, and the impact on interest and fair return.

The Applicant requested an equity return on the Escrow Account on the grounds that the Escrow Funds represent equity. The $30.38 million requested includes a return at 11.8% on the $161 million average Escrow Account balance for 2010, along with a provision for income taxes.

4.1 Characterization of the Escrow Account

Views of Parties

The Applicant

The Applicant argued that the Escrow Account is a rate base asset because it is used and useful, and was prudently incurred. The Applicant further submitted that the asset is 100 percent funded by equity and warrants an equity return.

Mr. Reed recommended the Board address whether the Escrow Provision was a reasonable condition of obtaining the debt which had financed the project. He proposed that, if this first question were answered affirmatively, the next question would be to address whether the escrow balances were prudently incurred and managed. Mr. Reed relied on Mr. Inskip's evidence to establish that the provision was reasonable. Representing the lenders, Mr. Inksip had indicated that the Escrow Account mechanism was "a reasonable protection to provide the lenders."

The Applicant stated that the Escrow Account contains funds that would otherwise have been distributed to the project sponsors as a return of and on their investment in the Pipeline. The Escrow Funds cash collateralize the debt, because they are required to be deposited into the Escrow Account to provide lenders with comfort that the debt can be serviced within the gas reserve life. The Escrow Account is held for the benefit of project lenders during 2010, particularly the holders of the 1999 Bonds, and, according to the Applicant, represents additional equity investment in the Pipeline.

Mr. Reed was unaware of any other case that dealt with precisely the same issue as the current one. However, he proposed that certain ratemaking principles apply in this case. For example, he suggested that treating the Escrow Account as rate base was analogous to the treatment of cash working capital required for operation of a pipeline system. In making the analogy, he noted that the Escrow Account is required to underpin bond debt in this case. Mr. Reed also cited several U.S. cases where publicly owned utilities were allowed to recover in tolls costs such as negative interest arbitrage from debt covenants. He asserted that these cases were equally applicable to those privately owned utilities that, due to their project financing, rely heavily on debt financing as do publicly owned utilities.

Mr. Inskip proposed that funds in the Escrow Account are equity since, without the Escrow Provision, the funds would have been available for distribution to equity holders.
Dr. Vander Weide noted that equity is the residual interest in the assets of an entity after deducting the entity's liabilities. He claimed that the rising Escrow Funds correspond to an increase in the equity of the Limited Partners.

Mr. Reed stated that the Applicant accounts for the Escrow Account on the balance sheet of the Limited Partnership as a restricted current asset. If the funds had been distributed, the Partners' Equity balances would have been reduced. Instead they are increasing. Ms. McShane noted that as the Escrow Account balance has grown, the reduction in pipeline-related assets has been reversed, resulting in a significant increase in reported equity. She noted that this translates into incremental equity on the balance sheet of the Limited Partnership.

Mr. Reed's evidence claimed that, in the absence of the Escrow Provision, the partners' equity in the Pipeline would have declined from $241 million at the end of 2007 to approximately $204 million by the end of 2010, consistent with the reduction in the net fixed assets and the debt repayment obligations. However, as a result of the Escrow Provision, the actual equity is forecast to increase to approximately $394 million by the end of 2010, a difference of $190 million. The $190 million net increase in equity compares to a forecast end of year 2010 Escrow Account balance of approximately $190 million. He noted the net change in the equity balance fully offsets the balance in the Escrow Account, demonstrating that the Escrow Account has been 100 percent financed by equity.

Mr. Reed stated that the Escrow Account is funded entirely by equity that would have been distributed to the Partners. He further noted broad North American regulatory support for establishing tolls that satisfy a utility's financing covenants, especially for publicly-owned utilities which rely on debt as the primary source of external capital.

Ms. McShane described the Escrow Account as a pipeline-related asset. Ms. McShane relied on the evidence of Dr. Vander Weide which in her view established that the entire amount reported as Partners' Equity on the financial statements of the Limited Partnership satisfies the definition of equity. Ms. McShane also relied on the evidence of Mr. Reed which in her view demonstrated that 100 percent of the Escrow Account balance has been financed by equity.

Ms. McShane noted that the audited financial statements of the Limited Partnership show actual equity increasing from $234 million in 2006 (the year prior to the Escrow Provision being triggered) to $347 million at the end of 2009.

