National Energy Board
Office national de l'énergie

The Maritimes Natural Gas Market

An Overview and Assessment

An ENERGY MARKET ASSESSMENT • June 2003

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An **O**verview ***and*** **A**ssessment

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FIGURES

APPENDICES

Metric to Imperial

Metric	*Imperial Equivalent Units*
1 cubic metre of natural gas	= 35.301 01 cubic feet (14.73 psia and 60ºF)
1 gigajoule (GJ)	= approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf

Units

Prefix	*Multiple*
Mcf	= thousand cubic feet
MMcf	= million cubic feet
Bcf	= billion cubic feet
Tcf	= trillion cubic feet
Mcf/d	= thousand cubic feet per day
MMcf/d	= million cubic feet per day
Bcf/d	= billion cubic feet per day
GJ	= Gigajoules (10^9 joules)
GJ/d	= Gigajoule per day
PJ	= Petajoule (10^{15} joules)

FOREWORD

The National Energy Board (the NEB or Board), as a part of its regulatory mandate, continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas and their by-products) and the demand for Canadian energy commodities in both domestic and export markets.

In 1987, the Board adopted the Market-Based Procedure (MBP) for assessing applications for long-term natural gas export licences. The MBP is based on the premise that the marketplace will generally operate such that Canadian requirements for natural gas will be met at terms and conditions, including price, similar to those applicable to natural gas exports.

The MBP consists of a public hearing and a monitoring component. The monitoring component of the MBP involves an ongoing assessment of Canadian energy markets, the publication of *Canadian Energy Supply and Demand* reports, and a series of *Energy Market Assessment* (EMA) reports.

This EMA, entitled *The Maritimes Natural Gas Market: An Overview and Assessment*, examines the development and functioning of the Maritimes natural gas market and provides an overview of the issues in this market.

During the preparation of this report, a series of meetings and discussions were conducted with a cross-section of the natural gas industry, including producers, gas marketers, pipeline company representatives, local distribution companies, end-users, industry associations and government agencies. The Board appreciates the information and comments it received.

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

FINDINGS AND CONCLUSIONS

There are two objectives to this report:

1) to provide an assessment of the functioning of the natural gas market in the Maritimes; and
2) to provide an objective discussion of the issues facing this market.

The Board is satisfied that the Maritimes natural gas market has been functioning reasonably well to meet the current requirements of domestic energy users. However, there are a number of features of the Maritimes gas market that create challenges for domestic buyers that are generally not faced by export buyers.

Approximately 20 percent of Scotian production is being consumed in the Maritimes, while the remainder is exported to the United States. Although some parties may question why a higher percentage of natural gas is not consumed in the Maritimes, there are a number of factors suggesting that the market is working to the benefit of Canadians.

- Energy users in the Maritimes have access to a diverse suite of fuels at competitive prices and natural gas must compete with well-established fuels. Where energy users have access to natural gas but have opted to use other fuels, it is because they believe that, having regard to price, costs of conversion and the logistics of using natural gas, these fuels better satisfy their needs than natural gas.
- The Maritimes has benefited from the existence and development of the natural gas industry. The production, transportation and sale of natural gas provide royalty and tax revenue to local governments and jobs to residents. The oil and gas sector, together with related investments in distribution systems and industrial facilities, has provided in excess of 70 percent of the region's investment over the past five years.
- The export market has provided the large anchor market that was necessary for the development of offshore reserves, without which the Maritimes would not have access to offshore natural gas at this time. Producers require certainty that they will be able to sell the natural gas they produce and the export market provides this certainty. In addition, the ability to resell natural gas into the export market enables domestic gas buyers to manage their gas purchase and transportation commitments. Without this ability, the risk of committing to long-term purchase and transportation contracts would likely render a decision to use natural gas uneconomic. Commercial flexibility to quickly access export markets is facilitated by the Board's export approval procedures under which unrestricted short-term access to these markets is provided.
- Growth in the domestic market has been aided by such features as the Lateral Policy on Maritimes & Northeast Pipeline Management Limited's (M&NP) pipeline system, which has kept transportation rates to domestic users lower than they would be if tolled on a stand-alone basis. The domestic market has also benefited from the toll discounts that M&NP has been providing to customers in Nova Scotia and New Brunswick.

Notwithstanding these positive features of the Maritimes gas market, there are a number of other factors that create challenges for domestic buyers that are generally not faced by export buyers.

- The fact that many of the markets in the Maritimes are relatively small reduces the economics of serving these markets. Natural gas use is most efficient when the buyer and, to a lesser extent the seller, can take advantage of economies of scale. The small scale of the Maritimes market creates hurdles for project proponents who would like to develop new markets, particularly if they require the construction of pipeline infrastructure.
- The lack of any storage capacity in the Maritimes makes it more difficult to manage gas purchase and transportation commitments. For example, it can be challenging to find additional supplies of natural gas on short notice without bidding gas back from the Boston market. In these instances, the seller seeks compensation for transportation costs that have been incurred for reserved pipeline capacity to New England. In certain circumstances, domestic consumers may view paying a price that includes charges for U.S. transportation as unfair. However, such behaviour does not necessarily constitute undue discrimination; rather, it is an understandable characteristic of the market that the seller will seek to recover that portion of the transportation charge commitments that cannot otherwise be mitigated. If storage existed, this issue could be alleviated, recognizing that there would also be some costs associated with storage services.
- There is a lack of liquidity in the Maritimes gas market. In other markets, such as Alberta or Ontario, there is a high degree of liquidity which provides better price discovery, facilitates the ability of parties to quickly make adjustments in their gas management operations and to undertake various hedging strategies. This lack of liquidity is not a result of inappropriate behaviour on the part of any market participants - it is simply a fact of this market. However, the lack of liquidity does create gas management challenges for domestic users.

While these factors create special challenges for domestic buyers, they are a normal feature of a developing market characterized by relatively small population centres. The Maritimes gas market is working as well as could be expected, given its geographic features and early stage of development.

Looking to the future, the most important issue is the uncertainty surrounding the timing of the development of additional supply. Most market observers believe that there will be incremental supplies of natural gas discovered and developed in the offshore, but the timing of these developments is highly uncertain. No amount of analysis can reveal the answer to this uncertainty - the answer will come when the industry finds reserves that are economic to develop, having regard to the state of the market as they perceive it.

Natural gas producers face considerable exploration risk and have noted that the time to obtain approvals of their projects has been, in their view, unduly long, thereby increasing the time before their exploration expenditures can be recovered. Clearly, natural gas producers need to believe that an attractive combination of geological potential and a predictable development framework exists if they are to continue to invest large sums of money into exploration in the basins offshore of Nova Scotia.

While the Board is satisfied that, given its characteristics, the Maritimes natural gas market is functioning as well as can reasonably be expected, the Board will continue to monitor developments in this market to ensure that gas sellers negotiate with Canadian buyers in good faith and that Canadians have access to Scotian offshore gas on market terms and conditions, including price, similar to those available to export buyers.

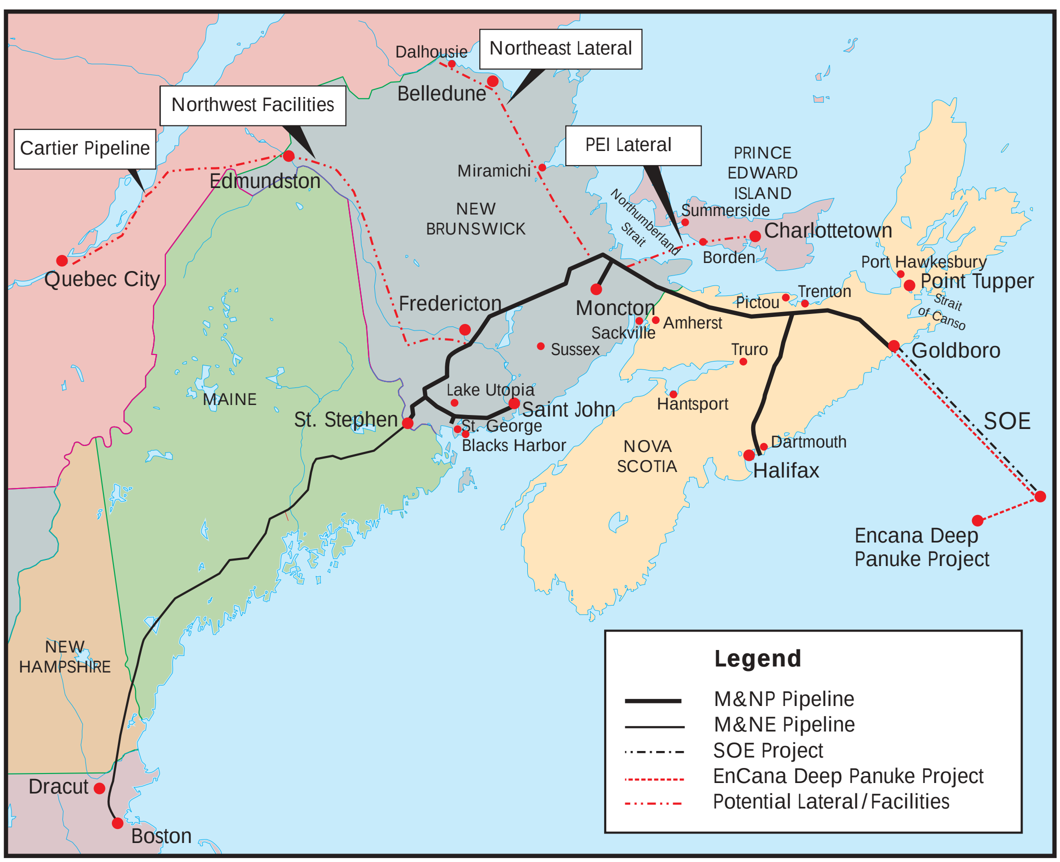
Introduction – The Birth of the Natural Gas Industry in the Maritimes

When the operators of the Maritimes and Northeast Pipeline (M&NP) system opened a valve on the night of 31 December 1999, it marked the first commercial flows of natural gas from fields offshore of Nova Scotia. This was a historic night for the energy industry in the Maritimes and, indeed, in the Canadian energy industry. For the first time, a major source of natural gas was being developed outside of the Western Canada Sedimentary Basin (WCSB).

The M&NP system carries natural gas from the Sable Offshore Energy Inc. (SOE) Project, which is currently the only producing natural gas project in the Scotian offshore basin (Figure 2.1). The

F I G U R E 2 . 1

M&NP Pipeline and Maritimes Canada



development of the SOE Project marked the culmination of years of offshore exploration, with the first seismic shot in 1959 and the first well drilled in 1967. Throughout these years, there were periods of high optimism that the offshore industry would take off and expand the economy of the Maritimes, only to be followed by cancelled plans and postponements. Thus, after nearly 40 years of raised and dashed expectations, the start-up of the SOE Project meant the offshore natural gas industry was finally underway. Expectations were high that the Maritimes would realize large benefits from access to the natural gas and from the jobs and spending associated with ongoing development.

Today, more than three years since the SOE Project started, pipeline facilities have been built off the mainline M&NP system to serve Halifax and Point Tupper in Nova Scotia, and to Saint John, Moncton, and St. George in New Brunswick. In addition, Enbridge Gas New Brunswick (EGNB) has constructed distribution facilities in Fredericton and Oromocto, New Brunswick. Natural gas is being delivered to large industrial and electric power generation customers in Nova Scotia and New Brunswick, and to residential and commercial customers in New Brunswick. However, there have been no deliveries of natural gas to residential or commercial customers in Nova Scotia as a distribution system has not yet been constructed. About 80 percent of the gas production from the SOE Project is being exported.

While natural gas is being used by the industrial and electricity generation sectors, most residential consumers in the Maritimes have not seen the development of the SOE Project as making a significant difference in satisfying their energy needs. Not surprisingly, this has led to a number of questions:

- Why haven't more energy users in the Maritimes started using natural gas?
- Are energy users in the Maritimes receiving fair access to the natural gas?
- Are the producers and the pipeline favouring deliveries to the United States?

There are two objectives of this report:

1) to provide an assessment of the functioning of the natural gas market in the Maritimes; and
2) to provide an objective discussion of the issues facing this market.

The remainder of this chapter provides some necessary background on the NEB's natural gas export approval procedures and the application by the Province of New Brunswick that, in part, led to this report. Chapter 3 provides an overview of the development of natural gas supply and pipeline infrastructure in the Maritimes and an overview of pricing formation. Chapter 4 provides a description of the natural gas market as it exists today in the provinces of New Brunswick, Nova Scotia and Prince Edward Island. Finally, Chapter 5 provides an assessment of the functioning of the market, and the issues and challenges associated with development of the Maritimes market.

This report focuses on the existing markets served by the M&NP pipeline in Nova Scotia and New Brunswick and includes some discussion of the other Maritimes markets that are currently proposed to be served by the pipeline before the end of the current decade. These include the Province of Prince Edward Island and other currently non-connected potential markets in Nova Scotia and New Brunswick.

For the purposes of the assessment, the Maritimes gas market is defined to include all potential markets in the provinces of Nova Scotia, New Brunswick and Prince Edward Island, but excludes any markets in Newfoundland or Quebec.

This report is largely based on consultations with a diverse group of stakeholders in the Maritimes natural gas market, including producers, gas marketers, pipeline company representatives, local distribution companies, end-users, industry associations and government agencies (see Appendix 1 for a list of the parties). The consultations took place over a period of three months and were conducted in the provinces of New Brunswick, Nova Scotia, Prince Edward Island, Quebec, Ontario and Alberta.

2.1 NEB Natural Gas Export Approval Procedures

The National Energy Board Act (the Act) sets out the Board's responsibilities with respect to the approval of the export of natural gas from Canada. The Act distinguishes between short-term export orders, which provide authority to export unlimited quantities of natural gas for periods of up to two years, and long-term licences, which apply to longer periods. If a seller wishes to obtain permission to export natural gas for a period of more than two years, it must obtain a licence from the NEB[1].

The Board's current approach to regulation of natural gas exports has its genesis in the 1985 "*Agreement Among the Governments of Canada, Alberta, British Columbia and Saskatchewan on Natural Gas Markets and Prices*". These governments agreed that natural gas producers in the western producing provinces should have substantially enhanced access to the export market and that the Board should adjust its export licencing procedures to reflect market principles. The agreement also directed that exporters be provided with the ability to export unlimited quantities of natural gas for periods of two years or less pursuant to short-term export orders. The intent of the short term orders was to facilitate short term market arrangements without unnecessary regulatory intervention. Further, there was no concern about approving unlimited exports of gas in the short term because exports were limited by both the production characteristics of wells and the capacities of export pipelines.

In 1987, the Board adopted the Market-Based Procedure (MBP), the method by which it assesses applications for licences to export natural gas. There are two parts to the MBP: a hearing component and a monitoring component. Under the hearing component, applicants for export licences are required to demonstrate that Canadians have access to natural gas on similar terms and conditions, including price, as export customers.

> ***Market Based Procedure***
>
> *Canadians have an opportunity to purchase natural gas on similar terms and conditions, including price, as those offered in the export market.*

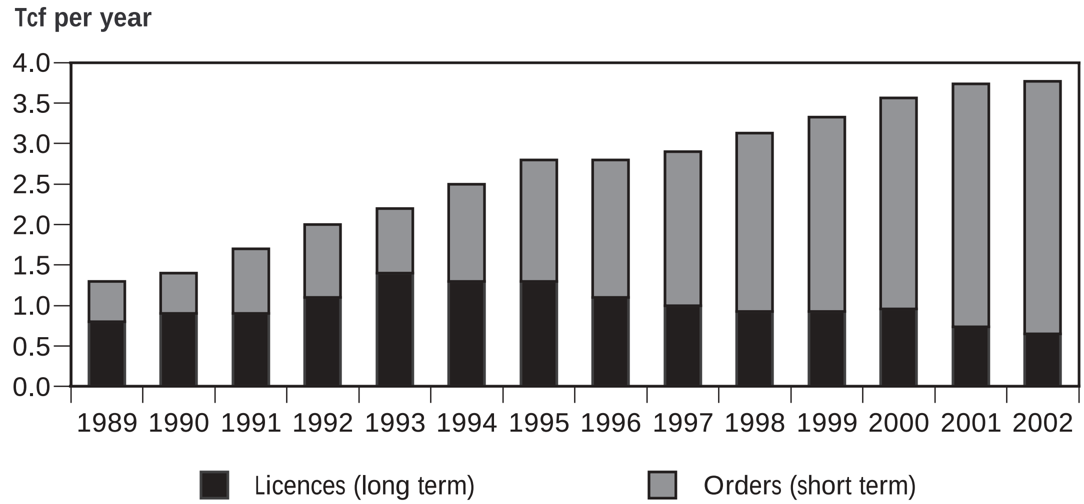
Under the monitoring component of the MBP, the Board monitors the Canadian natural gas market to ensure that the market is functioning as expected; i.e. that it is operating according to market principles and that Canadians have the opportunity to purchase natural gas on similar terms and conditions, including price, as export customers.

