CANADA

Office national de l'énergie

Reasons for Decision

Brooklyn Navy Yard Cogeneration Partners, L.P.

Husky Oil Operations Ltd.

ProGas Limited

Shell Canada Limited

Western Gas Marketing Limited

GH-5-93

February 1994

Gas Exports

Office national de l'énergie

Reasons for Decision

relativement à

Brooklyn Navy Yard Cogeneration Partners, L.P.

Husky Oil Operations Ltd.

ProGas Limited

Shell Canada Limited

Western Gas Marketing Limited

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

ProGas Limited

Applications Pursuant to Section 21 and Part VI of the *National Energy Board Act* to Amend Two Licences to Export Natural Gas

GH-5-93

February 1994

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Abbreviations

ACC	Annual Commodity Charge
ACQ	Annual Contract Quantity
Act	*National Energy Board Act*
ANR	ANR Pipeline Company
ANR Customer Group	Michigan Gas Utilities, Wisconsin Fuel & Light Company, Wisconsin Gas Company, Wisconsin Natural Gas Company, Wisconsin Power & Light Company, and Wisconsin Public Service Corporation
APMC	Alberta Petroleum Marketing Commission
APQ	Annual Purchase Quantity
Bcf	billion cubic feet
Board	National Energy Board
Bonneville	Bonneville Power Administration
BP	base price
BUG	Brooklyn Union Gas Company
Cascade	Cascade Natural Gas Company
Con Edison	Consolidated Edison Company of New York, Inc.
Crestar	Crestar Energy
DCQ	Daily Contract Quantity
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
DSQ	Daily Suspension Quantity
EARP Guidelines Order	*Environmental Assessment and Review Process Guidelines Order*
EIA	Export Impact Assessment
EMPR	(British Columbia) Ministry of Energy, Mines and Petroleum Resources
ERCB	(Alberta) Energy Resources Conservation Board

Exclusion List	List of automatic exclusions pursuant to the EARP Guidelines Order
FERC	(United States of America) Federal Energy Regulatory Commission
FS	Firm Service
GHR-1-87	*Review of Natural Gas Surplus Determination Procedures*
GIC	Gas Inventory Charge
GJ	gigajoule(s)
GLGT	Great Lakes Gas Transmission Limited Partnership
Husky	Husky Oil Operations Ltd.
IGTS	Iroquois Gas Transmission Systems, L.P.
Intercontinental	Intercontinental Energy Corporation
LDC	local distribution company
Lilco	Long Island Lighting Company
MAQ	Minimum Annual Quantity
MBP	Market-Based Procedure
MDQ	Maximum Daily Quantity
MGU	Michigan Gas Utilities
MMBtu	million British thermal units
MMcf	million cubic feet
MMQ	minimum monthly quantity
MW	megawatt (1000 kilowatts)
Navy Yard Partners	Brooklyn Navy Yard Cogeneration Partners, L.P.
NEB	National Energy Board
Northeast	Northeast Energy Associates, A Limited Partnership
North Jersey	North Jersey Energy Associates, A Limited Partnership
Northwest	Northwest Pipeline Corporation

NOVA	NOVA Corporation of Alberta
PanCanadian	PanCanadian Petroleum Limited
ProGas	ProGas Limited
QF	qualifying cogeneration facility
RMEC	Rocky Mountain Ecosystem Coalition
Salmon	Salmon Resources Limited
Shell	Shell Canada Limited
Tcf	trillion cubic feet
T-North service	service on the Westcoast System to Compressor Station No. 2
T-South service	service on the Westcoast System from Compressor Station No. 2 to the international border near Huntingdon, B. C.
Tenaska	Tenaska Gas Company and Tenaska Washington Partners II, L.P., collectively
Tenaska Gas	Tenaska Gas Company
Tenaska Washington Partners	Tenaska Washington Partners II, L.P.
TransCanada	TransCanada PipeLines Limited
U.S.	United States of America
Viking	Viking Gas Transmission Company
Westcoast	Westcoast Energy Inc.
Western Gas	Western Gas Marketing Limited
WF&L	Wisconsin Fuel and Light Company
WiGas	Wisconsin Gas Company
WNG	Wisconsin Natural Gas Company
WP&L	Wisconsin Power and Light Company
WPSC	Wisconsin Public Service Corporation

Recital and Appearances

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

AND IN THE MATTER OF applications under Part VI of the *National Energy Board Act* for new licences to export natural gas by:

Brooklyn Navy Yard Cogeneration Partners, L.P., Husky Oil Operations Ltd., ProGas Limited, Shell Canada Limited and Western Gas Marketing Limited;

AND IN THE MATTER OF applications made under Section 21 and Part VI of the *National Energy Board Act* to amend gas export licences GL-98 and GL-129 by;

ProGas Limited;

AND IN THE MATTER OF Hearing Order GH-5-93, as amended;

HEARD in Calgary, Alberta on 31 January 1994.

BEFORE:

R.L. Andrew, Q.C.	Presiding Member
R. Priddle	Member
R. Illing	Member

APPEARANCES:

L.E. Smith	Brooklyn Navy Yard Cogeneration Partners, L.P.
D.A. Holgate	Husky Oil Operations Ltd.
J.R.M. Kowch M.A.K. Muir	ProGas Limited
E.S. Decter	Shell Canada Limited
M.J. Samuel	Western Gas Marketing Limited
N. Sauder	Crestar Energy Inc.
J. St. Louis	Pan-Alberta Gas Limited
J.L. Evans	Tenaska Gas Corporation
M. Sawyer	Rocky Mountain Ecosystem Coalition
J. Snider G. Nettleton	Board Counsel

Part VI - Gas Export Licence Applications

1.1 The Applications

During the GH-5-93 proceeding, the National Energy Board ("the Board or NEB") examined seven applications for sixteen gas export licences from the following parties:

1. Brooklyn Navy Yard Cogeneration Partners, L.P. ("Navy Yard Partners");
2. Husky Oil Operations Ltd. ("Husky");
3. ProGas Limited ("ProGas");
4. Shell Canada Limited ("Shell");
5. Western Gas Marketing Limited ("Western Gas").

ProGas also requested amendments, pursuant to subsection 21(2) of the *National Energy Board Act* ("the Act"), to Licences GL-129 and GL-98. The proposed amendments would increase the authorized export volumes and extend the term of GL-129, and reduce the authorized export volumes under GL-98.

Table 1-1 provides a summary of each export licence application reviewed during the GH-5-93 proceeding.

1.2 Environmental Screening

The purpose of the environmental screening is to enable the Board to reach one of the conclusions required by section 12 of the *Environmental Assessment and Review Process Guidelines Order* ("EARP Guidelines Order"). To that end, the Board performed a screening, pursuant to Hearing Order GH-5-93, wherein it considered submissions from each of the applicants.

Each applicant filed statements with the Board concerning the potential environmental effects and the social effects directly related to those environmental effects that would be caused by the sending or the taking of gas from Canada.

ProGas, Shell and Western Gas stated that the development of new gas transmission facilities under the Board's jurisdiction would not be required to accommodate their applied-for exports. As a result, they submitted that their export licence applications fell within the ambit of the Board's List of Automatic Exclusions ("Exclusion List") pursuant to the EARP Guidelines Order .

Table 1-1
Summary of Applied-for Licences
GH-5-93

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. Navy Yard Partners	Navy Yard Partners (cogen. plant)	15 years following first deliveries	Iroquois, Ontario	750.0 (26.5)	274.0 (9.7)	4110.0 (145.0)
2. Husky	Tenaska (cogen. plant)	15 years following first deliveries	Huntingdon, B.C.	398.0 (14.0)	145.3 (5.1)	2179.1 (76.9)
3. ProGas* (ANR)	MGU (system supply)	7 years from 1 Nov. 93	Emerson, Manitoba	75.7 (2.7)	27.6 (1.0)	193.5 (6.8)
	WF&L (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	84.8 (3.0)	31.0 (1.1)	309.7 (10.9)
	WiGas (system supply)	7 years from 1 Nov. 93	Emerson, Manitoba	807.1 (28.5)	294.6 (10.4)	2062.0 (72.8)
	WNG (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	304.0 (10.7)	111.0 (3.9)	1109.7 (39.2)
	WP&L (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	95.9 (3.4)	35.0 (1.2)	350.2 (12.4)
	WPSC (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	313.8 (11.1)	114.5 (4.0)	1145.3 (40.4)
4. ProGas**	Intercontinental (2 cogen. plants)	7 years from 31 Oct. 2006	Niagara Falls, Ont.	2039.6 (72.0)	744.5 (26.3)	5211.2 (184.0)
5. ProGas* (Wisconsin)	WPSC (system supply)	4 years from 1 Nov. 93	Emerson, Manitoba	226.4 (8.0)	82.6 (2.9)	330.5 (11.7)
	WiGas (system supply)	9 years from 1 Nov. 93	Emerson, Manitoba	187.4 (6.6)	68.4 (2.4)	615.6 (21.7)
6. Shell	Tenaska (cogen. plant)	15 years following first deliveries	Huntingdon, B.C.	609.0 (21.5)	223.0 (7.9)	3002.0 (106.0)
7. Western Gas	WiGas (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	2533.0 (89.4)	927.0 (32.7)	9270.0 (327.0)
	WPSC. (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	776.0 (27.4)	283.0 (10.0)	2830.0 (100.0)
	WNG (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	752.0 (26.5)	275.0 (9.7)	2750.0 (97.1)
	WP&L (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	237.0 (8.4)	86.7 (3.1)	867.0 (30.6)
	WF&L (system supply)	10 years from 1 Nov. 93	Emerson, Manitoba	210.0 (7.4)	76.8 (2.7)	768.0 (27.1)

* ProGas has also applied for an amendment to Licence GL-98 to have these volumes removed.

** ProGas has applied for an amendment to Licence GL-129 to extend the term by seven years to 31 October 2013 and for a net increase to the term volume of 5 211.1 10^6m^3 (184.0 Bcf).