Ms. McShane also noted that the most recent (2009) DBRS report on the Limited Partnership refers to the expected continuing decline in the debt-to-capital ratio "due to continuing debt amortization and increasing equity base given the termination of distributions to owners & corresponding escrow build-up with no major capital spending."

NSDOE

The NSDOE noted that this Board has established that reasonable rates reflect costs reasonably and prudently incurred, and argued that the Applicant has the onus to establish that any costs sought to be included in tolls are reasonably and prudently incurred, citing the following:

> The utility will be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made based on the information that the owner of the utility knew or ought to have known at the time the decision was made. In making a decision a utility must take into account the best interest of its customers while still being entitled to a fair return.[15]

NSDOE argued that inclusion of any additional compensation in tolls for the Escrow Account would be both unjust and unreasonable, and that the requested equity return on the Escrow Account should be rejected as not prudently incurred.

ECPG

ECPG took the position that "prudence" and "reasonableness" are not synonymous. ECPG cited two cases to show that the synonym issue is not clear and depends on the relevant legislation. ECPG argued that a prudence finding was not required since there was no utility expenditure to evaluate, as the Escrow Account arose not from an expenditure, but from a contractual arrangement which temporarily discontinued cash distributions to the equity investors.

ECPG submitted that approving the Application would result in tolls on the M&NP Pipeline that are unjust and unreasonable and would be a violation of regulatory principles and practices, including the stand-alone principle, the fair return standard, and the cost of service toll methodology.

ECPG's witness Mr. Johnson submitted that the Escrow Account is an asset owned by the Limited Partnership, and is largely financed by equity. However, Mr. Johnson observed that being assets of the Limited Partnership does not necessarily make them regulated assets.[16] He noted other instances of assets excluded from rate base and liabilities excluded from regulated capitalization.

Mr. Johnson stated that the Escrow Account is not a rate base asset. Even if the Escrow Account were a rate base asset, the return and appropriate capital structure would be deemed, not actual. Further, the very low risk nature of the asset held would be taken into account. Citing some NEB decisions, Mr. Johnson noted that for decades Canadian regulators have regulated using deemed, not actual capital structure.

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15 The test for prudency articulated in Energy and Utilities Board Decision 2001-110 (Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates Proceeding and Gas Rate Unbundling Proceeding. Part B-1: Deferred Gas Account Reconciliation for ATCO Gas), p. 10, affirmed by the Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2005 ABCA 122, paragraphs 59 and 73.

16 ECPG's counsel argued that the Applicant's position amounted to the accounting tail wagging the dog of regulatory law and principle.

ECPG, noting the traditional basis for cost of service toll methodology, submitted that approval of the Applicant's request would amount to a unilateral recapitalization of the Pipeline. This would increase rate base by the $260 million in the Escrow Account in 2012.

ECPG submitted that the NEB has described the stand-alone principle as a "fundamental concept of utility regulation".[17] ECPG cited the following statement to describe the stand-alone principle:

> Under the stand-alone principle, a utility is regulated as if the provision of the regulated service were the only activity in which the company was engaged. The cost of providing utility service and rates for provision of that service are to reflect only the expenses, capital costs, risks and required returns associated with the provision of regulated service.[18]

ECPG argued that much of the evidence related to the Limited Partnership and not to the regulated pipeline that provides transportation service. The fact that distributions to the Limited Partners were suspended to meet an obligation to lenders is irrelevant to the regulated pipeline operations.

Views of the Board

Purpose of the Escrow Account

The Escrow Account is an asset that is held legally by the General Partner, on behalf of the Limited Partners. The Escrow Funds are held for the benefit of bondholders first, and then may be distributed to equity investors.

The Escrow Provision appears to be functioning as contemplated by the parties to the 1999 Offering Memorandum. Revenues from the tolls allow the Applicant to satisfy the financing covenant.

In the Board's view, the withholding of cash distributions to equity investors is the realization of a financial risk that was part of the agreement accepted by the General Partner on behalf of the equity investors (the Limited Partners) when it entered into the financial arrangement that included the Escrow Provision. The Board has concluded that the Escrow Account is a financial asset and not a regulated asset.