Since the early 1990s, there has been an increasing trend to export gas under short-term orders, instead of long-term licences (Figure 2.2). The last export licence issued by the Board followed an application by Imperial Oil Resources Limited to export up to 42.5 MMcf/d of natural gas from the SOE Project to Boston Gas Company. This licence was issued in 1999 and is scheduled to expire on 31 March 2007.

1 The exception to this is when the long-term export is for very small volumes, in which case a long-term order may be obtained.

FIGURE 2.2

Natural Gas Exports by Type



2.2 Background - Application by the Province of New Brunswick

In February 2002, the Province of New Brunswick (New Brunswick, or the Province) applied to the NEB to hold a public hearing with the objective of developing a specific set of rules that would apply to the export of incremental supplies of natural gas from the Scotian offshore[1].

In its application, New Brunswick noted that it had several concerns with the operation of the Maritimes natural gas market. It stated that there is only one producing project in the Maritimes market, very few sellers and buyers and hence, the Maritimes market is substantially different from the market in western Canada. It also noted that New Brunswick was not a signatory to the *Agreement Among the Governments of Canada, Alberta, British Columbia and Saskatchewan on Natural Gas Markets and Prices*, following which the NEB adopted the MBP. New Brunswick also stated that it had grounds to believe that producers were not dealing in good faith with gas buyers in New Brunswick. The Province also noted that exporters were relying almost entirely on short-term orders to export their gas and, consequently, there was no mechanism for Canadian gas buyers to intervene if they believed they were being disadvantaged.

For all of the above reasons, the Province requested the Board hold a hearing with the objective of implementing a specific set of rules for the export of incremental natural gas supplies from the Scotian Shelf. The Province stated that the intent of these rules would be to ensure that gas buyers in the Maritimes had access to natural gas produced in Canada on fair market terms and conditions; the intent of these rules would be to achieve the same objective that the MBP is intended to achieve with respect to western Canadian gas.

A public hearing (MH-2-2002) was held on New Brunswick's application during the month of July 2002 in Fredericton. In its Decision, the Board declined to implement separate export approval procedures for new supplies of natural gas produced from the Scotian Shelf. The Board noted that there was no evidence produced in the hearing that gas buyers in the Maritimes had not had an

1 The Province recognized that the SOE Project was approved under the existing export rules and accordingly proposed that the new rules only be applied to incremental exports.

opportunity to purchase Scotian offshore gas supplies on terms and conditions similar to those offered in the export market. The Board stated that, in the absence of any clear evidence of significant market failure, the public interest would best be served by allowing markets to work unimpeded by regulatory processes.

However, the Board also noted that there are a number of unique characteristics of the Maritimes gas market that give rise to concern. Among other things the Board noted that, at the time of the decision, there was only one potential provider of incremental gas supplies over the next five years - EnCana Corporation's (EnCana) Deep Panuke project. Further, most gas buyers in the Maritimes would need to make significant investments in gas-burning equipment and pipeline infrastructure which would only be economic if utilized for many years. However, the expected production profile of the Deep Panuke project was approximately three and a half years before decline, making it difficult for EnCana to provide long-term commitments to supply gas. In addition to these considerations, the economics of expanding the M&NP mainline to existing markets, including the United States, are more favourable than building new laterals to serve domestic markets. Due to the combination of these factors, the Board found that the "developing Maritime gas market faces many challenges that are not faced by buyers in the mature export market"[1].

Accordingly, the Board decided to mobilize a team that would be responsible for monitoring the Maritimes gas market and to report publicly on the functioning of this market, with the first report to be produced before 31 July 2003.

The Board stated ...

in the absence of any clear evidence of significant market failure, the public interest would best be served by allowing markets to work unimpeded by regulatory processes.

The Board found ...

the developing Maritimes gas market faces many challenges that are not faced by buyers in the mature export market.

The Board decided ...

to mobilize a team that would be responsible for monitoring the Martimes gas market and to report publicly on the functioning of this market.

1 MH-2-2002 Reasons for Decision, page 42.

DEVELOPMENT OF THE MARITIMES NATURAL GAS MARKET

3.1 Scotian Offshore Supply

There have been significant discoveries of natural gas in three major offshore regions in eastern Canada - offshore Nova Scotia, offshore Labrador[1] and in the Jeanne d'Arc Basin east of St. John's, Newfoundland[2]. However, the only major commercially viable discoveries in eastern Canada have been in offshore Nova Scotia basins.

The Scotian Basin includes the Scotian Shelf and deepwater plays beyond the shelf on the Scotian Slope. The Scotian Basin can be subdivided into nine geologic entities. Two of these areas (Sable and Abenaki) account for most of the discoveries to date (Figure 3.1). Some 20 gas fields have been discovered in the Sable sub-basin.

Since 1999 there has been much interest in the deeper waters of the Scotian Basin beyond the Scotian Shelf, specifically in the area along the edge of the upper slope in waters exceeding 1000 metres in depth. The deep water area is believed to be dominated by turbidite plays which have been prime exploration targets in other areas of the world because they tend to contain very large resources.

Estimates of discovered reserves in the Sable sub-basin range from 3.6 to 5.2 Tcf. An additional 4.8 Tcf of undiscovered resources are estimated to lie in the Sable sub-basin[3].

In October 2002, the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) published a report entitled "*Hydrocarbon Potential of the Deep-water Scotian Slope*". In that study, the CNSOPB estimated undiscovered gas resources in the deep-water portion of the Scotian basin to range between 15 and 41 Tcf. This is the first publicly available assessment of the deepwater slope based on original geologic, geophysical and geochemical studies.

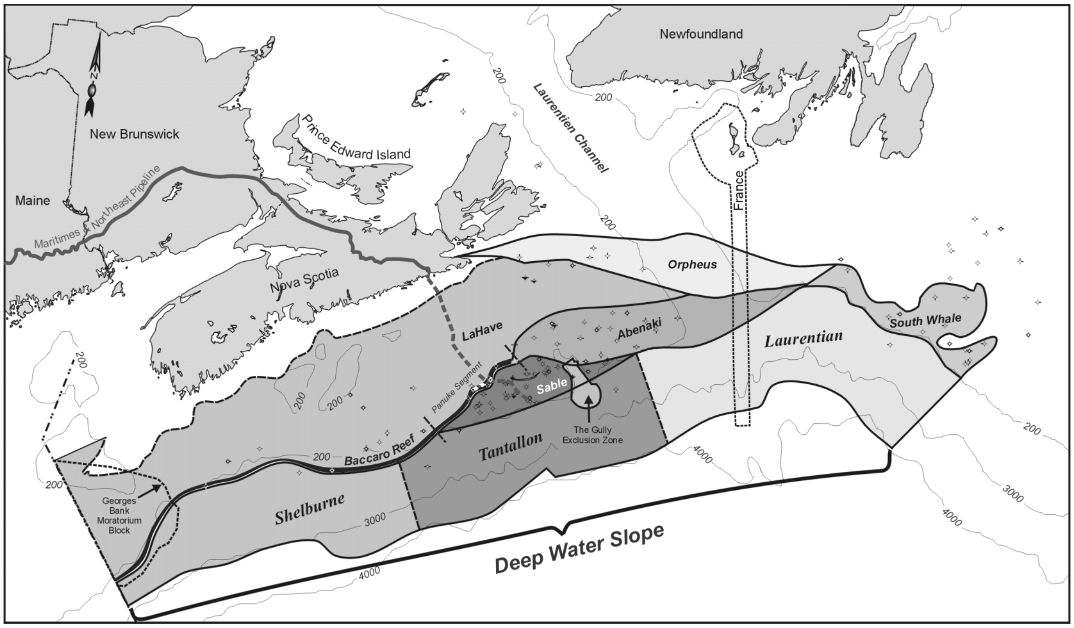
1 In the Offshore Labrador area, there have been five gas fields discovered with estimated marketable reserves of some 4.6 Tcf. By far the largest discovery offshore Labrador is the Bjarni field with over 50 percent of the discovered resources in the area.

2 In the Jeanne d'Arc Basin, the discovered fields are predominantly oil with 79 percent of the discovered gas in place either associated or solution gas. Total marketable gas is estimated at about 3.9 Tcf with the two largest accumulations at Hibernia and White Rose representing some 66 percent of the total.

3 Canadian Gas Potential Committee, 2001.

FIGURE 3.1

Nova Scotia Offshore Basins and Play Groups



3.1.1 Development of the Scotian Basin

The exploration and development of the Scotian Basin, to date, can be characterized by three cycles.

The first significant exploration cycle, from the late 1960s to the late 1970s, saw 68 wells drilled with five oil and gas discoveries in the Sable sub-basin and one oil discovery on the Baccaro Reef at Cohasset.

The second exploration cycle began in 1979, with the Venture D-23 gas discovery offshore Nova Scotia and ended in 1989. During this cycle, some 38 wells were drilled with 15 discoveries in the Sable sub-basin plus another oil discovery on the Baccaro Reef at Panuke.

The third cycle of activity began in 1990 with the Cohasset-Panuke oil field development and continued through to the development of the SOE Project. In June 1992, the Cohasset-Panuke Field produced the first commercial oil from an offshore area in Canada. In December 1999, the SOE Project produced its first gas, and M&NP received its first natural gas for delivery to market.

Since the development of the SOE Project, there have been a number of other exploration efforts in the Scotian Basin. PanCanadian, now EnCana, announced the discovery of gas at Deep Panuke in 2000.

In 2002, the Marathon Oil Company (Marathon) announced it had encountered 100 feet of net gas pay at its Annapolis deepwater wildcat well some 350 km southeast of Halifax, making this Nova Scotia's first deepwater discovery. In the same year, Chevron Canada Resources, Canadian Superior Energy Inc. (Canadian Superior), and EnCana drilled exploratory wells that were later abandoned. However, Canadian Superior did encounter a reservoir with significant hydrocarbon porosity and will likely be pursuing this play.

Sable Offshore Energy Project (SOE Project)

The SOE Project consists of six gas fields - Tier I: Thebaud, Venture and North Triumph, and Tier II: Alma, South Venture and Glenelg - located southeast of Nova Scotia near Sable Island, 10-40 km north of the edge of the Scotian shelf. The various components of the project are the Thebaud central processing platform, Venture and North Triumph satellite platforms, interfield pipelines, a pipeline to shore, the Goldboro gas processing plant, and the Point Tupper liquids fractionation plant.

Available estimates of discovered reserves in the six SOE Project fields range from 2.3 to 2.6 Tcf, down from earlier estimates of approximately 3.5 Tcf. Figure 3.2 illustrates the monthly raw gas production to date from the Tier I fields - Thebaud, Venture and North Triumph. To offset the recent decline in production, the operators have accelerated their plans to bring the Tier II fields on to production. The Alma field's development production platform is now under construction and is expected to be in production by the end of 2003. Based on the current range of estimates, the Tier II fields - Alma, South Venture and Glenelg, are expected to maintain historical production levels through approximately 2010.

Deep Panuke

EnCana's Deep Panuke natural gas field is located approximately 175 km southeast of Goldboro on the Scotian Shelf, approximately 45 km southwest of the SOE Project's Thebaud platform (Figure 3.3). Estimated reserves for Deep Panuke are approximately one Tcf with estimates of undiscovered resources for the Baccaro Reef play ranging from three to nine Tcf.

In March 2002, EnCana filed applications with the CNSOPB and the NEB to develop the Deep Panuke field. At the same time, M&NP sought approval from the NEB to expand its existing pipeline to transport up to 400 MMcf/d (422 GJ/d) of Deep Panuke natural gas, starting in 2006. In November 2002, the NEB granted a conditional approval for M&NP to construct the additional facilities required to transport the EnCana volumes.

The CNSOPB and the NEB established a joint regulatory process to review the proposed Deep

F I G U R E 3 . 2

Sable Monthly Raw Gas Production

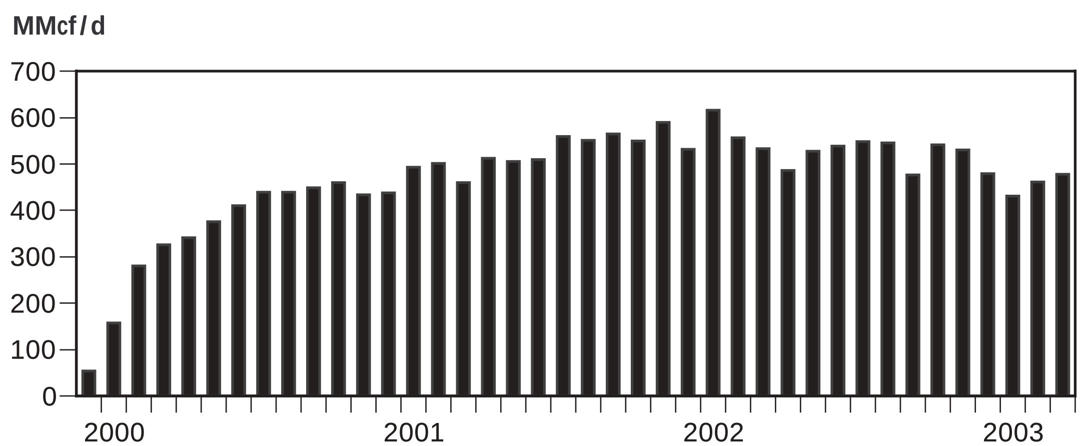
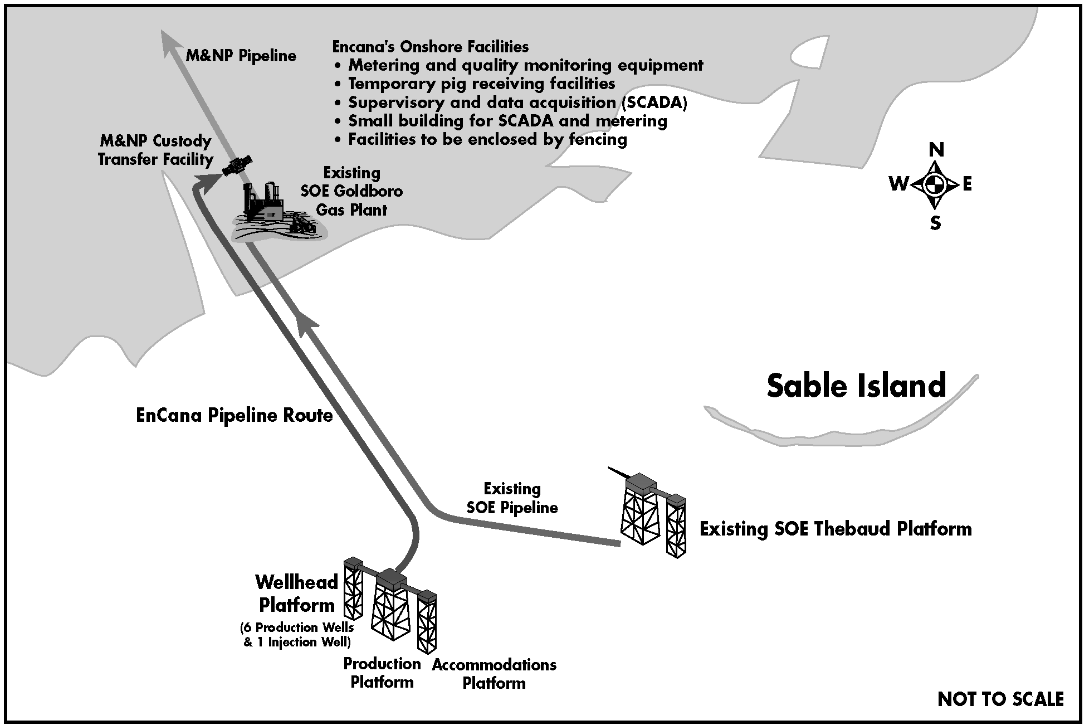


FIGURE 3.3

Proposed Deep Panuke Facilities



Panuke development (the CNSOPB Public Review and NEB proceeding GH-4-2002). The regulatory review began in January 2003 with public consultation sessions, and the oral hearing was scheduled to begin at the end of April 2003.

On 14 February 2003, EnCana asked the CNSOPB and NEB to adjourn the regulatory process, stating that it needed more time to enhance the Deep Panuke Project - time to develop an understanding of its options, including design and commercial improvements, additional drilling and evolving transportation and market opportunities. Accordingly, the CNSOPB terminated its Public Review of Deep Panuke, and the NEB adjourned the GH-4-2002 proceeding.

If EnCana is successful in developing additional reserves with its proposed shallow water drilling program for the Deep Panuke project, additional production from the Scotian Basin could be available as early as 2007 or 2008. If not successful, EnCana may look at other options to develop its Deep Panuke reserves.

3.1.2 Onshore Supply

The development of the SOE Project and the construction of the M&NP pipeline have spurred interest in exploration and development of natural gas in the Maritimes.

