CANADA

National Energy Board

Reasons for Decision

Mobil Oil Canada Ltd.
Unigas Corporation
Western Gas Marketing Limited

Western Gas Marketing Limited as agent for Northern Minnesota Utilities, a Division of UtiliCorp United Inc.

GH-3-91

October 1991

Volume 1
Gas Exports

National Energy Board

Reasons For Decision

In the Matter of

Amoco Canada Petroleum Company Ltd.
Canadian Occidental Petroleum Ltd.
Mobil Oil Canada Ltd.
North Canadian Marketing Inc. and East Georgia Cogeneration (Vermont) Limitd Partnership
ProGas Limited
Shell Canada Limited
Unigas Corporation
Western Gas Marketing Limited
Western Gas Marketing Limited as agent for Northern Minnesota Utilities, a Division of UtiliCorp United Inc.

Applications Pursuant to Part VI of the National Energy Board Act for Licences to Export Natural Gas

GH-3-91

October 1991
Volume I
Gas Exports

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Table of Contents

List of Tables

List of Figures

List of Appendices

Abbreviations

ACQ	Annual Contract Quantity
Act	*National Energy Board Act*
Amoco Canada	Amoco Canada Petroleum Company Ltd.
APMC	Alberta Petroleum Marketing Commission
Base Volumes	a volume of gas less than sixty percent of the MDQ
Bcf	billion cubic feet
Board or NEB	National Energy Board
Boise Cascade	Boise Cascade Corporation
CanadianOxy	Canadian Occidental Petroleum Ltd.
Centra Pipelines	Centra Pipelines Minnesota Inc.
Centra Transmission	Centra Transmission Holdings Ltd.
Coles Gilbert	Coles Gilbert Associates Ltd.
Consolidated	Consolidated Natural Gas Limited
DCQ	Daily Contract Quantity
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EARP Order	*Environmental Assessment and Review Process Guidelines Order*
EGC	East Georgia Cogeneration (Vermont) Limited Partnership
EIA	Export impact Assessment
Enron	Enron Gas Marketing, Inc.
ERCB	(Alberta) Energy Resources Conservation Board
FERC	(United States of America) Federal Energy Regulatory Commission
FMCC	Firm Market Commodity Charge

Foothills	Foothills Pipe Lines (Yukon) Limited
FS	Firm Service
Gas contract	contract for the purchase or sale of natural gas
GJ	gigajoule(s)
GLGT	Great Lakes Gas Transmission Company
IMCC	Interruptible Market Commodity Charge
Incentive Volumes	a volume of gas in excess of sixty percent of the MDQ but less than the MDQ
km	kilometre(s)
kPa	kilopascal(s)
LDCs	local distribution companies
Lockport	Lockport Energy Associates, L.P.
MDQ	Maximum Daily Quantity
Midwest Gas	Midwest Gas, A Division of Iowa Public Service Company
MiQ	Minimum Annual Quantity
MMBtu	million British thermal units
MMcf	million cubic feet
Mobil Canada	Mobil Oil Canada, Ltd.
Morgan Hydrocarbons	Morgan Hydrocarbons Ltd.
NCMI	North Canadian Marketing Inc.
NEB	National Energy Board
NMU	Northern Minnesota Utilities, a Division of UtiliCorp United Inc.
Northern Border	Northern Border Pipeline Company
Northern Natural	Northern Natural Gas Company, a Division of Enron Corp.
NOVA	NOVA Corporation of Alberta

NSPW	Northern States Power Company, a Wisconsin corporation
overrun gas	a volume of gas in excess of the MDQ to be delivered on a "best-efforts" basis
Part VI Regulations	*National Energy Board Part VI Regulations*
PJ	petajoule(s)
ProGas	ProGas Limited
RR/P	remaining reserves to production ratio
Salmon	Salmon Resources Ltd.
Shell	Shell Canada Limited
TransCanada	TransCanada PipeLines Limited
TransGas	TransGas Limited
U.S.	United States of America
Unigas	Unigas Corporation
UtiliCorp	UtiliCorp United Inc.
Vermont Gas	Vermont Gas Systems, Inc.
Viking	Viking Gas Transmission Company
WACOG	weighted average cost of gas
Western Gas	Western Gas Marketing Limited
Western Gas USA	Western Gas Marketing USA Ltd.

Recital and Appearances

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

AND IN THE MATTER OF applications by:

Amoco Canada Petroleum Company Ltd;
Canadian Occidental Petroleum Ltd;
Mobil Oil Canada, Ltd;
North Canadian Marketing Inc. and
East Georgia Cogeneration (Vermont) Limited Partnership;
Pro Gas Limited;
Shell Canada Limited;
Unigas Corporation;
Western Gas Marketing Limited; and,
Western Gas Marketing Limited, as agent for
Northern Minnesota Utilities, a Division of UtiliCorp United Inc.

for new gas export licences pursuant to section 117 of the *National Energy Board Act*;

AND IN THE MATTER OF Hearing Order AO-1-GH-3-91;

HEARD in Calgary, Alberta on 25, 26, and 27 June 1991.

BEFORE:

R. Illing	Presiding Member
W.G. Stewart	Member
C. Bélanger	Member

APPEARANCES:

F.R. Foran, Q.C.	Amoco Canada Petroleum Company Ltd.
F.M. Saville, Q.C. P.J. Webster	Canadian Occidental Petroleum Ltd.
R.J. Lane	Mobil Oil Canada, Ltd.
A.S. Hollingworth A.H. Trawick	North Canadian Marketing Inc. and East Georgia Cogeneration (Vermont) Limited Partnership
K.J. MacDonald J. Kowch	Pro Gas Limited
D.G. Davies	Shell Canada Limited
D.G. Hart, Q.C.	Unigas Corporation

M.J. Samuel	Western Gas Marketing Limited; and Western Gas Marketing Limited as agent for Northern Minnesota Utilities, a Division of UtiliCorp United Inc.
H.D. Williamson	Foothills Pipe Lines Ltd.
L.G. Keough	Northern Natural Gas Company
J.H. Smellie F. Horton	Northern States Power Company
K.L. Meyer	Pan-Alberta Gas Ltd.
W.M. Moreland	Alberta Petroleum Marketing Commission
J. Syme M. Fowke	National Energy Board

Chapter 1
Part VI - Gas Export Licence Applications

1.1 The Applications

During the GH-3-91 proceeding, the National Energy Board ("the Board") examined 12 applications for gas export licences. The applications were filed by the following companies:

1. Amoco Canada Petroleum Company Ltd. ("Amoco Canada") for export to Northern States Power Company, a Wisconsin corporation ("NSPW");

2. Canadian Occidental Petroleum Ltd. ("CanadianOxy") for export to NSPW;

3. Mobil Oil Canada, Ltd. ("Mobil Canada") for export to Northern Natural Gas Company, a Division of Enron Corp. ("Northern Natural");

4. North Canadian Marketing Inc. ("NCMI") and East Georgia Cogeneration (Vermont) Limited Partnership ("EGC") for export to EGC;

5. Pro Gas Limited ("Pro Gas") for export to Lockport Energy Associates, L.P. ("Lockport");

6. Pro Gas for export to NSPW;

7. Shell Canada Limited ("Shell") for export to Salmon Resources Ltd. ("Salmon")/Midwest Gas, A Division of Iowa Public Service Company ("Midwest Gas") and Salmon/Enron Gas Marketing, Inc. ("Enron");

8. Unigas Corporation ("Unigas") for export to Northern Natural;

9. Western Gas Marketing Limited ("Western Gas") for export to Northern Natural;

10. Western Gas for export to Northern Minnesota Utilities, a Division of UtiliCorp United Inc. ("NMU");

11. Western Gas, as agent for NMU, for export to NMU; and

12. Western Gas for export to Vermont Gas Systems, Inc. ("Vermont Gas").

Table 1-1 provides a summary of each of the export licence applications reviewed during the GH-3-91 proceeding.

Those applicants who applied for licences to commence on 1 November 1991 requested that the Board issue its decisions at as early a date as possible. Consequently, the Board has decided to publish its

GH-3-91 Reasons for Decision in two volumes.[1] This volume, Volume I, deals with the following applications:

- Mobil Canada for its sale to Northern Natural;
- Unigas for its sale to Northern Natural
- Western Gas for its sale to Northern Natural;
- Western Gas for its sale to NMU;
- Western Gas as agent for NMU; and
- Western Gas for its sale to Vermont Gas.

The remaining six applications will be included in Volume II of these Reasons, to be issued at a later date.

1.2 Market-Based Procedure

The Board, in considering an export application, must take into account section 118 of the *National Energy Board Act* ("the Act"), which requires that the Board have regard to all considerations that appear to it to be relevant and, in particular, that the Board satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. The following discussion of the Board's Market-Based Procedure is general in nature and applies to each of the export applications heard in the GH-3-91 proceeding.

The Market-Based Procedure provides that the Board consider:

- complaints, if any, under the complaints procedure;
- an export impact assessment ("EIA"); and
- any other factors that the Board considers relevant to its determination of the public interest.

[1] Notwithstanding the Board's decision to publish the GH-3-91 Reasons for Decision in two volumes, these Reasons would not have been available until after l November 1991. However, the applicants who applied for licences to commence on l November 1991 were not adversely affected by the issuance of these Reasons at a date later than l November 1991 as they were able to export the gas under short-term orders.

Table 1-1
Summary of Applied-for Licences

GH-3-91

Application		Buyer (Type of market)	Term	Export Point	Maximum Quantities Applied For: Daily 10^3m^3 (MMcf)	Annual 10^6m^3 (Bcf)	Term 10^6m^3 (Bcf)
1.	Amoco Canada	NSPW (system supply)	1 Nov. 1992 to 31 Oct. 2002	Emerson, Manitoba	424.9 (15.0)	155.1 (5.5)	1 551.0 (54.8)
2.	CanadianOxy	NSPW (system supply)	1 Nov. 1992 to 31 Oct. 2002	Emerson, Manitoba	212.5 (7.5)	77.5 (2.7)	775.5 (27.4)
3.	Mobil Canada	Northern Natural (system supply)	GIC approval to 31 Oct. 2000	Emerson, Manitoba	563.5 (20.0)	205.7 (7.3)	2 056.9 (73.0)
4.	NCMI/EGC	EGC (cogen, plant)	1 Nov. 1992 to 1 Nov. 2012	Philipsburg, Quebec	192.6 (6.8)	70.3 (2.5)	1 416.4 (50.0)
5.	ProGas	NSPW (system supply)	1 Nov. 1992 to 31 Oct. 2002	Emerson, Manitoba	212.5 (7.5)	77.5 (2.7)	775.5 (27.4)
6.	ProGas	Lockport (cogen, plant)	1 Nov. 1992 to 31 Oct. 2007	Niagara Falls, Ontario	339.9 (12.0)	124.1 (4.4)	1 861.1 (65.7)
7.	Shell (A)	Salmon/Midwest (system supply)	1 Nov. 1991 to 1 Nov. 2006	Monchy, Saskatchewan	580.7 (20.5)	212.5 (7.5)	3 181.2 (112.3)
	Shell (B)	Salmon/Enron (system supply)	1 Nov. 1991 to 1 Nov. 2001	Monchy, Saskatchewan	277.6 (9.8)	102.0 (3.6)	1 014.1 (35.8)
8.	Unigas	Northern Natural (system supply)	1 Nov. 1991 to 1 Nov. 2001	Monchy, Saskatchewan	2 820.0 (100.0)	1 030.0 (36.5)	10 300.0 (365.0)
9.	Western Gas (A)	Northern Natural (system supply)	GIC approval to 31 Oct. 2001	Emerson, Manitoba	1 345.6 (47.5)	492.9 (17.4)	product of MDQ & days in term
	Western Gas (B)	Northern Natural (system supply)	GIC approval to 31 March 1996	Emerson, Manitoba	1 416.4 (50.0)	170.0 (6.0)	849.8 (30.0)
	Western Gas (C)	Northern Natural (system supply)	GIC approval to 31 Oct. 2001	Monchy, Saskatchewan	708.2 (25.0)	260.6 (9.2)	product of MDQ & days in term
10.	Western Gas	NMU (system supply)	1 Nov. 1991 to 1 May 2001	Emerson, Manitoba	283.3 (10.0)	103.7 (3.6)	product of MDQ & days in term
11.	Western Gas for NMW	NMU (system supply)	1 Nov. 1991 to 31 Oct. 2002	Sprague, Man. & Fort Frances, Ont.	1 059.5 (37.4)	388.1 (13.7)	4 270.0 (151.0)
12.	Western Gas	Vermont Gas (system supply)	1 Nov. 1991 to 31 Oct. 2006	Philipsburg, Quebec	906.5 (32.0)	331.4 (11.7)	4 980.0 (176.0)

In its Proceeding No. GHW-1-91, dated 14 August 1991, the Board advised interested parties of proposed changes to be made to the Market-Based Procedure. These proposed changes affect the application of the Complaints Procedure and the other public interest considerations. Comments from parties were requested to be filed on 15 October 1991.

Insofar as the GHW-1-91 proceeding has not been completed, the Board relied upon the existing procedure for its assessment of the applications heard in GH-3-91.

1.2.1 Complaints Procedure

When an application for an export licence is filed with the Board, interested parties have an opportunity to examine the various elements of the proposal. It is open to Canadian users of natural gas to come forward and object to the export on the grounds that they cannot obtain additional supplies of gas under contract on terms and conditions, including price, similar to those in the export proposal.

There were no complaints made with respect to the applications for export licences in the GH-3-91 proceeding.

1.2.2 Export Impact Assessment

The purpose of the EIA is to assist the Board in determining whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. When the Market-Based Procedure was first introduced, each export applicant was required to file an EIA assessing the impact of the proposed export on domestic natural gas supply, demand, and prices, and on the ability of Canadian energy markets to adjust to these changes without difficulty.

Pursuant to a review of EIA filing requirements conducted in the fall of 1989, the Board decided that, while it would retain the EIA as part of its Market-Based Procedure, it would conduct its own non-project-specific assessment. Applicants now have the option of using the Board’s analysis or of preparing and submitting their own analysis as a basis for assessing whether the proposed exports would result in adjustment difficulties in Canadian energy markets.

The six applicants included in this volume adopted the Board’s EIA.

In this regard, the Board believes that the applied-for export volumes would have little impact on the production, consumption, and price of gas in Canada, and that Canadian energy users would not experience difficulty in meeting their future energy requirements as a result of the proposed exports. The Board is also of the view that Canadian buyers of natural gas would not have significant problems adjusting to market forces that would result from approval of these exports.

1.2.3 Other Factors Relevant to the Public Interest

In addition to using the complaints procedure and the EIA to ascertain whether gas proposed to be exported is surplus, the Board continues, as required by section 118 of the Act, to have regard to all other factors it considers relevant in determining whether a proposed export is in the public interest.

In general, these factors can be placed into two categories: a) gas supply and b) market, commercial arrangements and regulatory status. This listing of factors that the Board may regard as relevant is illustrative rather than exhaustive, but the Board relies heavily on information filed by export licence applicants in accordance with the *National Energy Board Part VI Regulations* ("Part VI Regulations"). This information is used to assess whether an export proposal is in the public interest. The onus is on the applicant to ensure that the filed material is such as to persuade the Board that the project has substance and is at a sufficiently advanced stage of completion to warrant the issuance of a licence.

1.2.3.1 Gas Supply

The Board conducts a review of the applicants' gas supply arrangements to assist it in determining whether the proposed exports are in the public interest. In its assessment of gas supply, the Board examines the contractual arrangements pertaining to supply, the adequacy of both reserves and productive capacity to support the applied-for exports, and the status of provincial removal authorizations.

The applicants provide estimates of remaining established reserves for those fields from which they intend to produce gas for the proposed export. The Board conducted geological and engineering analyses of the applicants' gas supply in order to prepare its own estimate of the applicants' marketable gas reserves.

In its evaluation of gas reserves, the Board makes use of its gas reserves database, which is maintained on an ongoing basis. The evaluation of gas reserves includes a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools and performance analysis of producing pools. A review and assessment of the ownership and contractual status of all pools included in the applications is also done.

The Board's estimate of reserves, along with basic deliverability data for each of the pools for which estimates of reserves were submitted, are used in preparing productive capacity projections. Productive capacity projections are generally adjusted to reflect an applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements shown in the productive capacity figures are based on a load factor of 100 percent and may therefore somewhat overstate the applicants' actual supply requirements. To the extent that a lower load factor was to be experienced, productive capacity would be sustained beyond the time the Board's analysis indicates.

1.2.3.2 Market, Commercial Arrangements and Regulatory Status

The Board conducts a review of the market, commercial arrangements and regulatory status underpinning projects to assist it in determining whether the proposed exports are in the public interest. The six applications dealt with herein were for sales either directly to local distribution companies ("LDCs"), or to an interstate pipeline company for resale to LDCs. The Board's review of these markets included consideration of the LDCs' or the interstate pipeline company's current and projected requirements and overall supply portfolio with a view to determining the need for and the role of the Canadian gas supply within that portfolio.

The review included consideration, among other items, of the load factors at which the proposed exports are expected to flow and the status of all pertinent regulatory authorizations in Canada and in the United States of America ("U.S.").