Regulatory Treatment

The Board's authority relates to the Pipeline. Under the Act, the Board regulates aspects of the physical and financial operation of the Pipeline, including the tolls charged for its use.

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17 Reasons for Decision, RH-R-1-2002 TransCanada Pipelines Limited Review of RH-4-2001, Cost of Capital Decision, p. 26.

18 The quotation is evidence from TransCanada as mentioned in the above Decision RH-4-2001.

The Applicant suggested analogies to cash working capital, which supports pipeline operations by helping to manage the persistent lag between accounts receivable and accounts payable. However, in RH-6-85,[19] the Board clarified that cash working capital was not to include: payments on long-term debt because they are not a function of operations but of financing; other non-cash items, such as the delay in the collection of depreciation and amortization; or items that do not involve the day-to-day operations of the pipeline company. The Board specifically excluded costs related to contractual obligations entered into between shareholders and other investors.

The Board finds that the Escrow Account is not required for pipeline operations, but to meet conditions the General Partner agreed to in the financial arrangements. The Escrow Account resulted from a contractual obligation between the lenders and the equity investors. The operation of the Pipeline would not be affected by such financial arrangements as a different ownership structure, different debt terms, refinancing of the 1999 Bonds, or Limited Partners borrowing from the Escrow Account.

The Board finds that the Escrow Account is an asset but it is not a rate base asset. Since the Escrow Account is not a rate base asset, the Board finds that its existence does not impact the total fair return of the Pipeline.

Impact on Capital Structure

The Escrow Account was funded by diverting cash that would otherwise have been available for distribution to equity investors. The Board notes that the Escrow Account was funded by retained earnings, as the Applicant argued. However, the use of retained earnings to fund an asset does not necessarily create a regulatory asset.

Setting the deemed capital structure for regulatory purposes is closely tied to the stand-alone principle. The Board regulates the enterprise related to a pipeline as if the enterprise were a discrete business entity. Hence, the Board regularly deems the portion of assets that is regulated, as well as the relevant elements of the capital structure. The temporary existence of the Escrow Account as a financial asset does not change the appropriate deemed capital structure supporting the Pipeline's rate base assets.

Accounting

When the Escrow Provision was triggered in 2007, cash distributions were swept to the Escrow Account, according to the Operating Period Cash Waterfall. The sweeping of cash created a temporary financial asset,

19 Reasons for Decision RH-6-85 Westcoast Transmission Company Limited, Application for new tolls effective 1 January 1986, p. 79.

which serves to collateralize the debt. The cash is held as a restricted cash asset. The restriction on the cash is a result of a financial agreement.

The Escrow Account is a cash asset on the balance sheet of the Limited Partnership. In its evidence, the Applicant based many of its conclusions on this accounting treatment for the Escrow Account. However, accounting treatment does not drive regulatory decisions. The Board also notes that the Required Escrow Amount appears to represent a contractual obligation of the Limited Partnership, which does not appear on the Limited Partnership's balance sheet.

Prudence of the Escrow Mechanism

Some time was spent in this case on the question of prudence and reasonableness. Since the Board concludes that the impact of the trigger is not a business risk to be borne by the shippers and that the Escrow Account is not a rate base asset, there is no need to address the question of prudence of the original financing or its trigger.

4.2 Financial Arrangements as One Package

Views of the Parties

The Applicant

The Applicant submitted that shippers benefited from the financing package that included the Escrow Provision. The package kept tolls at a level that permitted the shippers to attach anchor markets in the U.S. Northeast. Mr. Inskip stated that it is difficult to make conclusions on what the credit ratings and spreads would have been without specific provisions. He asserted that the Escrow Provision was the key provision to address the economic fundamentals of the Pipeline.

Moreover, the Applicant submitted that the existence of funds in the Escrow Account was a factor in the favourable 2009 refinancing. As such, costs associated with the Escrow Provision are properly recoverable under the Board's traditional cost of service ratemaking model. However, Mr. Inskip also referred to the 1999 Bonds as project financing, noting that project financing carries a premium (i.e., higher interest) compared to bonds with recourse to the parent companies.