In New Brunswick, smaller onshore commercial accumulations have produced gas for local markets. Until 1991, natural gas was produced from the Stoney Creek field serving Hillsborough and parts of Moncton. Exploration spending in New Brunswick totalled $12 million in 2002, and two exploration wells were drilled. This year, Corridor Resources Inc. began producing 2.3 MMcf/d from its McCully discovery to serve the needs of a nearby potash mill in New Brunswick.

In Nova Scotia, there are currently 10 exploration agreements and one coal gas agreement held onshore. Four onshore wells are expected to be drilled over a period of a year. A recent "call for bids" resulted in more than $10 million in work commitments over the next two to three years for onshore Nova Scotia.

Exploration activities in Prince Edward Island have identified the existence of potential hydrocarbon reservoirs and natural gas. Prince Edward Island's hydrocarbon potential has yet to be fully assessed as only 16 exploratory wells and one re-entry well have been drilled in the region. Currently, there are over one million acres of land under permit to 11 exploration companies, which are in various stages of exploration.

3.1.3 Offshore Supply Development Activity

Canadian Superior is pursuing two shallow water Scotian Shelf prospects - Marquis and Mariner - to the northwest and northeast of Sable Island, respectively. Canadian Superior plans to drill its first well on the Mariner project in mid-2003.

Other than Deep Panuke, the next substantive increment of production is expected to come from potential deepwater discoveries. Of Nova Scotia's 57 offshore exploration licences (with some $1.5 billion in work commitments), about two thirds are in the deep-water area. Some producers believe that as many as eight to ten new exploratory wells could be drilled between 2003 and 2005.

EnCana, Imperial Oil Resources (Imperial), Shell Canada Limited (Shell), and Marathon have plans to drill deepwater prospects in the next year or so - EnCana and Imperial possibly later this year and Shell and Marathon in 2004. All of these prospects are within about 100 km of the SOE Project Thebaud platform.

Canadian Superior has plans to drill an exploratory well sometime in 2004 at its Mayflower deepwater project in the Shelburne sub-basin in the western-most portion of the Scotian Basin, approximately 200 km south of Nova Scotia and over 500 km southwest of Sable Island.

Due to differing outlooks for pricing and development costs, there is a range in the views of producers as to what makes a stand-alone deepwater project economic. Estimates range from as little as 1.5 Tcf to as much as 6 Tcf for development of a stand-alone deepwater project. Smaller discoveries, between 750 Bcf and 1.5 Tcf, could possibly be tied into existing infrastructure as long as the distance is relatively short and there is some excess capacity on the pipeline to shore. Lead time for the development of a large deepwater project is currently approximately six years.

In late 2002, Emera Energy Inc. (Emera Energy), along with Duke Energy and KeySpan Delivery Companies publicly announced they were exploring the concept of an offshore gathering system, known as the Highlander Pipeline. The Highlander Pipeline would provide transportation for proposed offshore fields that are too small, 150-200 Bcf, to warrant a separate pipeline to shore. The project is in the early stage of development and requires an anchor tenant to fund the initial sizing of the pipeline. A project the size of EnCana's Deep Panuke Project could be a likely candidate. A pipeline larger in size than required by the anchor tenant could be installed in order to provide the economies of scale to attract other shippers. The project sponsors noted that the additional 20-25 percent expense to install a large diameter pipeline could result in a doubling of the total capacity available. The proposed project would include the construction of spur lines to access other fields as they become available. Goldboro is the proposed landfall for the pipeline as the project sponsors wish to ensure that as much gas as possible would be available in the area. The project sponsors are also planning for the development of a petrochemical industry in the Strait of Canso area.

Summary

The Scotian Basin is a relatively unexplored geologic basin that has considerable potential for new discoveries and increased levels of natural gas production.

There has been much recent interest in the deeper waters of the Scotian Basin. However, gas production from a deepwater project is unlikely before 2009/2010.

Offshore exploration in a relatively unexplored geologic basin is a risky and costly endeavor. In addition to exploration risks, producers must bear a number of other risks such as price and transportation risks. Moreover, the long lead times associated with obtaining regulatory approvals for an offshore project add another element of risk in the capital investment decision making process. Producers must believe that they are operating in an attractive geologic and regulatory environment in order to undertake high risk exploration work.

3.2 Transportation

3.2.1 Transportation Infrastructure Development

Following the construction of M&NP in 1999, considerable additional work was necessary before domestic users could begin to take delivery of natural gas. Laterals had to be constructed from the mainline, distribution facilities had to be developed and end-users had to make the necessary investments to be able to receive and burn natural gas.

Due to the high capital costs required to develop pipeline infrastructure, a large volume of gas is required to justify the initial investment in a transmission pipeline (see Economies of Scale textbox). For the SOE Project and the M&NP system, the necessary market mass was provided by access to the New England market.

The high capital costs of pipeline infrastructure require large volumes of gas to justify investment.

Pipeline transmission companies must have adequate assurances that they will be able to recover their investment in pipeline facilities. Accordingly, when facilities are constructed, a transmission pipeline requires shippers to enter into long-term contracts. These contracts require shippers to pay reservation (or demand) charges on the contracted volume of gas which ensures that the pipeline will cover its fixed costs for the term of the transportation contracts. The SOE Project producers committed to backstopping the M&NP pipeline on certain revenue shortfalls if the contracted pipeline capacity drops below a certain level during the initial 20 years of operation.

To facilitate the development of the Canadian market, the SOE Project producers, M&NP, and the provinces of Nova Scotia and New Brunswick signed an agreement referred to as the *Joint Position on Tolling and Laterals* (the Joint Position). The Joint Position supported a postage stamp toll design for M&NP under which the base price charged to any delivery point off the M&NP system in Canada would be the same. Firm service tolls to delivery points located in Nova Scotia were discounted by ten percent for the initial eight years, and by four percent for another two years; and to New Brunswick delivery points by four percent for the initial three years.

A key feature of the Joint Position was that costs, up to a certain level, related to the Canadian laterals would be rolled into the mainline costs and allocated to all shippers. To determine whether laterals are economically feasible, the proposed facilities must meet a threshold test toll of $0.60/MMBtu. If the contract demand requested will generate enough revenue to cover the annual cost of service, based on the test toll, M&NP will construct the lateral without any incremental cost, or capital contribution, being required of the shippers on the lateral. The Lateral Policy, together with postage stamp tolling, results in customers at the end of a lateral paying no more for transportation than mainline customers. The test toll will remain in place until the first mainline expansion, at which time the level of the test toll will be reviewed.

Under the Lateral Policy, M&NP constructed the Point Tupper, Halifax, and Saint John laterals, a spur line to Lake Utopia, laterals to Moncton and St. George, and delivery facilities for EGNB in Fredericton.

The Joint Position also committed M&NP to build laterals to Halifax, and Saint John and to develop work plans for laterals to Cape Breton and northern New Brunswick as demand reaches an economic threshold.

In addition, the SOE producers agreed to keep 10,000 MMBtu/d of gas available for local distribution companies (LDCs) in Nova Scotia and New Brunswick for the initial three years of production.

Economies of Scale in Pipeline Transportation

All other things being equal, the amount of natural gas that can be transported in a pipeline is indirectly proportional to its diameter. Small increases in the diameter of the pipeline can yield large increases in the capacity of the pipeline to transport gas. Further, there are a number of costs that are relatively independent of the size of the pipeline, including engineering design, excavation costs, landowner compensation costs and regulatory approval costs. For these reasons, it is generally much more economic on a per unit basis to transport natural gas in large volumes.

In the example below, a 16 inch diameter pipe can deliver twice as much gas as a 12 inch diameter pipe. To meet the same structural safety requirement, however, the thickness of the larger pipe, when made from the same type of steel, will be 33% greater than the smaller pipe. More steel and more welding is required to construct the larger diameter pipe. There is, however, only a relatively small increase in the amount of excavation and width of right of way needed for the larger pipe so, overall, the increased capital cost is in the order of 25%.

Example A	Example B
Pipeline Diameter = 12”	Pipeline Diameter = 16”
Length = 130 km	Length = 130 km
Capacity = 50 MMcf/day	**Capacity = 100 MMcf/day**
Design, Survey = $3M	Design, Survey = $3M
Right of Way costs = $3M	Right of Way costs = $3.5M
Material Costs = $12.5M	Material Costs = $22M
Construction Costs = $19M	Construction Costs = $23.5M
Total Cost = $37.5M	**Total Cost = $52M**

In other words, for a 38% increase in capital costs, a doubling in capacity is achieved. Since operating costs are almost the same for the two pipelines, this translates into a much lower toll for transporting gas on the larger pipeline, allowing for a lower delivered price for the gas and higher netbacks to producers.

The principle of economies of scale applies to the construction of laterals and distribution systems, as well as to mainline transmission facilities.

3.2.2 Transportation Contracts and Utilization

M&NP has a total firm contracted load of approximately 585,500 GJ/d. This includes approximately 205,800 GJ/d of deliveries scheduled to primary delivery points in Canada. The balance, approximately 379,700 GJ/d is contracted to the St. Stephen export point (Figure 3.4). The figure depicts the role that the export market has in providing the anchor load for the M&NP system and the development of the SOE Project.

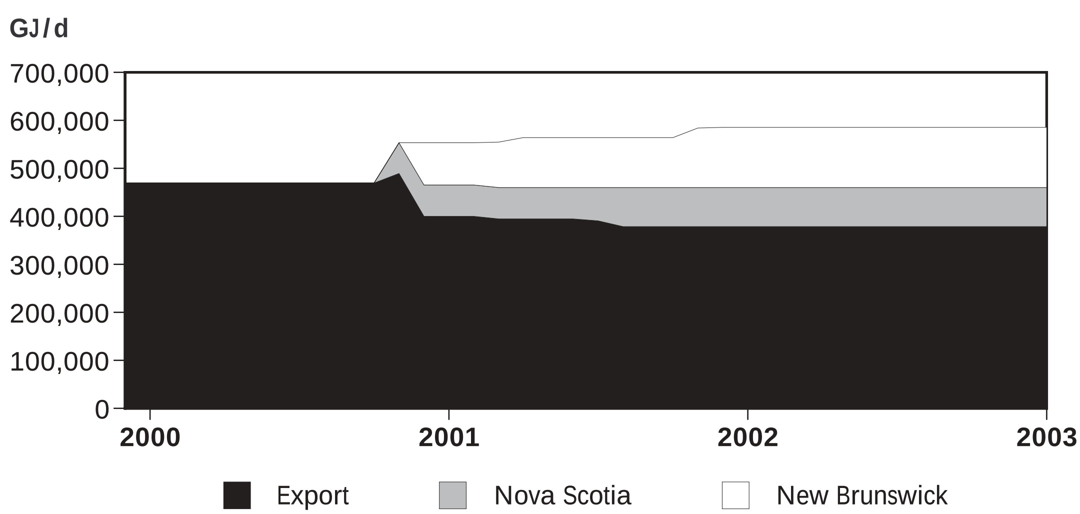
Natural gas buyers in the Maritimes normally do not use their full contracted volumes year round and, hence, actual gas flows on the M&NP system do not reflect the contractual split between domestic and export markets. From a slow start in the latter half of 2000, Canadian deliveries have increased significantly (Figure 3.5). In 2002, Canadian deliveries averaged approximately 127,000 GJ/d, or about 62 percent of Canadian shippers' firm contracted entitlement to M&NP capacity. The balance of the Canadian transportation entitlements is almost entirely used to export gas to markets in the U.S. The ability to divert gas to the U.S. has been a major factor in the development of the Maritimes market for natural gas because it has allowed Canadian users to better manage their gas supplies. The U.S. market provides an important outlet for contracted Canadian gas, without which Canadian buyers would be faced with obligations to pay for gas and transportation capacity they could not fully use. Without this ability, Canadian buyers likely could not assume the risks of contracting for natural gas on a long-term basis.

3.2.3 M&NP System Expansion

The M&NP pipeline was originally constructed without compression because sufficient pressure was available from the gas fields and processing plant. When increases in throughput are anticipated, it is more economic to initially oversize a pipeline and then add compression to increase capacity. In this way, throughput can be increased without the purchase of additional pipeline and the costs associated with construction in the pipeline right-of-way. The M&NP system can take advantage of these expansion economics and, in 2002, M&NP applied to the Board pursuant to section 58 of the Act for approval to construct four compressor stations and one meter station to expand the capacity of the pipeline by 422,000 GJ per day.

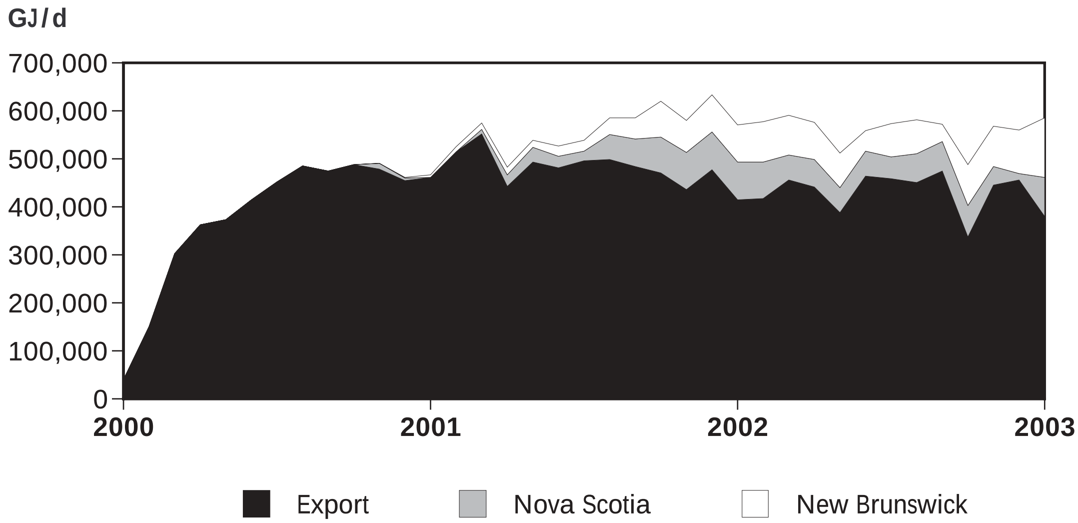
FIGURE 3.4

Firm Contract Volumes on M&NP Pipeline



F I G U R E 3 . 5

M&NP Average Monthly Throughput - January 2000 to December 2002



The purpose of the applied-for expansion was to provide transportation capacity for EnCana's Deep Panuke project. EnCana signed conditional firm service agreements (FSA) with M&NP for transportation on both the Canadian and U.S. portions of the pipeline. These agreements provide for the transportation of up to 422,000 GJ per day (400,000 MMBtu per day) of natural gas for an initial term of ten years. For the full 422,000 GJ per day expansion, the proposed addition of compression to the mainline would result in the postage stamp toll being reduced in Canada from $0.68 per GJ to approximately $0.48 per GJ. EnCana noted that the existing pipeline infrastructure and the economics of expansion are positive factors in the economics of the planned Deep Panuke project.

Given the relatively low cost of the proposed expansion and the resulting reduction in tolls, the netback at Goldboro to all producers would increase if exports to the U.S. were increased. The maximum toll discount would be achieved by transporting the entire amount of incremental production to Dracut. In contrast, supply that is contracted to a customer in Canada would not require a contract for the U.S. portion of the pipeline and, consequently, a Canadian sale would not contribute to reducing the U.S. pipeline toll. Therefore, producer netbacks would not increase as much as they would without the sale to a Canadian customer.

In November 2002, the Board granted a conditional approval of M&NP's proposed facilities expansion. In its Decision, the Board noted the need to further develop the Scotian Basin so that new supplies could become available. The Board also noted the commitments made by EnCana to proceed with regard to the needs of domestic energy users.

Summary

For the SOE Project and M&NP, the necessary market mass to make the project economic was provided by access to the New England market. The ability to divert gas to the U.S. has enabled Canadian users to manage the risk of firm commitments to gas supply and transportation. M&NP's Lateral Policy, together with postage stamp tolling, has encouraged the development of laterals to several markets in the Maritimes. The economics of expanding the M&NP mainline are favourable since throughput can be increased without the purchase of additional pipeline.

3.3 Natural Gas Pricing

Natural gas is normally sold at the wellhead to a marketing agent or to a large end-user. Since natural gas is a fungible product, it can be easily resold. Transactions that take place between producers, marketers and end-users comprise the wholesale market for natural gas. As discussed in 3.3.2, natural gas is often bought and sold many times at market hubs before it is finally consumed.

When natural gas is delivered to residential or commercial users through a local distribution utility, the delivered, or retail price, also includes a charge for distribution. In a “bundled” market model, the retail customer is charged one price by the distribution utility, in which the price of distribution is bundled together with the price of the natural gas. In an unbundled market, a third party may provide the natural gas commodity and the end-user is presented with a bill in which the charges for natural gas and distribution are clearly separated.

This section examines the determination of natural gas prices, price volatility and price transparency. In this section we refer to wholesale natural gas prices, unless otherwise specified.