The Board's review of the commercial arrangements included consideration of information the applicants were required to provide in accordance with either the Part VI Regulations or in response to Board information requests issued during the course of the hearing. This information included the following:

- the status of upstream and downstream transportation arrangements including all transportation contracts, either in final form or as precedent agreements; and

- the contractual obligations entered into between the Canadian sellers and the U.S. buyers including executed gas sales contracts.

In its review of the gas sales contracts entered into between the Canadian sellers and the U.S. buyers, the Board made the following determinations:

- whether the contracts are likely to recover associated Canadian intraprovincial and interprovincial transportation costs; whether the contracts contain provisions which permit adjustments to reflect changing market conditions over the life of the contract;

- whether the contracts ensure that the volumes contracted for are likely to be taken; and

- whether the contracts have the support of the Canadian producer(s) supplying the gas to the export project.

With respect to the second of the factors listed above, that of contractual responsiveness to changing market conditions, the Board recognizes that there may be cases where contracts are attractive to the parties involved, notwithstanding a lack of flexibility. In implementing the criterion relating to contract responsiveness, the Board operates on the presumption that, where contracts are freely negotiated at arm's length, they are in the public as well as private interest.

1.3 Sunset Clauses

It has generally been Board practice in issuing a gas export licence to set an initial term of the licence for a short period of time during which, if the export of gas commences, the licence becomes effective for the full period approved by the Board. This condition in the licence is referred to as a sunset clause because the licence would expire if exports had not commenced within a specified timeframe. Inclusion of the sunset clause is intended to limit outstanding licences to those for which the gas actually flows within a reasonable period after the decision. The Board questioned each applicant concerning the acceptability of a sunset clause in the applied-for licence and in each case the applicant indicated that the inclusion of a sunset clause would be acceptable.

1.4 Environmental Screening

On 8 February 1990, the Minister of Energy, Mines and Resources, the Honourable Jake Epp, wrote to the Board requesting clarification on how the Board complied or would comply with the *Environmental Assessment and Review Process Guidelines Order* ("EARP Order") in arriving at its decision to issue licences for the export of natural gas. In his response to the Minister, the Chairman of the Board advised that, in compliance with the EARP Order, the Board would be instituting a screening procedure to examine the potential environmental effects of each export proposal before the Board.

The purpose of the environmental screening is to enable the Board to reach one of the conclusions required by section 12 of the EARP Order. To that end, the Board held a written hearing, pursuant to Hearing Order AO-1-GH-3-91, wherein it considered submissions from the applicants as well as submissions from all interested parties to GH-3-91.The applicants filed with the Board environmental information concerning the potential environmental effects of the proposal and the social effects directly related to those environmental effects, including any effects that are external to Canadian territory.

Interested parties were served with the applicants' written submissions and were provided with an opportunity to provide their written views on the issues referred to in those submissions. The applicants were then afforded an opportunity to reply to the written submissions from interested parties.

The Board has completed its environmental screenings and has concluded that, in respect of the export proposals of the applicants, the potentially adverse environmental effects and the social effects directly related thereto are insignificant or mitigable with known technology.

Chapter 2
Mobil Oil Canada, Ltd.

2.1 Application Summary

By application dated 28 February 1991, Mobil Canada, as managing partner of Mobil Oil Canada (a general partnership), sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	upon Governor in Council approval to 31 October 2000
Point of Export	-	near Emerson, Manitoba
Maximum Daily Quantity	-	564 10^3m^3 (20.0 MMcf)
Maximum Annual Quantity	-	206 10^6m^3 (7.3 Bcf)
Maximum Term Quantity	-	2 057 10^6m^3 (73.0 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas supplying the proposed export would originate from fields located in Alberta. This gas would be transported on the facilities of the NOVA Corporation of Alberta ("NOVA") for delivery to the TransCanada PipeLines Limited ("TransCanada") system near Empress, Alberta. TransCanada would forward the gas to the international border near Emerson, Manitoba. The gas would then be transported on the Great Lakes Gas Transmission Company ("GLGT") system for final delivery to Northern Natural.

The gas would be used by Northern Natural for resale to LDCs.

2.2 Gas Supply

2.2.1 Supply Contracts

No gas supply contracts were required as Mobil Canada submitted a list of its own pools from which it intends to provide the required volumes for the proposed export. The Board notes that no specific pools have been contractually dedicated to the proposed export and that the gas would be supplied from Mobil Canada's undedicated reserves. However, to demonstrate that it had adequate supply, Mobil Canada relied primarily on three pools which it identified.

2.2.2 Reserves

Mobil Canada submitted estimates of established reserves for its interests in three gas pools: Fir Triassic C, Lone Pine Creek Wabamun A and Clearwater Rundle A. A comparison of the Board's and Mobil Canada's estimates of established reserves with the applied-for volumes is shown in Table 2-1.

The Board's estimate is approximately 13 percent less than Mobil Canada's estimate, but is 34 percent greater than the applied-for term volume.

It should be noted that both the Board's and Mobil Canada's estimate of reserves includes approximately 400 10^6m^3 (14 Bcf) of anticipated production prior to the pools flowing under the proposed licence. This is largely because the Fir and Lone Pine Creek reserves are contracted to Western Gas until 1 November 1992 when Mobil Canada will have the right to decontract those pools from Western Gas. In order to make up deliverability shortfalls until the Fir and Lone Creek reserves are decontracted, Mobil Canada will rely on its other properties.

The difference between the Board's and Mobil Canada's estimates of total reserves is primarily attributable to differences in estimates of reserves for the Fir Triassic C pool. The Board's interpretation indicates that the productive area of the south lobe of the pool is not as large as Mobil Canada's estimate.

2.2.3 Productive Capacity

Figure 2-1 compares the Board's and Mobil Canada's projections of productive capacity with the applied-for annual volume. Mobil Canada stated that Northern Natural would arrange to provide gas for pipeline fuel and shrinkage requirements.

Mobil Canada's projection tracks the applied-for annual volumes and shows a shortfall in the first year of the proposed export term. The Board's projection of productive capacity, on the other hand, is adjusted to reflect production at the demand level and is thus higher overall than Mobil Canada's. The Board's projection also indicates a shortfall in the first year of the proposed export term.

Mobil Canada intends to rely on other properties to alleviate the expected shortfall in the 1991 contract year and any other deliverability shortfalls which may occur throughout the proposed export term. In this regard, Mobil Canada stated that it had available excess corporate supply of 4.0 10^9m^3 (141 Bcf) from currently producing properties and a further 21.7 10^9m^3 (766 Bcf) of established reserves from its non-producing properties in the Western Canada Sedimentary Basin.

Table 2-1
Comparison of Estimates of Mobil Canada's Established Gas Reserves
With the Applied-for Term Volume
10^6m^3 (Bcf)

Mobile Canada[1]	NEB[2]	Applied-for Volume
3 176[3]	2 756[3]	2 057
(112)	(97)	(73)

1. As of November 1990.
2. As of 31 December 1990.
3. Includes approximately 400 10^6m^3 (14Bcf) of anticipated production before the pools commence flowing under the proposed licence.

2.3 Market, Commercial Arrangements and Regulatory Status

2.3.1 Market

As Northern Natural is the market to be served in each of the applications by Mobil Canada and Unigas, and by one of the applications by Western Gas, the following section is generic to all three applications. Northern Natural is currently purchasing gas from these applicants under short-term authorizations.

Northern Natural, a subsidiary of Enron Corp., is an interstate pipeline engaged in the sale, delivery and transportation of gas. The gas proposed for export would be resold by Northern Natural to 73 client LDCs in ten states in the midwest and upper midwestern United States. The 73 LDCs serve a residential population of approximately six million. In 1990, Northern Natural's gas sales totalled 7 818 10^6m^3 (276 Bcf).

Northern Natural's sales levels have declined since 1986, when it became an open-access carrier. Since that time, markets previously served solely by Northern Natural now include third-party supplies transported on Northern Natural's system. Northern Natural's customers have indicated their desire to continue purchasing volumes, but the demand level of these customers has not yet been firmly established due to a number of variables, including:

- the impact of Northern Natural bypassing other systems, or other companies bypassing Northern Natural to reach markets;

- the exercising of Northern Natural's customers' rights to re-instate sales levels previously converted to transport service, as well as the right to further convert sales service to transport service;

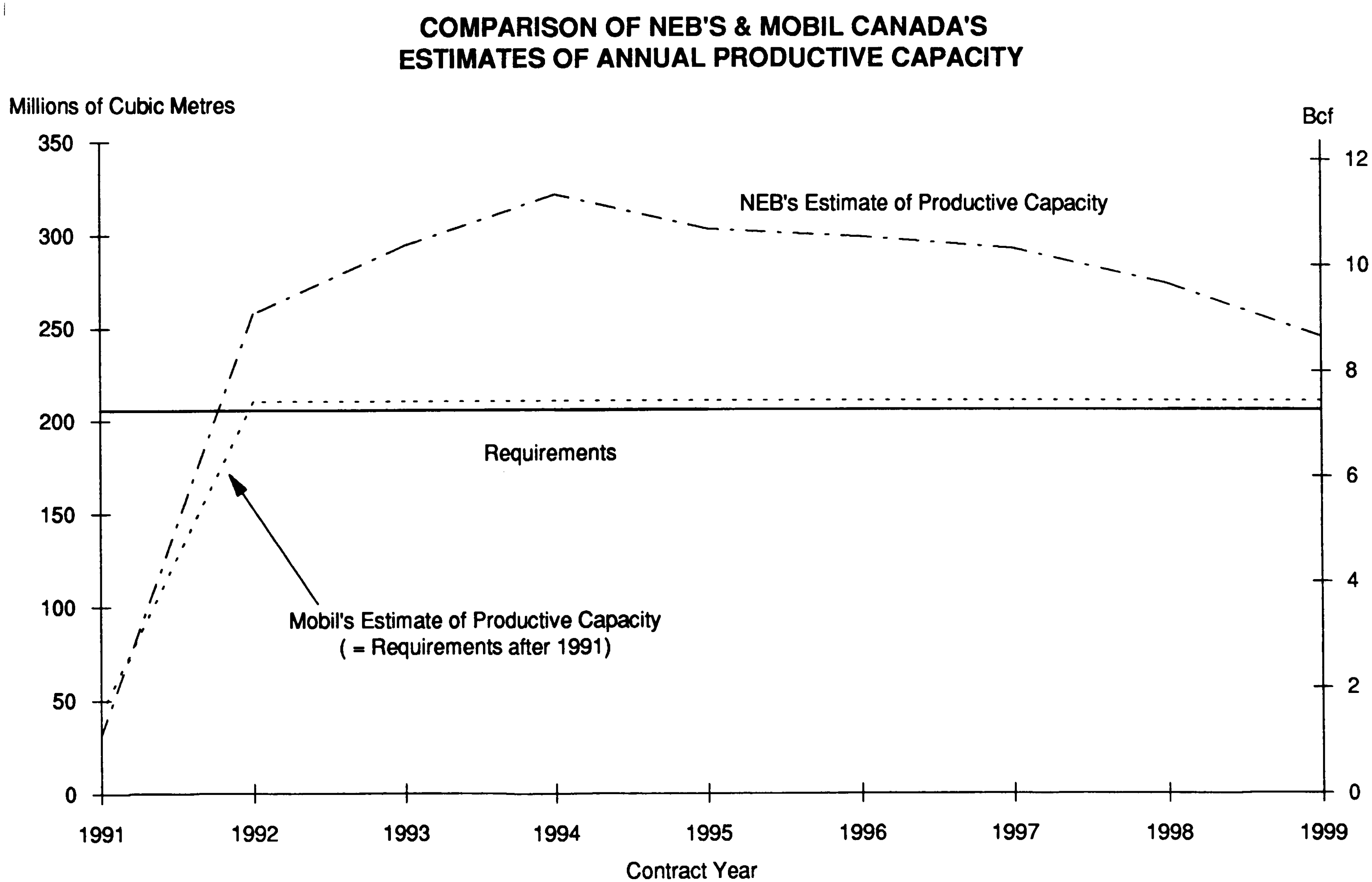
- the competing effects of market growth and increased conservation; and

- the impact of weather on Northern Natural's customers' supply choices.

To date, gas purchased by Northern Natural under Canadian contracts has flowed at a 70 percent load factor. Northern Natural views this as a reasonable projection of its future load factor. This forecast is based upon Northern Natural's requirements for the volumes; the market-sensitive nature of the pricing provisions; the minimum purchase/deficiency payment obligations contained in the supply contracts; the inclusion of incentive pricing provisions; and Northern Natural's obligation to pay transportation demand charges on upstream pipelines.

Northern Natural purchases 43 percent of its gas supply from Canadian sources, with the remainder of its supply coming from the U.S. The volumes to be supplied by Mobil Canada would represent approximately three percent of total Canadian purchases and one percent of all purchases by Northern Natural. The volumes applied for by Unigas and Western Gas would represent, respectively, approximately 15 and 18 percent of total purchases from Canadian sources and five and six percent of all purchases by Northern Natural.

FIGURE 2-1


COMPARISON OF NEB'S & MOBIL CANADA'S
ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY
Millions of Cubic Metres
Bcf
350
300
250
200
150
100
50
0
12
10
8
6
4
2
0
NEB's Estimate of Productive Capacity
Requirements
Mobil's Estimate of Productive Capacity
(= Requirements after 1991)
1991
1992
1993
1994
1995
1996
1997
1998
1999
Contract Year

Until November 1989, Northern Natural purchased 4 745 10^3m^3/d (167.5 MMcfd) of gas from Consolidated Natural Gas Limited ("Consolidated") under Licence No. GL-75, which has subsequently expired. The contracts with Mobil Canada and Unigas, and the contract with Western Gas for 1 346 10^3m^3 (47.5 MMcf) per day, effectively replace the Consolidated contract, and have enabled Northern Natural to diversify its supply portfolio as it related to those volumes. Two other contracts between Western Gas and Northern Natural, dealt with in section 4.3.3, requiring Western Gas to deliver gas at Carlton, Minnesota and at Ventura, Iowa respectively, would replace an expiring third-party storage arrangement and short-term purchases respectively.

2.3.2 Transportation

The gas proposed for export would be transported by NOVA to the interconnection with TransCanada near Empress, Alberta for delivery to GLGT near Emerson, Manitoba.

Mobil Canada presently has 86 percent of the required transportation service on NOVA in place. The remainder is for the Lone Pine South receipt station, for which NOVA anticipates service will be available 1 November 1991.

Consolidated, which holds transportation rights on the TransCanada system, has agreed to take delivery of the volumes nominated from Mobil Canada by Northern Natural near Empress, Alberta and redeliver these volumes to Mobil Canada for the account of Northern Natural at Emerson. Northern Natural would be responsible for demand charges on TransCanada.

Northern Natural has contracted for 3 400 10^3m^3/d (120.0 MMcfd) of firm service on GLGT, and currently has priority overrun rights on that system. Northern Natural has stated that, as the overrun rights diminish over the next four years, it may enter into an interruptible transportation agreement with GLGT. Northern Natural's existing firm transportation agreement with GLGT expires 31 October 1992. At the time of the hearing, Northern Natural was negotiating with GLGT for a five-year extension with an option to renew for an additional five years.

No new facilities would be required to facilitate the export.

2.3.3 Gas Sales Contract

A gas contract, dated 24 August 1990, has been entered into by Mobil Canada and Northern Natural. The primary and secondary terms of the contract total ten years, with the primary term extending to 31 October 1995. If both parties are satisfied that the terms and conditions of the contract are appropriate, then exports may continue for a second term ending 31 October 2000. The contract would continue on a year-to-year basis thereafter.

The contract provides for the daily delivery of up to 564 10^3m^3 (20.0 MMcf) of gas at the interconnection of the TransCanada and GLGT systems near Emerson, Manitoba.

The contract is subject to receipt of all necessary Canadian and U.S. regulatory approvals.

Northern Natural is obligated to pay Mobil Canada a deficiency charge equal to 25 percent of the commodity charge on the difference between a 60 percent annual load factor and actual nominations.

Further, should Northern Natural nominate less than 60 percent of the Maximum Daily Quantity ("MDQ") on an annual basis, then Mobil Canada may reduce its daily delivery obligations.

Mobil Canada also has the option to decline to make summer deliveries should the commodity charge be less than a minimum price previously set by Mobil Canada.

The price paid by Northern Natural for gas purchased from Mobil Canada would consist of a monthly reservation fee, a commodity charge and a demand charge. Any levy pursuant to the Alberta *Take-or-pay Costs Sharing Act* and/or an adjustment arising from (U.S.) Federal Energy Regulatory Commission ("FERC") Opinion 256 would be subtracted from the commodity charge. The monthly reservation fee would equal the product of 16 percent of the commodity charge and the maximum monthly volume.

The initial commodity charge would be $U.S. 1.60/GJ ($U.S. 1.72/MMBtu). Thereafter, the commodity charge would be adjusted monthly to reflect, in equal proportions, changes in spot gas purchase prices in Kansas and Oklahoma and changes in the average commodity charge of exports originating from Alberta.

Each party has a one-time opportunity in each of the primary and secondary terms of the contract to request renegotiation of the terms of the contract. Failure to reach agreement would result m the contract terminating automatically. Renegotiation may also occur at the end of the primary term.