The Applicant submitted that, in a general sense, it could be said everyone involved in the project benefitted from the Escrow Provision in that it allowed the project to proceed. However, it asserted that it was the shippers, not the Applicant, that directly benefitted from the more favourable debt terms. The Applicant did not initially estimate savings on interest costs for 2010 and beyond, describing such incremental cost as speculative. In its reply evidence, the Applicant suggested there were savings on the 1999 Bonds, the 2009 Bonds and the 1999 bank debt. Mr. Inskip estimated savings amounting to 70 to 80 basis points, dependent on the bond rating in 1999. However, he indicated that there was a risk of erroneous conclusions from such calculations because of problems with data and comparisons. The Applicant used these estimates to argue that the financial arrangements had been prudent and had benefitted shippers and producers. Mr. Reed stated that past benefits went directly to the issue of inclusion of this asset in rate base.

The Applicant indicated that it was not able to reach agreement with the shippers for compensation for the funds in the Escrow Account, nor for a refinancing with recovery of a make-whole payment premium in rates. The Applicant indicated that if the Board were to find equity compensation for funds in the Escrow Account fair and reasonable, then

> M&NP expects it will be less costly for shippers if M&NP were to refinance the existing debt and the associated make-whole premium. The costs associated with the thicker equity ratio that would result from a refinancing of the existing 1999 Bonds (including the make-whole premium) likely would be more than offset by the cost savings associated with the release of the equity capital associated with the Escrow Account.

ECPG

ECPG described as unidentifiable and unquantifiable the Applicant's view of benefits to shippers from the Escrow Provision. Mr. McCormick indicated that without the escrow mechanism the lender risk profile would have been higher. He was uncertain, however, whether the lender risk profile would have been sufficient to "alter the perceptions of rating agencies and prospective bond purchasers and, if so, by how much."

Mr. McCormick noted that, in the GH-6-96 hearing, the Applicant indicated it was targeting a 'BBB' rated financing. An 'A' rated bond was ultimately issued. Mr. McCormick also estimated possible benefits in the range of 60 basis points on the principal of the 1999 Bonds. He submitted it was unclear whether all such savings would be attributable to the Escrow Provision. The interest savings could amount to $1.56 million on $260 million debt outstanding. In ECPG's view, the value of these benefits is dwarfed by the $30 million compensation sought by the Applicant for 2010.

Mr. McCormick based some of his evidence on comparisons to handling of significant deferral accounts imposed upon regulated companies by government, such as the Alberta Pool Price Deferral Account.[20] In that case, he noted that the deferral account attracted a distinct assessment of the deemed capital structure and cost of capital appropriate to the very low risk nature of the asset.

Views of the Board

From the Applicant's perspective, the Escrow Provision and Escrow Account were part of one package that supported the Pipeline. The Applicant supported that perspective qualitatively by noting that the Escrow Provision had benefitted shippers through lower interest costs.

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20 Alberta Energy and Utilities Board Decision 2001-92 (GENCO and DISCO 2000 pool price deferral accounts proceeding: Part K: Recovery period, carrying cost rates, collection issues, and hedging issues).

ECPG and the Applicant provided some limited information about potential interest savings on the 1999 Bonds.

The Board finds that possible interest savings would not justify treating the Escrow Account as equity. Whether or not the Escrow Provision helped the Applicant obtain bond financing in 1999 or in 2009, the Applicant did not demonstrate how past, current or future possible interest savings form a basis for 2010 compensation.

4.3 Fair Returns

Views of the Parties

The Applicant

The Applicant claimed that if it does not receive compensation for the Escrow Account then it will be denied the opportunity to earn a fair return on the investor-supplied capital that is required to support its regulated pipeline business. The Applicant submitted that the Escrow Account increases the amount of equity supporting the rate base and therefore increases the weighted average cost of capital.

Ms. McShane suggested that, to ensure that M&NP is fairly compensated on the entirety of the equity underpinning the total pipeline assets, the Escrow Account could be treated as incremental rate base that is 100 percent financed by equity and to which an appropriate return on equity is applied. Ms. McShane indicated that the equity would not be recovered until later when there is greater uncertainty regarding revenue.

The Applicant noted that it is firm contracts rather than gas volumes themselves that are relevant in terms of revenues to fund the Escrow Account. The Applicant expects there is a reasonable prospect that it will recover its full revenue requirement for each of the years 2012 to 2019. Further, it expects to distribute cash to the Limited Partners for each of these years.