The export proposals by Navy Yard Partners and Husky would require new facilities on the pipeline systems of TransCanada PipeLines Limited ("TransCanada") and Westcoast Energy Inc. ("Westcoast") respectively. Navy Yard Partners and Husky submitted that pursuant to the Federal Court of Appeal's decision in *Attorney General of Quebec* v. *National Energy Board*, [1991] 3 F.C. 443, the Board's jurisdiction with respect to the environmental screening of gas exports is restricted to the actual export of the energy commodity in question. Navy Yard Partners and Husky stated that it was their position that an assessment of the environmental impact of exporting natural gas therefore relates only to the sending or taking of gas by means of a high pressure underground pipeline from Canada to the United States of America ("U.S."). Moreover, Navy Yard Partners and Husky stated that the environmental effects of constructing new pipeline facilities required for exporting such gas would be properly reviewed in the course of the Board's Part III facilities review.

By letter dated 22 December 1993, Rocky Mountain Ecosystem Coalition ("RMEC") applied for intervenor status in GH-5-93. That letter indicated that the RMEC was interested in examining three aspects related to the export applications: (1) the causal relationship between export applications and upstream environmental effects which impair ecosystem integrity and biodiversity; (2) any uncertainty and risk to Canadian gas consumers having regard for energy security, sovereignty, social, health and economic implications of the applications, and; (3) the public interest. By letter dated 5 January 1994, RMEC was granted late intervenor status in GH-5-93. RMEC was advised that aspect (1) did not fall within the bounds of the Board's jurisdiction and therefore, the Board was not prepared to hear evidence on this aspect. RMEC replied by letter dated 10 January that the above listed aspects needed to be examined in the context of the GH-5-93 hearing to reflect the spirit of the EARP Guidelines Order; consequently, RMEC stated that it would be presenting arguments based on questions of law and jurisdiction in support of its position. By letter dated 19 January 1994, the Board reiterated its position and its refusal to consider evidence which related to the causal relationship between export applications and upstream environmental effects.

Views of the Board

The Board, by means of a review pursuant to the EARP Guidelines Order, has completed its environmental screening of the applications considered in this hearing. The Board has concluded that the applications of ProGas, Shell and Western Gas are for gas export licences where the development of new facilities for gas transmission under the Board's jurisdiction would not be required. The Board has determined that these applications fall within the ambit of Note 3 of the Board's Exclusion List and may be excluded from further environmental assessment.

As export proposals by Navy Yard Partners and Husky would require new facilities to be constructed on the TransCanada and the Westcoast systems respectively, they are not excluded from the EARP Guidelines Order process. For the Navy Yard Partners and Husky gas export applications, the Board has determined, pursuant to section 12 of the EARP Guidelines Order that none of subsections (a) to (f) set out therein are applicable as there are no potentially adverse environmental effects associated with the sending of gas from Canada.

The Board is of the view that the upstream environmental matters raised by RMEC are dealt with in other forums and that the concern expressed by RMEC does not represent a level of public concern such as to make it desirable to refer the export proposals to the Minister of the Environment for public review by a Panel.

1.3 Market-Based Procedure

The Board, in considering an export application, must take into account section 118 of 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 must satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada.

In July 1987, pursuant to a Review of Natural Gas Surplus Determination Procedures ("GHR-1-87"), the Board implemented a new procedure, known as the Market-Based Procedure ("MBP"), founded on the premise that the marketplace would generally operate in such a way that Canadian requirements for natural gas would be met at fair market prices.

The MBP provides that the Board will act in two ways to ensure that natural gas to be licensed for export is both surplus to reasonably foreseeable Canadian requirements and in the public interest: it will hold public hearings to consider applications for licences to export natural gas, and it will monitor Canadian energy markets on an ongoing basis.

The public hearing portion of the MBP provides that the Board consider:

- complaints, if any, under the Complaints Procedure;
- an Export Impact Assessment ("EIA"); and
- any other considerations that the Board deems relevant to its determination of the public interest.

The following description of these three components is general in nature and applies to each application heard in GH-5-93.

1.3.1 Complaints Procedure

The basic premise of the Complaints Procedure is that, in a market which is working satisfactorily, Canadian purchasers will be able to obtain domestic natural gas supplies under contract on terms and conditions, including price, similar to those offered to purchasers in the U.S. In order to test whether the market is in fact working in this manner, in its GHR-1-87 Reasons for Decision the Board stated that:

> "The inclusion of a complaints mechanism in the new surplus determination procedures is based on the principle that gas should not be authorized for export if Canadian users have not had an opportunity to buy gas for their needs on terms and conditions similar to those of the proposed export. Applicants for export licences will have to be prepared to address any concerns on this score which may be identified in the complaints procedure ...."

The Complaints Procedure seeks to ensure that Canadian gas buyers who have been active in the market have access to gas on terms and conditions no less favourable than export customers. The Complaints Procedure enables these buyers to assess the terms and conditions of the gas sales contracts underlying export licence applications relative to the terms and conditions they are being offered. If the terms and conditions being offered to export customers are more favourable than those available to domestic customers, a Canadian buyer may wish to file a complaint with the Board. The Board would adjudicate each complaint on the basis of an assessment of whether, as a matter of fact, the complainant has or has not been able to obtain additional gas supplies on terms and conditions, including price, similar to those contained in the gas export licence application submitted to the Board.

Domestic gas purchasers who wish to file a complaint must demonstrate that they have attempted to contract for additional gas supplies and that they have not been able to obtain such supplies on terms and conditions similar to those contained in the gas sales contract. At the same time, export licence applicants are expected to respond to concerns expressed by a complainant. If the Board were to find that a complaint is valid, it would then have to determine what action needs to be taken to remedy the situation. This could involve a delay in the licence proceeding, a denial of the export licence application or some other action appropriate to the circumstances of the particular application.

1.3.2 Export Impact Assessment

The purpose of the EIA is to allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

The Board periodically produces an EIA using several projections of exports. The study, which is prepared in consultation with the natural gas industry and other interested parties, covers long-term natural gas supply, demand, prices and export levels and endeavours to provide an adequate statement of assumptions and explanation of the analytical technique used.[1]

Applicants and intervenors have the option of using the Board's analysis or of preparing and submitting their own analysis. In the absence of any adjustment-related problems being identified by the Board itself or being raised by interested parties, the Board presumes that the proposed export would not cause a market-adjustment problem.

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[1] By letter dated 8 December 1993, the Board announced changes to the EIA process. Commencing with the supply/demand report to be issued in mid-1994, the Board will include in those reports an analysis of the long-term implications of alternate export levels for Canadian markets. These reports will be supplemented by an assessment of market adjustment issues in the Board's Natural Gas Market Assessment reports.

The applicants examined in these Reasons, with the exception of Western Gas, adopted the Board's most recent EIA, dated 7 September 1989. Western Gas chose to adopt the Board's draft EIA dated 3 September 1992.

1.3.3 The Other Public Interest Considerations

As part of its assessment of the other public interest considerations, the Board normally:

- makes an assessment of the likelihood that licensed volumes will be taken;
- makes an assessment of the durability of gas sales contracts;
- has regard to whether gas sales contracts were negotiated at arm's length;
- verifies that there is producer support for a gas export application;
- verifies that there are provisions in the gas sales contracts for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contract; and
- determines the appropriate length of term for an export licence, having regard to:

(i) evidence on the adequacy of the gas supply available to the export licence applicant to support the applied-for volumes over the requested licence term;

(ii) evidence on the necessity of the requested term in light of the terms of the associated gas sales and transportation contracts and the terms of the approvals from other regulatory bodies; and

(iii) any other evidence which the Board deems to be relevant to the appropriate term of the licence.

The above statement on the other public interest considerations should be interpreted as providing guidance to parties as to which considerations the Board normally has regard to in assessing the merits of gas export licence applications. However, in the context of each specific export licence application, the Board has regard to whatever factors appear to it to be relevant to the Canadian public interest.

In assessing the considerations above, the Board takes into account information regarding gas supply, transportation, markets, sales contracts and the status of regulatory authorizations. This information is provided by the applicant in response to the information filing requirements of the Board's *Part VI Regulations* and during the public hearing process.

Gas Supply

In its assessment of gas supply, the Board reviews the contractual arrangements pertaining to supply and the adequacy of both reserves and productive capacity.

In making its assessment as to the adequacy of the gas supply available to the export licence applicant to support the applied-for volumes over the requested licence term, the Board is flexible but normally expects applicants to demonstrate that established reserves are equal to or exceed the applied-for volume and that productive capacity is adequate to meet the proposed annual export volumes over the majority of the applied-for licence term.

Each applicant is required to provide an estimate of established reserves for those fields from which it intends to produce gas for the proposed export. The Board conducts geological and engineering analyses of each applicant's gas supply in order to prepare its own estimate of the applicant's 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 an assessment of the ownership and contractual status of all pools included in the applications are also done.

The Board uses its estimate of reserves, along with basic deliverability data for each pool for which estimates of reserves were submitted, in preparing its productive capacity projections. These projections are generally adjusted to reflect production at the annual level of requirements. 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 usually based on an annual load factor of 100 percent and may therefore somewhat overstate each applicant's actual supply requirements. If load factors are lower than anticipated, productive capacity would be sustained beyond the time the Board's analysis indicates.

Transportation

Regarding the transportation arrangements underpinning an export project, the Board reviews the status of upstream and downstream transportation arrangements, including all transportation contracts, either in final form or as precedent agreements. The Board also considers the term and contracted capacity of the transportation arrangements.

Markets

The applications dealt with in GH-5-93 were for sales to two types of end-use markets: sales for system supply and sales to cogeneration facilities. The Board's review of these types of markets includes consideration of the following for each market type:

- for exports for system supply, consideration of the purchaser's current and projected requirements and supply portfolio with a view to determining the need for and the role of the Canadian gas supply within that portfolio; and,

- for exports to a cogeneration facility, consideration of the contractual chain, from the gas contract to the power and thermal sales contracts. The Board also considers the markets for the power and thermal output of the facility and the status of project financing and construction schedules.

For each type of end-use market, the review includes consideration, among other items, of the load factors at which the proposed exports are expected to flow.