3.3.1 Relationship Between Oil, Natural Gas and Electricity Prices

Natural gas competes with fuel oil and electricity. The relationship with fuel oil is better established as some large industrials can switch rapidly from one fuel to another. However, the ability to substitute one fuel for another varies across regions and industries. The benefits from substituting one fuel for another must be clear and of sufficient duration to, at a minimum, recover the initial investment. For example, homeowners may be unwilling to replace their existing furnaces just because natural gas may enjoy a price advantage over fuel oil at a point in time.

Natural gas has in the past been priced at a discount to fuel oil, due to the lower energy content per unit of volume, the need for expensive infrastructure, and the limited flexibility in using natural gas. Originally natural gas was often found as a by-product of oil exploration and, in western Canada, producers were initially willing to sell natural gas at very high discounts relative to oil. However, companies active in exploration in Offshore Nova Scotia must recover full-cycle costs of production. Hence, it is unrealistic to expect natural gas to sell at a very large discount to oil in today’s market.

Natural gas is increasingly being used for power generation and, accordingly, it may develop a closer relationship with electricity prices. Therefore, there is some expectation that gas prices may rise vis-à-vis fuel oil prices[1].

An examination of natural gas and fuel oil prices in the U.S. northeast market suggests that natural gas has been a competitive fuel choice in that market (Figure 3.6). While prices can exhibit a great degree of volatility, over time natural gas has proven to be a competitive fuel source.

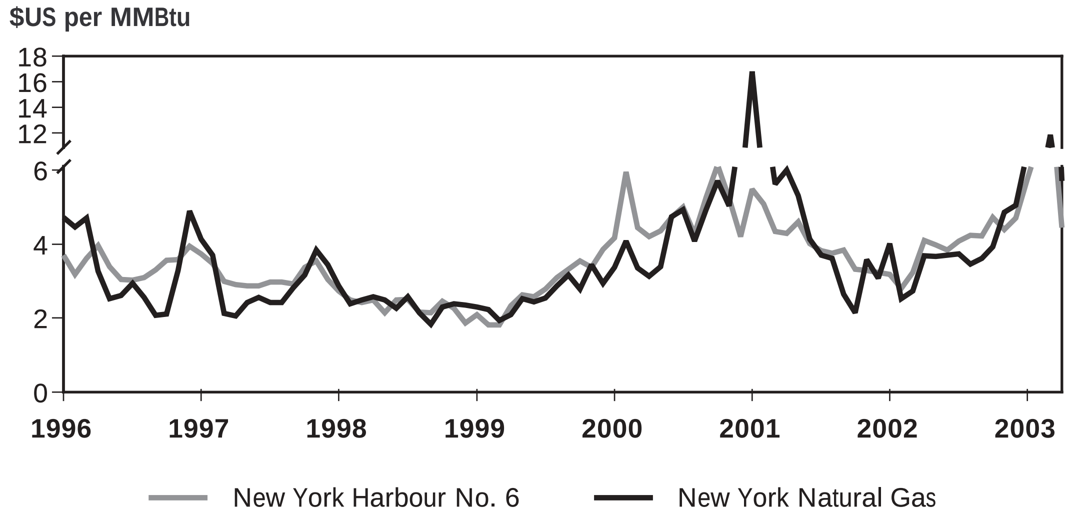
3.3.2 Natural Gas Price Volatility

Natural gas has some unique characteristics that cause its price to be more volatile than other fuels. These characteristics include a fixed amount of pipeline capacity, long lead times to develop additional supply and transportation, and weather-related demands. In Canada, the demand for

1 Since 1986, when natural gas prices were deregulated, natural gas has been sold, on average, at about a 30 percent discount to fuel oil in an energy equivalent basis. Many analysts expect natural gas to be priced at a discount, but the gap may narrow.

F I G U R E 3 . 6

Price Comparison of New York Natural Gas vs. New York Harbour No. 6 Fuel Oil



natural gas in the winter is nearly double that in the summer. This seasonality generally results in higher prices during the winter to meet winter peak requirements.

In large market centres, peak demand requirements are usually met by natural gas placed into storage facilities during periods of low demand. Storage reduces the need to construct expensive pipeline transmission capacity to meet peak requirements, improves the reliability of supply and dampens the volatility of natural gas prices. Storage is used by both buyers and sellers of natural gas for price risk management. There are, as of yet, no storage facilities developed in the Maritimes, although several parties are investigating the possibilities for developing such facilities.

Unique characteristics of natural gas cause its price to be more volatile than other commodities.

3.3.3 Price Discovery and Information

Natural gas is priced in the context of a North American market and most industry observers believe that the North American natural gas market can be considered, for the most part, as one large integrated market. There are numerous locations in Canada and the U.S. where natural gas is bought or sold, and over time many of these points have evolved into trading hubs. Typically hubs are locations where several pipelines interconnect, there is access to storage facilities, and where numerous buyers and sellers choose to transact. The level of liquidity is determined by the volume of natural gas traded, the number of transactions and the number of trading parties. Pricing points that have fewer pipeline interconnections and lack storage facilities are likely to be less liquid. Liquidity is a desirable aspect of a market as it ensures that willing buyers and sellers can easily find other parties to transact business, and it assists in providing price transparency.

Energy price information exists primarily due to the operation of secondary markets where natural gas changes title. Producers in Canada and the U.S. do not normally disclose the price or terms of their primary gas sales transactions at the wellhead or in the field as these matters are viewed to be commercially sensitive. Price disclosure generally occurs downstream of the wellhead at points such as the interconnection of pipeline systems or market hubs where supply aggregation occurs, and title to gas can change ownership. Under these conditions there are a sufficient number of buyers and sellers in the market transacting large enough volumes of natural gas so that commercial sensitivity is less of an issue. Buyers and sellers will normally disclose their prices on a confidential basis to a third party who then publishes, for example, an average daily price for gas at the hub. The reliability of these price indices is normally a function of the number of traders and the volumes traded at these points.

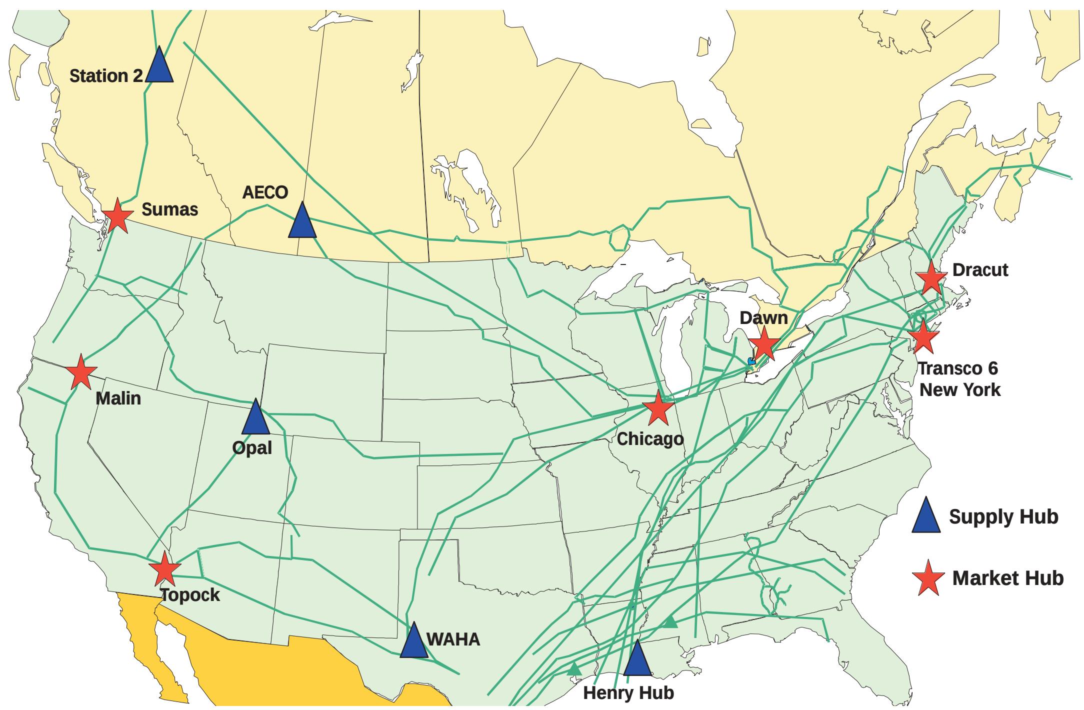
Hubs are locations where several pipelines interconnect, there is access to storage facilities, and numerous buyers and sellers choose to transact business.

Traders and marketers provide a valuable service as their activities improve liquidity and price transparency at these points. The main pricing point for natural gas sold in western Canada is at the AECO-C storage hub in Alberta. In eastern Canada the main pricing point for natural gas is at Dawn, the location of the Union Gas storage facilities in southern Ontario (Figure 3.7).

In the Maritimes, the gas pipeline, distribution and marketing infrastructure is in an early stage of development and therefore does not have a well developed secondary market. Under these conditions, there is limited opportunity for price discovery within the region. Many market transactions occur through the primary sales between producers and large industrial end-users, while transactions in the secondary market are primarily bilateral deals between parties. Moreover, the unbundling of distribution from retail sales has limited the opportunity to develop representative city-gate prices in the Maritime Provinces compared with other regions where the LDC is able to aggregate sufficient volumes of natural gas to be representative of the market price.

FIGURE 3.7

North American Natural Gas Hubs



3.3.4 Natural Gas Pricing in the Maritimes

The price of Scotian gas is based on its value in the larger U.S. northeast market at pricing points such as Dracut, Tennessee Zone 6, Boston City Gate, Transco Zone 6 (non-New York) and Tetco M3. These U.S. downstream pricing points are integrated with the rest of North America and can be correlated to prices at either the NYMEX Henry Hub in Louisiana, or AECO-C in Alberta. The pricing of natural gas in the Maritimes can therefore be expressed as the differential between pricing points in the U.S. northeast or the Henry Hub, providing an additional measure of flexibility for buyers and sellers of natural gas in the Maritimes (Figure 3.8).

The price of natural gas in the Maritimes can be correlated to other pricing points in the U.S. northeast.

Consistent with the rest of the North American markets, Maritimes natural gas supply is typically priced according to either a daily or monthly index price. Dracut, Massachusetts, the interconnection between M&NP and the Tennessee Gas Pipeline, is used as a reference point for the daily pricing of natural gas in the Maritimes as this is the first interconnection of another major pipeline system. However, the liquidity of this point is quite low and varies with Sable production levels. Pricing is based on data from Platt's Gas Daily. Dracut is no longer used for monthly-based pricing gas supply contracts because the Dracut monthly index is no longer being published.

Dracut, Massachusetts is used as a reference point for the daily pricing of natural gas in the Maritimes. However, the liquidity of this point is limited.

An issue has arisen with respect to the degree of price transparency and liquidity in the Maritimes market. Some parties note that prices and terms in the Maritimes market are not transparent because they are directly negotiated between buyers and sellers with no public disclosure. As a result, these parties claim that there is no source of readily available information on domestic gas prices and that gas buyers in the Maritimes do not have adequate information to determine what terms and conditions are available. Some parties, particularly small volume users, are concerned about the low level of liquidity in the Maritimes market, which reduces their ability to effectively manage their gas purchase and transportation commitments economically.

Producers are price-takers in the North American natural gas market.

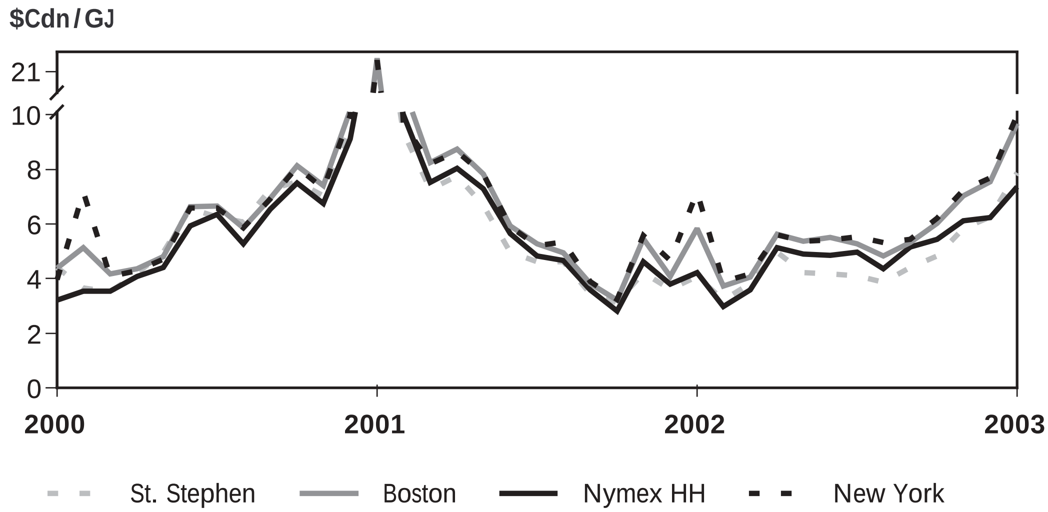
Other parties note that gas producers are price takers in the North American natural gas market and that prices in the Maritimes can be effectively priced off the Boston market at Dracut. This is similar to the method by which prices are established in smaller markets such as Manitoba, where gas is priced off the market in Alberta at the AECO-C hub. These parties also noted that prices for primary transactions are not disclosed in any North American natural gas market and that it would not be reasonable to expect Scotian Basin producers to disclose the terms and conditions of their primary sales contracts.

The SOE Project producers sell natural gas to a variety of buyers who resell the gas to secondary buyers. Thus, when there is sufficient production and available pipeline capacity, there is a small secondary market for production from Sable. Functioning within the secondary market are gas marketers who are able to assist buyers and sellers in price discovery.

Since there are no natural gas storage facilities in the Maritimes, gas delivered from the M&NP pipeline is required to balance daily load requirements of distribution companies, marketers and industrial end-users. To avoid paying pipeline imbalance penalties, daily load management (consisting of buying and selling quantities of natural gas) is required in order to keep in balance with M&NP.

FIGURE 3.8

Comparison of Scotian Offshore Natural Gas Export Prices with U.S. Pricing Points



For natural gas buyers with highly variable and uncertain load requirements, gas purchases would likely consist primarily of daily index purchases and, therefore, prices would be subject to the daily price volatility in the U.S. northeast market. For some consumers in the Maritimes, fuel switching provides another option for daily load balancing.

To reduce price volatility, natural gas buyers with more predictable load requirements may structure a portion of their portfolio to be priced on monthly or longer timeframes. However, firm gas purchases and firm transportation in excess of daily requirements would need to be sold or traded in an attempt to recover those costs.

Summary

Natural gas has traditionally been priced at a discount to fuel oil. While natural gas has been a competitive fuel source, prices can exhibit a great degree of volatility. There are numerous locations in Canada and the U.S. where natural gas is bought or sold and the North American natural gas market can be considered as one large integrated market.

The market for natural gas in the Maritimes is in an early stage of development. Opportunities for local price discovery are limited due to the size of the market. However, some price discovery is provided by pipeline connections to a number of downstream pricing points in the U.S. northeast.

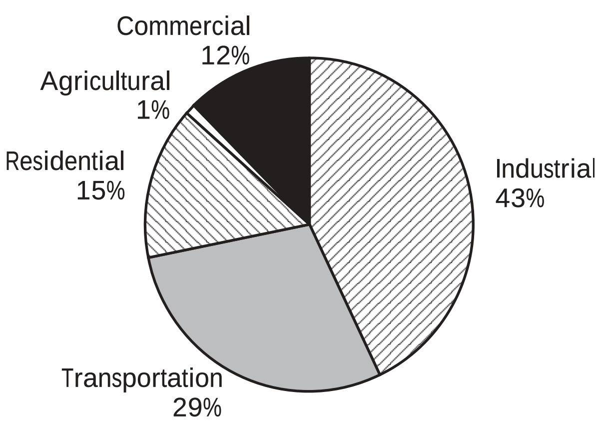
MARITIMES NATURAL GAS MARKETS

4.1 New Brunswick

4.1.1 Energy Overview

F I G U R E 4 . 1 . 1

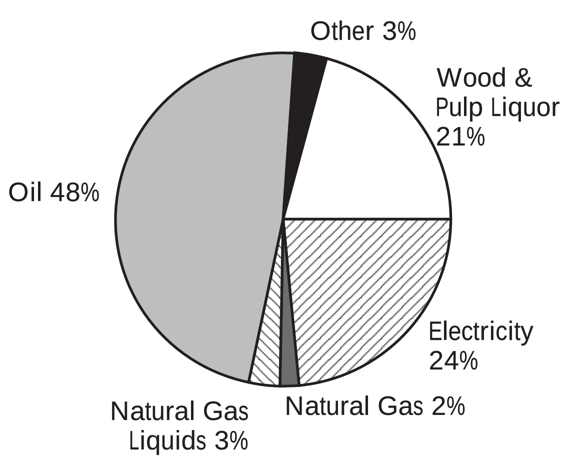
New Brunswick Energy Consumption - 2001



Total = 218.1 PJ/year

F I G U R E 4 . 1 . 2

New Brunswick End Use Fuel Shares - 2001



In New Brunswick, the industrial sector accounts for about 43 percent of total end-use energy demand, compared with only 18 percent and 12 percent in Nova Scotia and PEI respectively (Figure 4.1.1). The industrial sector is made up primarily of the pulp and paper industry, oil refining and food manufacturing.