The demand charge component of the contractual price reimburses Mobil Canada for transportation charges incurred on NOVA and TransCanada, and, if necessary, on TransGas Limited ("TransGas").

Should Northern Natural experience a significant decrease in its gas sales, then it has the right to reduce its volume obligations under this contract. This right may not be exercised by Northern Natural to displace the contracted volumes with alternative supplies.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 March 1991 was $Cdn. 1.51/GJ ($Cdn. 1.62/MMBtu).

2.3.4 Regulatory Status

Mobil Canada has applied to the Alberta Energy Resources Conservation Board ("ERCB") for a removal permit. The ERCB’s decision is pending.

Northern Natural indicated that it intended to apply for (U.S.) Department of Energy, Office of Fossil Energy ("DOE/FE") import authorization in mid-June 1991.

2.4 Views of the Board

The Board is satisfied with Mobil Canada’s gas supply position based on the specific pool information which was submitted. The Board is further assured that shortfalls in productive capacity can be made up from Mobil Canada’s corporate gas supply.

Inasmuch as Mobil Canada is relying on its own gas supply to support the export proposal, no finding of producer support was necessary.

The Board recognizes that Northern Natural has been a long-term, large volume purchaser of Canadian gas and expects this to continue in the future. The Board also notes that Mobil Canada's sales would represent approximately one percent of Northern Natural's total annual requirements and, therefore, it is unlikely that changes in the overall demand for LDCs served by Northern Natural would be borne wholly by Mobil Canada. In particular, the Board notes that the applied-for licence reflects the intentions of Mobil Canada and Northern Natural to convert a short-term export to a long-term one.

The Board notes that transportation has been arranged on all required pipelines and that the extension of transportation agreements, where necessary, is well advanced. Furthermore, the Board is satisfied that all fixed transportation costs associated with the export in Canada will be recovered.

In the Board's view, the contractual provisions regarding deficiency charges, supply reservation charges, demand charges and Mobil Canada's ability to reduce delivery obligations ensure adequate take levels under the gas sales contract.

The Board has reviewed the gas contract and has noted that it has been negotiated at arm's length.

The Board notes that DOE/FE import authorization remains outstanding but does not foresee difficulties in this regard.

2.5 Decision

The Board has decided to issue a gas export licence to Mobil Canada, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence upon Governor in Council approval and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end on 31 October 2000.

Chapter 3
Unigas Corporation

3.1 Application Summary

By application dated 11 February 1991, Unigas sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	commencing 1 November 1991 and ending 1 November 2001
Point of Export	-	near Monchy, Saskatchewan
Maximum Daily Quantity	-	2 820 10^3m^3 (100.0 MMcf)
Maximum Annual Quantity	-	1 030 10^6m^3 (36.5 Bcf)
Maximum Term Quantity	-	10 300 10^6m^3 (365.0 Bcf)
Tolerances	-	10 percent per day

The gas supplying the proposed export would originate from pools, fields and areas located in Alberta and Saskatchewan.

Transportation of the gas to be exported would be through the facilities of either NOVA or TransGas for delivery to the Foothills Pipe Lines (Yukon) Limited ("Foothills") system near MacNeil, Alberta or Crane Lake, Saskatchewan respectively. Foothills would then forward the gas to the international border near Monchy, Saskatchewan for delivery to the Northern Border Pipeline Company ("Northern Border").

The gas would be used by Northern Natural for resale to LDCs.

3.2 Gas Supply

3.2.1 Supply Contracts

Unigas has executed gas purchase contracts with Western Gas and thirteen producers, namely: Altex Resources Ltd., Blue Range Resource Corp., Cube Energy Corp., Czar Resources Ltd., Dekalb Energy Canada Ltd., Enron Oil Canada Ltd., Inverness Petroleum Ltd., Mobil Canada, Morgan Hydrocarbons Ltd. ("Morgan Hydrocarbons"), Omega Hydrocarbons Ltd., Pancontinental Oil Ltd., Ranchmen's Resources Ltd., and Renaissance Energy Ltd. The term of each contract ends on 31 October 2001.

With the exception of Western Gas, the gas purchase contract with each producer contains a firm MDQ volume covenant. If any producer fails to meet its MDQ and cannot restore it within a period of two weeks, Unigas has the right to reduce that producer's MDQ and make up those volumes from Western Gas. Also, under the provisions of the contract with Western Gas, Unigas is under a "reasonable best efforts" obligation to increase Western Gas' volume from 428 $10^3m^3/d$ (15.1 MMcfd) up to a maximum of 566 $10^3m^3/d$ (20.0 MMcfd).

Each of the producers, with the exception of Mobil Canada and Western Gas, has dedicated specific reserves to Unigas. Although Mobil Canada has identified specific pools, which will also be used to support an application for a provincial removal permit, it has retained the flexibility to supply Unigas with gas from its corporate supply pool. Likewise, Western Gas will supply Unigas with gas from its corporate supply pool. In addition, as with its other long-term contracts, Western Gas has agreed to maintain a remaining reserves to production ratio ("RR/P") of not less than ten. If Western Gas' RR/P falls below ten, it would be precluded from entering into new sales or renewing current sales.

3.2.2 Reserves

Table 3-1 shows that the Board's estimate of Unigas' contracted remaining established reserves is slightly less than Unigas' estimate, and exceeds the applied-for volume by six percent.

Unigas' contracted gas supply is comprised of reserves in Saskatchewan and Alberta. Unigas' estimates of reserves are 1 109 10^6m^3 (39 Bcf) in Saskatchewan and 10 591 10^6m^3 (374 Bcf) in Alberta. This compares to the Board's estimates of 783 10^6m^3 (28 Bcf) and 10 151 10^6m^3 (358 Bcf) for Unigas' reserves in Saskatchewan and Alberta respectively.

All of Unigas' Saskatchewan reserves are located in the Liebenthal Milk River Pool with the exception of one small Cretaceous pool in the Senlac area. Since the Liebenthal reserves are largely undeveloped, Unigas' independent consultant, Coles Gilbert Associates Ltd. ("Coles Gilbert"), included an economic hurdle in estimating established reserves for this pool. However, during the hearing, Unigas relied on the position of its producer, Morgan Hydrocarbons, that the Liebenthal reserves should be considered as proven and thus, the application of a risk factor was not necessary. Notwithstanding this, the Board concurs with Coles Gilbert that there is uncertainty associated with the development of the undrilled lands and accordingly, the Board applied a geological risk factor in its assessment of the undrilled lands because of sparse well control and a lack of production data. For these reasons, and because of differences in interpreting Milk River net pay, the Board's estimate of Saskatchewan reserves is approximately 29 percent lower than Unigas' estimate.

Table 3-1
Comparison of Estimates of Unigas' Established Gas Reserves With the Applied-for Term Volume
10^6m^3 (Bcf)

Unigas[1]	NEB[2]	Applied-for Volume
11 700	10 934	10 300
(413)	(386)	(364)

1. Estimate to 1 November 1991.
2. As of 31 December 1990. The Board's estimate of remaining reseves would be a minium of 530 10^6m^3 (19 Bcf) less than shown if further adjusted for estimated production to 1 November 1991. The Board's estimate of reserves would then be 11 percent less than Unigas' and slightly greater than the applied-for-volume.

The Board's estimate of Unigas' Alberta reserves is similar to Unigas' estimate. Differences in estimates of net pay, area and recovery factors are minor in the 210 pools that the Board recognized. Many of the pools are located in Cretaceous sands and are currently single-well pools. Nearly 80 percent of the pools are not producing and have reserves of less than 100 10^6m^3(3.5 Bcf).

In summary, the Board's estimate of total established reserves is slightly lower than Unigas' estimate. However, the Board recognizes that its estimate of reserves in Saskatchewan could potentially be revised upwards. Both the Board's and Unigas' estimates of established reserves exceed the applied-for volume.

3.2.3 Productive Capacity

Figure 3-1 compares the Board's and Unigas projections of productive capacity with the applied-for volume at a 100 percent load factor.

Unigas' projection indicates adequate productive capacity until the 1996 contract year, with increasing shortfalls thereafter. The Board's projection is similar to that of Unigas', but suggests that deficiencies in productive capacity may occur as early as mid-1994. Both projections, as shown in Figure 3-1, assumed that Western Gas' MDQ would be increased to the maximum possible level, as discussed in section 3.2.1.

If deficiencies in productive capacity were to occur, Unigas stated it could request that its producers dedicate additional lands or enter into additional gas purchase contracts with other suppliers. Unigas also stated that it could make up any temporary shortfalls in productive capacity from its own alternate supply pool and in this regard it provided a corporate supply/demand balance for its alternate supply pool.

3.3 Market, Commercial Arrangements and Regulatory Status

3.3.1 Market

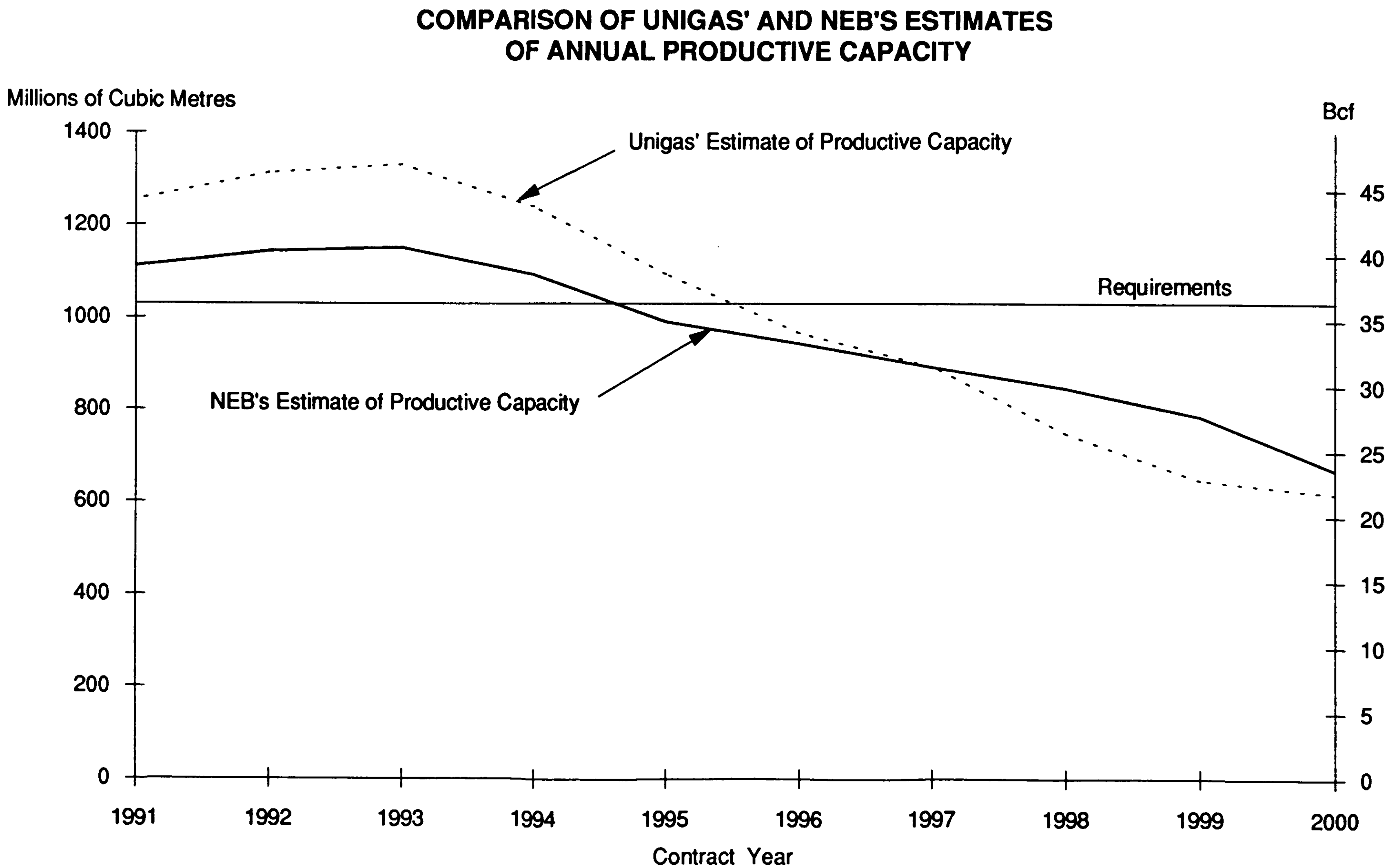
A discussion of Northern Natural's market is provided in section 2.3.1 of these Reasons.

3.3.2 Transportation

The gas proposed for export would be transported on either NOVA or TransGas to their respective points of interconnection with Foothills for delivery to Northern Border near Monchy, Saskatchewan.

Unigas would utilize currently contracted and existing firm transportation capacity on NOVA. Morgan Hydrocarbons would contract for service on TransGas.

Figure 3-1


COMPARISON OF UNIGAS' AND NEB'S ESTIMATES
OF ANNUAL PRODUCTIVE CAPACITY
Millions of Cubic Metres
1400
1200
1000
800
600
400
200
0
Bcf
45
40
35
30
25
20
15
10
5
0
Unigas' Estimate of Productive Capacity
Requirements
NEB's Estimate of Productive Capacity
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
Contract Year

Volumes transported on Foothills would utilize firm capacity under an existing transportation agreement between Consolidated and Foothills.

Northern Natural would transport the gas from Monchy, Saskatchewan to Ventura, Iowa utilizing capacity under a firm shippers agreement between itself and Northern Border.

Minor construction would be required on NOVA and TransGas to facilitate the export.

3.3.3 Gas Sales Contract

A contract, dated 1 November 1989 and terminating 31 October 2001, has been entered into by Unigas and Northern Natural. Gas has been flowing under that contract pursuant to short-term regulatory authorizations since November 1989. The contract enables the continuation of deliveries made to Northern Natural under a contract between Northern Natural and Consolidated, a subsidiary of Unigas, which expired 31 October 1989.

The contract provides for the daily delivery of up to 2 820 10^3m^3 (100.0 MMcf) of gas at the interconnection of the Foothills and Northern Border systems near Monchy, Saskatchewan.

The contract is subject to receipt of all necessary Canadian and U.S. long-term regulatory approvals and firm transportation capacity.

Northern Natural is contractually obligated to make annual purchases of no less than 60 percent of the Annual Contract Quantity ("ACQ"). Should Northern Natural nominate less than this amount, then it would be obligated to pay a shortfall charge equal to 25 percent of Northern Natural’s weighted average cost of gas ("WACOG") for that year on the deficient volumes.

The price paid by Northern Natural for volumes of gas up to 60 percent of the ACQ would consist of the WACOG and a demand and fuel gas charge component. The WACOG would be adjusted monthly to reflect changes in the price of Northern Natural’s U.S.-sourced gas supplies. The price of volumes in excess of 60 percent would be set by negotiation.

Prior to 31 October 1991, should Northern Natural agree to purchase gas from any other Canadian supplier on terms more favourable to Northern Natural than those contained in the subject contract, then Unigas, at its option, may request that Northern Natural purchase such gas from Unigas on similar terms.

Between 1 November 1990 and 1 November 1992, each party has a one-time opportunity to request renegotiation of the contract terms. A failure to reach agreement would result in the contract terminating automatically.

The demand charge component of the contract price would reimburse Unigas for demand-related transportation charges incurred on NOVA and TransGas and cost of service-related charges on Foothills.

Should Northern Natural determine that it is experiencing a significant decrease in its gas sales, then it has the right to reduce its volume obligations under this contract. This right may not be exercised by Northern Natural to displace the contracted volumes with alternative supplies.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 March 1991 was $Cdn. 1.55/GJ ($Cdn. 1.66/MMBtu).

3.3.4 Regulatory Status

Unigas has applied for an Alberta removal permit under which most of its contracted gas supply would be delivered. Gas to be supplied from Mobil Canada, Western Gas, and from Morgan Hydrocarbons' Saskatchewan reserves would flow under removal permits held by those companies.

Western Gas' reserves would be delivered under Alberta removal permit GR 91-9. Decisions on the other three removal permit applications are pending.

Evidence of producer support for this sale by Western Gas was provided by way of a finding released by the Alberta Petroleum Marketing Commission ("APMC") dated 7 February 1990.

DOE/FE import authorization for the full export volume and term was granted on 20 December 1990.

3.4 Views of the Board

The Board notes that while its estimate of Unigas' established reserves exceeds the applied-for term volume, its projection of productive capacity suggests that deficiencies in productive capacity may commence in mid-1994. However, the Board recognizes that there may, in the future, be justification for its estimate of Saskatchewan reserves being revised upwards and agrees with Unigas that deficiencies in productive capacity could be eliminated by the addition of more lands and purchases and the use of Unigas' alternative supply pool. Thus, the Board is satisfied with Unigas' gas supply arrangements. The Board also notes that Unigas has producer support for its proposed export sale to Northern Natural.

The Board recognizes that Northern Natural has been a long-term, large volume purchaser of Canadian gas and expects this to continue in the future. The Board also notes that Unigas' sale would represent approximately five percent of Northern Natural's total annual requirements and, therefore, it is unlikely that changes in overall demand would be borne wholly by Unigas. In particular, the Board notes that the applied-for licence reflects the intention of Unigas and Northern Natural to convert a short-term export to a long-term one.