Sales Contracts

The Board's review of the contractual arrangements includes consideration of the contractual obligations between the Canadian sellers and the U.S. buyers, including executed gas sales contracts. The Board's review also includes any resale arrangements that occur beyond the international boundary sale point, where such arrangements have a direct effect on the international sales agreement, including the filing of these downstream contracts.

Status of Regulatory Authorizations

The Board reviews the status of pertinent regulatory authorizations in Canada and the U.S., including provincial removal authorizations, Department of Energy, Office of Fossil Energy ("DOE/FE") import authorization and, for cogeneration facilities, qualifying cogeneration facility ("QF") certification under the U.S. Public Utility Regulatory Policies Act.

The Board's review also includes evidence of producer support and the status of any necessary state regulatory commission approvals.

1.4 Sunset Clauses

It has generally been Board practice in issuing a gas export licence to set an initial period of time during which, if the export of gas commences, then 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 starts to flow 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.

As a matter of general policy, and after questioning each applicant, the Board has set the timeframe by which exports must commence at approximately two years from the expected commencement of the licence term.

Views of the Board

The Board notes that there were no complaints registered with respect to the applications for export licences in the GH-5-93 proceeding.

All of the applicants examined in these Reasons adopted the Board’s EIA. As neither the Board nor any interested parties identified any adjustment-related problems, the Board concludes that the proposed exports would not cause a market-adjustment problem.

Since no complaints were registered with respect to the subject applications and the Board has determined that the proposed exports would not cause a market-adjustment problem, the Board is satisfied that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada.

The remaining chapters of these Reasons review the evidence of each applicant pertaining to the Other Public Interest Considerations. The findings of the Board in respect of these considerations and any other factors the Board has deemed to be relevant are contained in the "Views of the Board" section at the end of each chapter.

Brooklyn Navy Yard Cogeneration Partners, L.P.

2.1 Application Summary

By application dated 21 October 1993, Navy Yard Partners sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	for 15 years following the date that the cogeneration facility begins commercial operation	
Point of Export	-	Iroquois, Ontario	
Maximum Daily Quantity	-	750.0 10^3m^3	(26.5 MMcf)
Maximum Annual Quantity	-	274.0 10^6m^3	(9.7 Bcf)
Maximum Term Quantity	-	4 110 10^6m^3	(145.0 Bcf)
Tolerances	-	ten percent per day and two percent per year	

The gas proposed for export would be produced from the Alberta supply pools of Crestar Energy ("Crestar") and PanCanadian Petroleum Limited ("PanCanadian"). The gas would be transported on the NOVA Corporation of Alberta ("NOVA") system to the TransCanada system at the contract delivery point near Empress, Alberta. The gas would then flow on the TransCanada system to the international border near Iroquois, Ontario. At this point, the gas would flow on the Iroquois Gas Transmission System, L.P. ("IGTS") to the Long Island Lighting Company ("Lilco"). Lilco will in turn exchange this gas for an equivalent amount delivered to Brooklyn Union Gas Company ("BUG") which will transport the gas to the cogeneration facility in Brooklyn, New York. Electrical and/or thermal energy produced by the cogeneration facility would be purchased by Consolidated Edison Company of New York, Inc. ("Con Edison"), Brooklyn Navy Yard Development Corporation, Domino Sugar, and the Red Hook Water Pollution Control Plant.

2.2 Gas Supply

2.2.1 Supply Contracts

Gas supply contracts were not required as Crestar and PanCanadian will provide the gas from their Alberta supply pools. No specific pools have been contractually dedicated by Crestar or PanCanadian to the proposed sale.

2.2.2 Reserves

Table 2-1 shows that the Board's estimate of Navy Yard Partners' reserves is ten percent higher than that submitted by Navy Yard Partners and is much greater than each producer's total requirements including the applied-for term volume. The estimates of reserves provided by the applicant for these supply pools are those recognized by the Alberta Energy Resources Conservation Board ("ERCB").

Table 2-1

Comparison of Estimates of Navy Yard Partners' Established Gas Reserves with the Applied-for Term Volume
10^6m^3
(Bcf)

	Navy Yard Partners[1]	NEB[1]	Applied-for[2] Volume
Crestar	11 897 (420.0)	13 716 (484.2)	N/A
PanCanadian	13 945 (492.3)	14 664 (517.6)	N/A
Total	25 842 (912.3)	28 380 (1,001.8)	4 110 (145.0)

1. As of 31 December 1992.
2. This represents about 18 percent of Crestar's and 36 percent of PanCanadian's total requirements of 9 595 10^6m^3 (339 Bcf) and 7 049 10^6m^3 (249 Bcf), respectively.

2.2.3 Productive Capacity

Figure 2-1 compares the Board's and Crestar's projections of productive capacity with Crestar's annual requirements. Both the Board's and Crestar's projections show that Crestar has adequate gas supply over the proposed export term.

A comparison of the Board's and PanCanadian's projections of productive capacity with its annual requirements is shown in Figure 2-2. Both the Board's and PanCanadian's projections show that PanCanadian has adequate gas supply to meet its total requirements over the proposed export term.

2.3 Transportation

Crestar and PanCanadian have each applied for the requisite capacity on the NOVA system. Navy Yard Partners expects to execute a precedent agreement, shortly after the hearing, for firm service ("FS") on the TransCanada system for a term of 20 years. On 28 July 1993, Navy Yard Partners executed a precedent agreement with IGTS for FS over a 20-year term. Navy Yard Partners also expects to execute a 20-year FS precedent agreement with BUG shortly after the hearing. It is expected that new facilities will be required on each pipeline system to deliver the proposed exports.

Delivery of gas from the BUG system to the cogeneration facility requires construction of a new pipeline lateral approximately 60 metres (200 feet) in length. BUG is expected to construct the pipeline lateral in the spring of 1995.

Figure 2-1

Comparison of Crestar's and NEB's Estimates of Annual Productive Capacity

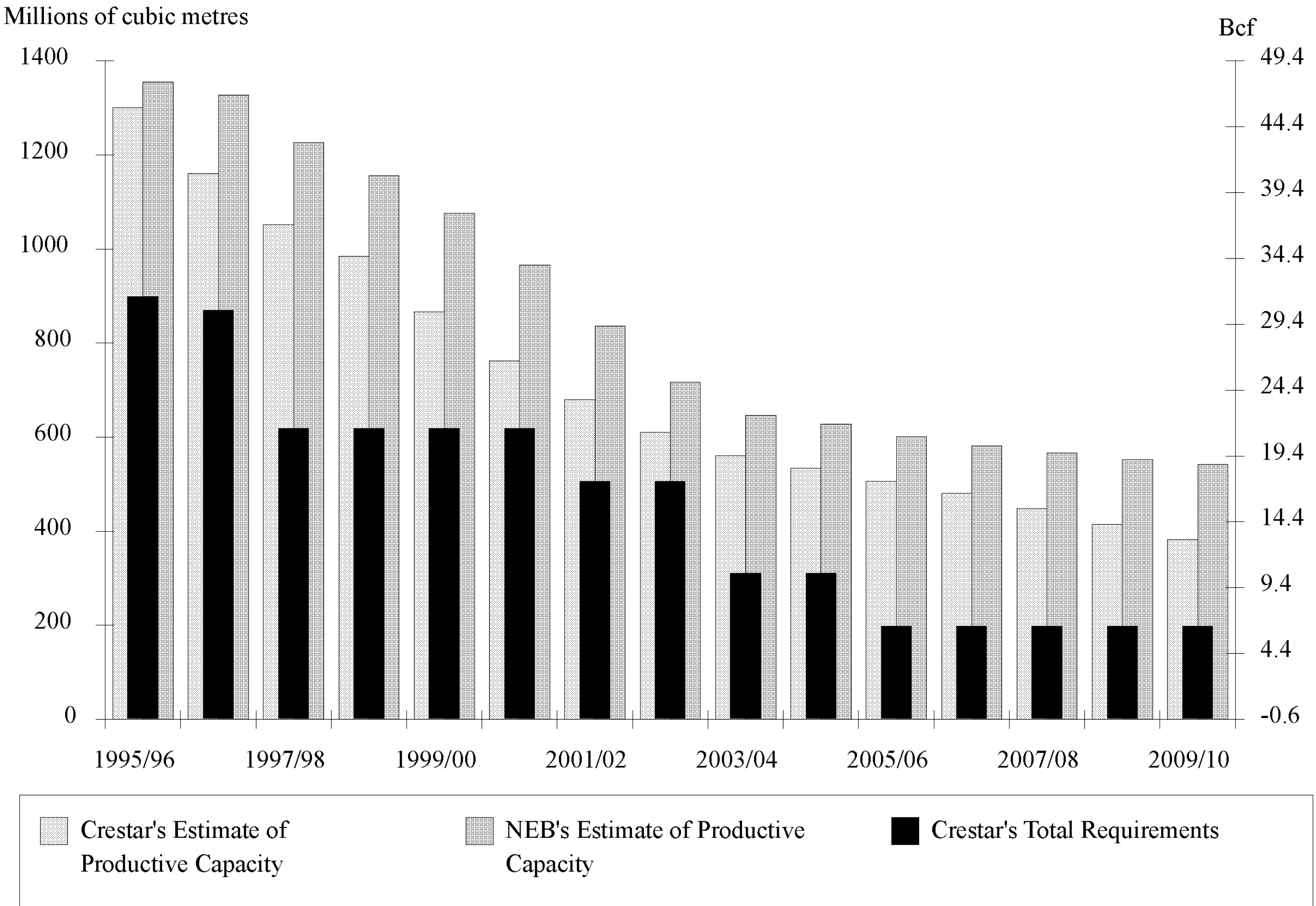
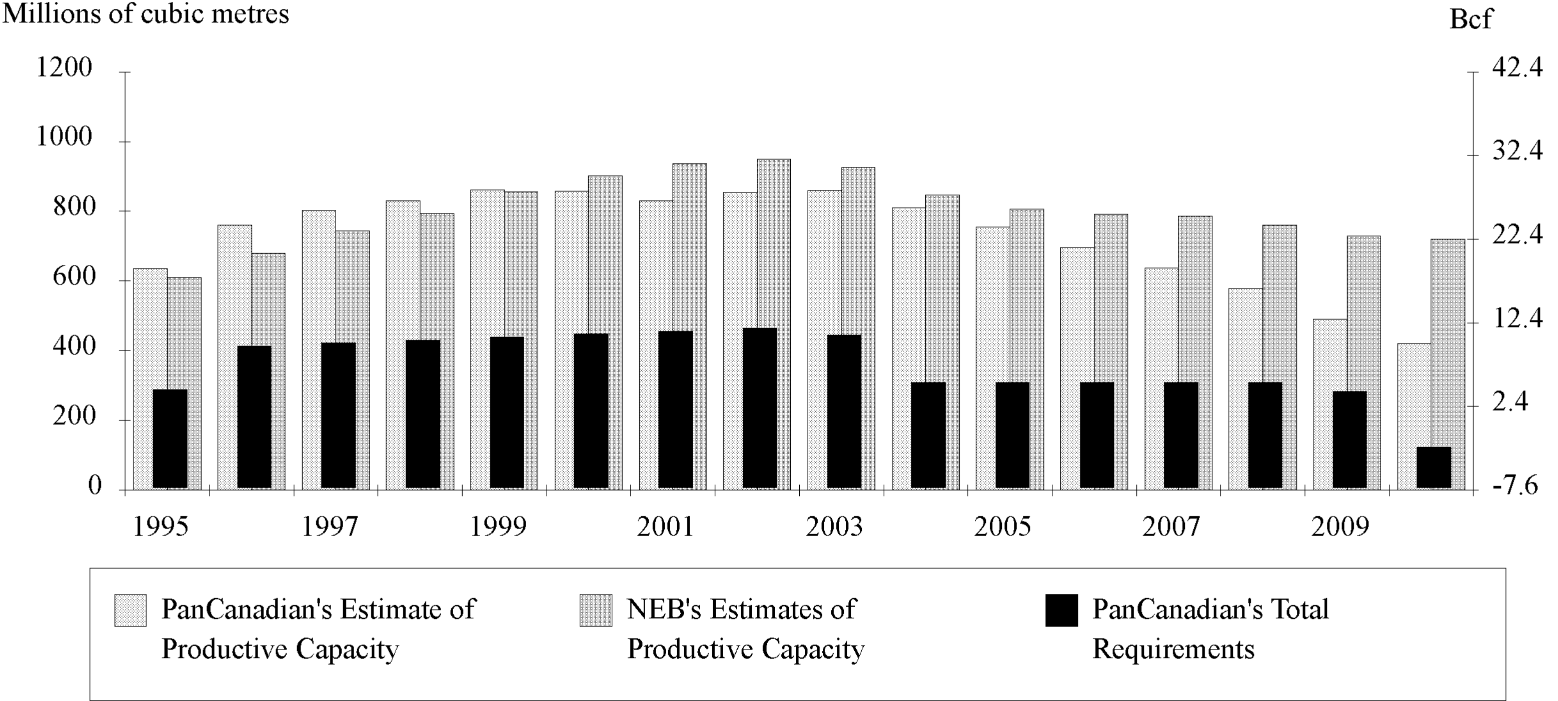