Currently, oil and electricity are the key fuel sources in New Brunswick, accounting for over 70 percent of total end-use consumption (Figure 4.1.2). Over half of all of residences are heated by electricity, the price of which has been kept stable through the regulatory process. As in other regions of Atlantic Canada, wood and wood waste are important energy sources in rural New Brunswick for use in the residential sector and pulp and paper industry. Propane is also used in all sectors as an alternative to burning oil or wood.

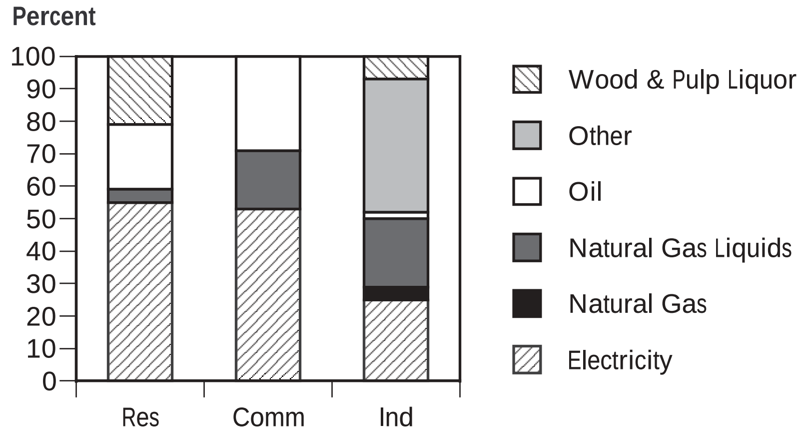
Electricity accounts for almost 25 percent of the energy mix in New Brunswick. New Brunswick Power, the provincially-owned electric power utility, currently generates about 50 percent of its electricity from oil and coal, another 25 percent from the hydro and biomass. NB Power is currently in the process of converting the Coleson Cove plant (3 units totaling 1,000 MW) to use Orimulsion®. The recent political events in Venezuela seriously impacted Orimulsion®

supply to NB Power's 300 MW Dalhousie Station in the first quarter of 2003.

While natural gas has shown appreciable penetration into the industrial sector, consumption in the residential and commercial sectors was minimal in 2002 as facilities were being constructed to provide these markets access to natural gas.

F I G U R E 4 . 1 . 3

New Brunswick Res/Comm/Ind Fuel Shares - 2001



4.1.2 Natural Gas Market

The major population centres in New Brunswick are located in the south of the province and have access to natural gas.

The major population centres in New Brunswick are located in the south of the province and already have access to natural gas from the M&NP mainline (Figure 2.1). There are currently no pipeline facilities to the northeast and northwest portions of New Brunswick. In order for these regions to be served, relatively long pipelines of approximately 190 km and 220 km would need to be constructed to these parts of the province, respectively.

In 1999, the New Brunswick Government passed the *Gas Distribution Act, 1999*, which sets out the framework for development of the natural gas industry in New Brunswick. The *Gas Distribution Act, 1999*, provides for three types of franchises: the general distribution franchise that grants the rights to distribute gas within a defined market area, subject to single end-use franchises and local producer franchises. A single end-use franchise grants the rights to a single gas user to access natural gas directly from the transmission system for its own use, but with no rights to distribute gas to other users; and a local producer franchise that grants specific rights to distribute locally-produced gas.

In 1999, Enbridge Gas New Brunswick was awarded a general distribution franchise.

In 1999, Enbridge Gas New Brunswick (EGNB) was awarded a 20-year general distribution franchise by the Province (its terms and conditions were later approved by the Board of Commissioners of Public Utilities of New Brunswick (NB PUB)) to be the sole distributor of natural gas in the Province. EGNB constructed distribution facilities to Oromocto and Fredericton in 2000 and a lateral to St. George was constructed by M&NP in 2001. Distribution facilities are currently planned to be built in the communities of St. Stephen, Sackville and Blacks Harbour by 2005. EGNB's plan is to serve 25 communities in New Brunswick. The NB PUB also awarded a local producer franchise to the Potash Company of Saskatchewan New Brunswick Division, a company that discovered a small natural gas field that is producing natural gas for its own consumption.

Prior to the enactment of the *Gas Distribution Act, 1999*, the Province awarded five single end-use franchises to large industrial users in Saint John and St. George. In Saint John, the oil refinery owned by Irving Oil, the various plants owned by J.D. Irving, and Bayside Power L.P. served as the anchor loads for the lateral to the city. Both the J.D. Irving newsprint plant and the refinery have the ability to switch fuels. When natural gas prices are high relative to fuel oil, the operators switch off natural gas, burn alternative fuels and remarket their natural gas in other markets, primarily in the United States. Since these are privately owned companies, the specifics of their natural gas consumption are not publicly available.

With respect to the rules governing the sale of natural gas, the *Gas Distribution Act, 1999*, requires that the sale of natural gas be separate from gas distribution. The sale of gas must be performed by gas marketers who are licensed by the NB PUB. Thus, EGNB has been dependent upon third party marketers to sell gas to develop the gas market. To date, there have been five gas marketers who have been licensed by the NB PUB: Irving Energy Services Limited, WPS Energy Services, Park Fuels, GasGo Energy and Enbridge Atlantic Energy Services (EAES). EAES is a wholly-owned subsidiary of Enbridge Inc. created in September 2001 that is required to operate at arms-length from EGNB.

The penetration of natural gas in the New Brunswick market has been very slow with the exception of the uptake by the large industrial users who have direct service. At the end of 2002, EGNB had approximately 1200 commercial and residential customers taking natural gas, representing less than one percent of this market in New Brunswick. As discussed above, EGNB does not serve the largest industrial loads which were granted single end-use franchises. As a result, EGNB must build up its franchise with commercial and residential gas users and smaller industrial customers.

Setting the Rules for a New Gas Distribution Franchise – The Bypass Issue

In establishing the framework for a new natural gas industry, the goals of the government are usually to create a business and regulatory environment that will facilitate the development of the industry, while being fair to all parties involved, including parties in ancillary businesses and in competitive businesses. One of the most problematic issues to be addressed are the rules around direct service to large customers that involve "bypass" of a distribution company.

On one hand, it is often more economic for a large industrial user to tap directly into a transmission pipeline and bypass the distribution company, thereby avoiding a payment for distribution services. From the point of view of developing local use of natural gas, this can be positive as it may encourage one or more large industrials to sign up for long-term natural gas service, thereby forming the necessary market to support the construction of an expensive lateral. In this way, the industrials may serve as an "anchor" that provides the basis around which gas service can eventually be extended to smaller gas users. Without the anchor market, it may be difficult to obtain financing for a lateral and gas service may not become available in a community at all.

Although direct service may benefit the industrial gas user, it prevents the distribution company from including the largest local gas users in its distribution network, and precludes it from accessing a major source of income. In the event of bypass by the major industrial users, the distributor is forced to build its business with smaller commercial and residential customers. Since the economics of serving small loads are considerably less attractive, the distribution company may face a difficult task in building its market. Consequently, some jurisdictions have in the past opted to prevent bypass and allow a distributor to cross-subsidize its distribution rates by charging more to industrial customers and somewhat less to commercial and residential customers.

An industrial gas user who opts for direct service to its plant gate avoids having to pay a distribution charge and, to that extent, may realize economic benefits. However, it should be noted that an industrial consumer who opts for bypass will likely be required to commit to paying firm reservation ("demand") charges on a long-haul transmission system. If the industrial consumer does not require the gas due to plant turnarounds, cutbacks in production, strikes, etc., it must be able to resell the transportation capacity or it will realize a loss by paying for unused transportation. Similarly, the industrial will likely have to remarket its commitments to purchase natural gas supplies. Distribution companies can provide load balancing services, storage services and transportation contract management that can relieve the industrial user of these concerns. Due to the financial commitments and operational obligations that accompany a decision to bypass, it is generally only economic for the largest industrial gas users.

Market penetration by natural gas has been hampered by competing fuels in New Brunswick. Many residential customers currently have oil furnaces, with either wood heat or electric baseboard heaters as a backup. Many homes do not have a forced air duct system and, therefore, would have to incur significant costs beyond the costs of converting a furnace to use natural gas for space heating. EGNB has been concerned that competition with electricity for residential space heating has not been entirely fair because residential electricity prices are largely sheltered from swings in the cost of fuels through the regulatory process in which electricity prices are set. In its view, the current fuel market is dominated by a very concentrated oil market and an electricity market that it regards as sending inappropriate price signals.

Market penetration by natural gas has been hampered by competing fuels in New Brunswick.

To enhance the competitiveness of natural gas, EGNB has developed distribution rates that will, when combined with the cost of natural gas supply (provided by a marketer), result in a total cost on an annual basis that will be approximately 30 percent below heating oil costs for homeowners, 15-30 percent below fuel costs in the light fuel oil market, and five percent in the heavy fuel oil market. EGNB notes that individual savings will vary depending upon the user's current energy choice, energy profile and equipment efficiency.

EGNB has developed distribution rates that result in a total delivered cost approximately 30 percent below heating oil for homeowners.

Since the wholesale price of natural gas has been higher than forecast, EGNB has had to maintain lower than forecast distribution rates to achieve the target savings for delivered natural gas prices at the burner-tip. Shortfalls between EGNB's operating costs and its revenues are accumulated and the NB PUB has allowed EGNB to amortize these losses over the 20 year term of its franchise in order to assist the company with market penetration. EGNB forecasts an expected crossover to profitability occurring in approximately 2010.

Some parties believe that development of the market has been hampered because EGNB was prohibited from directly selling natural gas. Residential customers currently have to make as many as three contacts in order to switch to natural gas; first, the customer must contact a marketer with whom he/she must establish a pricing arrangement; second he/she must make arrangements with EGNB for service; and finally the customer must make arrangements with a contractor in order to install gas burning equipment. Market penetration has also been hampered by the lack of skilled contractors to install gas-burning equipment. The lack of skilled professionals has meant that many homeowners have had lengthy waits before their gas equipment has been installed.

Some marketers have also stated that it is difficult to compete in the small volume residential and commercial market in New Brunswick. Marketers have indicated that it is difficult to arrange supply at attractive prices for small volume markets with unpredictable needs for natural gas. With small loads and limited ability to aggregate loads, there has been little willingness to make commitments to reserve capacity on M&NP. Thus, some marketers are purchasing natural gas on a daily basis for their markets. With limited daily price discovery in the Maritimes and little advance knowledge about the likely availability of spare capacity on M&NP, it is difficult to optimize a purchasing strategy. There are times when natural gas must be bid away from other users elsewhere in the Maritimes and the U.S.

... it is difficult to arrange supply at attractive prices for small end-use markets with unpredictable needs.

4.1.3 Market Developments

There is potential for increased use of natural gas in New Brunswick in the following areas:

- increased penetration of natural gas in current market areas served by EGNB;
- the potential for natural gas service to be extended into the northeast and northwest parts of the province; and
- the potential for electric power generation in areas already served by natural gas.

EGNB is currently planning to connect about 2675 new customers in 2003. This will be achieved by the construction of approximately 90 km of distribution mains in Greater Moncton, Saint John, Fredericton, Oromocto and St. Stephen.

With respect to the potential construction of pipeline facilities to northeast and northwest New Brunswick, there has been a lot of interest and support from the New Brunswick government for extension of natural gas service to these regions. The Province believes that there is a load in these areas that needs to be met, consisting of pulp and paper plants, other industrial demand including food processing, and residential demand in the local communities. There is more industrial development in the northeast portion of the province, particularly around the Belledune area. There was considerable interest expressed by Tractabel in building a large cogeneration plant at Belledune, but the project faced a number of challenges including obtaining a long-term gas supply.

One of the challenges to building extensions to the northeast and the northwest portions of the province is the economics that arise due to distance and potential natural gas demand. The economics of pipeline construction favour short hauls of large quantities of natural gas. As the distance increases, and the potential volumes decrease, the economics of construction deteriorate. M&NP has indicated that, based on preliminary estimates of construction cost and the likely volumes that would be delivered, the customers supporting construction of laterals to the northeast or northwest would be required to make a contribution in aid of construction. This would, of course, detract from the economics of burning natural gas from the point of view of the potential end-users.

Restructuring of New Brunswick Power Corporation (NB Power)

On 30 May 2002, the New Brunswick Government announced a major restructuring initiative for New Brunswick Power Corporation (NB Power). As of 1 April 2003, NB Power became a holding company with four operating companies: Generation, Nuclear, Transmission and Distribution/Customer Service. The NB PUB has been holding a public hearing into an open access tariff. Once the tariff is established, it should facilitate the construction of third party generation which will have access to the electricity transmission grid on the terms and conditions established in the tariff.

There is currently considerable uncertainty in New Brunswick's electricity market, in part due to the expected need to refurbish or close down Point Lepreau. The nuclear power plant has been operating for nearly 20 years and will soon require a major refurbishment. The costs of this refurbishment have been estimated to be in the neighbourhood of $850 million and there is some doubt as to when, or whether, it will proceed. If the plant were to be refurbished, there would be a dramatic fall in the available generating capacity when removed from service.

With or without a refurbishment of Point Lepreau, the reserve margin of generating capacity over peak power demand in New Brunswick has been falling and it is expected that there will be a need for some new generation capacity. New Brunswick Power has been having discussions with natural gas suppliers on the possibility of obtaining supplies for electric power generation. NB Power reported that the discussions were progressing in good faith.

There had been considerable interest expressed in building an extension of the M&NP pipeline to the New Brunswick-Quebec border to connect to the proposed Cartier pipeline, sponsored by Gaz Métropolitain and Co. L.P. and Enbridge Inc., which would bring Sable offshore gas to Quebec City and beyond. Gas supply for the project has not been secured and, for the time being, the project has been cancelled.

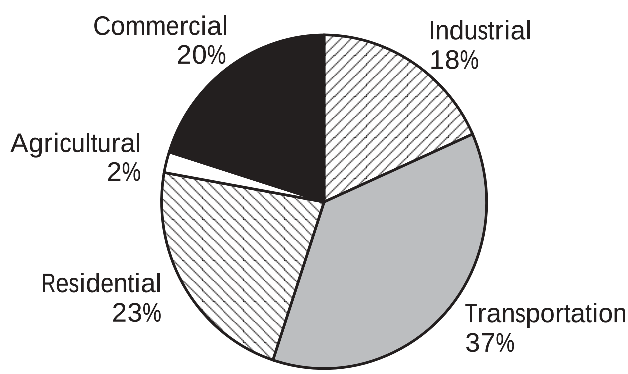
4.2 Nova Scotia

4.2.1 Energy Overview

End-use energy consumption in Nova Scotia, like much of the Atlantic region, is weighted heavily towards the use of oil products and electricity, reflecting local fuel availability and delivery systems. Overall, oil products and electricity account for about 90 percent of total end-use consumption in Nova Scotia. Wood and wood waste are also significant sources of fuel in the residential sector and in the pulp and paper industry.

FIGURE 4.2.1

Nova Scotia Energy Consumption - 2001

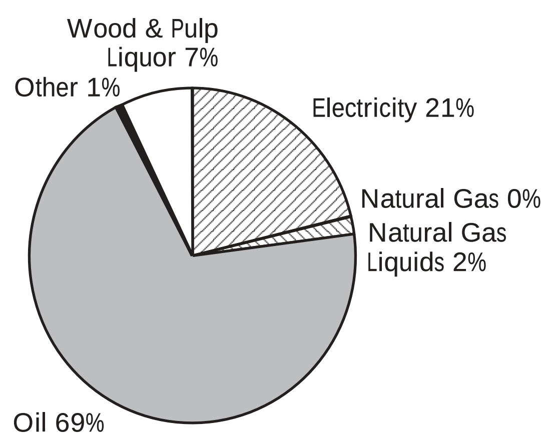


Total= 184.5 PJ/year

Although natural gas has recently become available in Nova Scotia, local delivery systems have not yet been developed to reach the residential and commercial markets. As of early 2003, natural gas consumption in Nova Scotia had been limited mostly to the power generation market, with minimal penetration into the industrial sector.

FIGURE 4.2.2

Nova Scotia End Use Fuel Shares - 2001



4.2.2 Natural Gas Market

The natural gas market in Nova Scotia is entirely composed of large volume industrial users. Up until the spring of 2003, the absence of a local distribution system in Nova Scotia has precluded access to natural gas for small volume commercial and residential customers.