The Board notes that transportation has been arranged on all required pipelines. Further, the Board is satisfied that all fixed transportation costs associated with the export in Canada would be recovered.

In the view of the Board, the contractual provisions regarding deficiency charges and demand charges would ensure adequate take levels under the gas sales contract.

The Board has reviewed the gas sales contract and has noted that it has been negotiated at arm's length.

The Board notes that DOE/FE import authorization has been granted and that outstanding removal permit authorizations are well advanced.

3.5 Decision

The Board has decided to issue a gas export licence to Unigas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence upon Governor in Council approval and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end on 1 November 2001.

Chapter 4
Western Gas Marketing Limited for Export to Northern Natural

4.1 Application Summary

By application dated 11 April 1991, Western Gas applied under Part VI of the Act for three natural gas export licences with the following terms and conditions:

Licence A. "Emerson 47.5 MMcf Contract"

Term	-	first day of the first full month following Governor in Council approval to 31 October 2001
Point of Export	-	near Emerson, Manitoba
Maximum Daily Quantity	-	1 346 10^3m^3 (47.5 MMcf)
Maximum Annual Quantity	-	492 10^6m^3 (17.4 Bcf)
Maximum Term Quantity	-	product of the number of days in the term and 1 346 10^3m^3 (47.5 MMcf)
Tolerances	-	10 percent per day and 2 percent per year

Licence B. "Emerson 6 Bcf Contract"

Term	-	first day of the first full month following Governor in Council approval to 31 March 1996
Point of Export	-	near Emerson, Manitoba
Maximum Daily Quantity	-	1 416 10^3m^3 (50.0 MMcf)
Maximum Annual Quantity	-	170 10^6m^3 (6.0 Bcf)
Maximum Term Quantity	-	850 10^6m^3 (30.0 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

Licence C. "Monchy Contract"

Term	-	first day of the first full month following Governor in Council approval to 31 October 2001

Point of Export	-	near Monchy, Saskatchewan
Maximum Daily Quantity	-	708 10^3m^3 (25.0 MMcf)
Maximum Annual Quantity	-	259 10^6m^3 (9.2 Bcf)
Maximum Term Quantity	-	product of the number of days in the term and 708 10^3m^3 (25.0 MMcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas supplying the proposed exports would originate from certain pools, fields and areas located in Alberta.

The gas to be exported at Emerson, Manitoba would be transported on the facilities of NOVA for delivery to the TransCanada system near Empress, Alberta. TransCanada would then forward the gas to the international border near Emerson, Manitoba where the gas would then be shipped on the GLGT system for delivery to Northern Natural near Carlton, Minnesota.

The gas to be exported at Monchy, Saskatchewan would be shipped on the Foothills system from MacNeil, Alberta to Monchy, Saskatchewan for delivery to Northern Border. Western Gas Marketing USA Ltd. ("Western Gas USA") would take possession of the gas at Monchy for resale to Northern Natural. Northern Border would then forward the gas from Monchy to Ventura, Iowa for delivery to Northern Natural.

The gas would be used by Northern Natural for resale to its customers. The three agreements are successors to long-term, bundled arrangements between Northern Natural and TransCanada which date from the construction of the TransCanada system and utilized now-expired long-term export licences.

4.2 Gas Supply

The following discussion of gas supply matters is generic to all of the Western Gas applications.

In support of its applications, Western Gas relied primarily upon the gas supply analysis that was provided to the Board during the GH-5-89 proceeding. Updates were made to this analysis to account for reductions in remaining established reserves due to production over the last two years and due to changes in the portfolio of contracts.

The Board’s review of Western Gas’ gas supply for these applications is based on the Board’s extensive analysis of the supply information provided in the GH-5-89 proceeding. Recognizing that the supply situation has remained substantially unchanged, the Board did not consider it necessary to conduct a second detailed review of Western Gas’ reserves and productive capacity. However, the Board’s analysis has been updated as described in the following sections.

Details of the Board’s earlier analysis are provided in Appendix II.

4.2.1 Supply Contracts and Reserves

Western Gas has revised its estimate of remaining established reserves since GH-5-89. Its current estimate, as of 30 September 1990, is 539 10^9m^3 (19.0 Tcf). The difference between Western Gas' current estimate and the estimate provided in GH-5-89, a reduction of 106 10^9m^3 (3.7 Tcf), is primarily attributable to production over the last two years and minor changes in Western Gas' portfolio of contracts with producers. The evidence regarding the outlook for terminations of producers' supply contracts was essentially unchanged from that provided in GH-5-89.

4.2.2 Productive Capacity

Western Gas submitted projections of productive capacity which reflect its most recent estimates of remaining established reserves and the notices of producer contract terminations which had been received at the time of the proceeding. These projections are very similar to those provided in GH-5-89.

In the Board's analysis, the effect of adjusting the Board's projection of productive capacity to reflect the increase in requirements stemming from the applied-for exports is negligible. Therefore, the Board relies upon its analysis of productive capacity conducted for GH-5-89.

Western Gas also stated that the applied-for exports have the same priority access to Western Gas' gas supply as do its other long-term sales. Under these contracts, Western Gas is precluded from entering into new sales arrangements or renewing existing arrangements if its remaining RR/P falls below ten. Western Gas stated that its RR/P ratio for the last year of the projected period was greater than seventeen.

4.3 Market, Commercial Arrangements and Regulatory Status

4.3.1 Market

A discussion of Northern Natural's market is provided in section 2.3.1 of these Reasons.

4.3.2 Transportation

All gas delivered to Northern Natural would be aggregated within Alberta and delivered to the Empress and MacNeil removal points under existing firm transportation contracts between TransCanada and NOVA. The majority of these contracts expire in 2001 and contain provisions for their extension.

4.3.2.1 Emerson 47.5 MMcf Contract

The gas proposed for export under this contract would be transported by NOVA to the interconnection with TransCanada near Empress, Alberta for delivery to GLGT near Emerson, Manitoba. GLGT would forward the gas to Northern Natural near Carlton, Minnesota.

Under an exchange agreement, Western Gas would utilize the transportation rights of Consolidated on TransCanada to deliver the gas to Emerson, Manitoba. The contract terminates 31 October 1992 but contains renewal rights.

The existing firm transportation agreement with GLGT expires 31 October 1992. At the time of the hearing, Northern Natural was negotiating with GLGT for a five-year extension with an option to renew for an additional five years.

No new facilities would be required to facilitate the export.

4.3.2.2 Emerson 6 Bcf Contract

The gas proposed for export would be transported by NOVA to the interconnection with TransCanada near Empress, Alberta for delivery to GLGT near Emerson, Manitoba.

Western Gas would transport the gas from Empress to Emerson using unutilized firm transportation on TransCanada from Western Gas' other Emerson transportation arrangements and, if necessary, under interruptible transportation service.

Northern Natural would transport the gas from Emerson to the Carlton, Minnesota interconnection between GLGT and Northern Natural using authorized overrun service on GLGT. Authorized overrun service is to be phased out by the beginning of the 1994 contract year. As overrun rights diminish, Northern Natural may enter into an interruptible agreement with GLGT.

4.3.2.3 Monchy Contract

The gas proposed for export would be transported by NOVA to the interconnection with Foothills near MacNeil, Alberta for delivery to Northern Border near Monchy, Saskatchewan.

Western Gas has contracted for 578 10^3m^3 (20.4 MMcf) of daily firm transportation on Foothills expiring 31 October 1996. Gas may also be transported under an agreement between Foothills and TransCanada for 2 833 10^3m^3 (100.0 MMcf) per day for service expiring 31 October 1996. The first contract year does not provide direct compensation for demand charges incurred. Western Gas has stated that the demand charges would be recovered through the commodity charge. Northern Natural would directly reimburse Western Gas USA for demand charges on Foothills after the second contract year. Demand charges on NOVA would be directly reimbursed after the third contract year. Prior to this, it is intended that the demand charges on Foothills and NOVA would be recovered through the commodity charge.

TransCanada has contracted for 3 400 $10^3m^3/d$ (120.0 MMcfd) of firm service on Northern Border extending from 1 November 1991 to 31 October 1996. It is anticipated that the transportation agreement with Northern Border would be extended.

FERC approval of the facilities additions required on the Northern Border system to facilitate the export has been granted.

4.3.3 Gas Sales Contracts

4.3.3.1 Emerson 47.5 MMcf Contract

Western Gas and Northern Natural executed a contract dated 1 November 1990, with a term commencing on that date and extending to 31 October 2001, for the daily delivery of up to 1 346 10^3m^3 (47.5 MMcf) of gas at the interconnection of the TransCanada and GLGT systems near

Emerson, Manitoba. Gas has been flowing under the contract pursuant to short-term regulatory authorizations since July 1990.

The contract is subject to receipt of all necessary Canadian and U.S. regulatory approvals and to transportation being in place.

Northern Natural is obligated to make annual Base Volume purchases of approximately 295 10^6m^3 (10.4 Bcf) from Western Gas. Should Northern Natural nominate less than 285 10^6m^3 (10.1 Bcf), then it would be obligated to pay a charge equal to 25 percent of the WACOG for that year on the deficient volumes.

The price paid by Northern Natural for gas purchased from Western Gas would consist of a demand charge, a Base Volume commodity charge, an Incentive Volume commodity charge, and a Canadian transportation commodity charge. Specifically, the commodity charge for Base Volumes would equal Northern Natural’s WACOG contracted from U.S. sources minus a commodity charge credit whereas the Incentive Volume commodity charge would be a negotiated price agreed to by Northern Natural and Western Gas. Incentive Volumes are those in excess of the Base Volumes but less than the MDQ. The commodity charge credit is an adjustment for FERC Opinions 256 and 256a.

Northern Natural would be responsible for demand tolls on TransCanada and NOVA regardless of nominations. Northern Natural would also pay for any transportation commodity charges and fuel costs incurred in Canada.

Either party may request renegotiation of the pricing terms of the contract at the end of any year. Failure to reach agreement may result in arbitration, the purpose of such arbitration being to determine a price comparable to Northern Natural’s WACOG and other long-term firm exports from Alberta.

Should Northern Natural determine that it is experiencing a significant decrease in its gas sales, then it has the right to reduce its volume obligations under this contract. This right may not be exercised by Northern Natural to displace the contracted volumes with alternate supplies.

The estimated price at the Alberta border under the terms of this contract as at 1 March 1991 would have been $Cdn. 1.67/GJ ($Cdn. 1.79/MMBtu).

4.3.3.2 Emerson 6 Bcf Contract

Western Gas and Northern Natural executed a contract dated 1 November 1990, with a term commencing on that date and terminating 31 March 1996, for the daily delivery of up to 1416 10^3m^3 (50.0 MMcf) of gas at the interconnection of the TransCanada and GLGT systems near Emerson, Manitoba. The contract "year" is a six-month period commencing 1 October and terminating the following 31 March.

The contract is subject to receipt of all necessary Canadian and U.S. regulatory approvals and the arrangement of downstream transportation.

Northern Natural is obligated to pay Western Gas a deficiency charge equal to twenty-five percent of the commodity charge on the difference between the Minimum Annual Quantity ("MiQ") and actual nominations. For the term of the applied-for licence, the MiQ is defined as 170 10^6m^3 (6.0 Bcf).

Northern Natural’s obligation to purchase gas is subject to the availability of transportation capacity on TransCanada and GLGT.

The price paid by Northern Natural for gas purchased from Western Gas would consist of a commodity charge and a demand charge component. The commodity charge would be set monthly and equals Northern Natural’s WACOG from U.S. sources. The demand charge component reimburses Western Gas for demand and commodity tolls and fuel gas costs incurred on NOVA and TransCanada plus the cost of transportation capacity on GLGT.The contract does not provide for price renegotiation. However, if the WACOG portion of the commodity charge component for Base Volumes in the Emerson 47.5 contract is renegotiated or arbitrated, then the commodity charge under this contract would be adjusted by substituting the redetermined WACOG.

Should Northern Natural determine that it is experiencing a significant decrease in its gas sales, then it has the right to reduce its volume obligations under this contract. This right may not be exercised by Northern Natural to displace the contracted volumes with alternative supplies.

The estimated price at the Alberta border under the terms of this contract as at 1 March 1991 would have been $Cdn. 1.80/GJ ($Cdn. 1.93/MMBtu).

4.3.3.3 Monchy Contract

Western Gas USA, an affiliate of Western Gas, and Northern Natural executed a contract dated 1 November 1990, with a term commencing on that date and terminating 31 October 2001 for the daily delivery of 708 10^3m^3 (25.0 MMcf) of gas. The point of delivery would be at the interconnection of the Foothills and Northern Border systems near Monchy, Saskatchewan.

The contract is subject to receipt of all necessary long-term Canadian and U.S. regulatory approvals and to obtaining firm downstream transportation capacity.

Northern Natural is obligated to make annual Base Volume purchases, equal to the MiQ, from Western Gas USA. For the first three contract years, the MiQ equals 75 percent of the ACQ and 60 percent thereafter. Should Northern Natural nominate less than the MiQ in a contract year, less two percent of the ACQ, then it would be obligated to pay a shortfall charge equal to 25 percent of the WACOG for that year on the deficient volumes.

The pricing provisions and renegotiation thereof regarding Incentive Volumes and the commodity charge component of the price paid for Base Volumes by Northern Natural are virtually identical to those in the Emerson 47.5 MMcf Contract. A discussion of that contract is found in section 4.3.3.1 of these Reasons.

During the first two years, the demand charge would consist of only the cost of service on Northern Border. During the third year, the demand charge would consist of the cost of service on both Northern Border and Foothills and thereafter would consist of the cost of service on Northern Border, Foothills and NOVA. The fixed costs of transportation on Foothills and NOVA in the early years of the contract would be recovered from the commodity charge component of the price. Northern Natural would also pay for any transportation commodity charges and fuel gas requirements incurred.

Should Northern Natural determine that it is experiencing a significant decrease in its gas sales, then it has the right to reduce its volume obligations under this contract. This right may not be exercised by Northern Natural to displace the contracted volumes with alternative supplies.

The estimated price at the Alberta border under the terms of this contract as at 1 March 1991 would have been $Cdn. 1.23/GJ ($Cdn. 1.32/MMBtu).

4.3.4 Regulatory Status

The Province of Alberta recently approved Western Gas' request to consolidate removal permits TC 80-14, TC 84-15, and TC 85-1 into one permit. As a result, all gas delivered under Western Gas' long-term arrangements will be removed from Alberta under removal permit GR 91-9. The primary term of the permit extends to 31 October 2005, with an extension to 31 October 2012 for volumes delivered to Ocean State Power II.

A finding of producer support for each of the three gas export contracts was provided by way of a finding released by the APMC on 5 December 1990.

DOE/FE import authorization of the gas to be delivered under the Emerson 47.5 MMcf Contract was granted on 24 June 1991. Northern Natural applied for authorization to import volumes under the Emerson 6 Bcf Contract on 8 January 1991. Regarding the volumes under the Monchy contract, Northern Natural indicated that it intended to apply for DOE/FE import authorization prior to the commencement of the hearing.

4.4 Views of the Board

The Board is satisfied, based on its review of Western Gas' gas supply, as revised since GH-5-89, that Western Gas has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed export to Northern Natural, even if there are future terminations in supply contracts beyond those coming into effect in the 1994-1995 contract year. The Board notes that its analysis indicates a shortfall in productive capacity will occur in 1999 to 2003 if the maximum number of supply contract terminations are exercised. However, the Board expects that the level of future contract terminations will fall between the two extreme cases of no further terminations and the maximum possible number of terminations, hence the Board is satisfied that Western Gas has adequate gas supply to meet its currently-contracted domestic and export requirements, including the exports applied for herein.

The Board also notes that producer support for each of the contracts was received.

The Board recognizes that Northern Natural has been a long-term, large volume purchaser of Canadian gas and expects this to continue in the, future. The Board also notes that Western Gas sales would represent approximately six percent of Northern Natural's total annual requirements and, therefore, it is unlikely that changes in the LDCs overall demand served by Northern Natural would be borne wholly by Western Gas. In particular, the Board notes that the applied-for licence reflects the intention of Western Gas and Northern Natural to convert a short-term export to a long-term one.

The Board notes that transportation has been arranged on all required pipelines and that extension agreements, where necessary, are anticipated to be executed shortly. Further, the Board is satisfied that all fixed transportation costs associated with the export in Canada will be recovered.

In the view of the Board, the contractual provisions regarding deficiency charges, supply reservation charges, demand charges and Western Gas' ability to reduce delivery obligations would ensure adequate take levels under the gas sales contracts.

The Board has reviewed the three gas sales contracts and notes that each has been negotiated at arm's length.

The Board notes that DOE/FE import authorizations remain outstanding regarding the Emerson 6 Bcf contract and the Monchy contract but does not foresee difficulties in this regard.

4.5 Decision

The Board has decided to issue three gas export licences to Western Gas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licences, including a condition that the terms of the licences shall commence on the first day of the first full month after Governor in Council approval and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the terms would end on the respective applied-for termination dates.