Figure 2-2

Comparison of PanCanadian's and NEB's Estimates of Annual Productive Capacity



2.4 Market

Navy Yard Partners proposes to develop a 286 MW gas fired cogeneration facility within the existing Building B-41 Powerhouse of the Brooklyn Navy Yard in Brooklyn, New York. Existing equipment in the former power plant will be removed and the building will be structurally modified to conform to the new equipment. Commercial operation of the cogeneration facility is expected to commence by 1 November 1995.

Electrical power produced by the cogeneration facility would be purchased by Con Edison pursuant to three power purchase agreements with terms ending on 31 December 2024.

Under full load operation the cogeneration facility will require approximately 1 560 $10^3m^3/d$ (55 MMcf/d) of natural gas of which 750 $10^3m^3/d$ (26.5 MMcf/d) would be provided from Canadian sources and the remainder from the U.S. Gulf Coast.

Navy Yard Partners has also entered into a fuel management agreement with Lilco dated 19 August 1993. As part of this agreement, Lilco has agreed to purchase any gas which Navy Yard Partners does not use.

2.5 Gas Sales Contracts

Navy Yard Partners will obtain its Canadian gas supply pursuant to gas sales agreements executed on 21 October 1993 with Crestar and PanCanadian. The term of each contract will continue for fifteen years following the date of commercial operation of the cogeneration facility. The contracts may be terminated by either Navy Yard Partners or the Canadian suppliers unless the necessary long-term Canadian and U.S. regulatory authorizations and transportation agreements are obtained by the closing of construction financing. Navy Yard Partners must also receive a parental guarantee from Crestar for its obligations. Construction financing is expected to close in May 1994.

The gas sales contract with Crestar provides for a Maximum Daily Quantity ("MDQ") of 10 546 GJ (10,000 MMBtu) plus fuel gas. If Navy Yard Partners fails to purchase 100 percent of the sum of the MDQs in any year, Crestar will be paid the commodity charge component of the contract price multiplied by the shortfall volume. Should Crestar fail to deliver the quantity of gas nominated on any one day, Navy Yard Partners will be indemnified for the incremental costs incurred in purchasing alternate fuel supplies.

The contract price to be paid to Crestar consists of two components, a demand charge and commodity charge. Prior to 1 January 1996, the demand charge would be $U.S. 0.14/GJ ($U.S. 0.15/MMBtu) while the commodity charge would be $U.S. 1.83/GJ ($U.S. 1.93/MMBtu). Effective 1 January 1996 the demand charge and commodity charge components will be escalated four percent annually.

Commenting on the pricing mechanism, Crestar stated that a varied portfolio of markets and prices, including fixed price/fixed escalator contracts, are in its commercial interest.

An MDQ of 15 819 GJ (15,000 MMBtu) is provided for in the contract with PanCanadian. Navy Yard Partners agrees to pay PanCanadian, on a monthly basis, the contract price multiplied by the sum of the MDQs in a month. However, if PanCanadian fails to deliver the nominated quantities, it must reimburse Navy Yard Partners for the incremental costs incurred in purchasing alternate fuel supplies.

The contract price to be paid to PanCanadian would be $U.S. 1.92/GJ ($U.S. 2.02/MMBtu) prior to 1 January 1996. Commencing on that date the contract price shall be adjusted by a floating index factor, weighted 70 percent, and a fixed index factor, weighted 30 percent. The floating index factor is based on the combined arithmetic average of nine U.S. Gulf Coast gas indices while the fixed index factor is 1.041.

As a provision in both gas sales contracts Crestar, PanCanadian and Navy Yard Partners have accepted the risk that the respective contract prices may be above or below the market price for gas at any time.

The parties may submit to binding arbitration should any dispute arise from the contracts.

2.6 Status of Regulatory Authorizations

Crestar and PanCanadian have filed applications for energy removal permits from the ERCB on 20 December 1993 and 30 November 1993 respectively. Decisions on the applications are pending.

On 26 January 1994 Navy Yard Partners applied to the DOE/FE for a long-term import authorization.

Views of the Board

The Board notes that Navy Yard Partners is contractually obligated to purchase the MDQs in any year under the two gas sales contracts. In addition, the Board recognizes that Navy Yard Partners' take obligation will be supported by Lilco. The Board is also cognizant that the markets for the electricity and thermal energy are likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes sought to be licensed will be taken.

The Board notes the market-oriented approach used to determine the PanCanadian contract price on an annual basis. With regard to the Crestar contract, the Board takes note of Crestar's comment that a varied portfolio of markets and prices, including fixed price/fixed escalator contracts are in its commercial interest. The Board also notes that Navy Yard Partners and both Canadian suppliers have agreed to accept the risk that the contract prices may be above or below market price at any time. The gas sales contracts are also subject to binding arbitration. The Board is thus satisfied that the gas sales contracts will remain attractive to the parties over their proposed terms, and are therefore durable.

The Board has reviewed the gas sales contracts between Navy Yard Partners and each of Crestar and PanCanadian and notes that they have been negotiated at arm's length.

Since Crestar and PanCanadian own the gas supply destined for export, a finding of producer support is not necessary.

The Board notes that, in the case of Crestar contract, the contract price contains a demand charge component for the recovery of NOVA demand charges throughout the term of the contract. The price that PanCanadian would receive will provide for the recovery of NOVA demand charges. TransCanada demand charges are the responsibility of Navy Yard Partners. Therefore, the Board is satisfied that there are provisions in the gas sales contracts for the payment of the associated transportation demand charges on Canadian pipelines over the term of each gas sales contract.

Regarding the adequacy of supply, the Board's estimate of total reserves for the two suppliers exceeds their total requirements, including the proposed export. The Board's projections of productive capacity for Crestar and PanCanadian show adequate supply throughout the proposed term. The Board notes that the term of the gas sales contracts, power purchase contracts, requested transportation service, and applied-for regulatory authorizations are consistent with, or exceed the term of the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

Decision

The Board has decided to issue a gas export licence to Navy Yard Partners, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence to be issued.

Husky Oil Operations Ltd.

3.1 Application Summary

By application dated 22 October 1993, Husky sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	for 15 years following commencement of deliveries under the Licence
Point of Export	-	Huntingdon, British Columbia
Maximum Daily Quantity	-	398.0 10^3m^3 (14.0 MMcf)
Maximum Annual Quantity	-	145.27 10^6m^3 (5.1 Bcf)
Maximum Term Quantity	-	2 179.05 10^6m^3 (76.9 Bcf)
Tolerances	-	ten percent per day and two percent per month

Husky would provide the gas proposed for export from its corporate supply pool in British Columbia. The gas would be transported on the Westcoast system for delivery to Tenaska Gas Co. ("Tenaska Gas") and Tenaska Washington Partners II, L.P. ("Tenaska Washington Partners") (collectively "Tenaska") near Huntingdon, British Columbia. The gas would then flow on either or both of the Northwest Pipeline Corporation ("Northwest") or Cascade Natural Gas Company ("Cascade") systems for delivery to an independent power production facility near Tacoma, Washington. Electricity from the facility would be sold to the Bonneville Power Administration ("Bonneville").