The Applicant provided estimates of annual cash distributions corresponding to three scenarios, as requested by the Board. If the Escrow Provision had not triggered, the estimated cash distributions would have totalled $650.5 million over the 2008 to 2019 period. The other two scenarios include the triggering of the Escrow Provision. If the current Application were rejected, as reflected in the second scenario, the estimated cash distributions total $653.8 million over the 2008 to 2019 period. The third scenario reflects cash distributions if the current Application were approved and similar treatment extended through the forecast period. In this scenario, the estimated cash distributions would total $900.6 million. (See section 4.3.2 where the Board has illustrated this data in Figure 4-1.)

ECPG

ECPG submitted that the requested surcharge would foist upon shippers the realization of a risk undertaken by the Applicant and for which the Applicant has been compensated in its allowed and achieved return since 1999.

ECPG suggested that the requested extra $30 million for 2010 could be interpreted as bringing the total after-tax weighted average cost of capital to 7.66%, which it described as inconsistent with the fair return standard, ECPG computed that the effective cost of debt supporting the rate base would be 24.6% if the requested compensation were approved.

ECPG argued that the Applicant took the supply risk when it sought an increased return in the GH-6-96 proceeding. ECPG drew on the GH-6-96 Decision and the RH-1-2000 Decision to support its view that the Applicant had been compensated for the supply risk, among other things, with a 13 percent return on equity. Further, ECPG argued that the Applicant's return has consistently exceeded NEB formula returns by approximately 300 basis points.[21]

ECPG asserted that, in 1999, the Applicant was initially awarded 13% on 25 percent equity. ECPG pointed out that with the 6.9% debt for the remaining 75 percent, this provides a total return on rate base of 8.425% exclusive of income tax provision. ECPG also noted that in 1999 counsel representing the owner of the Pipeline argued that the 13% allowed rate of return on equity was meant to cover the risk of attaching a new gas supply basin and new markets.[22]

Further, ECPG argued the Applicant's overall return was stable or rising, in contrast to the falling RH-2-94 formula return on equity issued by the NEB over the last decade.

Views of the Board

From the inception of the project, the Applicant understood there was supply uncertainty because the Pipeline would be dependent on gas from a single-source unproven basin. Throughout the 1999 to 2009 period, the Applicant collected tolls that included compensation for risks related to the Pipeline. Total returns were set for the initial five years in GH-6-96, where the Board stated that any interested party could ask the Board to change the regulated financial structure and rate of return on equity, should circumstances change within that period. Later, negotiated settlements adjusted the total returns, and were filed and approved in support of just and reasonable tolls. Over the last 10 years, the Applicant has not asked the Board for compensation for changing supply risk. That period covered 1999 to 2007 when there was a risk of the Escrow Provision triggering, and 2007 to 2009 when funds were accumulating in the Escrow Account.

Except for the escrow issue, the tolls for 2010 were agreed-to through negotiated settlement. Both financial risk and supply risk would normally be dealt with when negotiating or setting the total return on a pipeline. Whether the negotiated return for 2010 is sufficient to compensate the Applicant for its business risks was not the subject of this hearing.

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21 The term 'NEB Formula returns' refers to the NEB's annual publication of rate of return on equity derived from a formula set in Reasons for Decision RH-2-94, Multi-Pipeline Cost of Capital.