Chapter 5
Western Gas Marketing Limited for Export to NMU

5.1 Application Summary

By application dated 11 April 1991, as amended, Western Gas applied, pursuant to Part VI of the Act, for a natural gas export licence with the following terms and conditions:

Term	-	commencing 1 November 1991 and ending 1 May 2001
Point of Export	-	near Emerson, Manitoba
Maximum Daily Quantity	-	283 10^3m^3 (10 MMcf)
Maximum Annual Quantity	-	103 10^6m^3 (3.6 Bcf)
Maximum Term Quantity	-	product of the number of days in the term and 283 10^3m^3 (10 MMcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas reserves supporting the proposed export would be produced from certain pools, fields and areas within Alberta. The gas would be transported on NOVA within Alberta and on TransCanada to the Emerson, Manitoba export point. From the international border, the gas would then be shipped on GLGT for use as system supply by NMU.

5.2 Gas Supply

Western Gas' supply is discussed in section 4.2 and Appendix II of these Reasons.

5.3. Market, Commercial Arrangements and Regulatory Status

5.3.1 Market

NMU, an operating division of UtiliCorp United Inc. ("UtiliCorp"), is an LDC serving 24,000 residential and industrial customers in 46 communities in the state of Minnesota. These communities are served by GLGT, Viking Gas Transmission Company ("Viking"), Centra Pipelines Minnesota Inc. ("Centra Pipelines") and Northern Natural. NMU has a long history of purchasing Alberta gas dating back to 1970 when the GLGT system was constructed. Western Gas stated that it is expected that there would be gradual growth in NMU's market over the next several years based on aggressive sales and market development.

Western Gas testified that it expected that the load factor over the term of the licence would be 100 percent.

5.3.2 Transportation

The gas would be shipped within Alberta on the NOVA system and from Empress, Alberta to Emerson, Manitoba on TransCanada. In the U.S., GLGT and possibly Viking would provide transportation to the NMU franchise areas.

In Canada, NOVA would provide firm transportation service to TransCanada under an existing contract. With respect to transportation on TransCanada, Western Gas has an executed FS contract dated 1 January 1988.

In the U.S., the gas would be transported pursuant to an FS transportation agreement dated 15 December 1988 and an amendatory agreement dated 18 December 1989 between NMU and GLGT. NMU testified that the additional facilities required on GLGT have been certificated by the FERC and are expected to be in service by 1 November 1991. The gas sales contract also provides for the possibility that up to 113 10^3m^3 (4 MMcf) per day may be transported on Viking.

5.3.3 Gas Sales Contract

Western Gas and NMU have executed a gas sales contract dated 1 November 1990.

The contract's term commences on 1 November 1990 and terminates on 1 May 2001 and provides for a DCQ of 283.3 10^3m^3 (10 MMcf) per day. In addition to the foregoing, Western Gas may deliver overrun volumes to NMU on a best efforts basis.

The contract includes a minimum take obligation under which NMU is obligated to take in each contract year 60 percent of the ACQ. To the extent that NMU does not purchase 60 percent of the ACQ, the deficiency volume is to be made up in the succeeding contract year, otherwise Western Gas may permanently reduce the DCQ by an amount no greater than the deficiency.

The contract includes a two-part pricing structure consisting of a monthly demand charge and a commodity charge. NMU will pay, at a minimum, the demand charge component which will be an amount equal to the NOVA and TransCanada demand charges. The contract stipulates that for volumes up to the DCQ and overrun volumes, the commodity charge will be $U.S. 1.70/GJ ($U.S. 1.82/MMBtu) and $U.S. 1.63/GJ ($U.S. 1.75/MMBtu) respectively from 1 November 1990 through 30 April 1991. Thereafter, the commodity charge may be renegotiated if either party serves notice by 1 March of the contract year. In the event that the parties are unable to agree on a new price, either party may submit the issue to binding arbitration. The contract also contains a provision for the renegotiation, but not arbitration, of the commodity charge from a negotiated amount on an annual basis to an index or other mechanism. The demand charge is not subject to renegotiation or arbitration.

The estimated price at the Alberta border as at 1 March 1991 under this contract was $Cdn. 2.15/GJ ($Cdn. 2.31/MMBtu).

5.3.4 Regulatory Status

The Province of Alberta recently approved Western Gas' request to consolidate removal permits TC 80-14, TC 84-15, and TC 85-1 into one permit. As a result, all gas delivered under Western Gas' long-term arrangements will be removed from Alberta under removal permit GR 91-9. The primary term of the permit extends to 31 October 2005, with an extension to 31 October 2012 for volumes delivered to Ocean State Power II.

Evidence of producer support was provided by way of a finding released by the APMC on 6 November 1990.

On 29 November 1990, NMU received DOE/FE import authorization.

5.4 Views of the Board

The Board is satisfied, based on its review of Western Gas' gas supply, as revised since GH-5-89, that Western Gas has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed export to NMU, even if there are future terminations in supply contracts beyond those coming into effect in the 1994-1995 contract year. The Board notes that its analysis indicates a shortfall in productive capacity will occur in 1999 to 2003 if the maximum number of supply contract terminations are exercised. However, the Board expects that the level of future contract terminations will fall between the two extreme cases of no further terminations and the maximum possible number of terminations; hence the Board is satisfied that Western Gas has adequate gas supply to meet its currently-contracted domestic and export requirements, including the export applied for herein.

The Board notes that NMU has been purchasing Alberta gas for over twenty years and that gas is currently flowing under short-term authorizations. As a result, the Board is satisfied that Western Gas has adequately demonstrated that the NMU market represents a stable, long-term market for Canadian gas. The Board is of the view that the gas is likely to be taken at a high load factor in light of the market-sensitive nature of the price and NMU's obligation to pay Canadian pipeline demand charges.

The Board notes that Western Gas has received authorization to remove the gas from Alberta and that NMU has secured the necessary DOE/FE import authorization.

The Board is satisfied that the Western Gas/NMU sales contract would ensure the recovery of all fixed Canadian transportation costs in view of the fact that it provides for complete recovery of demand charges on the NOVA and TransCanada systems.

The Board notes that the commodity charge component of the price has been agreed to by both parties for the first six months of the contract and, at the request of either party, can be renegotiated on an annual basis. In the event that such negotiations are unsuccessful, the matter may be submitted to binding arbitration. The Board is of the view that the pricing provisions contained in the gas sales contract permit adjustments in the export price to reflect changing market conditions.

The Board notes that the contract has been negotiated at arm's length between Western Gas and NMU and that the pricing terms are such that the arrangement is likely to be durable over the term of the licence.

The Board also notes that producer support for the contract was received.

5.5 Decision

The Board has decided to issue a gas export licence to Western Gas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence upon Governor in Council approval and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 1 May 2001.

Chapter 6
Western Gas Marketing Limited as Agent for NMU

6.1 Application Summary

By application dated 11 April 1991, Western Gas applied, as agent for NMU, pursuant to Part VI of the Act, for a natural gas export licence in NMU's name with the following terms and conditions:

Term	-	commencing 1 November 1991 and ending 31 October 2002
Point of Export	-	near Sprague, Manitoba and Fort Frances, Ontario
Maximum Daily Quantity	-	1 059 10^3m^3 (37.4 MMcf)
Maximum Annual Quantity	-	388 10^6m^3 (13.7 Bcf)
Maximum Term Quantity	-	4.27 10^9m^3 (151 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas proposed for export would be produced from certain pools, fields and areas in Alberta. The gas would be transported to the Alberta/Saskatchewan border on NOVA and TransCanada would transport the gas to Spruce, Manitoba to the interconnection with the Centra Transmission Holdings Ltd. ("Centra Transmission") system on which the gas would be transported to the Sprague, Manitoba export point. From the international border, the gas would flow on a pipeline owned by Centra Pipelines until it re-enters Canada at Rainy River, Ontario and runs through to Fort France, Ontario on Centra Transmission. At this point, the pipeline re-enters the U.S. and the gas would be delivered to International Falls, Minnesota on Centra Pipelines.

The gas proposed for export would be used predominantly as system supply by NMU.

6.2 Gas Supply

Western Gas' supply is discussed in section 4.2 and Appendix II of these Reasons.

6.3 Market, Commercial Arrangements and Regulatory Status

6.3.1 Market

NMU is an LDC serving customers in the state of Minnesota. The gas proposed for export through the Sprague, Manitoba export point would be delivered to various towns in northern Minnesota near the international border, including Roseau, Baudette, and International Falls. The majority of the gas, 850.0 10^3m^3 (30.0 MMcf) per day, would be sold to the Boise Cascade Corporation ("Boise Cascade") paper mill in International Falls. The Boise Cascade volume would include a so-called first step-up volume of approximately 142 10^3m^3 (5.0 MMcf) per day which could only be delivered once Western Gas had obtained additional transportation capacity on TransCanada. The applicant also advised the Board that a further increment to the DCQ in the contract of another 142 10^3m^3 (5.0 MMcf) per day would be required to serve a cogeneration plant that Boise Cascade is planning. This second possible increment is referred to as the second step-up volume. The applicant held the view that the cogeneration volume would be an expansion of the existing Boise Cascade market.

Despite the second step-up volume for the cogeneration plant not having been contractually committed to and the transportation arrangements not yet being finalized, the applicant testified that the cogeneration volume was included in the applied-for volume so as to void the necessity of submitting another full licence application for such a small volume. Western Gas indicated that it would be satisfactory if the licence was conditioned on acceptable contract amendments, transportation arrangements and regulatory authorizations being filed with the Board and if the licence included a sunset date of 1 November 1993.

Further, Western Gas indicated that it would be acceptable if the licence initially authorized the export of 918 10^3m^3 (32.4 MMcf) and would increase to include the volume for sale to the cogeneration plant when all the conditions precedent had been satisfied.

Western Gas estimated that the annual load factor of NMU's purchases would be approximately 67 percent.

6.3.2 Transportation

The gas would be transported to the Alberta/Saskatchewan border on NOVA. TransCanada would transport the gas from that point to Spruce, Manitoba to the interconnection with Centra Transmission on which the gas would be transported to the Sprague, Manitoba export point. From the international border, the gas would flow on Centra Pipelines until it re-enters Canada at Rainy River, Ontario and runs through to Fort Frances, Ontario, on Centra Transmission. Thereafter, the gas re-enters the U.S. and would be delivered to International Falls, Minnesota on Centra Pipelines.

Within Canada, firm service would be provided on NOVA to the interconnection with TransCanada under an existing transportation contract between TransCanada and NOVA. With respect to transportation on TransCanada, firm service for the delivery of 775 $10^3m^3/d$ (27.4 MMcfd) would be provided pursuant to an FS transportation assignment agreement dated 1 November 1990 between NMU and Western Gas, an amending agreement dated 13 October 1988 between TransCanada and Western Gas, and an FS contract dated 1 May 1988 between TransCanada and Western Gas. The applicant stated that it is in the process of arranging, through construction or assignment, an additional 142 $10^3m^3/d$ (5.0 MMcfd) of capacity to Spruce, Manitoba to accommodate the first step-up volume increase provided for in the Western Gas/NMU gas sales contract. In addition, further capacity would be required for the second step-up volume of approximately 142 $10^3m^3/d$ (5.0 MMcfd) which is currently being negotiated between Western Gas and NMU. Western Gas expressed confidence that the capacity on TransCanada for both incremental requirements would be available. Centra Transmission would provide firm service under a transportation service agreement dated 1 November 1990 between UtiliCorp and ICG Transmission Holdings Ltd., that is, Centra Transmission. This agreement provides for the delivery effective 1 November 1991 of 748 $10^3m^3/d$ (26.4 MMcfd) and 889 $10^3m^3/d$ (31.4 MMcfd) on the date on which Western Gas secures an additional 142 $10^3m^3/d$ (5.0 MMcfd) of capacity on TransCanada for the first step-up volume. As was the case with respect to additional capacity on TransCanada, an additional 142 $10^3m^3/d$ (5.0 MMcfd) on Centra Transmission would also be required. Western Gas expressed confidence that the additional capacity on Centra Transmission would be available.

In the U.S., Centra Pipelines would provide firm service pursuant to a transportation service agreement dated 1 November 1990 between UtiliCorp and Inter-City Minnesota Pipelines Ltd., that is, Centra Pipelines. This agreement provides for the delivery of 748 $10^3m^3/d$ (26.4 MMcfd) effective 1 November 1991 and 889 $10^3m^3/d$ (31.4 MMcfd) on the date on which Western Gas secures an additional 142 $10^3m^3/d$ (5 MMcfd) of capacity on TransCanada for the first step-up volume. Further capacity would be required upon formalization of the second step-up volume of 142 $10^3m^3/d$ (5 MMcfd). Western Gas testified that Centra Pipelines has indicated that there would likely be capacity available on its system to meet both 142 $10^3m^3/d$ (5 MMcfd) incremental requirements.

6.3.3 Gas Sales Contract

Western Gas and NMU have entered into a gas sales contract dated 15 June 1990, the term of which commences on 1 November 1991 and terminates on 31 October 2002. The contract is subject to a variety of conditions precedent related to long-term regulatory authorizations and transportation arrangements.

The contract provides for a DCQ of 748 10^3m^3 (26.4 MMcf), of which 567 10^3m^3 (20 MMcf) would be for delivery to Boise Cascade, commencing 1 November 1991 and 889 10^3m^3 (31.4 MMcf), of which 708 10^3m^3 (25 MMcf) would be for delivery to Boise Cascade, commencing on the date on which Western Gas obtains an additional 142 $10^3m^3/d$ (5 MMcfd) of capacity on TransCanada to facilitate delivery of the first step-up volume. The Boise Cascade volumes would be delivered to International Falls in eastern Minnesota while the balance would be delivered to Roseau and Baudette in western Minnesota.

The contract also allows for the delivery of overrun gas subject to existing governmental authorizations and the availability of transportation capacity. In this regard, the applicant has included 28 $10^3m^3/d$ (1 MMcfd) of overrun volume in the total applied-for volume of 1 059 $10^3m^3/d$ (37.4 MMcfd).

With respect to price, NMU is obligated to pay, at a minimum, the demand charges applicable to the firm transportation on NOVA and TransCanada each month. For firm volumes, the contract provides for a two-tiered price, which attempts to maintain competitively-priced gas for Boise Cascade. The first tier, which may be renegotiated on an annual basis, would be for eastern and western Minnesota commodity charges. In the event that a price cannot be agreed upon, arbitration is provided for. Volumes destined for Boise Cascade would be priced under a separate index. Working from an initial base price at the Alberta border of $Cdn. 1.75/GJ ($Cdn. 1.88/MMBtu), the index takes into account changes to the prices that Western Gas receives under all of its long-term firm sales. The contract provides for price renegotiation every third year based on the prices paid for long-term Alberta supplies, the prices for alternative gas supplies available to Boise Cascade under long-term firm contracts, and the price of alternative energy sources, excluding wood waste and coal, available to Boise Cascade. In the event that arbitration of the price is required, it would be based solely on gas-to-gas competition.

Under the terms of the contract, NMU is obligated to take, in each contract year, 60 percent of the ACQ that is attributable to Boise Cascade. NMU has the right to make up any such deficiency in the subsequent two contract years, failing which Western Gas may permanently reduce the DCQ up to the amount equal to the shortfall. If NMU purchases less than 60 percent of Boise Cascade's ACQ, then NMU must pay a Gas Inventory Charge of $Cdn. 0.45/GJ (Cdn. 0.48/MMBtu) for any shortfall below the 60 percent level.

The estimated price at the Alberta border as of 1 March 1991 under this contract was $Cdn. 1.96/GJ ($Cdn. 2.10/MMBtu).

With respect to the second step-up volume, which is not currently contractually committed to, the applicant testified that discussions with NMU had led it to believe that the gas sales contract would be amended by simply increasing the DCQ.

6.3.4 Regulatory Status

The Province of Alberta recently approved Western Gas' request to consolidate removal permits TC 80-14, TC 84-15, and TC 85-1 into one permit. As a result, all gas delivered under Western Gas' long-term arrangements will be removed from Alberta under removal permit GR 91-9. The primary term of the permit extends to 31 October 2005, with an extension to 31 October 2012 for volumes delivered to Ocean State Power II.

The APMC released a finding of producer support on 31 July 1990.

On 16 October 1990, NMU received DOE/FE import authorization.

6.4 Views of the Board

The Board is satisfied, based on its review of Western Gas' gas supply, as revised since GH-5-89, that Western Gas has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed export to NMU, even if there are future terminations in supply contracts beyond those coming into effect in the 1994-1995 contract year. The Board notes that its analysis indicates a shortfall in productive capacity will occur in 1999 to 2003 if the maximum number of supply contract terminations are exercised. However, the Board expects that the level of future contract terminations will fall between the two extreme cases of no further terminations and the maximum possible number of terminations; hence the Board is satisfied that Western Gas has adequate gas supply to meet its currently-contracted domestic and export requirements, including the export applied-for herein.

With respect to the second step-up volume, the Board notes that the actual volume would not likely be finalized until November 1992. The Board also notes that this gas would be used in a cogeneration facility in 1994, as compared to supply for Boise Cascade for which authorization to export is being sought commencing 1 November 1991. In addition, Western Gas and NMU have not executed a contract with regard to this volume, transportation arrangements have not been finalized and cannot be until the exact volume has been agreed upon, and import authorization has not been granted. The Board recognizes that the applicant is agreeable to having the licence conditioned to provide for finalization of all necessary arrangements with respect to this volume and that the licence would commence at a level of 918 $10^3m^3/d$ (32.4 MMcfd) and be stepped-up to the full applied-for volume once all the conditions had been satisfied. However, the Board is not prepared to authorize the second step-up volume as it is the Board's view that this portion of the application is premature.