3.2 Gas Supply

3.2.1 Supply Contracts

Gas supply contracts were not required since Husky will provide the gas from its corporate supply pool in British Columbia. The Board notes that no specific pools were contractually dedicated to the proposed export.

3.2.2 Reserves

Table 3.1 shows that the Board’s estimate of Husky’s gas reserves for its British Columbia corporate supply pool is 27 percent higher than Husky’s; however, the Board’s estimate after adjusting for 1993

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

Husky[1]	NEB[2]	Applied-for[3] Volume
3 741 (132.1)	4 766 (168.2)	2 179 (76.9)

1. As of 31 December 1993. Husky's estimate of remaining reserves would be approximately 462 10^6m^3 (16 Bcf) less than shown if adjusted for estimated production to 1 July 1996.
2. As of 31 December 1992. The Board's estimate of remaining reserves would be 951 10^6m^3 (34 Bcf) less than shown if adjusted for estimated production to 1 July 1996.
3. This represents about 50 percent of Husky's estimated total requirements of 4 395 10^6m^3 (155 Bcf), including the proposed export, for its B.C. sourced gas.

production of 489 10^6m^3 (17.3 Bcf), is only 14 percent higher than Husky's estimate. The table also shows that the Board's estimate of Husky's gas reserves is approximately twice the applied-for volume and approximately eight percent higher than Husky's estimated total requirements, including the proposed export.

Husky's British Columbia corporate supply pool includes pools in the Boundary Lake, Pocketknife and Buckinghorse fields. Husky's estimates were based largely on material balance estimates. The Board's estimate of Husky's reserves in these fields (after adjusting for production to 31 December 1993) is 536 10^6m^3 (18.9 Bcf) higher than Husky's estimate. The Board relied primarily on volumetric analyses since the majority of the pools have been producing for only a few years and pressure information is limited.

Husky stated that reserves would be added to its gas supply as a result of drilling conducted on its submitted fields during 1994. One additional well has already been drilled and based on the results of this well, Husky indicated that it would be adding 680 10^6m^3 (24.0 Bcf) of proven and probable reserves after 1 April 1994. Husky also indicated that two additional wells are currently being drilled. The Board did not include the additional supply in its estimate since the data remains confidential; however, the Board recognizes the potential for increased supply through exploration and development on Husky's lands within the submitted fields.

3.2.3 Productive Capacity

A comparison of the Board's and Husky's projections of productive capacity for its British Columbia corporate reserves with the applicant's requirements for these reserves is shown in Figure 3-1. The Board's analysis indicates that Husky's British Columbia corporate reserves would be sufficient to satisfy Husky's requirements, including its sale to Tenaska, for eight years of the proposed 15-year term. Husky's analysis indicates its British Columbia supply would be sufficient to satisfy seven years of the proposed 15-year term.

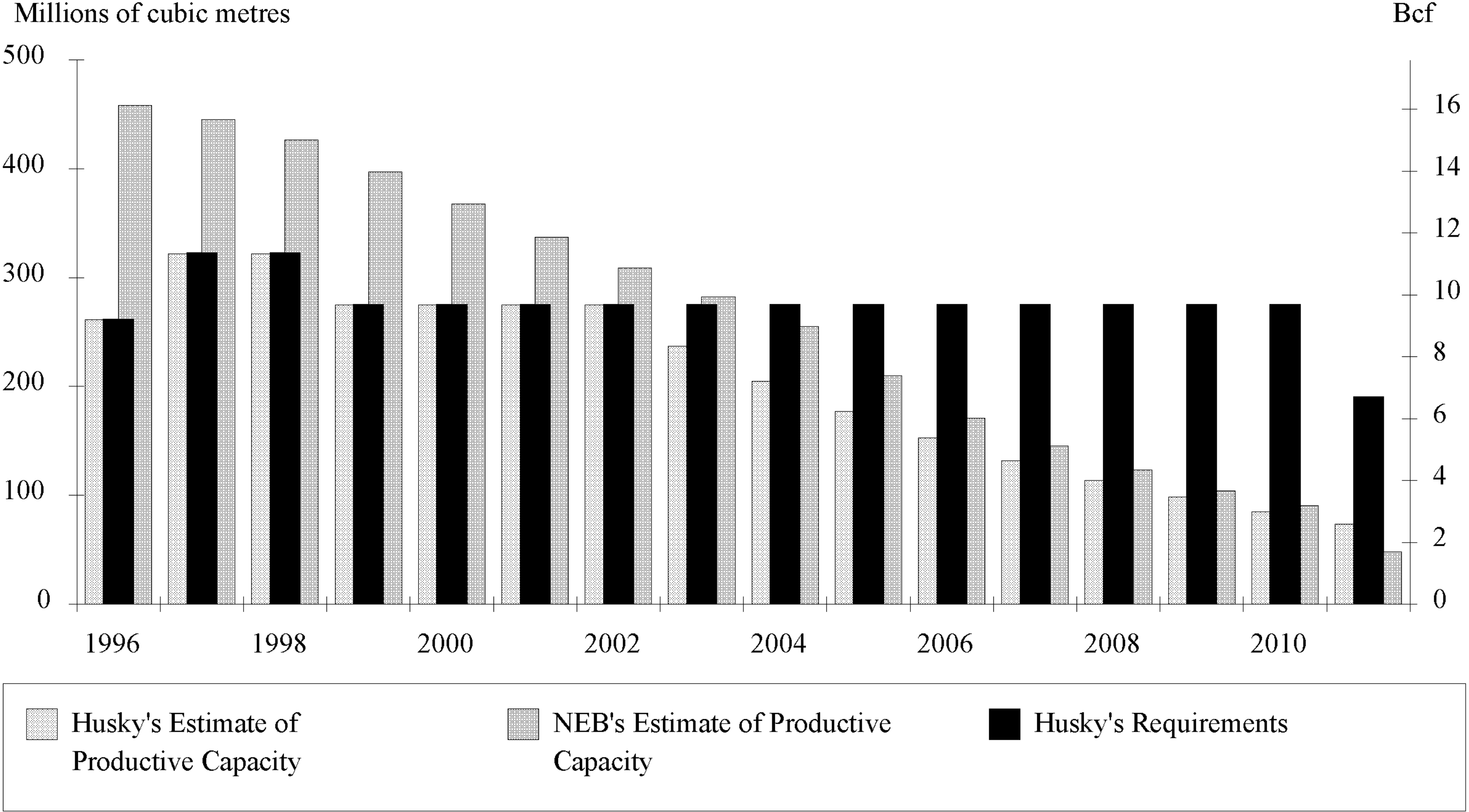
Husky stated that it has two options of transporting its surplus Alberta corporate supply to mitigate any shortfalls in its British Columbia supply. Husky stated that an additional gas supply of 567 $10^3m^3/d$ (20 MMcf/d) could supplant its British Columbia corporate reserves. One option is to move Alberta gas through the Gordondale lateral and a second option is through its 50 percent interest in the Boundary Lake gas plant, both of which can access the Westcoast system.

Husky also submitted its total corporate deliverability which includes both its submitted British Columbia supply and its Alberta supply. Husky's total corporate deliverability forecast indicates that there would be sufficient supply available to meet all of its requirements.

Figure 3-1
Comparison of Husky's and NEB's Estimates of Annual Productive Capacity

Figure 3-1

Comparison of Husky's and NEB's Estimates of Annual Productive Capacity



3.3 Transportation

Husky holds renewable firm service on the Westcoast system to Compressor Station No. 2 ("T-North service") and has executed a contract for an additional 705 $10^3m^3/d$ (25 MMcf/d) of T-North service in Westcoast's 1994 expansion. This provides Husky with more than adequate T-North service to support the proposed export. Tenaska Gas executed a FS agreement on 22 July 1993 for the transportation of 883 $10^3m^3/d$ (31.3 MMcf/d) of gas on Westcoast from Compressor Station No. 2 to the international border near Huntingdon, British Columbia ("T-South service"). Capacity on Westcoast for the requested T-South service is anticipated by 1 November 1994, at which time Tenaska Gas is to assign at least 398 $10^3m^3/d$ (14 MMcf/d) of its transportation capacity to Husky.

Husky Gas Marketing Inc., an affiliate of Husky, has contracted for 398 $10^3m^3/d$ (14 MMcf/d) of renewable firm transportation on Northwest. Husky and Tenaska have agreed that this capacity will be assigned to Tenaska once the power production facility commences operation.

While it is expected that the Northwest capacity will be utilized to transport the export volumes from the border to the power production facility, Tenaska Gas and Tenaska Washington Partners jointly hold, pursuant to a contract dated 15 January 1991, in excess of 42 200 GJ (40,000 MMBtu) of daily firm capacity on the Cascade system. The requested facilities on Cascade, which were completed in January 1994, are expected to be in service on 1 April 1994.

Delivery of gas from Northwest to the cogeneration facility requires construction of a 610 metre (2,000 foot) interconnecting pipeline.

3.4 Market

The gas proposed for export would be used to fuel Tenaska Washington Partners' 248 MW gas fired, combined cycle, independent power production facility to be located in the Frederickson Industrial Area near Tacoma, Washington. The cogeneration facility is expected to operate at a high load factor and nominate gas from Husky at a 75 percent load factor. The cogeneration facility will consume approximately 42 840 GJ (45,200 MMBtu) of natural gas daily which will be purchased from a number of suppliers, including Husky and Shell. Tenaska Gas will act as fuel manager.

Bonneville, a regional wholesaler of power in the Pacific Northwest, will purchase the entire net electrical output of the power production facility. To meet its loads in 1992, Bonneville had to cut back interruptible power that it normally sells to direct service industries and buy power from outside the region. Furthermore, Bonneville projects that medium load growth will result in an annual 886 MW firm energy deficiency in ten years and an annual 1 741 MW deficiency in twenty years.

Tenaska Power Partners, L.P. and Bonneville executed a Letter of Intent dated 16 July 1992. Although a power sales agreement has been fully negotiated, completion cannot legally occur until Bonneville has completed its environmental review of the cogeneration facility pursuant to the U.S. National Environmental Policy Act. A decision is expected by April 1994.