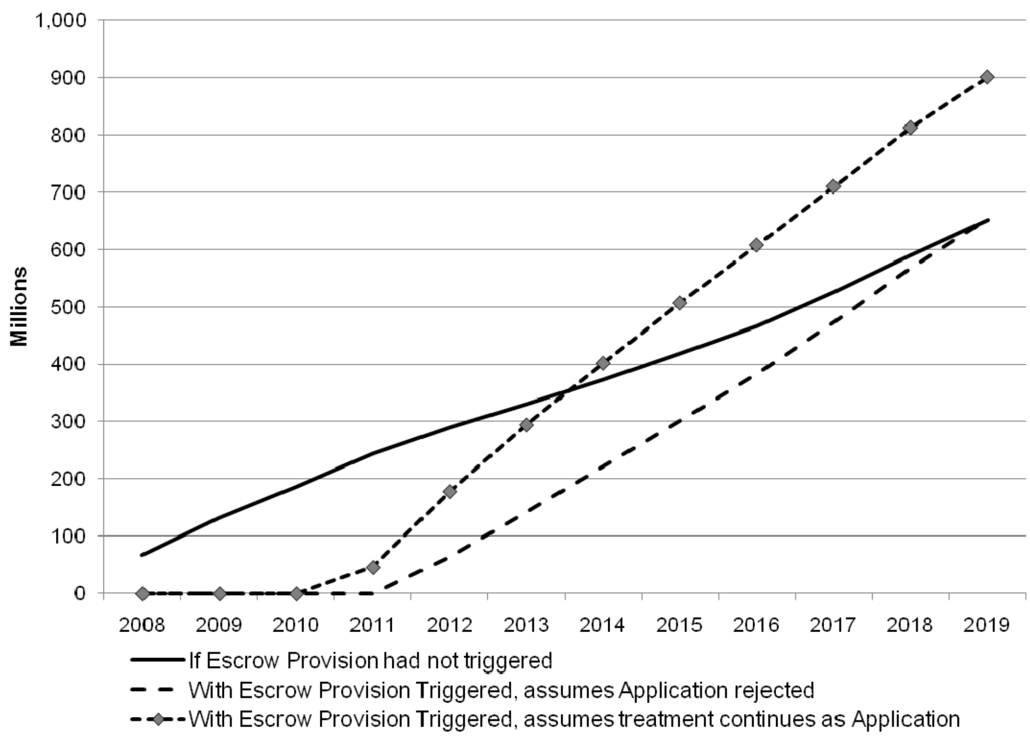
22 This was in the context of distinguishing such risk from the risk of capital cost overruns.

Cash distributions to equity investors are distinct from return on rate base. The Pipeline is earning a return on rate base. Generally, payments to equity investors are not regulatory decisions. However, as said in RH-R-1-2002, the Board may look beyond the regulated pipeline for evidence as to whether returns are fair.

In the near term, payments to the equity investors are suspended. In the interim, the Limited Partners' equity value in the Pipeline has increased on a tax-paid basis. The Board recognizes that cash later has less value than current cash. However, cash distributions have been restricted by a financial agreement, not by the regulator.

The General Partner expects to resume cash distributions soon. If the Escrow Provision had not triggered the Applicant indicated it would have distributed $650.5 million in cash from 2008 to 2019 (illustrated by the solid line in Figure 4-1[23]). If the Application is denied, the General Partner would expect to pay out approximately the same[24] total cash by 2019 (illustrated by dashed line). The Board concludes that the Applicant is able to provide a return on and of capital to its equity investors.

Figure 4-1
Cumulative Cash Distributions, starting from 2008, for 3 Scenarios



23 Figure 4-1 is a Board-generated graph illustrating data from Exhibit B-16, forecasts (2008-2019) provided by the Applicant.

24 As mentioned in 4.3.1, without the Escrow Account the Applicant expected it could distribute $650.5 million in cash. If the Application were denied, the Applicant expected it could distribute $653.8 million.

Hypothetically, if compensation of $30.38 million for the Escrow Funds were approved in 2010 and similar treatment continued until 2019, the General Partner would expect to pay out the same total cash sooner (illustrated by dashed-dotted line).[25]

The General Partner made arrangements, including contracts with shippers and producers, which give the equity investors a high probability of recovering their investment. The Applicant had a positive outlook for expected and possible gas reserves, despite the supply uncertainty. On the basis of its positive outlook, the Applicant assigned a low probability of the Escrow Provision being triggered. The 1999 Offering Memorandum and related documents did not mention treating the funds in the Escrow Account as rate base equity. The documents did provide some mitigating options for equity investors if the Escrow Provision triggered. These included refinancing with a make-whole payment, and accessing funds in the Escrow Account by offering corporate guarantees.

The Board concludes that the General Partner, on behalf of the Limited Partners, was aware of the risk to equity investors, and that the latter had opportunities to mitigate the impact of their risk. The Applicant has not demonstrated that it has been denied an opportunity to earn a fair return on the capital invested in the rate base.

25 As mentioned in 4.3.1, in this hypothetical third scenario the Applicant expected it could distribute $900.6 million, or $250 million more than in the absence of the Escrow Account.