Industrial Markets

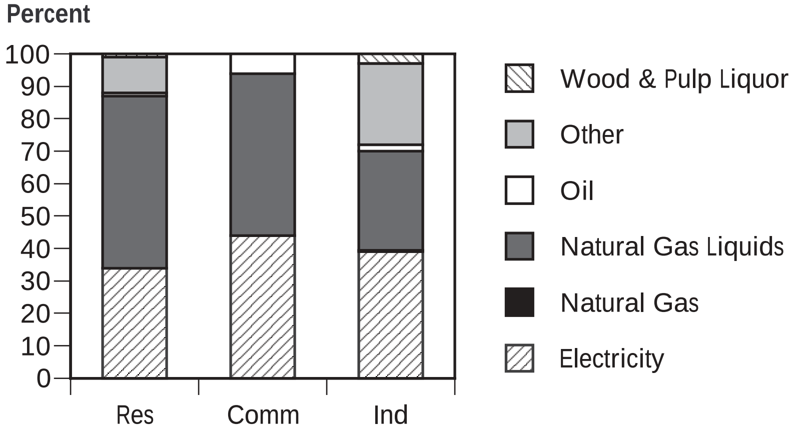
There are two major natural gas users in Nova Scotia, Stora Enso North America (Stora Enso) and Nova Scotia Power Inc. (NSPI).

The natural gas market in Nova Scotia is currently entirely composed of large volume industrial users.

Stora Enso's Port Hawkesbury Mill has been in operation since 1962 and is currently producing newsprint and supercalendered paper. The mill has the capability to use three fuels - hog fuel,

FIGURE 4.2.3

Nova Scotia Res/Comm/Ind Fuel Shares - 2001



heavy oil, and natural gas. Stora Enso has two natural gas supply contracts with matching transportation capacity on M&NP for a total of 11,000 MMBtu per day. Gas requirements for the Port Hawkesbury Mill vary on both a daily and seasonal basis, but are typically below the contracted levels of supply and transportation. Accordingly, Stora Enso sells excess natural gas in the secondary market through a marketer that resells the natural gas to both Canadian and U.S. purchasers.

Stora Enso originally planned to construct a gas-fired electricity generation facility. However, it did not proceed due to volatile natural gas prices and an unfavourable exchange rate with the U.S. dollar. Over the long-term, Stora Enso projects that its natural gas requirements will decrease.

Emera Inc. is a diversified energy and services company with three primary operating units: Nova Scotia Power Inc. (NSPI), Emera Energy, and Bangor Hydro-Electric Company. NSPI is the primary supplier and distributor of electricity in Nova Scotia. In 1998, NSPI and Shell Canada Limited signed the first contract for the use of Sable natural gas in Nova Scotia. The contract provided for a total of 61,600 MMBtu per day of natural gas for a period of ten years. The natural gas was intended for use at NSPI Tuft's Cove Power Plant in Dartmouth which became the anchor customer to enable the construction of a lateral to Halifax. NSPI invested $24 million in the project to modify Tuft's Cove's three generating units to burn either natural gas or Bunker "C" oil depending on relative fuel prices. The refitted Tuft's Cove plant became operational in late 2000 with the capacity to produce 350 MW and can burn as much as 88,000 MMBtu per day of natural gas.

NSPI strives to maximize its use of natural gas when economic, but natural gas must compete against a variety of fuels in NSPI's generation mix. After hydro production, which has no fuel cost component, coal is the utility's dominant fuel source having the lowest per unit fuel cost. Oil and natural gas are utilized next, depending on their relative pricing. In 2002, 74 percent of NSPI's electricity was produced by coal, 13 percent by natural gas, 2 percent by oil, with the remainder produced by hydro sources or purchased from independent power producers. By way of comparison, Tuft's Cove represents approximately 16 percent of NSPI's installed generation capacity.

Significant risks of long-term supply and transportation contracts require careful and skilled management.

NSPI has noted that gas prices have been extremely volatile. Without access to alternative fuels, using natural gas to generate electricity would be far riskier. NSPI notes that the significant risks of long-term supply and transportation contracts require careful and skilled management.

4.2.3 Market Developments

In November 1999, Sempra Atlantic Gas Inc. (Sempra Atlantic) was awarded a franchise to develop, build, and operate a natural gas distribution system in Nova Scotia by the Nova Scotia Utility and Review Board (UARB). The UARB also awarded four single end-use franchises to industrial users including Stora Enso, NSPI, Canadian Gypsum and the Point Tupper Fractionation Plant.

Sempra Atlantic decided to abandon its gas distribution franchise.

Sempra Atlantic began the construction of a local distribution system in 2000 but abandoned the project after only 15 kms of pipeline were constructed. By 2001, Sempra Atlantic submitted a revised plan for distribution to the UARB and indicated that it would surrender the franchise if the amendments were not approved. Overly ambitious distribution targets and the lack of approval to install distribution facilities in existing easements along road shoulders were among the reasons cited by Sempra Atlantic for seeking the revised agreement. A condition of the franchise, as set out by the UARB, was the requirement to supply natural gas to 18 counties within seven years. Ultimately Sempra Atlantic decided to abandon its gas distribution franchise.

Following Sempra Atlantic's decision to surrender its franchise, the Province of Nova Scotia implemented a process to re-examine its gas distribution requirements and the requirements were subsequently amended. Two of the key amendments were the elimination of province-wide service targets, and the move from an unbundled market structure to a hybrid model where marketers would compete with each other and the LDC in marketing natural gas supply. To protect the development of a franchise, direct access within a franchise area was prohibited for a period of ten years. However, direct access for the four existing sites, the Point Tupper Fractionation Plant, Canadian Gypsum, Stora Enso and NSPI's Tuft's Cove Generating Plant, were grandfathered. Communities not covered by a franchise would be eligible to apply for their own franchise.

The Province of Nova Scotia implemented a process to re-examine its gas distribution requirements.

In June 2002, the UARB issued a call for applications for "full regulation class" natural gas distribution franchises within the province. This class of gas franchise allows for the construction and operation of a natural gas delivery system covering multiple areas of the province for a period of 25 years. In order to be considered, applicants were required to support their application with a ten-year implementation plan for providing gas distribution service to at least four counties.

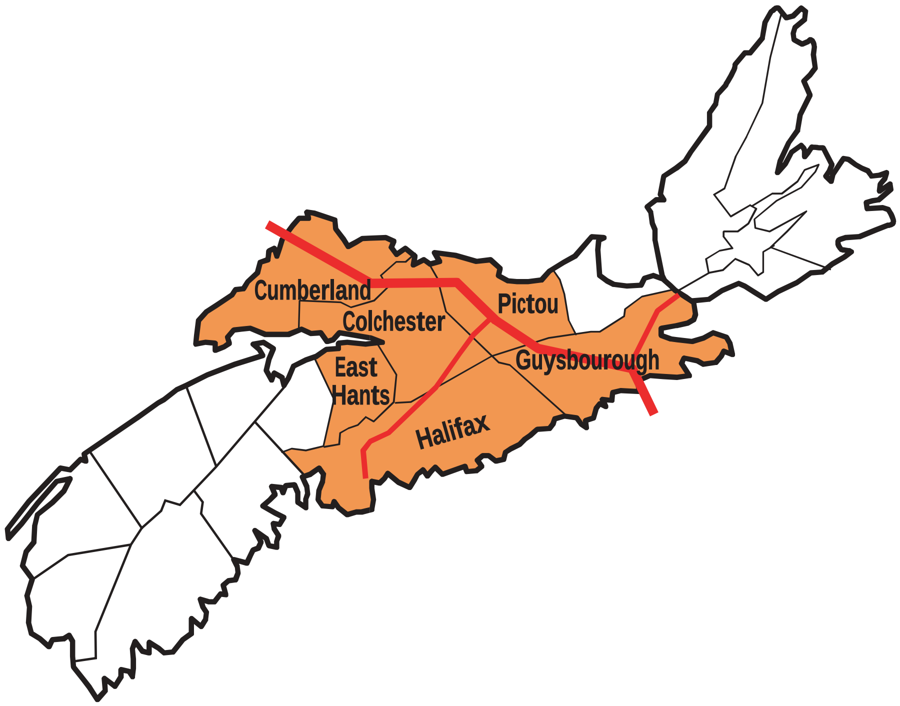
Two companies submitted their applications to the UARB for full regulation class franchises and, in February 2003, the government of Nova Scotia officially approved the UARB's decision to award a gas distribution franchise to Heritage Gas and a conditional franchise to the Strait Area Gas Corporation (Strait Area Gas).

The Province of Nova Scotia awarded a gas distribution franchise to Heritage Gas and a conditional franchise to Strait Area Gas.

Heritage Gas, an all-Canadian consortium led by SaskEnergy, AltaGas Services, and Scotia Investments, was formed for the sole purpose of distributing gas in Nova Scotia. In the first ten years, Heritage proposes to invest up to $120 million to build a system that will reach 10,000 business and residential customers in the Cumberland, Colchester, Pictou and Halifax Counties, the Municipality of the district of East Hants, and the Goldboro area of Guysborough County (Figure 4.2.4).

FIGURE 4.2.4

Heritage Gas Franchise Area



Heritage Gas plans to deliver natural gas to customers in Dartmouth and Amherst possibly in 2003. Planning, marketing and engineering work is expected to begin in all the franchise areas during the first three years of the franchise. Heritage Gas expects to extend its distribution facilities where economically warranted. This would entail the development of facilities along the existing M&NP system and in locations where new pipeline facilities become available.

Heritage Gas projects the total potential natural gas consumption for its franchise area to be approximately 37.5 million GJ per year. Within the Heritage Gas franchise area, small volume users are expected to comprise approximately 97 percent of its customers and approximately 50 percent of the total natural gas load. Commercial and institutional customers represent about three percent of its potential customers and 29 percent of consumption. Finally, industrial and power generation customers are expected to comprise less than one percent of customers but account for 21 percent of natural gas deliveries.

Heritage Gas anticipates that its initial gas supply requirements will be very modest and, therefore, will only contract for natural gas on an as-needed basis. Other than a Memorandum of Understanding (MOU) with Emera, Heritage Gas does not have any firm contractual commitments for supply. However, Heritage Gas is hopeful that the SOE producers would make 10,500 GJ/d (3.8 million GJ per year) available in Nova Scotia as per the initial SOE agreement. Heritage Gas expects that other existing marketers in the region will sell natural gas in Nova Scotia.

Because of the small customer base and the lack of storage to manage supply, Heritage Gas expects that there will be little opportunity for price hedging and that gas purchases will be subject to the daily market price volatility in the U.S. northeast. While price risk will be passed on to customers, Heritage Gas will establish a deferral account to help manage price fluctuations.

The UARB also awarded a second conditional gas distribution franchise to Strait Area Gas, a newly established local enterprise, created and jointly owned by the towns of Port Hawkesbury and Mulgrave. Their submission to the UARB included a $4.2 million gas distribution plan to bring natural gas to 350 residential and industrial customers in five years and to 1,100 more by 2025. Their customer base would be located in portions of the counties of Antigonish, Guysborough, Inverness and Richmond.

The UARB has requested further information from Strait Area Gas and has asked that the company appear at a second public hearing to provide more extensive details about its plans. In particular, more information is requested on the details of how Strait Area Gas would build and operate a natural gas distribution network, and how Strait Area Gas will distribute the commodity once the infrastructure has been put in place.

M&NP is in the conceptual phase of investigating the development of a 50 km lateral to the Hantsport/Windsor area in Nova Scotia to supply a potential gas-fired generation facility. If constructed, this lateral could provide a starting point to provide natural gas to the Annapolis Valley. As well, a short 20 km lateral has been studied to serve the Trenton/Pictou County Area to serve industrial consumers in the area. While this area has the second highest industrial energy demand in Nova Scotia, many of the industries and businesses are small and would not likely have the resources to make long-term commitments to transmission capacity and natural gas purchases. It is expected that service would be provided via a distribution system.

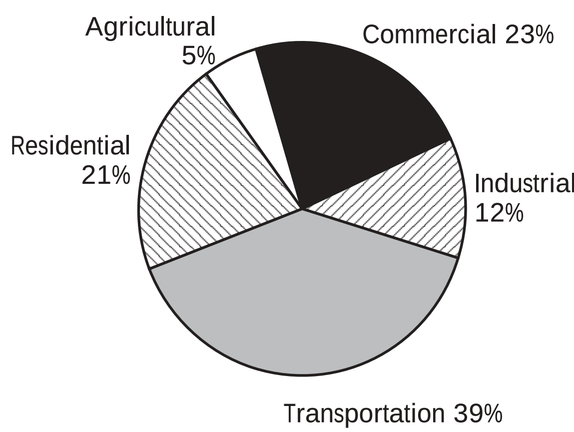
4.3 Prince Edward Island

4.3.1 Energy Overview

The introduction of Scotian offshore natural gas to the Maritimes has provided the Province of Prince Edward Island with an opportunity to diversify its energy supply requirements. With the exception of wood use in the residential sector and some propane use across all sectors, oil and electricity account for over 90 percent of the end-use energy consumed in Prince Edward Island. Electricity is supplied primarily through an interconnection to the NB Power grid by way of a sub-sea electricity transmission cable that is nearing its capacity.

FIGURE 4.3.1

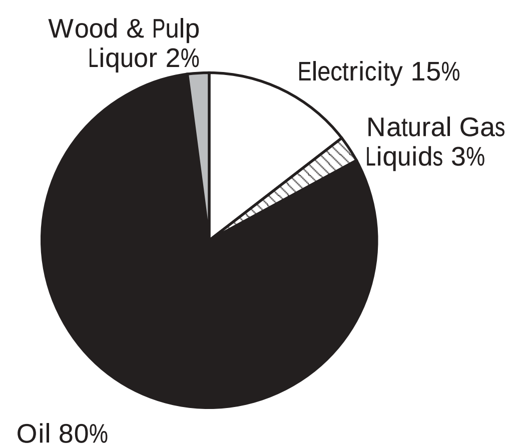
Prince Edward Island End Use Energy Consumption - 2001



Total = 23.9 PJ/year

FIGURE 4.3.2

PEI End Use Fuel Shares - 2001



4.3.2 Market Developments

In the past, Maritime Electric, the supplier and distributor of electricity on the Island, was able to purchase electricity from the mainland at reasonable prices due to the rapid construction of a number of large generation facilities that were constructed to achieve economies of scale. These large units were more efficient than the existing on-Island generation and surplus power could be purchased from the generating capacity that was available after NB Power had first used its lowest cost sources to meet requirements in New Brunswick. The pricing was attractive as it was based on NB Power's cost of production and was significantly lower than Maritime Electric's costs. However, in the last few years, higher prices available to NB Power in the U.S. northeast market have translated into an increase in the price of electricity provided to Prince Edward Island. In addition, the level of surplus generation capacity that existed in New Brunswick has eroded as in-province loads have increased while there has been no new addition to generating capacity since 1993. This has resulted in more costly sources of generation being used to supply export sales to the Island. The recent increase in the price of oil has further compounded the situation because the generation available to Maritime Electric is predominantly oil-fired.

PEI's objective is to achieve stability in electricity rates.

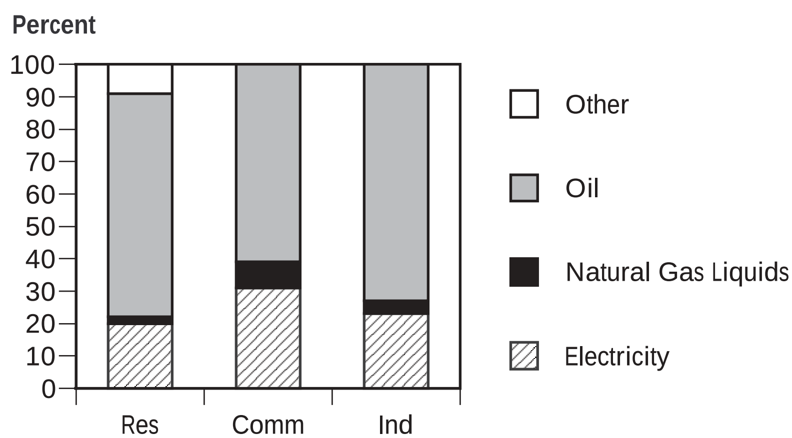
Prince Edward Island's objective is to achieve stability in electricity rates and to become less dependent on generation sources from the mainland. Load growth on the Island has increased to the point where peak loads will soon exceed the capacity of the sub-sea electricity transmission cables. Moreover, an expansion to the existing transmission cables may not provide for increased stability in electricity rates as the Island would still be dependent on sources of supply and prices on the Mainland. In this connection, the contract with NB Power for electricity supply is scheduled to expire in 2006 and there is some uncertainty about the availability of future electricity supply given the need to refurbish the Point Lepreau Nuclear Generating Station.

Unlike Nova Scotia and New Brunswick, Prince Edward Island does not possess natural resources such as coal or hydro to generate electricity. To meet its energy requirements, the Province of Prince Edward Island has developed a Natural Gas Development Plan (Development Plan). Elements of the Development Plan include an allowance for on-Island gas-fired electricity generation, gas distribution and access to natural gas for the Province's largest industrial consumers. Implementation of the Plan was originally targeted to coincide with the availability of natural gas supplies from Deep Panuke. Total natural gas requirements for the Development Plan are expected to be approximately 44,000 MMBtu per day by year three and to reach 47,700 MMBtu per day by year ten of the plan.