The power purchase agreement provides for a fixed energy rate for each calendar year that the cogeneration facility delivers its electrical output. This rate assumes a five percent annual rate of inflation and a three percent real discount rate. Bonneville may elect to displace the cogeneration facility's electric generation in monthly increments through either "Base Level Displacement" or "Additional Displacement". Base Level Displacement is applicable for up to two months for each twelve-month period commencing in May. Additional Displacement, which is available during any of the remaining ten months, is a function of a spot market index price for gas, the fuel transportation firm commodity rate and fuel and losses associated with fuel transportation less costs associated with the re-marketing of fuel.

The initial term of the power purchase agreement is for 20 years from the date of commercial operation, which is currently estimated to be 1 July 1996.

3.5 Gas Sales Contract

Husky executed a gas sales contract dated 1 June 1993, as amended, with Tenaska. The primary term of the contract is 20 years and commences on the date of commercial operation. Husky stated that the contract was negotiated at arm's length. The parties may submit to binding arbitration should any disagreement or controversy arise from the contract.

The contract provides for a MDQ of 15 100 GJ (14,311 MMBtu) plus the fuel requirement on Northwest for transporting such amount from the point of delivery to the cogeneration facility. The points of delivery are defined as the interconnection of the Westcoast system near Huntingdon, British Columbia with each of Northwest and Cascade.

The contract contains conditions precedent requiring the parties to obtain certain regulatory authorizations by 1 November 1994 and firm Westcoast transportation service by 1 August 1994. As well, construction financing is to close by 1 October 1995 and the cogeneration facility must be operational and receiving gas in 1998. The contract may be terminated if a condition precedent is not satisfied by its deadline or if the power purchase agreement is terminated.

Tenaka may reduce the MDQ for up to two months in each twelve-month period commencing 1 May. Any reduction of the MDQ will be a pro-rata reduction to the extent of the exercise by Bonneville of its right of base level displacement under the power purchase agreement. The purpose of this reduction is to match the gas supply to the operational needs of the cogeneration facility.

Tenaska also has the right to reduce the MDQ in the gas sales contract by an amount known as the daily suspension quantity ("DSQ"). The DSQ may be in effect for a period of not less than one month and only to the extent that the cogeneration facility will not be producing power. Husky may market the gas to the spot market or other markets during such periods.

Commencing 1 January 1996, the price will be $U.S. 2.07/GJ ($U.S. 2.18/MMBtu) at the international border and will escalate annually at five percent until the year 2000. Thereafter, the price escalates at 5.5 percent per year.

Should Tenaska's purchases in any month be less than the Minimum Monthly Quantity ("MMQ"), then it must make a deficiency payment equal to the product of 30 percent of the contract price and the difference between actual takes and the MMQ. The MMQ is defined as 90 percent of the MDQ summed over the month, adjusted for force majeure, delivery shortfalls and 95 percent of the DSQ summed over the month.

An additional deficiency payment arises when Tenaska's takes fall below the MMQ due to Tenaska purchasing gas under contract with a term of one year or less in preference to gas supplied by Husky. The additional deficiency payment equals the positive difference between 70 percent of the contract price and the price for Canadian spot gas delivered to Northwest multiplied by the difference between actual takes and the MMQ.

Should an event of force majeure affecting Tenaska's ability to receive gas under the contract occur, Tenaska is to curtail all receipts of interruptible natural gas from other parties to the extent required to maintain deliveries under its contract with Husky.

Husky submitted that, on 1 January 1994, the British Columbia border price that would have been in effect under the terms of the contract was $Cdn. 2.65/GJ ($Cdn. 2.79/MMBtu).

3.6 Status of Regulatory Authorizations

Husky expected to file an application on 4 February 1994 for a long-term energy removal certificate from the British Columbia Ministry of Energy, Mines and Petroleum Resources ("EMPR"). The application will be for a term and volume commensurate with the gas sales contract.

Tenaska received DOE/FE authorization for long-term import on 5 January 1994. Various other U.S. federal, state and local regulatory approvals are expected before May 1994.

Views of the Board

The Board notes that Tenaska is subject to a deficiency payment should it take less than the MMQ and an additional deficiency payment should it take less than the MMQ while purchasing short-term gas from other sources. Further, should an event of force majeure affect Tenaska's ability to receive gas, Tenaska is to curtail receipts of interruptible gas to the extent required to maintain deliveries under its contract with Husky. The Board is also cognizant that the market for the electricity is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes sought to be licensed will be taken.

The Board observes that the escalation provisions of the gas sales contract and the power purchase contract are similar and that the gas sales contract is subject to binding arbitration. The Board is thus satisfied that the gas sales contract will remain attractive to the parties over its proposed term, and is therefore durable.

The Board has reviewed the gas purchase agreement and notes that it has been negotiated at arm's length.

Since Husky owns the gas supporting this export licence application, a finding of producer support is not necessary.

The Board is of the view that the total price under the gas sales contract more than recovers the fixed cost of transportation. As well, the Board is of the view that the deficiency payment on volumes not nominated would more than recover the fixed costs of transportation for such volumes. Therefore, the Board is satisfied that there are provisions in the gas sales contract for the payment of the associated transportation demand charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves for Husky's primary supply source exceeds Husky's total requirements. Additionally, the Board's projection of productive capacity shows that Husky can satisfy its total requirements throughout the majority of the term of the proposed export. The Board notes that Husky provided some evidence on other B.C. reserves which will become available to it, and that it has access to Alberta supply, if required, through its Boundary Lake gas plant. For these reasons, the Board is satisfied with the adequacy of Husky's gas supply. The Board observes that the terms of the transportation, gas sales and power purchase contracts and of the applied-for regulatory authorizations are for a term consistent with the requested licence. The Board is therefore satisfied that the requested licence term is appropriate.

Decision

The Board has decided to issue a gas export licence to Husky, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence to be issued.

ProGas Limited

4.1 Application Summary

By application dated 16 September 1993, ProGas applied for six natural gas export licences, pursuant to Part VI of the Act, for sale to six local distribution companies ("LDCs") in the States of Michigan and Wisconsin, (collectively the "ANR Customer Group"), with the following terms and conditions:

Michigan Gas Utilities ("MGU")

Term	-	commencing on 1 November 1993 and ending on 31 October 2000	
Point of Export	-	Emerson, Manitoba	
Maximum Daily Quantity	-	75.7 10^3m^3	(2.7 MMcf)
Maximum Annual Quantity	-	27.6 10^6m^3	(1.0 Bcf)
Maximum Term Quantity	-	193.5 10^6m^3	(6.8 Bcf)
Tolerances	-	ten percent per day and two percent per year	

Wisconsin Fuel and Light Company ("WF&L")

Term	-	commencing on 1 November 1993 and ending on 31 October 2003	
Point of Export	-	Emerson, Manitoba	
Maximum Daily Quantity	-	84.8 10^3m^3	(3.0 MMcf)
Maximum Annual Quantity	-	31.0 10^6m^3	(1.1 Bcf)
Maximum Term Quantity	-	309.7 10^6m^3	(10.9 Bcf)
Tolerances	-	ten percent per day and two percent per year	

Wisconsin Gas Company ("WiGas")

Term	-	commencing on 1 November 1993 and ending on 31 October 2000	
Point of Export	-	Emerson, Manitoba	
Maximum Daily Quantity	-	807.1 10^3m^3	(28.5 MMcf)
Maximum Annual Quantity	-	294.6 10^6m^3	(10.4 Bcf)
Maximum Term Quantity	-	2 062.0 10^6m^3	(72.8 Bcf)
Tolerances	-	ten percent per day and two percent per year	

Wisconsin Natural Gas Company ("WNG")

Term	-	commencing on 1 November 1993 and ending on 31 October 2003
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	304 10^3m^3 (10.7 MMcf)
Maximum Annual Quantity	-	111.0 10^6m^3 (3.9 Bcf)
Maximum Term Quantity	-	1 109.7 10^6m^3 (39.2 Bcf)
Tolerances	-	ten percent per day and two percent per year

Wisconsin Power & Light Company ("WP&L")

Term	-	commencing on 1 November and ending on 31 October 2003
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	95.9 10^3m^3 (3.4 MMcf)
Maximum Annual Quantity	-	35.0 10^6m^3 (1.2 Bcf)
Maximum Term Quantity	-	350.2 10^6m^3 (12.4 Bcf)
Tolerances	-	ten percent per day and two percent per year

Wisconsin Public Service Corporation ("WPSC")

Term	-	commencing on 1 November 1993 and ending on 31 October 2003
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	313.8 10^3m^3 (11.1 MMcf)
Maximum Annual Quantity	-	114.5 10^6m^3 (4.0 Bcf)
Maximum Term Quantity	-	1 145.3 10^6m^3 (40.4 Bcf)
Tolerances	-	ten percent per day and two percent per year

In the same application, ProGas also requested an amendment, pursuant to subsection 21(2) of the Act, of Licence GL-98 as follows:

(i) amending Condition 2(d) to provide that, for the period commencing 1 November 1993 and ending on 31 October 2000, the total quantity authorized for export in any one day shall be reduced from 7 316 300 cubic metres to 5 634 900 cubic metres and the quantity authorized for export in any consecutive twelve (12) month period shall be reduced from 2 325 000 000 cubic metres to 1 711 289 000 cubic metres; and

(ii) amending Condition 2(e) to provide that the total quantity of gas that may be exported during the term is 31 626 100 000 cubic metres reduced from 36 796 500 000 cubic metres.

ProGas will provide the gas for the proposed export from its contracted supply pool. The gas would be transported by NOVA and TransCanada to the international border at Emerson, Manitoba. The proposed gas export would then be transported on the Viking Gas Transmission Company ("Viking") system to the ANR Customer Group. Gas has been exported to the ANR Customer Group under short-term export authorization since 1 November 1993.

Gas exports under Licence GL-98, as amended, are destined for the markets of several interstate pipelines including ANR Pipeline Company ("ANR").