With respect to the remainder of the applied-for volume, i.e. 918 $10^3m^3/d$ (32.4 MMcfd), the Board notes that NMU will be required to pay the Canadian demand charges each month; accordingly, the Board is satisfied that the price would recover its appropriate share of incurred costs.

The Board is satisfied that the gas sales contract between Western Gas and NMU was negotiated at arm's length and that the terms of the contract provide for renegotiation of the price and, if necessary, arbitration. As a result, the Board is satisfied that the export contract contains provisions which permit adjustments to reflect changing market conditions over the term of the contract.

The contract contains a minimum take provision and, as previously mentioned, demand charges must be paid by NMU as a minimum each month. The Board notes that NMU is a long-term consumer of Canadian gas with purchases dating back to 1970. For these reasons, in addition to the market-sensitive nature of the pricing mechanisms, the Board is satisfied that there is a reasonable assurance that the volumes contracted-for will be taken.

The Board notes that Western Gas' producers support the contract, as demonstrated by the APMC finding released on 31 July 1990, and that import authorization has been secured.

6.5 Decision

As described in section 6.3.2 of these Reasons, some of the gas will be exported for consumption in northeastern Minnesota. In order to serve this market, the gas must be exported at Sprague, Manitoba, imported at Rainy River, Ontario and re-exported at Fort Frances, Ontario. To accommodate this arrangement, the Board has decided to issue a licence, subject to the approval of the Governor in Council, which will facilitate the initial export, and an accompanying order to facilitate the import and re-export described above.

The applied-for commencement date of the licence was 1 November 1991. As the Board's decision would not be released by that date, Western Gas, as agent for NMU, requested that the Board issue the necessary short-term authorizations as an interim measure. The Board decided to grant the relief requested, consisting of an export for import order and an export order. Gas will continue to flow under these short-term orders until Governor in Council approval of the licence is received.

Appendix I contains the terms and conditions of the licence and new order, including a condition that their terms shall commence upon Governor in Council approval of the licence and shall end on 1 November 1993, unless exports have commenced on or before 1 November 1993, in which case the terms would end on 31 October 2002.

Chapter 7
Western Gas Marketing Limited for Export to Vermont Gas

7.1 Application Summary

By application dated 11 April 1991, as amended, Western Gas sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	commencing 1 November 1991 for a period of 15 years
Point of Export	-	near Philipsburg, Quebec
Maximum Daily Quantity	-	906 10^3m^3 (32.0 MMcf)
Maximum Annual Quantity	-	332 10^6m^3 (11.7 Bcf)
Maximum Term Quantity	-	4.98 10^9m^3 (176.0 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The proposed export volumes would be produced from certain pools, fields and areas within the province of Alberta. The gas would be transported to Empress, Alberta on NOVA and then travel through TransCanada's system to the international border near Philipsburg, Quebec at the interconnection with the Vermont Gas pipeline. The gas would be sold at the international border to Vermont Gas, an LDC in northern Vermont.

7.2 Gas Supply

Western Gas' supply is discussed in section 4.2 and Appendix II of these Reasons.

7.3 Market, Commercial Arrangements and Regulatory Status

7.3.1 Market

Vermont Gas owns and operates a 57-mile transmission system extending from the TransCanada interconnect at the international border near Philipsburg, Quebec to Burlington, Vermont. It also operates a 317-mile distribution system serving 22,000 customers in the greater Burlington area and the counties of Chittenden and Franklin in northern Vermont. Vermont Gas had been purchasing gas from TransCanada under a long-term licence which expired two years ago and, since that time, Vermont Gas has purchased its gas under short-term orders. From 1985 through 1990, Vermont Gas experienced an average annual increase of 6.4 percent in natural gas sales with sales in 1990 totalling 190.9 10^6m^3 (6.7 Bcf). The number of customers served by Vermont Gas has almost doubled in the past seven years and is expected to increase by another 6,000 customers over the next five years, or approximately five percent annually. Vermont Gas' forecast is based on the assumptions of strong growth in heating customers, as a result of conversions from electricity and oil, as well as increased development in power generation, including cogeneration. This forecast increase in customers would represent an additional 19.0 10^6m^3 (0.7 Bcf) in natural gas sales over the five-year period ending 1995. The degree of growth will depend largely on the price of natural gas in relation to competing fuels.

Vermont Gas' only source of supply is through its interconnection with TransCanada at Philipsburg, Quebec. Currently, the gas sales contract with Western Gas represents 100 percent of Vermont Gas' natural gas supply. However, the contract recognizes the possibility of supply diversification by allowing Vermont Gas the one-time option of reducing the DCQ by up to 141.0 10^3m^3 (5.0 MMcfd). Assuming that Western Gas remains its sole supplier, Vermont Gas estimates that the load factor under this contract would increase from 59 percent in the first contract year, 1991-1992, to 95 percent in the 1994-1995 contract year and remain at that level for the duration of the contract's term as a result of the initiation of storage services. Vermont Gas stated that it is included in several storage queues, including Union's queue for service beginning April 1994.

7.3.2 Transportation

The proposed export volumes would be aggregated and transported to the Alberta/Saskatchewan border at Empress using existing TransCanada capacity on the NOVA system. From Empress, the gas would be transported on TransCanada's system to the international border at Philipsburg, Quebec pursuant to an FS contract dated 1 November 1988 between Western Gas and TransCanada. The gas would be delivered directly into the Vermont Gas system at that point.

No new facilities are required to continue this export.

7.3.3 Gas Sales Contract

A letter agreement dated 17 January 1991 between Western Gas and Vermont Gas was filed with the application. Western Gas anticipated filing the completed gas sales contract during May, 1991 but was unable to file the contract prior to the hearing date. During the hearing, Western Gas agreed to a sixty-day waiting period from the date the executed gas sales contract was filed in order to allow interested parties a chance to review the contract and to file complaints, if any, under the Board's Complaints Procedure.

The gas sales contract, dated 26 June 1991, between Western Gas and Vermont Gas was filed with the Board on 29 July 1991. The agreement includes several conditions precedent which must be met by 31 October 1992 or the contract automatically terminates. These conditions include: receipt of all Canadian and U.S. regulatory authorizations; renewal by Western Gas of its FS transportation agreement with TransCanada; and execution by TransCanada of a warranty of performance by Western Gas.

The contract provides for a DCQ of up to 906.0 10^3m^3 (32.0 MMcf) for a 15-year period beginning on the later of 1 November 1991 or the date that all conditions precedent are met. Vermont Gas has the one-time right to reduce the DCQ by up to 141.6 10^3m^3 (5.0 MMcf), provided that the reduction is not requested prior to the planned initiation of storage services. Should this right be exercised, Western Gas would then have the right to further reduce the DCQ by up to the same amount as the Vermont Gas reduction and could opt to assign TransCanada transportation rights to Vermont Gas for the amount of the reduction in the DCQ. Vermont Gas can also request an increase in the DCQ at any time prior to the last four contract years, subject to regulatory authorization and the availability of transportation.

Supply assurances have been included in the contract whereby Western Gas' supplier, TransCanada, agrees to maintain an RR/P above a factor of ten, calculated for selected periods. TransCanada and Western Gas are not permitted to enter into new sales arrangements if the RR/P ratio is below ten or if the new agreements could cause the RR/P ratio to fall below ten. Further, should the total supply of gas be insufficient to meet its commitments, TransCanada would be required to first curtail short-term sales and then, if necessary, to prorate long-term sales.

The contract includes a two-part pricing structure at the delivery point of Philipsburg, consisting of a demand charge and a commodity charge.

The demand charge component consists of two parts: the TransCanada monthly demand charge and the NOVA monthly demand charge. However, for the period extending from first deliveries until 30 October 1992, the demand charge component would consist of 85 percent of the TransCanada monthly demand charges only. This percentage would be increased by 5 percentage points at the beginning of each contract year, with payment of 100 percent of the TransCanada demand charge being required by 1 November 1994. Should Vermont Gas initiate storage services prior to 1 November 1994, then it would be required to reimburse Western Gas for the full TransCanada demand charge.

The demand charge component would be increased on 1 November 1992 to include the monthly NOVA demand charge. This increase could be delayed until 1993 if the TransCanada demand toll in effect for 1992-1993 is five percent higher than the toll in effect for 1991-1992. In any event, once the demand charge component of the pricing structure is increased to take into account the NOVA demand charge, the commodity charge component of the price would be reduced to reflect the separate payment of that charge.

Until Vermont Gas directly reimburses Western Gas for the full amount of the demand charges, Western Gas would recover the demand charges from the commodity portion of the price.

The commodity charge component is comprised of a two-tier pricing structure: the Interruptible Market Commodity Charge ("IMCC") for Vermont Gas' interruptible customers, and the Firm Market Commodity Charge ("FMCC") for its firm service customers. The monthly weighted average commodity charge is determined using the actual volumes sold to Vermont Gas' firm and interruptible customers.

The IMCC is based on the prices of alternative fuels used by Vermont Gas' interruptible industrial customers. The weighting of these fuels is to be adjusted annually to reflect the mix of alternative fuels.

The FMCC is based on the sum of projections of: a) the average price paid by eastern Canadian LDCs at the Alberta border under long-term firm contracts with Western Gas; b) TransCanada commodity tolls; and c) fuel gas charges. The FMCC would be recalculated each year, prior to 1 April, for the upcoming contract year. If the projected FMCC for the next contract year cannot be agreed upon, it would be determined monthly based on the actual nominations.

Western Gas submitted that the FMCC and IMCC for the month of March 1991 was $Cdn. 2.30/GJ ($Cdn. 2.47/MMBtu) and $Cdn. 1.77/GJ ($Cdn. 1.90/MMBtu) respectively, resulting in a weighted average commodity charge of $Cdn. 2.10/GJ ($Cdn. 2.25/MMBtu).

The two part demand/commodity pricing structure is not subject to renegotiation and arbitration. However, renegotiation of the pricing components of the monthly commodity charge is available every two years to allow for adjustments if either party feels the pricing structure is not representative of the market prices. The FMCC may be renegotiated annually. The demand charge can also be renegotiated annually provided that such renegotiation would attempt to provide for an overall pricing structure which would permit full recovery by Western Gas of all costs of transportation. If agreement on a new pricing formula, excluding the demand charge, cannot be reached, final and binding arbitration is provided for. Any contractual changes made must be acceptable to all Canadian and U.S. regulatory authorities or renegotiation/arbitration will continue until acceptance by those authorities is obtained.

Vermont Gas must purchase at least 96.3 $10^6 m^3$ (3.4 Bcf) per year (29 percent of the DCQ) at the FMCC as long as Western Gas remains the sole supplier or it must pay the difference between the FMCC and the IMCC on the deficient volumes. Provision is made for revision of this annual take clause should Vermont Gas wish to add other suppliers to its portfolio.

7.3.4 Regulatory Status

The Province of Alberta recently approved Western Gas' request to consolidate removal permits TC 80-14, TC 84-15, and TC 85-1 into one permit. As a result, all gas delivered under Western Gas' long-term arrangements will be removed from Alberta under removal permit GR 91-9. The primary term of the permit extends to 31 October 2005, with an extension to 31 October 2012 for volumes delivered to Ocean State Power II.

A finding of producer support was issued by the APMC on 31 October 1990.

Vermont Gas was to apply to the U.S. DOE/FE in mid-July 1991 for import authorization for a period of 15 years commencing 1 November 1991. It expected authorization to be granted in September 1991.

7.4 Views of the Board

The Board is satisfied, based on its review of Western Gas' gas supply, as revised since GH-5-89, that Western Gas has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed export to Vermont Gas, even if there are future terminations in supply contracts beyond those coming into effect in the 1994-1995 contract year. The Board notes that its analysis indicates a shortfall in productive capacity will occur in 1999 to 2003 if the maximum number of supply contract terminations are exercised. However, the Board expects that the level of future contract terminations will fall between the two extreme cases of no further terminations and the maximum possible number of terminations; hence the Board is satisfied that Western Gas has adequate gas supply to meet its currently-contracted domestic and export requirements, including the export applied-for herein.

The Board also notes that producer support for the contract was received.

The Board is satisfied that Western Gas' sale to Vermont Gas represents a stable long-term market for Canadian gas. The Board notes in particular that, initially TransCanada, and then its subsidiary, Western Gas, have been Vermont Gas' sole suppliers since 1967, with gas moving to Vermont Gas under licence GL-19 until its expiration, and that gas is currently moving to Vermont Gas under a short-term order. This proposed sale represents 100 percent of Vermont Gas' requirements.

The Board notes that transportation arrangements are in place under existing agreements between Western Gas, NOVA and TransCanada and that the gas is currently flowing pursuant to these agreements.

The Board has reviewed the gas sales agreement between Western Gas and Vermont Gas and has noted that it has been negotiated at arm's length. Although Vermont Gas would not be directly responsible for full payment of the fixed transportation charges until November 1994, the Board is satisfied that the costs of transportation in Canada would be recovered through the combined demand and commodity charges.

The Board is satisfied that the commodity component in the pricing structure, which is indexed to both Western Gas' long-term firm contracts with eastern Canadian LDC's and the price of competing fuels in Vermont Gas' market area, would be responsive to changing market conditions over the life of the contract. The Board also notes that a finding of producer support was issued by the APMC on 31 October 1990.

With regard to the late filing of the gas sales contract, the Board decided that, in order to ensure proper operation of its complaints procedure, a sixty-day waiting period from the ate of filing, 29 July 1991, was necessary so that interested parties would be afforded an opportunity to review the agreement. The Board notes that no complaints regarding the contract were received.

7.5 Decision

The Board has decided to issue a gas export licence to Western Gas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence upon Governor in Council approval and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2006.

Chapter 8
Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of the applications heard by the Board in the GH-3-91 proceedings.

R. Illing
Presiding Member

W.G. Stewart
Member

C. Bélanger
Member

Calgary, Canada
October 1991

Appendix I
Terms and Conditions of the Licences to be Issued

Terms and Conditions of the Licence to be Issued to Mobil Oil Canada, Ltd. for Sale to Northern Natural

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 31 October 2000.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 563 540 cubic metres in any one day;

   (b) 205 690 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 056 900 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence to be Issued to Unigas Corporation for Sale to Northern Natural

1. The term of this Licence shall commence on the date of Governor in Council approval here of and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 1 November 2001.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 2 820 000 cubic metres in any one day;

   (b) 1 030 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 10 300 000 000 cubic metres during the term of this Licence.

3. As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Monchy, Saskatchewan.

Terms and Conditions of the Three Licences to be Issued to Western Gas Marketing Limited for Sale to Northern Natural

Licence A. "Emerson 47.5 MMcf Contract"

1. The term of this Licence shall commence on the first day of the first full month after Governor in Council approval hereof and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 31 October 2001.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 1 346 000 cubic metres in any one day;

   (b) 492 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) during the term of this Licence, a volume not exceeding the product of the number of days included in the licence term and 1 346 000 cubic metres.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Licence B. "Emerson 6 Bcf Contract"

1. The term of this Licence shall commence on the first day of the first full month after Governor in Council approval hereof and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 31 March 1996.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 1 416 000 cubic metres in any one day;

(b) 170 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 850 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Licence C. "Monchy Contract"

1. The term of this Licence shall commence on the first day of the first full month after Governor in Council approval hereof and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 31 October 2001.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

(a) 708 000 cubic metres in any one day;

(b) 259 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) during the term of this Licence, a volume not exceeding the product of the number of days included in the licence term and 708 000 cubic metres.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Monchy, Saskatchewan.

Terms and Conditions of the Licence to be Issued to Western Gas Marketing Limited for Sale to Northern Minnesota Utilities, a Division of UtiIiCorp United Inc.

1. The term of this Licence shall commence on the first day of the first full month after Governor in Council approval hereof and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 1 May 2001.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 283 000 cubic metres in any one day;

   (b) 103 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) during the term of this Licence, a volume not exceeding the product of the number of days included in the licence term and 283 000 cubic metres.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence and the Order to be Issued to Northern Minnesota Utilities, a Division of UtiIiCorp United Inc.

Licence Conditions:

1. The term of this Licence shall commence on the date of Governor in Council approval here of and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2002.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 917 800 cubic metres in any one day;

   (b) 335 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 3 685 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Sprague, Manitoba.

5. Order GO-88-91 is rescinded upon Governor in Council approval of this Licence.

Order Conditions:

1. The term of this Order shall commence on the date that the gas export licence issued to NMU pursuant to Hearing GH-3-91 receives the approval of the Governor in Council and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2002.

2. (a) Gas imported under the authority of this Order shall be delivered to the point of import near Rainy River, Ontario.

   (b) Gas exported under the authority of this Order shall be delivered to the point of export near Fort Frances, Ontario.

3. The quantity of gas exported under the authority of this Order shall not exceed the thermal equivalent of the quantity of gas imported under the authority of this Order.

4. Order GOL-3-91 is hereby rescinded on the date that this Order comes into effect.

Terms and Conditions of the Licence to be Issued to Western Gas Marketing Limited for Sale to Vermont Gas Systems, Inc.