The key component of the plan is the development of gas-fired electricity generation facilities on the Island to provide an anchor load to support the construction of a lateral from the Mainland. The Government of Prince Edward Island, through

FIGURE 4.3.3

PEI Res/Comm/Ind Fuel Shares - 2001



the PEI Energy Corporation and its partners Maritime Electric and Emera Energy, has developed a plan to construct generation consisting of three 50 MW gas-fired turbines that would consume a total of approximately 32,000 MMBtu per day at peak capacity. An additional 40 - 50 MW of electricity would be provided through a steam generating unit operating in combined-cycle mode with the gas turbines.

The key component of the plan is the development of gas-fired electricity generation facilities on the Island.

In total, the proposed plan would provide for a total of 190 - 200 megawatts of electricity. By way of comparison, PEI's peak demand for electricity is approximately 200 MW. Maritime Electric expects that it would utilize approximately 50 percent of the proposed generation to meet on-Island requirements with the remainder to be marketed by Emera to markets in New Brunswick, Nova Scotia and the U.S. northeast. The project proponents noted that access to external markets to sell excess electricity is essential in order for the project to proceed because the PEI load is not large enough to absorb all of the project's output. Access to gas markets outside of PEI is also required to manage the risk of long-term firm commitments to gas supply and transportation.

The generation capacity of the project is larger than required to support the PEI load in order to add additional volumes of natural gas to help assist in meeting the requirements of the economic test under M&NP's Lateral Policy. However, it is expected by all parties that the economics of the proposed lateral will not fully meet the requirements of the test and an aid to construct will be required.

The Development Plan includes provision for natural gas distribution to retail end-users. To initiate gas distribution on the Island, the Province of Prince Edward Island, through the PEI Energy Corporation, will sign agreements for both gas supply and transportation. The PEI Energy Corporation has commenced preliminary design and engineering for local distribution for a number of communities including Charlottetown, Summerside, and Borden-Carleton. The plan calls for local distribution to be phased in over a ten-year period with the most economic areas being served initially, and those areas determined to be less economic to be attached at a later time. The Province plans to work with the private sector in the development of the system and to divest its interest once the distribution system has been developed.

... local distribution will be phased in ... with the most economic areas to be served first. The Province will divest its interest once the distribution system has been developed.

Negotiations for Supply

The PEI project proponents entered into discussions with a number of suppliers of natural gas. Parties stated that they were reasonably pleased with the negotiations and that they were cautiously optimistic that a deal for supply would be reached. EnCana noted that it was willing to sell Deep Panuke gas to Canadian buyers, subject to the negotiation of mutually acceptable terms and conditions. While the Deep Panuke production profile did not lend itself to supporting long-term sales, EnCana was negotiating with several Canadian buyers with a view to accommodating their interests.

At the end of January 2003, the Province of Prince Edward Island announced that the project partners had reached a deal and signed a term sheet with EnCana for the supply of natural gas. The term sheet included the basic terms and conditions for the sale of natural gas including the price, volume and duration of contract and provided the basis for a Firm Gas Sales Agreement.

The Province of Prince Edward Island announced it had reached a deal and signed a term sheet with EnCana for the supply of natural gas.

The PEI project proponents expect that EnCana's request for a postponement in the regulatory proceedings will, in the best case, result in a one year delay and estimate that gas will become available on the Island by late 2007. The project proponents note that the signed term sheet provides an assurance that they will be able to purchase natural gas when Deep Panuke begins production. In the meantime, Maritime Electric will examine options to manage the loading on the interconnection with New Brunswick. It may install an oil-fired generating unit with a plan to convert the facility once natural gas becomes available.

Negotiations for Pipeline Transmission

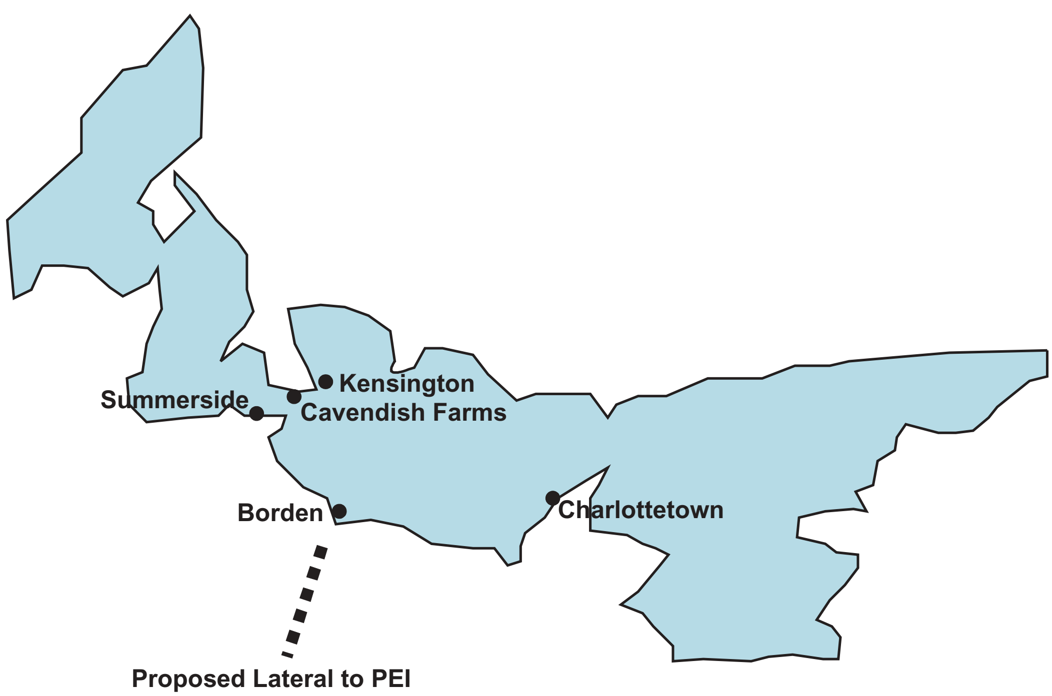
The PEI project proponents have been negotiating with M&NP concerning the construction of a lateral from the Mainline to transport natural gas to the Island. M&NP noted that it would require evidence of gas supply and a signed Firm Service Agreement for transportation before it would begin detailed engineering and costing to advance the project to the next level of development. If EnCana did proceed with its originally proposed November 2006 in-service date, a transportation contract for the PEI lateral would have been required by the end of 2003 to allow M&NP sufficient time to perform the detailed engineering, develop an application and proceed through the regulatory process. Due to the delay, all of the dates in EnCana's transportation agreement are expected to be pushed into the future by at least one year. This will provide more time for domestic purchasers to develop projects before EnCana would have to commit to firm transportation in the U.S.

The proposed lateral would cross the Northumberland Strait close to the Confederation Bridge near Borden.

The proposed lateral would extend from M&NP's main transmission line in New Brunswick across the Northumberland Strait close to the Confederation Bridge to landfall near Borden. M&NP would build pipeline facilities to Charlottetown, Borden and Summerside and one industrial delivery point to Cavendish farms (Figure 4.3.4).

FIGURE 4.3.4

Map of Prince Edward Island



At the time of writing, two sites were being considered for proposed gas-fired generation. One of the sites proposed is the Charlottetown Generating Station while the other site is located at Maritime Electric's existing Borden generating station located near the landfall of the Confederation Bridge. If the generating facility were built in Borden, this would reduce the cost of building a lateral to Prince Edward Island as the lateral extension between Borden and Charlottetown could be constructed with smaller size pipe.

To assist in a fuller understanding of the costs of construction by all parties, M&NP and a consultant for PEI worked together to review initial estimates that ranged between $75 to $85 million. Due to a number of uncertainties, including the cost of the Northumberland Strait Crossing, M&NP noted that this estimate could be lower by 15 percent or higher by as much as 40 percent. Given the degree of uncertainty that exists in the current estimates, an agreement on the costs of a lateral to PEI has not, as of yet, been reached by the parties. The PEI Energy Corporation notes that, if final estimated costs are significantly higher than the preliminary estimate of $75 to $85 million, it would render the project uneconomic.

Some concerns were expressed by the PEI project proponents regarding M&NP's estimated costs of construction. The geology of Prince Edward Island should provide for lower construction costs compared to New Brunswick and Nova Scotia. The project proponents have expressed a degree of comfort with the reliability of their engineering estimates and would consider alternatives to having M&NP construct the proposed lateral. Other concerns were expressed that, since M&NP receives a return based on the size of its rate base, there may be a lack of incentive for seeking greater efficiency in costs of construction. However, M&NP notes that it is required to demonstrate the prudency of its investments.

MARITIMES NATURAL GAS MARKET ISSUES

This chapter discusses the issues that may act as barriers to the development of the Maritimes natural gas market. This report concludes with a brief discussion of benefits to the Maritimes from the natural gas industry.

5.1 Issues facing the Development of the Maritimes Natural Gas Market

A number of parties had high expectations when the SOE Project was developed that natural gas would become widely used in the Maritimes. As discussed in the foregoing sections, natural gas has not made an appreciable penetration into the residential or commercial sectors and, with the exception of a few significant large users, is not widely used in the industrial sector either. Many factors have prevented more widespread use of natural gas from developing to date; most will also impact on the future development of the market.

A major obstacle to the increased use of natural gas is the challenge to compete against well-established fuels.

Competition from Other Fuels

As a result of discussions with natural gas users in the Maritimes, it has become clear that a major obstacle to the increased use of natural gas is the challenge to compete against well-established fuels that exist in these provinces.

In general, the Maritime Provinces have easy access to imported fuel oil available at competitive prices on the world market. Since the large increase in natural gas prices that occurred in January 2001, natural gas has been on average much more expensive than it had been throughout the 1990s, including the period during which the SOE Project was conceived and built.

In addition, Nova Scotia has traditionally used coal for electricity generation. New Brunswick possesses the Point Lepreau nuclear power reactor, which supplies one-quarter of the province's electric power needs (and 20 percent of PEI's needs) at a very low marginal cost of generation. New Brunswick also has access to hydroelectric power and considerable quantities of hog fuel. The latter is available as an inexpensive by-product of its large pulp and paper industrial production.

Prince Edward Island does not have access to hog fuel or coal, but it has had access to fuel oil at competitive prices. PEI obtains most of its electricity through an undersea cable connection with New Brunswick and, until recently, electricity has been available at reasonable prices.

At the residential level, many customers use oil or propane, which is more easily delivered across a wide geographic area without the need to construct a distribution system. Many residential users also use wood as a backup, another fuel that is widely available throughout much of New Brunswick, Nova Scotia and PEI.

Many fuels available in the Maritimes do not require an investment in infrastructure or new gas burning equipment.

In short, many fuels are available in the Maritimes that do not require an investment in pipeline infrastructure or new gas-burning equipment. Further, energy users in the Maritimes have a long tradition of using these fuels, are comfortable with them, and need to see considerable benefits in using gas before making investments to switch over. Some parties have noted that education and awareness of the benefits of natural gas will be the focus of developing a successful foundation for the development of the natural gas market in the Maritimes.

For areas that would require new pipeline facilities in order to obtain access to natural gas, such as Prince Edward Island, northeast and northwest New Brunswick, large financial commitments must be made to underpin the construction of these facilities. The need for these large up-front commitments reduces the attractiveness of natural gas relative to other fuels, including fuel oil.

Cost of Conversions - Long payback period

Costs of converting to natural gas present a hurdle to potential domestic consumers.

The cost of converting equipment and facilities to burn natural gas presents another hurdle facing domestic consumers. Industrial and commercial users generally require a maximum of a 3-year payback in terms of fuel savings in order to justify capital expenditures on gas-burning equipment. If industrial users cannot be certain of significant fuel savings, they will be reluctant to switch to natural gas.

Fuel savings from switching to natural gas arise not just through lower fuel costs, but through more efficient combustion of natural gas. Heritage Gas estimates that the average oil furnace in Nova Scotia is only approximately 60 percent efficient, while natural gas furnaces range in efficiency from about 80 percent to 90 percent (mid to high-efficiency furnaces). For residential users installing a new gas furnace in place of an oil furnace, the costs normally range from $3,000 - $3,500. This is a considerable cash outlay and consumers have to be quite certain that they will realize benefits in the longer term to make this investment. In Nova Scotia, the producer funded *Nova Scotia Gas Market Development Initiative* is available for use by the Nova Scotia government to encourage penetration of natural gas. The $20 million fund will be available to fund conversion costs for residential, commercial and industrial customers.

One possibility to also reduce conversion costs and improve payback is the use of conversion burners that typically range in cost from $500 - $1,000. However, conversion burners have lower efficiencies than a new gas-fired furnace.

Many homes in the Maritimes, particularly in New Brunswick, are heated by electricity through baseboard heaters. These homes do not have forced air or boiler systems, in which case the costs of converting to natural gas would be increased by the need to install such systems. There is little potential for full conversion to natural gas in these homes. In some cases, homeowners in New Brunswick have been opting to connect to natural gas to heat their water and to use in a gas range and outdoor barbecue. However, the natural gas usage associated with these partial conversions is quite small. Hence, the economics from the point of view of the distributor or a marketer are marginal.

Skilled Labour Shortages

Both M&NP and EGNB noted that, initially, their contractors had difficulty in finding skilled labour to construct laterals, distribution mains and downstream installations. The costs associated with finding and contracting skilled labour who can build high pressure natural gas pipelines has increased the cost of pipeline construction in the Maritimes.

Similarly, EGNB has noted that homeowners have had difficulties in finding sufficient numbers of skilled workers to provide hook-ups and install residential furnaces and appliances. While EGNB has taken steps to resolve this issue, the initial delays in obtaining equipment and in installing furnaces likely did not enhance the reputation of natural gas amongst residential users.

Distribution and Retail

There have been issues concerning the rules surrounding natural gas distribution franchises in both New Brunswick and Nova Scotia. In New Brunswick, EGNB was initially prevented from selling natural gas. This model, in which the distribution company must act as solely the transporter of natural gas to connected customers, and gas is solely sold by third-party marketers, has only recently been adopted in the State of Georgia. Other jurisdictions, such as Ontario, do not have regulations preventing the LDC from selling natural gas. Unbundled distribution models have only been adopted in areas where there was a well-developed pipeline and distribution infrastructure and natural gas was very well established as a fuel. EGNB has maintained that the restriction placed on it with respect to sales of natural gas is not appropriate for a new market and has hampered the development of the natural gas market in New Brunswick. In March of this year, the government of New Brunswick gave royal assent to an amendment to the *Gas Distribution Act*, *1999* which permits the gas distributor to sell natural gas in accordance with the terms and conditions prescribed by regulation. The legislative change effectively allows EGNB to offer a bundled service.

The Province of New Brunswick passed a legislative change to allow EGNB to offer a bundled service.

One of the difficulties that EGNB noted was that the previous model relied on marketers to develop the market for natural gas. In its view, the existing marketers also supply fuel oil and propane to end-users and therefore may not have as large an incentive to develop the market for natural gas.

Natural Gas Conversion Economics

A residential customer who switches from fuel oil to natural gas for home heating is generally banking on saving money in the long run due to the lower cost of the natural gas. The savings must be assessed against an up-front investment in a new natural gas furnace, which normally costs in the range of $3,000 - $3,500, in return for a long run saving on fuel costs.

Assuming a residential customer who switches to natural gas would save $500 per year on fuel, the customer would recoup conversion costs in 6 to 7 years.

For some residential customers, the prospect of making an up-front cash outlay will deter making the investment in a gas furnace. However, for those customers who may need to replace their oil furnace or their oil tank, the economics of conversion may improve because they would have to make cash outlays to stay on fuel oil. Further, many customers will be attracted by the additional features that natural gas can provide, such as a natural gas fireplace, outdoor barbecue, water heating, and a more effective gas range.

The actual economics facing any individual customer will depend on a number of factors. It must be noted that this example is purely illustrative of the trade-off between an up-front capital expenditure and annual fuel savings and it may not accurately represent the economics of using either fuel oil or natural gas for any specific customer or group of customers in the Maritimes.

In Nova Scotia, as discussed above, the initial distribution franchise that was awarded to Sempra Atlantic failed. Consequently, there has not been, to date, any residential or commercial use of natural gas in this province. While in hindsight it may be easy to view the targets for market development that were placed on the original franchise as overly ambitious, the situation highlights the difficulty of determining appropriate rules for a new gas distribution franchise.

Supply Issues

Success rates are typically low in a new basin; hence exploration and development in offshore Nova Scotia is high risk. Producers indicate that costs are high (10 - 25% higher than the Gulf of Mexico), seismic is difficult to interpret and lead times for development are long. High costs are due to a number of factors, including climate and oceanographic conditions, as well as poor economies of scale due to a lack of a sustained level of activity. Shallow water wells on the Scotian shelf cost from $40 to $80 million to drill while costs for deepwater wells range from $70 to $120 million. However, there is an opportunity to bring costs down in the future as activity levels increase.

Success rates are typically low in a new basin; exploration and development in offshore Nova Scotia is high risk.