4.2 Gas Supply

The following discussion of gas supply applies to the three ProGas applications heard in GH-5-93, which are presented in Chapters 4, 5 and 6 of these Reasons.

4.2.1 Supply Contracts

ProGas will provide the gas for the proposed export from its contracted supply pool. This supply pool consists of approximately 600 gas purchase contracts with about 160 producers. Approximately 87 percent of ProGas' contracted supply is in Alberta and the remainder is in British Columbia.

4.2.2 Reserves

In support of its application, ProGas provided an estimate of the gas reserves that will be used to meet both its existing sales commitments and the proposed export to the ANR Customer Group.

The Board has analyzed ProGas' contracted supply pool and has prepared its own estimate of ProGas' gas reserves under contract. Table 4-1 shows that the Board's estimate of reserves is 15 percent lower than ProGas' estimate, but is much higher than the applied-for volume and 23 percent higher than ProGas' total requirements, including the proposed export.

4.2.3 Productive Capacity

Figure 4-1 compares both the Board's and ProGas' projections of productive capacity with ProGas' estimated total requirements, including fuel and shrinkage. ProGas has estimated its annual requirements based on a 90 percent load factor.

Both projections of production capacity show that ProGas has adequate gas supply to meet its total requirements at a 90 percent load factor throughout the forecast period.

Table 4-1
Comparison of Estimates of ProGas' Established Gas Reserves with the Applied-for Term Volume
10^6m^3
(Bcf)

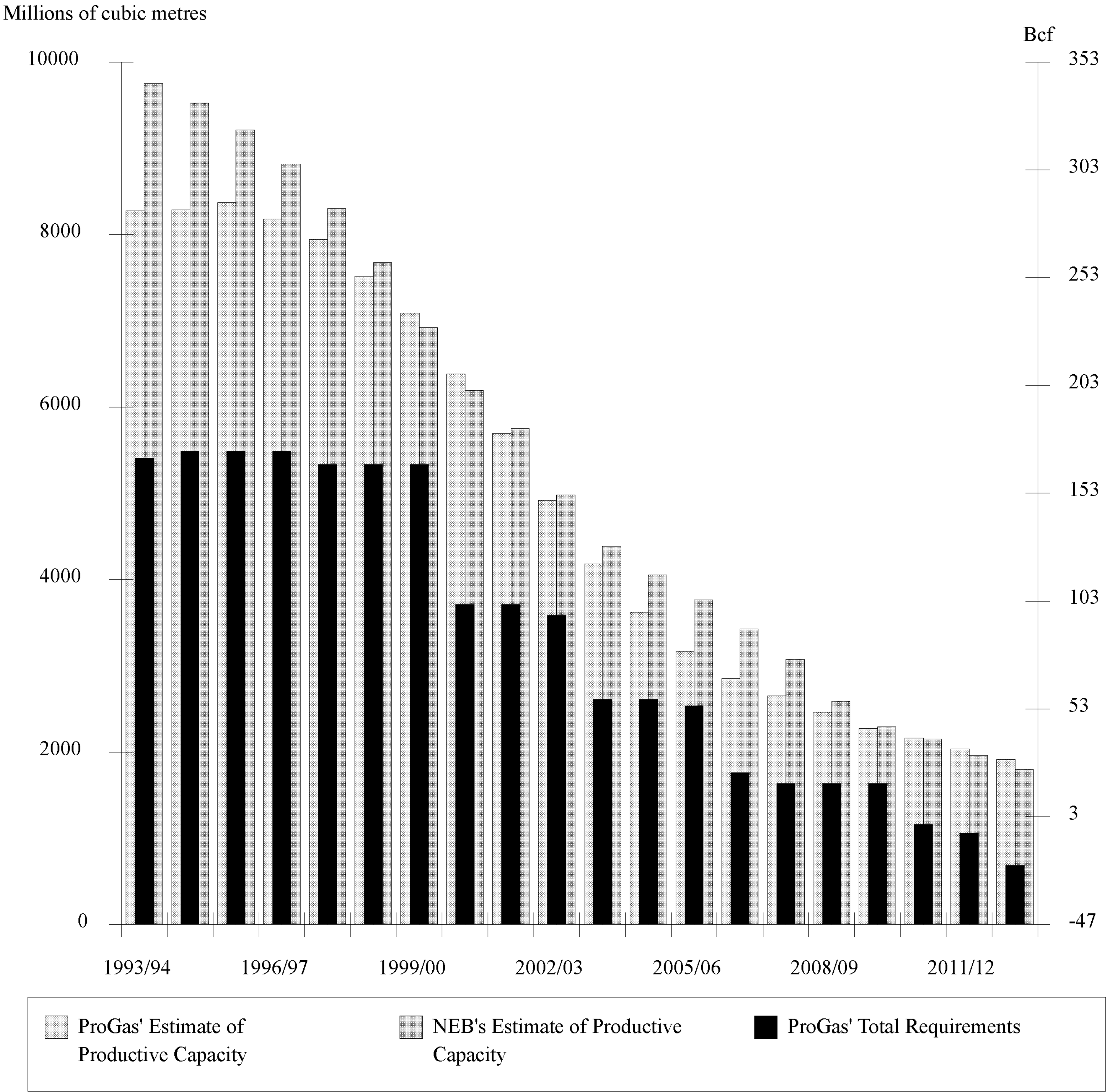
ProGas[1]	NEB[2]	Applied-for[3] Volume
107 400 (3,791.2)	91 690 (3,236.7)	5 211 (184.0)

1. As of 30 June 1993.
2. As of 31 December 1992. The Board's estimate of reserves would be about 3 100 10^6m^3 (109 Bcf) less than shown if adjusted for production to 30 June 1993.
3. These are the applied-for volumes which would result from the proposed extension of Licence GL-129, discussed in Chapter 5 of these Reasons. This represents about seven percent of ProGas' total requirements, which are 74 300 10^6m^3 (2 623 Bcf), including the proposed export. The volumes for the applied-for licences discussed in Chapters 4 and 6 of these Reasons will be removed from Licence GL-98.

Figure 4-1
Comparison of ProGas' and NEB's Estimates of Annual Productive Capacity

Figure 4-1

Comparison of ProGas' and NEB's Estimates of Annual Productive Capacity



4.3 Transportation

ProGas will utilize its existing FS capacity on the NOVA system to transport the proposed export volumes to Empress, Alberta. The gas would then be shipped on the TransCanada system under ProGas' FS contract with TransCanada to Emerson. The ANR Customer Group would take delivery at Emerson and transport the gas on the Viking and ANR systems for delivery to their respective markets in Michigan and Wisconsin. As a result of ANR's restructuring under the Federal Energy Regulatory Commision ("FERC") Order 636, the ANR Customer Group has obtained firm service from ANR and an assignment of ANR's right to Viking capacity as of 1 November 1993. No new facilities are required for the export.

4.4 Markets

As a result of the elections of its customers under FERC Order 636, ANR will eventually cease being a merchant of and, therefore, a direct purchaser of gas. The applied-for licences are underpinned by gas sales contracts with several of ANR's traditional customers. These sales will replace most of the gas previously authorized for export to ANR pursuant to Licence GL-98.

The gas to be exported will be used by six LDCs in Michigan and Wisconsin. ProGas expects that the proposed exports would occur at load factors ranging from 80 to 100 percent.

The ANR Customer Group's present gas supply consists of purchases from various U.S. interstate pipelines, spot market, intrastate pipelines and other Canadian suppliers. Direct Canadian gas purchases by the ANR Customer Group would vary from 20 to 45 percent of their individual total gas supply portfolio.

MGU operates in the southern and western portions of the lower Michigan peninsula. MGU currently serves about 126 000 customers of which approximately 90 percent are residential. Total gas purchases in 1993 were expected to be about 700 10^6m^3 (24.7 Bcf). Market growth of eight percent is expected over the next five years.

WF&L, located in Manitowoc, had sales of 450 10^6m^3 (15.8 Bcf) in 1992, with a customer mix of 90 percent residential, 9 percent commercial and 1 percent industrial.

WiGas, located in Milwaukee, purchased and transported 3 315 10^6m^3 (117 Bcf) in 1992. Usage by customer category included residential, commercial, and industrial, at 39, 43 and 18 percent respectively.

WNG serves the areas west and south of Milwaukee, and Appleton. Annual throughput for 1994 is expected to be some 1 985 10^6m^3 (70 Bcf) of which 27 percent will consist of end user transportation. Of the forecast 1 445 10^6m^3 (51 Bcf) of gas sales to its customers, firm residential demand is expected to constitute 54 percent, while firm commercial/industrial demand and interruptible sales are expected to constitute 40 and six percent respectively.

WP&L, located in Madison, conducts both electric and gas operations. Total sales in 1992 were 660 10^6m^3 (23.3 Bcf) with residential demand accounting for 39 percent of the total. In addition, WP&L transported over 170 10^6m^3 (6 Bcf) for its large, direct-purchase industrial customers.

WPSC is an investor-owned electric and gas utility located in Green Bay, Wisconsin. At year-end 1992, the customer mix, by volume, was 33, 22 and 45 percent, for the residential, commercial and industrial sectors respectively.

4.5 Gas Sales Contracts

ProGas and the ANR Customer Group executed gas sales agreements in October 1993. The agreements with MGU and WiGas will expire seven years from the effective contract date of 1 November 1993 whereas the remaining agreements have terms of ten years. Each agreement provides for a certain DCQ ("Daily Contract Quantity") and can be terminated if either party fails to obtain all regulatory authorizations and transportation contracts required for the proposed exports. ProGas stated the agreements were negotiated at arm's length.

The ANR Customer Group must purchase a minimum Annual Purchase Quantity ("APQ") equal to each LDC's pre-selected percentage of the DCQ for each contract. The APQs range from 50 to 100 percent of the DCQ. The buyer must pay a Gas Inventory Charge ("GIC") which is equal to a pre-determined percentage of the monthly commodity charge. The GICs range from 1.5 to four percent depending on the APQ chosen by the LDC.