1. The term of this Licence shall commence on the date of Governor in Council approval here of and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2006.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 906 000 cubic metres in any one day;

   (b) 332 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 4 980 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Philipsburg, Quebec.

Appendix II
Western Gas' Gas Supply

An extensive review of Western Gas' supply was conducted coincidentally by the Board for the GH-5-89 and GH-6-89 proceedings. The Board's analysis of Western Gas' supply contained herein, including contracts, estimates of reserves and productive capacity, is essentially unchanged from what was presented in the GH-5-89 Reasons for Decision, with the exception of minor revisions to the text.

Reserves and Supply Contracts

As Western Gas' gas supply will be obtained from TransCanada's general supply pool, all references to Western Gas' gas supply, lands, etc. relate to TransCanada's contracted supply pool.

Western Gas provided an estimate of TransCanada's remaining established reserves under contract that will be drawn on to meet both existing commitments and the proposed exports. Table A-1, which sets out the estimates as of December 1988, shows that the Board's estimate of Western Gas' reserves is approximately 19 percent lower than the estimate provided by Western Gas.

During its review of Western Gas' reserves submission, the Board noted that Western Gas had not submitted reserves estimates for a number of pools which appeared to be under its control. Western Gas was requested to review these pools and subsequently has advised the Board that ERCB reserves estimates should be used for them until Western Gas has an opportunity to review the pools more thoroughly. The Board has included these pools in its estimate of Western Gas' reserves.

In its analysis of Western Gas' gas supply, the Board recognized approximately 8,000 pools, almost all of which are in Alberta. They are distributed across most of the province and include all major producing horizons. Most of the pools are in Cretaceous zones in central and east-central Alberta. The Jurassic to Carboniferous zones include about 600 pools and are largely located in the Foothills area and north of the Deep Basin. The Devonian pools are fewer in number but contain fairly large reserves. These pools are located in the central and northern areas of Alberta.

Approximately 54 percent of Western Gas' reserves are contained in 100 pools, each with initial established reserves in excess of 3 000 10^6m^3 (106 Bcf). In contrast, only 16 percent of Western Gas' reserves are contained in small pools numbering approximately 6 700 with initial established reserves less than 100 10^6m^3 (3.5 Bcf) per pool.

Differences in the Board's and Western Gas' estimates of reserves arise primarily from:

(a) differences in the geological and engineering assessment of reserves for specific pools; and

(b) differences in the interpretation of Western Gas' contracted lands position.

The Board's estimates of reserves for a number of large and medium-sized pools are lower than those of Western Gas, in part because performance data for some of these pools do not appear to substantiate Western Gas' reserves estimates which were based on volumetric analysis. Other reasons for these differences relate to the assignment of recovery factor, add interpretation of pool area and various reservoir parameters.

A further difference between the Board’s and Western Gas’ estimates of reserves arises from the approach to reserves estimation for single-well pools. Western Gas generally employs an area assignment of 256 hectares (one section) to estimate reserves for a single-well pool. However, Western Gas stated that it uses a smaller single-well area where experience and knowledge support such action. The Board uses a variable area assignment, based on experience with pool sizes in specific plays, usually ranging from 150 hectares to 259 hectares or greater, but most often uses 200 hectares for a single-well pool. Differences in reserves attributed to single-well pools also arise from the cumulative effect of small differences in other reservoir parameters.

Western Gas also tends to coalesce several small pools into one larger pool, which often has the effect of increasing the overall Western Gas estimate of reserves. While the Board reviewed the geological interpretation for these pools, the Board is unable to agree with Western Gas’ assessment in some cases and therefore a somewhat lower estimate of reserves has been adopted.

For pools in which Western Gas holds a partial interest, the Board and Western Gas also use different approaches to determine Western Gas’ share of cumulative production, and hence differences arise in the estimates for remaining established reserves for Western Gas producing interests. Western Gas determines its remaining reserves for a pool by deducting cumulative production from Western Gas’ initial marketable reserves. While Western Gas undoubtedly is in the best position to determine its cumulative production, this approach can have the effect of distorting the estimate of remaining Western Gas reserves for the pool if production by Western Gas to date has not been in proportion to Western Gas’ overall interest in the pool. The Board’s estimate of Western Gas’ remaining reserves is obtained by applying Western Gas’ percent control to the remaining reserves for the pool. Remaining reserves for the pool are determined by deducting cumulative pool production from initial reserves. This approach assumes that remaining production would be in proportion to the ownership interests in the pool and, with the data available to the Board, is the only viable means of assigning remaining reserves to specific producer interests.

Table A-1

Comparison of Estimates of Western Gas' Established Gas Reserves with the Applied-for Term Volume

10^9m^3 (Tcf)		
Western Gas[1]	NEB[2]	Applied-for[3] Volume
645.6	520.6	18.6
(22.8)	(18.4)	(0.66)

1. As of December 1, 1988. This estimate of reserves includes ERCB estimate for numerous small pools which are on Western Gas lands but for which Western Gas has not submitted an estimate of reserves. Without inclusion of these pools, the Western Gas estimate is 595.7 10^9m^3 (210 Tcf).
2. As of Decembe 1988.
3. Includs all of Western Gas' GH-3-91 applications but represents only a very small portion of Western Gas' total requirements.

During its assessment of Western Gas' reserves, the Board reviewed its data regarding Western Gas' contractual interests in gas units. The Board found that its percentage for estimates of the unit control Western Gas were frequently understated. Updated information has been used to develop the Board's estimate of these Western Gas reserves, and these data are now generally in agreement with those submitted by Western Gas. Differences in interpretation of Western Gas' contractual interests remain, however, for a number of non-unitized pools.

In summary, the Board's estimate of Western Gas' remaining established reserves is lower than the estimate provided by Western Gas. The discrepancy in estimates of reserves arises primarily from differences in geological and engineering evaluations of specific pools, but is also due to differences in interpretation of Western Gas' contracted lands position. The Board is cognizant of the difficulty in maintaining reliable current estimates of reserves for the large number of pools in Western Gas' supply portfolio and is aware that legitimate differences in technical evaluations arise due to the interpretative nature of reserves analysis. For these reasons, the Board will continue to review its reserves data on an ongoing basis in an effort to further assess the noted differences.

Gas Supply Contracts

A further issue relevant to consideration of Western Gas' gas supply is the extent to which its producers are contractually committed to Western Gas in the longer term. Western Gas submitted evidence in this regard during the GH-5-89 proceeding.

Western Gas' gas supply is contracted from approximately 750 producers and suppliers. The 30 November 1988 netback agreement between Western Gas and its producers established new termination dates for all of Western Gas' producer contracts by extending them to the economic life of the reserves. The agreement has been accepted by producers representing 99 percent of Western Gas' contracted supply and provides producers with three options related to their contracts with Western Gas. The options available to the producer are as follows:

(a) do nothing, in which ease the contracts remain as amended by the netback agreement and are extended to the economic life of the reserves under contract;

(b) exercise the "volume reduction entitlement option", which allows the producer, in the years following 1994, the opportunity to reduce contract volumes in a following year if a performance level of 75 percent rate-of-take is not achieved by TransCanada; and/or

(c) exercise the option to re-establish the initial contract termination date by serving notice four years prior to such date, to be effective after the 1993/94 contract year.

The specifics of each of these options are discussed below.

- Do Nothing Option

A producer can maintain the status quo under a contract and let it run to the end of the economic life of the reserves. Western Gas will continue to purchase and market the producer's gas under the terms of the agreement.

- Volume Reduction Option

If the rate-of-take from all of a producer's contracts is less than 75 percent in any contract year commencing on or after 1 November 1993, a producer may subsequently elect to reduce its volume obligation to Western Gas according to a formula in the agreement. The volume obligation may be reduced in any one or more of the following ways, provided that all Top Gas advances have been recovered:

(i) by terminating a contract (if one exists at an appropriate volume);

(ii) by reducing the reserves under contract through the deletion of a portion of the lands dedicated to the contract; and/or

(iii) by reducing the "Allocation Reference Quantity"[1] in effect under a contract, which provides the producer the right to sell gas produced from the contract lands in excess of the maximum daily quantity.

For each of the above methods, the rate-of-take from all of a producer's contracts would be the lower limit of the extent to which volume reduction can be implemented. The volume reduction option has

[1] The Allocation Reference Quantity established by the netback agreement is the minimum daily quantity of production specified in the original contract multiplied by 365.

the practical effect of allowing producers the flexibility to remove from Western Gas' supply base a portion of the supply between the producer's rate-of-take level and the 75 percent level.

- Termination Option

The termination option in the netback agreement gives a producer the right to terminate a contract with Western Gas by serving notice four years in advance. The earliest date that a contract can be terminated is 1 November 1994, and producers wishing to pursue this option were to notify Western Gas by 4 January 1991. This option is subject to there being no outstanding TopGas advances to the producer or any other party to the contract.

Western Gas indicated that contracts representing some 85 percent of its year-end 1989 total remaining reserves are eligible for contract termination between 1994 and 2005. The largest block of contracts, in terms of volume, is eligible for termination effective 1 November 1994. Western Gas estimated that this block would represent about 30 percent of its remaining reserves in 1994. Additionally, allowing for the production, this volume is significantly larger than the annual volumes eligible for contract termination in other years and exceeds the total volume eligible for termination between 1995 and 2005.

Western Gas estimated during the early stages of the GH-5-89 proceeding that producers representing less than 5 percent of its total remaining reserves on 31 October 1994 would exercise the Termination Option. This estimate was predicated on the belief that producers would opt for the Volume Reduction Option. Western Gas was of the view that producers might not be able to project beyond the required four-year notice period and that this time period would effectively act as a deterrent to contract termination. Western Gas also believed that the joint venture nature of the producing industry would deter producers from exercising the termination option because unanimity between partners would be difficult to attain for multi-party contracts.

As the GH-5-89 proceeding progressed, Western Gas revised its estimate of terminations to between seven and ten percent of its total remaining reserves as of 31 October 1994. This amount was equivalent to approximately one-third of the gas supply eligible for contract termination at that time.

The deadline for notification by producers intending to terminate contracts with Western Gas effective 1 November 1994 was extended from 1 November 1990 to 4 January 1991. Western Gas subsequently indicated that it had received termination notices from producers for approximately 14 percent of its total remaining reserves as of 31 October 1994. Thus, about one-half of the supply eligible for contract termination in November 1994 will be removed from Western Gas' gas supply portfolio via this option. Although producers' reasons for terminating their contracts are varied, Western Gas cited current low rates-of-take under particular contracts and consolidation of highly fractionated working interests through property acquisition as reasons why the level of contract termination was higher than it had previously expected.

In addition to extending the deadline for termination notices to 4 January 1991, Western Gas offered producers the option to roll-over the four-year notice period for eligible contracts for one year, so that notices on those contracts could be given 1 November 1991 for termination on 31 October 1995. Initially, a maximum of 14.2 10^9m^3 (0.5 Tcf) of remaining reserves was eligible for termination on 31 October 1995; that eligible volume will now be approximately 56.7 10^9m^3 (2 Tcf). Western Gas indicated that termination of approximately 19.8 10^9m^3 (0.7 Tcf) on 31 October 1995 was expected.

At the request of the Board during the GH-5-89 hearing, Western Gas presented a "worst case" scenario for contract termination which assumed that all producers would terminate their contracts at the earliest possible time. This case, which assumes that production continues at capacity and that reserves development on contract lands continues at historical rates, is presented in Figure A-1 along with the cumulative eligible volume and the actual termination expected for the 1994/1995 contract year. The cumulative volume eligible for contract termination in 1994 includes the roll-over of terminations discussed above. Volumes included under contracts which have not been terminated by producers may be carried forward and thereby are eligible for contract termination in 1995 and subsequent years. The worst case scenario does not include volumes which may be removed from the Western Gas supply pool by producers under the volume reduction option.

Western Gas received more notification of contract terminations effective 1 November 1994 than it had anticipated. However, it believes that the level of future terminations will be reduced considerably because higher rates-of-take under its producer contracts will be achieved through increased market requirements and declining supply capability. For these reasons Western Gas projects that its average rate-of-take for producers contracts will be above 75 percent when the reduction entitlement becomes effective in the 1994/95 contract year. Therefore, Western Gas does not anticipate any further significant reductions in supply under the volume reduction option. Western Gas further submitted that if partial de contracting options are available because the rate of take does not rise as expected, then the volume reduction option will have the desired result of bringing supply and requirements into line.

The extent to which the contract termination options in Western Gas' producer contracts are exercised may have implications for Western Gas' ability to contract new sales. Western Gas stated that as licences expire and renewals are sought, it will have to seek Board approval. However, its contractual provisions preclude it from making new commitments or renewing existing contracts if its RR/P ratio falls below ten. Assuming that production equals total contracted requirements, both Western Gas' and the Board's preliminary estimates indicate that, after allowance for those contract terminations effective 1 November 1994, the RR/P ratio for any year of the projection period would not fall below ten.

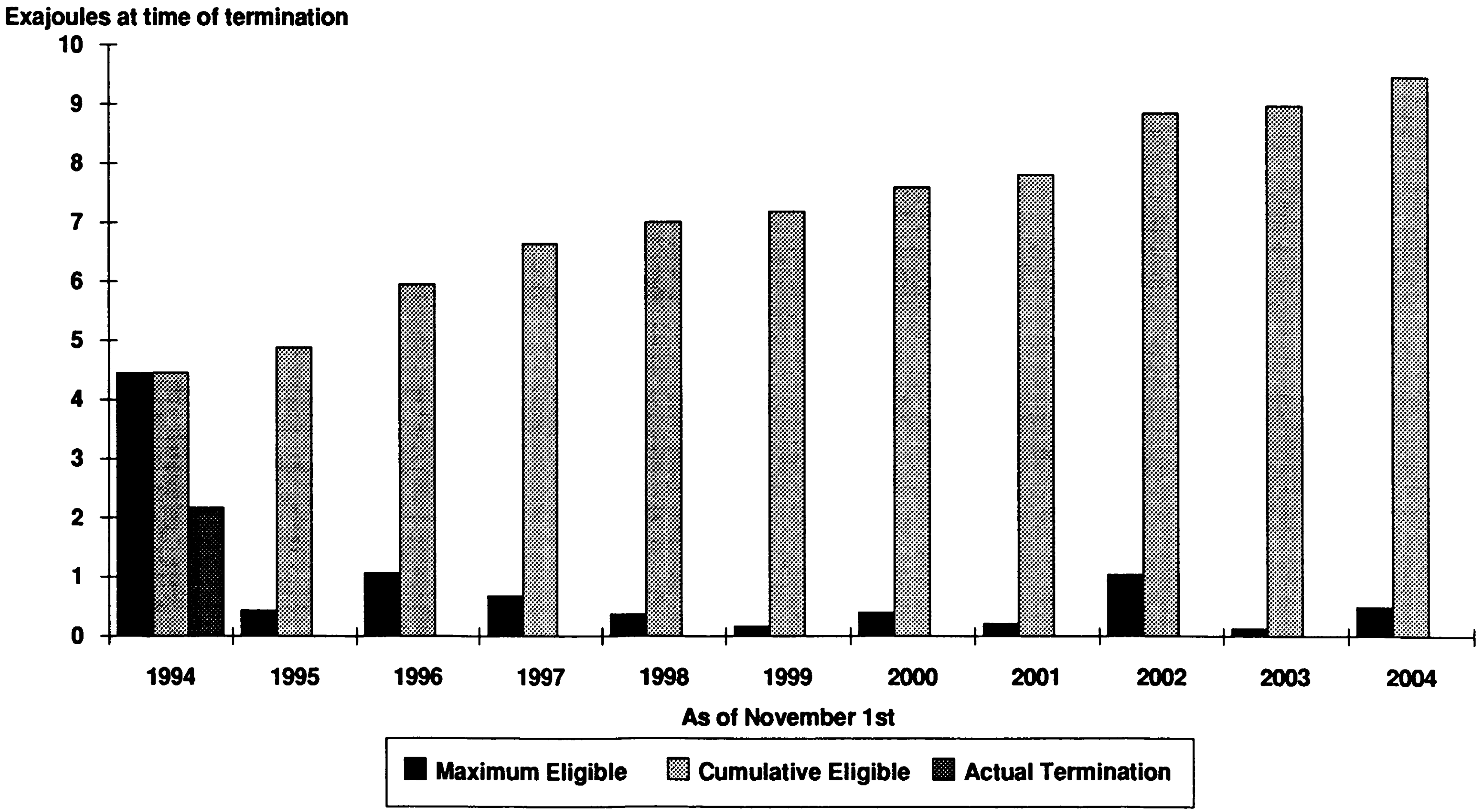
- Productive Capacity

In order to assess the adequacy of Western Gas' gas supply, it was necessary to compare projections of productive capacity relative to requirements under various scenarios. These scenarios relate to the extent to which contract termination by Western Gas' producers may occur and the outlook for requirements which is anticipated.