Producers have expressed the need for greater regulatory efficiency. Any unnecessary delay in the regulatory approval process of a proposed project could have a significant impact on the present value economics of the project and its ability to attract capital in the ranking of investment alternatives. Another concern is the number of regulators and amount of regulation involved in developing an offshore project in Canada. Concerns were expressed that it is difficult to get the various regulatory bodies aligned and working toward a common purpose. Producers see the *Canadian Environmental Assessement Act* as problematic, especially a proposed requirement for a comprehensive study for exploratory wells. The Atlantic Energy Roundtable was held in Halifax in November 2002 to develop joint government-industry initiatives that address key challenges and opportunities related to the offshore. The Atlantic Energy Roundtable was attended by Herb Dhaliwal, Minister of Natural Resources Canada, along with other federal ministers, provincial counterparts and senior industry representatives. The discussions resulted in the creation of the Offshore Oil and Gas Issues Steering Committee that is responsible for the recommendation of improvements for offshore regulation.

In a similar vein, several producers noted the need for regulatory certainty, particularly with respect to access to markets, in order to offset risks involved in developing an offshore project. These risks include exploration, production, and price risks, as well as the risk of having to make long-term firm commitments to transportation capacity.

Producers have expressed the need for regulatory certainty with respect to market access.

Many market participants noted that, on a day to day basis, the availability and access to natural gas supply has not been a major issue. In general, the adequacy of gas supply has not been a constraint on development of the Maritimes market in areas that already have access to gas through the laterals that are in place. However, the market is still dependent on a sole supply source, the SOE Project. Lately, production has been declining and the operators have announced their plans to bring on Tier II of the project to maintain production volumes. In the interim, some gas buyers have been finding it difficult to purchase volumes of gas in the daily market due to supply constraints. In these instances, they have had to bid back gas from the Boston market, thereby incurring higher gas costs. If more supply were available, this issue would be alleviated.

In areas not served by transportation facilities, long-term access to firm natural gas supply is required to support the development of additional infrastructure. This would require either the development of a new source of supply, or the bidding back of supply from other users. Some parties noted that the recent performance of the SOE Project has been disappointing and does not send a positive signal concerning the robustness of supply. The announcement by EnCana to put the Deep Panuke project on hold also cast a certain amount of gloom over the prospects for additional supply development.

The results of drilling programs over the next few years will be critical in indicating the production potential of the basin. In the longer term, production from the Scotian offshore basin is highly dependent on the results of the exploration work commitments. Exploration drilling successes are needed to continue the development of the basin.

While all parties agree that the basin has very significant geological potential and there will be a number of wells drilled in the next two years, it is fair to say that the prospects for additional supply are uncertain at this time. In the face of this uncertainty, it will be difficult to develop any new major gas markets in the Maritimes including, for example, Prince Edward Island.

Province-Specific Issues

In addition to the above issues, there are a number of province-specific issues. In Nova Scotia, under the current regulations, distribution companies are not allowed to lay pipe in the shoulder of roads without special permission. Nova Scotia has bedrock very close to the surface which makes it expensive to excavate and lay pipe in new rights-of-way. If distribution companies could use the existing cleared areas adjacent to highways, it would result in considerable cost savings and better facilitate new construction. To develop a better understanding of the issues involved in developing local distribution systems, Heritage Gas has signed a number of MOUs with municipalities looking to obtain natural gas.

In New Brunswick, there is considerable uncertainty about the future need for incremental power generation, partly due to uncertainty about the future of the Point Lepreau nuclear power plant. This uncertainty translates into an uncertain demand for natural gas as a fuel for electric power generation. New Brunswick Power has been restructured as 1 April 2003 and the rules now allow for the construction of independent power plants. However, given the situation with Point Lepreau, the demand for new power is not clear and investment in gas-fired power generation will likely be deterred until the situation becomes clearer.

The Province of New Brunswick would like to develop pipeline transmission facilities to the northeastern and northwestern portion of the province. The challenge in building these facilities is whether these markets can be economically supplied. This would require that a sufficient amount of capacity is contracted to warrant the construction of these facilities. A capital contribution as an “aid to construct” may be required to ensure that the proposed facilities do not negatively impact existing shippers. The Province has indicated its willingness to consider an “aid to construct” to support the development of these facilities.

M&NP and many of its existing shippers expressed concern that the cost of the proposed Northwest Facilities would add significantly to the toll borne by shippers. They noted the importance of M&NP’s competitiveness and they expressed the concern that if M&NP’s tolls were higher than its competitors, this would send a negative price signal to producers and make it easier for a competitive pipeline to be developed to bypass M&NP to its anchor market in the U.S. northeast. This would have a negative impact on domestic markets as customers located along its system would not have access to these new offshore gas supplies.

M&NP suggested that the most economic laterals have already been built. The next round of laterals is targeting smaller loads, and therefore project economics will be increasingly challenging.

Prince Edward Island was expecting to have access to supplies from EnCana's Deep Panuke project, based on which there have been plans to construct a gas-fired electric power plant on the Island. EnCana has stated that it is undertaking a review of the Deep Panuke project with the objective of improving project economics. This situation is creating some difficulty for Maritime Electric's ability to plan for the future electric power needs of the Island. The company is currently considering its options, including the possibility of installing an oil-fired power generating unit that could later be converted to natural gas.

Maritime Electric must plan for the future electric power needs of the Island.

Transportation Issues

In general, domestic buyers in the Maritimes market have been able to contract for natural gas supply and transportation for their longer term needs. While some parties have suggested that some over-contracting has occurred and may be due to domestic customers trying to meet the requirements of the Lateral Policy, other parties have suggested that some over-contracting has occurred due to seasonal variations in requirements and customers targeting longer-term needs.

In order to manage long-term firm commitments to gas supply and transportation, end-users noted the importance of M&NP's flexibility in transportation delivery points and access to the export market in managing firm supply and transportation contracts. This is a key feature of the market that many participants have come to rely upon. For example, if PEI could not resell excess gas supply and transportation capacity on M&NP, it would render its proposed project uneconomic.

Domestic buyers noted the importance of flexibility and access to the export market to help manage gas supply and transportation.

However there are some other issues that give rise to concern. Small volume gas users have claimed that many aspects of the gas market in the Maritimes are not very user-friendly. It was suggested, for example, that the transportation tariff on M&NP is more suited to high volume users and not flexible enough to address the concerns of small volume users. Without storage, some end-users and marketers use the pipeline for balancing daily load requirements. Some of these parties have suggested that tolerances are small and penalties are steep. These parties claimed there was a need for the pipeline to provide a Park and Loan service. M&NP has noted that, at the onset of operations, tolerances were exceptionally broad to allow customers to develop an understanding of their operations within the M&NP tariff. Although tighter than the initial requirements, M&NP views its current balancing charges as no more onerous than other pipelines. On a related matter, some parties have suggested that M&NP does not provide sufficient information to meet all types of shipper requirements, and that tariff provisions appear to be too inflexible, particularly for the retail market. One party suggested that more information should be provided on customer activities, similar to information available from other pipeline web sites.

Natural Gas Pricing

Opportunities for local price discovery are limited due to the size of the market. However, price discovery is indirectly provided by pipeline connections to a number of downstream liquid pricing points in the U.S. northeast.

Opportunities for local price discovery in the Maritimes are limited due to the size of the market and early stage of development. However, price discovery is indirectly provided by pipeline connections to a number of downstream liquid pricing points in the U.S. northeast. Some parties suggested that, until more gas supply becomes available, price discovery may be based on limited volumes and transactions. Most parties noted that issues surrounding price transparency would improve with further development of the market.

The majority of stakeholders indicated that price discovery was not an issue as sufficient information was readily available to determine price. A minority of stakeholders did express a concern that, at times, there was not a sufficient amount of price transparency in order to understand how local prices were determined. While these parties expressed concerns about the lower level of liquidity and price transparency, the issue appears to be one of fair pricing, and not price discovery.

For example, a few parties noted that current SOE production levels are presenting a challenge for domestic pricing. Supply deliverability is expected to be tight until production levels increase with the additional production from the Alma field expected later in 2003. As a result, domestic consumers are bidding on gas that was committed to long-term transportation to the U.S. to backstop the viability of M&NP. In this case, domestic consumers are being required to reimburse the seller for transportation capacity that would otherwise be stranded on the US portion of M&NP. Accordingly, domestic purchasers looking for additional or incremental supplies of natural gas are not able to obtain a netback price and are having to pay the full Boston price including U.S. transportation charges. Concerns were also expressed that not all shippers exporting natural gas to the U.S. have firm transportation on the U.S. portion of the M&NE system and, therefore, a netback price equal to the full Boston price is not warranted.

The costs of managing supply and transportation become more significant on a per unit basis when there are smaller volumes involved. A number of parties noted that this is a significant issue in the development of a gas distribution market. In addition, it is likely that small and irregular load requirements are fully exposed to the volatility of daily spot market prices for natural gas.

5.2 Benefits

... the availability of natural gas for consumption is not the only benefit.

Local benefits are an important concern in the development of a resource industry. The availability of natural gas for consumption is a visible benefit. However, it is not the only benefit, nor is it likely to be the most significant.

The $3-billion SOE Project was the largest development of its kind in Canada and, to date, more than 10 million hours of work have been undertaken in Nova Scotia since construction began in 1998. More than 1700 Nova Scotian companies have won nearly $1.6 billion worth of contracts, representing about 54 percent of total project spending.

According to the Atlantic Provinces Economic Council, 77 percent of the region's investment in the last five years has come from offshore oil and gas projects and related investments in distribution systems and industrial facilities.

A recent survey of the Canadian Association of Petroleum Producers indicated that more than $900 million was paid to supply and service companies in the region in 2001, even though there was no major project development activity taking place. Terra Nova was in its commissioning phase; White Rose and Sable Tier II had not yet begun construction. The survey also found that more than 4,800 Atlantic Canadian companies provided goods and services to the industry between 1996 and 2001. Although many of these contracts went to companies in St John's and Halifax, a large number went to smaller communities, such as Antigonish, Yarmouth, Grand Falls and Clarenceville, and the vendor lists included more than 1000 companies from New Brunswick and Prince Edward Island.

Summary

It is clear that there are a number of market and contextual factors that have mitigated against a more rapid development of natural gas use in the Maritimes. It is challenging for natural gas to compete for market share against well-established fuels. In addition, North American natural gas prices have been higher than originally expected since the SOE Project began production. For some users, given its price versus other fuel choices and the capital investment in infrastructure required to obtain and consume gas, natural gas has not provided a large enough economic benefit to warrant switching fuels. Due to the need for large capital investments in infrastructure, natural gas is most economic when transported and used in large volumes. Not surprisingly, most gas consumption in the Maritimes has been accounted for by large industrial users, including Irving Oil, NSPI, J.D. Irving, Bayside Power L.P., and Stora Enso.

In order to avoid negative impacts on existing consumers and to ensure the competitiveness of gas supply delivered in the Maritimes, future development of the market must strike a balance between the desire for extending natural gas service to new markets and the economic viability of the associated facilities. Without the development of additional sources of gas supply, future market development will be limited.

GLOSSARY

Aggregator	A company that consolidates a number of suppliers into a group.
Alternate Delivery Point	Firm receipt or delivery point, not including primary delivery points designated in a contract, at which a firm shipper may schedule gas receipt or delivery.
Back-Stopping	Arranging for alternate supplies of gas, or payment, in the event that the primary source of gas fails to be delivered.
Balancing	Equalizing the volume of gas withdrawn from a pipeline system with the volumes of gas, or contracted amounts, injected into the pipeline. Penalties may be assessed for transportation imbalances beyond specified tolerances.
Baseload Volumes	The minimum amount of natural gas delivered or required over a given period of time at a steady rate.
Bilateral Contract	A private commercial arrangement between two parties.
Boiler Fuel	Fuels suitable for generating steam or hot water in a large industrial or electricity generation facility.
British Thermal Unit (Btu)	One Btu is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.
Broker	An individual or independent corporation engaged in bringing together sellers and buyers.
Bundled Sales Service	The sale or transportation of natural gas under one rate, which does not differentiate separate rate components for the sale, transportation, storage or gathering services associated with such sale or transportation.
Bypass	A delivery of natural gas to an end-user directly off a transmission pipeline without moving the gas through the end-users traditional local distribution company.
Capacity	The amount of natural gas that can be produced, transported, stored, distributed, or utilized in a given period of time.

City-gate	A location at which natural gas ownership passes from one party to another, neither of which is the ultimate consumer. The city-gate is the location where pipelines deliver natural gas to local distribution companies.
Cogeneration	The use of a single fuel source to generate both electricity and thermal energy.
Commercial Sector	Non-manufacturing business establishments including, hotels, motels, restaurants, wholesale businesses, retail stores, and health, social and educational institutions.
Cross-Subsidization	The practice of charging higher prices to one group of customers in order to provide lower prices for another group.
Firm Customer	A customer for who contract demand is reserved and to whom the supplier is obligated to provide service.
Firm Service	Service offered to customers under schedules or contracts that anticipate no interruptions, except for force majeure.
Force Majeure	A superior or irresistible force that excuses a failure to perform. An event that is beyond the control, and is without fault or negligence, of the party excused.
Hedging	Hedging is the process of protecting the value of an investment from the risk of loss in case the price fluctuates. Hedging is accomplished by protecting one transaction with another.
Hog Fuel	Fuel consisting of pulverized bark, shavings, sawdust, low grade lumber and lumber rejects from operations of pulp mills, sawmills and plywood mills.
Hub	A Hub is a location where large numbers of buyers and sellers trade natural gas and where gas can be physically delivered.
Industrial Sector	Manufacturing, construction, mining, agriculture, fishing and forestry establishments.
Interruptible Service	Gas service that is provided to customers which may be curtailed due to supply or system capacity limitations.
Joule	A unit of work and energy. It is defined as the work done (energy transferred) in one second by a current of one ampere at a potential difference of one volt. One watt is equal to one joule per second.
Lateral	A pipeline that branches away from the central and primary part of the system.
Liquidity	A measure of the ease with which potential buyers and sellers may transact business.

Lease	An instrument that gives a producer the right to drill for, produce, and dispose of oil and natural gas in, under and from the lands described therein.
Load	The amount of natural gas delivered or required at any specific point or points on a system.
Local Distribution Company (LDC)	An entity that owns a distribution system for the delivery of natural gas or energy to end-use customers.
Netback Price	The price per unit paid by a consumer, or received by a seller, based on the downstream market price for natural gas less the charges for delivering the natural gas to market.
Operator	The party in control of the physical operation and maintenance of a pipeline, well or other facility.
Park and Loan	The storing or borrowing of natural gas from a pipeline system, subject to the pipeline's operational requirements.
Postage Stamp Toll	A transportation rate that applies for a given zone or area (a substantial portion of the pipeline's system) rather than the distance of actual transportation.
Price Differential	The difference in gas prices between two trading points.
Price Transparency	The degree to which prices and other aspects of trades (duration, volumes, etc.) can be determined or verified at trading points.
Reserves	Natural gas in natural underground formations in wells, fields, or pools.
Residential Customers	The portion of the natural gas market consisting of private dwellings and larger residential units with individually metered apartments.
Secondary Market	The market in which shippers or marketers contract with parties other than pipelines for transportation services or delivered gas services. This market is unregulated.
Spot Market	Commodity transactions in which the transaction commencement is near term (e.g., within 10 days) and the contract duration is relatively short (e.g., 30 days).
Storage	A facility or reservoir used to accumulate natural gas during periods of low demand and used to deliver natural gas during periods of high demand.
Tariff	A published statement of rate schedules and general terms and conditions under which a service will be supplied.
Unbundled Services	The selling and pricing of energy service separately as opposed to offering services "bundled" into packages with a single price for the whole package. With unbundling, separate fees are charged for each service.

LIST OF PARTIES CONSULTED

1. Atlantic Gas Engineers
2. Atlantic Institute of Market Studies
3. Canada-Nova Scotia Offshore Petroleum Board
4. Canadian Association of Petroleum Producers
5. Duke Energy Marketing Limited Partnership
6. Emera Energy Inc.
7. Emera Inc.
8. Enbridge Atlantic Energy Services
9. Enbridge Gas New Brunswick
10. EnCana Corporation
11. GasWorks Energy Corporation
12. Heritage Gas
13. Imperial Oil Resources
14. Irving Energy Services Limited
15. J.D. Irving Limited
16. Marathon Canada Limited
17. Maritime Electric Limited
18. Maritimes and Northeast Pipeline Management Limited
19. New Brunswick Board of Commissioners of Public Utilities
20. New Brunswick Power Corporation
21. Nova Scotia Power Inc.
22. Nova Scotia Utility and Review Board
23. Prince Edward Island Energy Corporation
24. Province of New Brunswick, Department of Natural Resources and Energy
25. Province of Nova Scotia, Department of Energy
26. Quebec, Ministère des Ressources Naturelles
27. Quebec, Régie de l'Énergie
28. Shell Canada Limited
29. Stora Enso North America
30. Talisman Energy Inc.

Canada