Chapter 5

Disposition

In the letter accompanying Hearing Order RH-4-2010, the Board indicated that if it decided the Applicant should be compensated for funds in the Escrow Account, the Board would allow a period for parties to negotiate with respect to the appropriate level of compensation. If the Board decided the Applicant should not be compensated for funds in the Escrow Account, it would proceed to set final 2010 tolls equal to the interim 2010 tolls included in the Settlement Agreement.

The Board invited parties to comment on whether they wanted any guidance from the Board for negotiations. The Applicant noted that negotiations on ongoing business, such as settlements for 2011 and 2012, are unlikely until the escrow issue is resolved, and that some guidance to narrow the range of potential outcomes would enhance the prospects for a successful negotiation and reduce the prospect of regulatory delay. ECPG indicated that it did not need guidance if the only issue to negotiate were a return on equity, but that it would find guidance useful if there were other methods to determine compensation, such as a margin, a debt cost or a different capital structure.

The Board asked the Applicant and ECPG their interpretation of the next steps. Each agreed that if the Board were to find that the 2010 final tolls should not include any compensation for the Escrow Funds, it expected that the Board would then set the interim tolls as final.

The Board has determined that the funds in the Escrow Account do not warrant additional compensation in 2010 and as a result the Board denies the Application.

As the Board has decided that no additional 2010 compensation is appropriate for the funds in the Escrow Account, there is no need for a second phase of this proceeding. As a result, no guidance is offered on these topics.

The foregoing chapters together with Order TG-03-2011 constitute our Reasons for Decision in respect of the 2010 Application for Final Tolls. Order TG-03-2011 gives effect to the Board's decision to make interim tolls final.

R. J. Harrison, Q.C.
Presiding Member

R. R. George
Member

L. Mercier
Member

Calgary, Alberta
June 2011

Appendix I

List of Issues

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

1. Should 2010 tolls include compensation for funds in the Escrow Account?

    a. Role of escrow provision: history, present and future

    b. Board jurisdiction to require escrow funds compensation

2. If 2010 tolls should include compensation for the escrow funds, how should the amount of compensation be determined?

    a. Relationship of escrow funds to balance sheet and to rate base

    b. Relationship of escrow funding to other financing

    c. Impact on cash flow to owners

Appendix II

ORDER TG-03-2011

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

IN THE MATTER OF an application by Maritimes and Northeast Pipeline Management Ltd. (M&NP Management Ltd.) on behalf of Maritimes & Northeast Pipeline Limited Partnership dated 26 July 2010 for approval of final tolls for 2010 pursuant to Part IV of the Act, filed with the National Energy Board (Board) under File OF-Tolls-Group 1-M124-2010-02 01.

BEFORE the Board on 1 June 2011.

WHEREAS M&NP Management Ltd. has been authorized to charge tolls for service on an interim basis effective 1 January 2010 under Board Order TGI-05-2009 issued 17 December 2009;

AND WHEREAS M&NP Management Ltd. has been authorized to charge tolls for service on an interim basis effective 1 April 2010 in accordance with the terms of the *Maritimes & Northeast Pipeline 2010 Toll Settlement* approved under Board Order TGI-01-2010 issued 17 March 2010;

AND WHEREAS on 26 July 2010 M&NP Management Ltd. applied to the Board for approval of final tolls for the period 1 January 2010 to 31 December 2010 reflecting the recovery by M&NP Management Ltd. of an amount equal to $30.38 million as compensation for funds held in escrow;

AND WHEREAS the Board issued Hearing Order RH-4-2010 on 13 October 2010;

AND WHEREAS the Hearing was held in Halifax, Nova Scotia from 1-3 March 2011 and in Calgary, Alberta on 23 and 24 March 2011;

AND WHEREAS the Board has considered M&NP Management Ltd.'s application and has resolved the escrow issue by deciding that compensation on funds in the Escrow Account is not warranted;

THEREFORE, IT IS ORDERED, under Part IV of the Act that the tolls agreed to in the *Maritimes & Northeast Pipeline 2010 Toll Settlement* are approved as final tolls for the period 1 January 2010 to 31 December 2010 with no adjustment to the Total Revenue Requirement for the Escrow Funds.

NATIONAL ENERGY BOARD

Anne-Marie Erickson
Secretary of the Board