In all cases, both Western Gas' and the Board's projections of productive capacity have been adjusted to reflect production at the projected level of requirements. As well, projections of productive capacity reflecting both contract terminations effective 1 November 1994 and maximum possible contract terminations have been adjusted consistent with the methodology used by Western Gas. Productive capacity was reduced in the years following 1 November 1994 by percentages indicative of the amount of reserves lost due to contract termination. This methodology is somewhat conservative, in that the majority of the terminating contracts will have produced for well in excess of 20 years at the time of termination and would be generally at a higher rate of decline than the supply as a whole. Thus, this method foresees a greater impact on the total productive capacity in the remainder of the projection period than may actually materialize.

Figure A.1

Estimated Remaining Reserves Eligible for Termination



Two demand scenarios were examined. The first provides for the evergreening of both Western Gas' export and domestic requirements. It can be characterized as Western Gas' expected level of requirements if gas were to continue to flow to its traditional domestic and export markets. The second demand scenario examines only Western Gas' contracted domestic and export requirements, or simply its non-evergreened requirements. This is the level of demand to which Western Gas is currently contractually committed. Included in the early years of both requirements scenarios are Western Gas' estimates of excess gas sales to non-Western Gas markets from its contracted pools.

Three supply scenarios were developed to compare to these requirements scenarios. Both Board and Western Gas estimates of Western Gas' productive capacity were examined. Western Gas' projections include its estimates of productive capacity from reserves growth on contracted lands, whereas the Board projections represent productive capacity from established reserves only. Both the inclusion of reserves growth by Western Gas and the fact that the Board's estimates of established reserves are less than Western Gas' tend to make Western Gas' projections higher than the Board's, particularly in the latter part of the projection period.

The first supply scenario represents productive capacity from all remaining reserves under contract to Western Gas as of 31 October 1988, without any contract termination. The second supply scenario illustrates the effect of maximum contract termination. This scenario does not, however, reflect the impact of the volume reduction option which may occur in addition to the eligible volume for contract termination. The third supply scenario reflects the known contract termination notices effective 1 November 1994, but assumes that no further contract terminations occur. We would expect that Western Gas' future productive capacity would fall within the band between scenarios 2 and 3. As noted earlier, Western Gas does not expect future terminations to be very significant because higher rates-of-take under its producer contracts will be achieved through increased market requirements and declining supply capability.

Western Gas' evergreened domestic and export demand requirements are compared to all three Western Gas and Board supply scenarios in Figures A-2 and A-3, respectively.

Assuming no contract termination, Figure A-2 illustrates that Western Gas' estimates of productive capacity suggest that it would be able to meet fully evergreened requirements up to and including 1998, whereas Figure A-3 demonstrates that the Board's estimates suggest that Western Gas could meet its fully evergreened requirements up to and including 1997. Although the Board's estimate of reserves is significantly less than Western Gas', the Board believes that a higher rate-of-take than that used by Western Gas is feasible. This results in the Board's projection of productive capacity being higher than Western Gas' projection initially, and then lower towards the end of the term of the proposed licences. This is further influenced by Western Gas' inclusion of reserves growth on its contracted lands, whereas the Board's projection reflects only established reserves.

Assuming maximum contract termination, both Western Gas' and the Board's estimates of productive capacity, shown in Figures A-2 and A-3 respectively, suggest shortfalls from 1995 onwards. Furthermore, this presentation does not include any loss of gas supply which may occur through the volume reduction option.

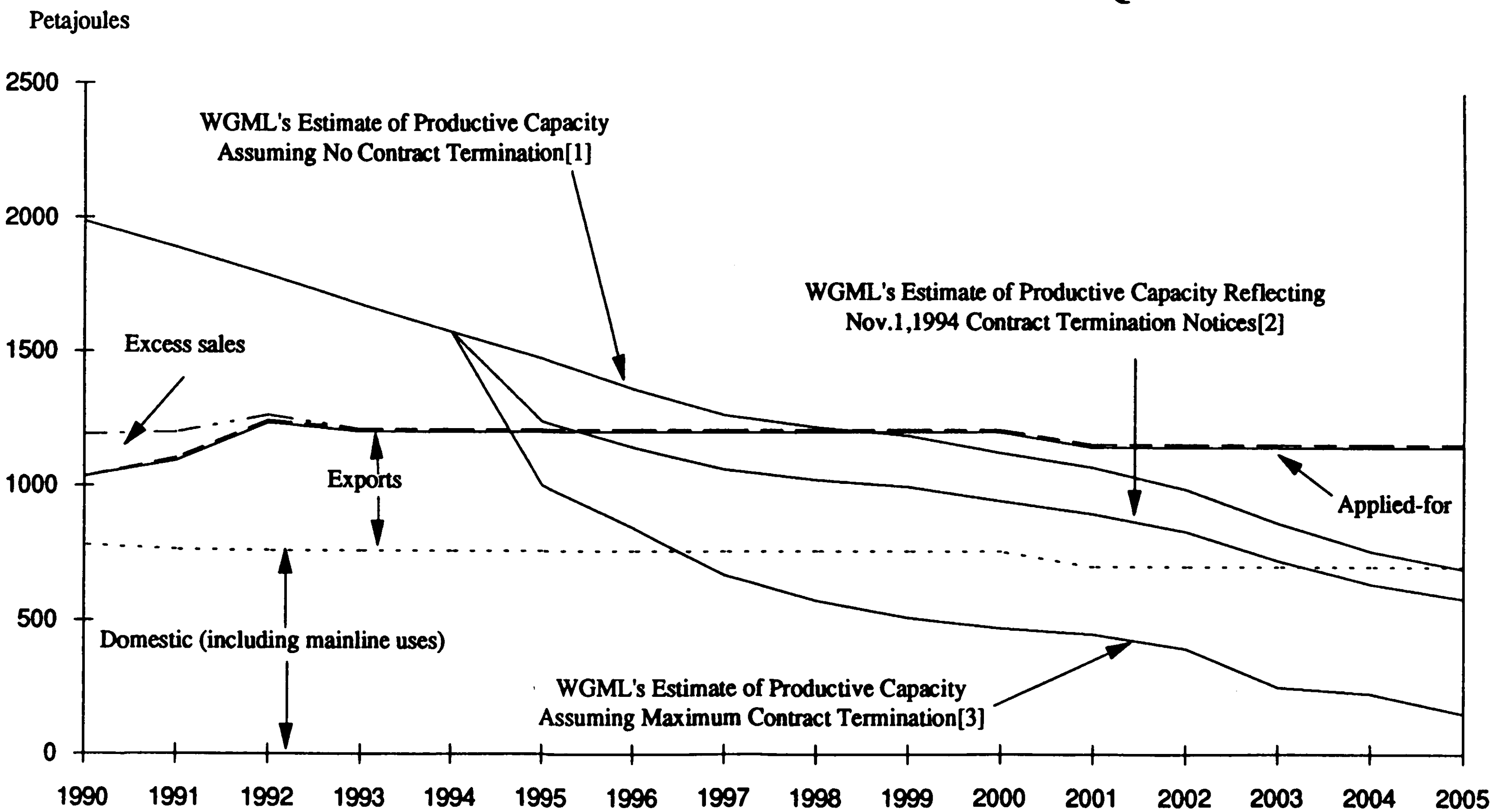
Both Western Gas' and the Board's estimates of productive capacity reflecting only the 1 November 1994 contract terminations indicate shortfalls commencing in 1996. As expected, these projected shortfalls are much less than those indicated for the maximum contract termination scenario.

Figure A-4 provides a comparison of Western Gas' and the Board's estimates of productive capacity to non-evergreened domestic and export requirements, that is to satisfy Western Gas' current and proposed contractual commitments only. Both Western Gas' and the Board's estimates of productive capacity reflecting the 1 November 1994 contract terminations indicate that Western Gas would be able to meet its current and proposed contractual commitments throughout the term of the proposed export licences. Figure A-4 also compares Western Gas' and the Board's productive capacity projections assuming maximum contract termination. Under this supply scenario, both Western Gas' and the Board's projections suggest that contracted requirements could not be met from 1999 to 2003.

While Western Gas expects to service the volumes included in the evergreened case, it indicated that, with respect to project specific supply, it is bound to serve only its contracted requirements. Western Gas emphasized that no party at the GH-5-89 proceeding substantially challenged its assertion that it had enough gas to meet its contracted requirements, and assured the Board that it will be able to manage its supply in order to meet these future requirements.

Figure A.2

COMPARISON OF WGML'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY TO WGML'S EVERGREENED DOMESTIC & EXPORT REQUIREMENTS



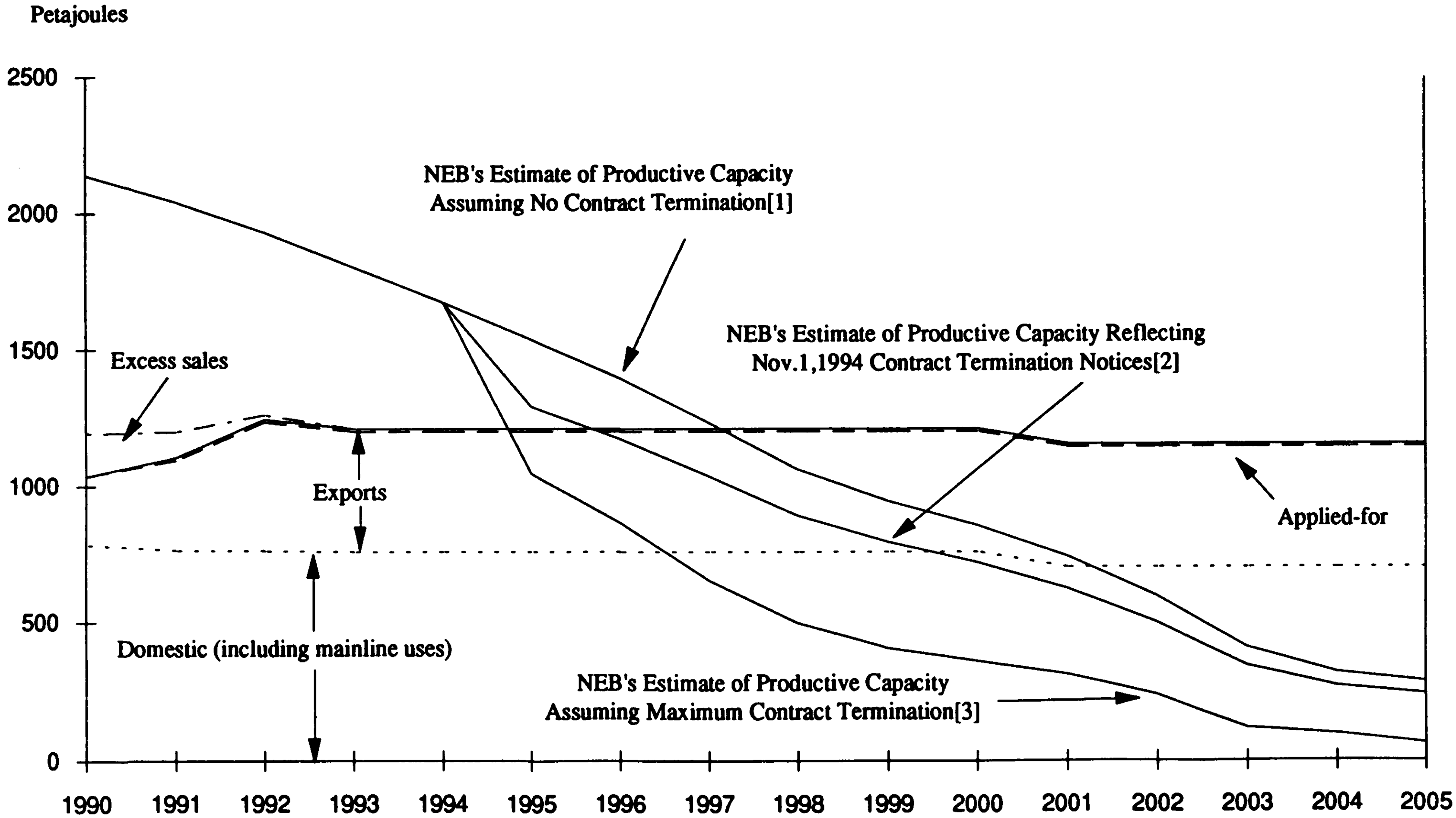
1. WGML's estimate of productive capacity assuming that no contract terminations occur over the projection period.

2. WGML's estimate of productive capacity reflecting termination notices received to date and effective in the 1994/95 contract year. No contract terminations beyond the 1994/95 contract year are reflected in this projection.

3. WGML's estimate of productive capacity assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible dates over the projection period.

Figure A.3

COMPARISON OF NEB's ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY TO WGML's EVERGREENED DOMESTIC & EXPORT REQUIREMENTS



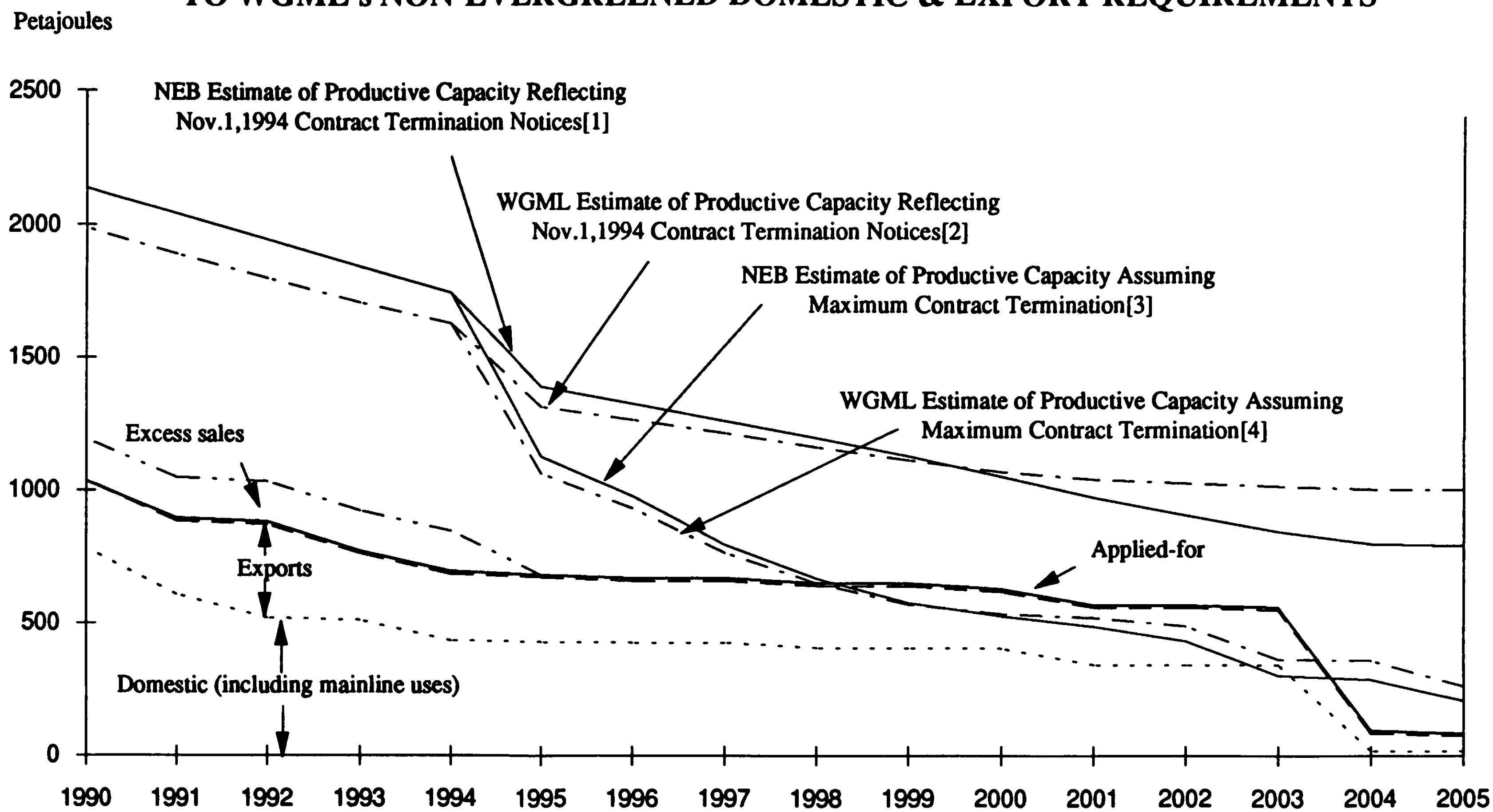
1. NEB's estimate of productive capacity assuming that no contract terminations occur over the projection period.

2. NEB's estimate of productive capacity reflecting termination notices received to date and effective in the 1994/95 contract year. No contract terminations beyond the 1994/95 contract year are reflected in this projection.

3. NEB's estimate of productive capacity assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible dates over the projection period.

Figure A.4

COMPARISON OF NEB's & WGML's ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY TO WGML's NON-EVERGREENED DOMESTIC & EXPORT REQUIREMENTS



1. NEB's estimate of productive capacity reflecting termination notices received to date and effective in the 1994/95 contract year. No contract terminations beyond the 1994/95 contract year are reflected in this projection.

2. WGML's estimate of productive capacity reflecting termination notices received to date and effective in the 1994/95 contract year. No contract terminations beyond the 1994/95 contract year are reflected in this projection.

3. NEB's estimate of productive capacity assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible dates over the projection period.

4. WGML's estimate of productive capacity assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible dates over the projection period.