If there is any deficiency in take, the buyer has a one-year make-up period to purchase the deficient volumes. After this period, for any outstanding annual deficiency, the buyer must pay a penalty for the remaining volume. If ProGas fails to deliver the nominated volumes, it is responsible for the incremental cost of alternate supplies obtained by the buyer.

For all contracts, the price consists of a monthly demand charge, a commodity charge and the GIC. The monthly demand charge consists of monthly demand tolls on TransCanada, NOVA, and ProGas' cost of service. The monthly commodity charge is equal to a Base Price ("BP") of $U.S. 1.71/GJ ($U.S. 1.80/MMBtu), adjusted monthly by the change in the spot price (from April 1993) for gas delivered to ANR from Louisiana and Oklahoma.

The contracts provide for re-negotiation and binding arbitration of the commodity charge in the event that ProGas and the buyers are unable to agree on a replacement index used to calculate the monthly commodity charge. Arbitration would be in accordance to the rules of the British Columbia International Commercial Arbitration Centre.

ProGas submitted that, in December 1993, the Alberta border price would have been approximately $Cdn. 2.70/GJ ($Cdn. 2.80/MMBtu) under the terms of the various contracts.

4.6 Status of Regulatory Authorizations

ProGas will apply to the ERCB for an amendment to its existing removal permit. MGU and WiGas will apply to the DOE/FE for import authorization. The other LDCs have received their DOE/FE import authorization. ProGas has received a finding of producer support from the Alberta Petroleum Marketing Commission ("APMC").

Views of the Intervenor

RMEC argued that the ProGas applications, as described in Chapters 4, 5 and 6 of these Reasons, should be denied because of what RMEC described as the enormous un-inventoried and calculated upstream environmental impact and its concern that Canadian consumers will not have access to adequate gas supply in the foreseeable future.

Views of the Board

The Board’s views on the environmental screenings are presented in Section 1.2 of these Reasons. With respect to RMEC’s views on the issue of supply, the Board notes that RMEC did not submit any evidence to support its claims. In addition, as descibed in Chapter 1 of these Reasons, the Board has satisfied itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada.

The Board notes that the ANR Customer Group must nominate at least 50 percent of their respective DCQs. The Board also notes that there is a deficient take penalty on the remaining balance after a one year make-up period. The Board also recognizes that the markets for the gas have been and are likely to continue to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes sought to be licensed will be taken.

The Board has noted the market-oriented approach, including binding arbitration, used to determine the commodity prices on a monthly basis. As well, the Board takes comfort in ProGas’ evidence that it is unlikely that any circumstances would occur that would cause ProGas and the buyers to terminate the gas sales contracts. The Board is thus satisfied that the gas sales contracts will remain attractive to the parties over the proposed terms, and are therefore durable.

The Board has reviewed the gas sales contracts and notes that they have been negotiated at arm’s length. As well, a finding of producer support was obtained from the APMC.

The Board notes that the contract price contains a non-negotiable demand charge component equal to ProGas’ demand charge obligations on all upstream pipelines. Therefore, the Board is satisfied that there are provisions in the gas sales contracts for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contracts.

The Board's estimate of reserves exceeds ProGas' total requirements by 23 percent. Additionally, the Board's estimate of productive capacity shows that ProGas can meet its requirements throughout the proposed export terms. As well, the Board notes that an application will be made to the ERCB for an amendment to ProGas' removal permit. DOE/FE authorizations have been received by four of the LDCs and applications by the remaining two will be made. All other regulatory authorizations are in place. The Board also recognizes that transportation on all required pipelines has been arranged. The terms of these authorizations, transportation arrangements and of the gas sales contracts are consistent with the proposed terms of the licences. The Board is therefore satisfied that the requested licence terms are appropriate.

Finally, the Board notes that ProGas has applied for commencement dates of 1 November 1993. Since the Board does not backdate its licences, the applied-for term volumes must be adjusted to account for a shorter term. Assuming a commencement date of 1 May 1994 for each licence, the Board has reduced the applied-for term volumes by commensurate amounts. The volume reductions are the product of the individual DCQs and the number of days between 1 November 1993 and 1 May 1994. ProGas agreed with the Board's method of calculating the necessary reductions in the applied-for volumes.

Decision

The Board has decided to issue six gas export licences to ProGas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licences to be issued.

ProGas Limited

5.1 Application Summary

By application dated 16 September 1993, ProGas applied for an amendment to natural gas export Licence GL-129, pursuant to subsection 21(2) of the Act, as follows:

(i) amending Condition 1 so that the term of Licence GL-129 shall be extended for seven (7) years, expiring on 31 October 2013;

(ii) amending Condition 2(c) by increasing the total quantity of gas that may be exported during the term from 13 804 160 000 m^3 to 19 015 349 200 m^3; and

(iii) for the period beginning 1 November 2006 and ending 31 October 2013, authorizing the export of 2 039 604 m^3 (72 MMcf) in any one day and 744 455 600 m^3 (26.28 Bcf) in any consecutive twelve (12) month period ending 31 October.

ProGas will provide the gas for the proposed export from its contracted supply pool. The gas would be transported by NOVA and TransCanada to the international border at Niagara Falls, Ontario.

Gas exports under Licence GL-129, as amended, were authorized for export to Northeast Energy Associates, a Limited Partnership ("Northeast") and North Jersey Energy Associates, A Limited Partnership ("North Jersey") for two cogeneration facilities in Bellingham, Massachusetts and Sayreville, New Jersey, respectively.

5.2 Gas Supply

A description of ProGas' supply is provided in Section 4.2 of these Reasons.

5.3 Transportation

ProGas will utilize its existing FS capacity on the NOVA system to transport the proposed export volumes to Empress. The gas would then be shipped on the TransCanada system under ProGas' FS contract with TransCanada to Niagara Falls. Northeast and North Jersey would transport the gas on the CNG Transmission Company, TransContinental Gas Pipe Line Corporation, Public Service Electric & Gas Company and Algonquin Gas Transmission Company systems to the two plants. The parties will use their renewal rights in their transportation contracts to ensure the availability of transportation capacity for the proposed extension. No new facilities are required for the export.

5.4 Markets

The gas to be exported will be used by the two 300 MW gas-fired cogeneration facilities owned by Northeast and North Jersey and managed by Intercontinental Energy Corporation ("Intercontinental"). Both plants commenced commercial operation in the summer of 1991. The electrical output of the plants is sold to utilities in the New England Power Pool pursuant to long-term power sales contracts ranging from 20 to 30 years.

ProGas proposed a term extension to further strengthen the market for Canadian gas and to assist the owners of the cogeneration facilities to re-finance the projects.

5.5 Gas Sales Contracts

ProGas, Northeast and North Jersey executed Amending Agreements dated 30 July 1993. The agreements extend the original terms of the gas purchase contracts dated 12 May 1988 by seven years to expire 31 October 2013. Both Amending Agreements have the same terms and conditions. ProGas stated that the Amending Agreements were negotiated at arm’s length.

Among the amendments to the original gas purchase contracts, Northeast and North Jersey agreed to waive their right to be relieved of demand charge payment obligations during periods of scheduled or unscheduled outages of the cogeneration facilities. In kind, ProGas agreed to attempt to re-market elsewhere the gas not taken, and to negotiate a demand charge credit with the other buyers.

The parties also modified the renegotiation and arbitration provisions.

The parties also agreed to a one time sign-in bonus to increase the base price in the previous pricing formula by $U.S. 0.036/GJ ($U.S. 0.038/MMBtu) upon the successful refinancing of the plants and the receipt of all regulatory authorizations. Other provisions in the contracts remain unchanged.

ProGas submitted that, in December 1993, the Alberta border price would have been $Cdn. 2.42/GJ ($Cdn. 2.55/MMBtu) under the terms of the amended contracts.

5.6 Status of Regulatory Authorizations

ProGas will apply to the ERCB for an amendment to its existing removal permit and Intercontinental will apply to the DOE/FE for additional import authorization. A finding of producer support has been received from the APMC.

Views of the Board

The Board notes that Northeast and New Jersey must continue to nominate at least 75 percent of the DCQ. The Board also recognizes that the market for the gas is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes sought to be licensed will be taken.

The Board has noted that the market-oriented approach, including binding arbitration, remains essentially the same as outlined in the original gas sales contracts. As well, the Board takes comfort in ProGas’ evidence that it is unlikely that any circumstances would occur that would cause ProGas and the buyers to terminate the gas sales contracts. The Board is thus satisfied that the amended gas sales contracts will remain attractive to the parties over the proposed extended terms, and are therefore durable.

The Board has reviewed the amending agreements and notes that they have been negotiated at arm's length. As well, a finding of producer support was obtained from the APMC.

The Board notes that the buyers' demand charge obligation remains unchanged for all upstream pipelines. Therefore, the Board is satisfied that there are provisions in the gas sales contracts for the payment of the associated transportation charges on Canadian pipelines over the extended term in the gas sales contracts.

The Board's estimate of reserves exceeds ProGas' total requirements by 23 percent. Additionally, the Board's estimate of productive capacity shows that ProGas can meet its requirements throughout the proposed export term. As well, the Board notes that applications to the ERCB and the DOE/FE will be made and that all other regulatory authorizations are in place. The Board also recognizes that transportation on all required pipelines has been arranged. The terms of these authorizations, transportation arrangements and of the gas sales contracts are consistent with the proposed term of the licence. The Board is therefore satisfied that the requested licence term is appropriate.

Decision

The Board has decided to approve the amendments to Licence GL-129, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the amendments to Licence GL-129.

ProGas Limited

6.1 Application Summary

By application dated 20 October 1993, ProGas applied for two natural gas export licences, pursuant to Part VI of the Act, for sale to two LDCs in the State of Wisconsin, with the following terms and conditions:

WPSC

Term	-	commencing on 1 November 1993 and ending on 31 October 1997	
Point of Export	-	Emerson, Manitoba	
Maximum Daily Quantity	-	226.4 10^3m^3	(8.0 MMcf)
Maximum Annual Quantity	-	82.6 10^6m^3	(2.9 Bcf)
Maximum Term Quantity	-	330.5 10^6m^3	(11.7 Bcf)
Tolerances	-	ten percent per day and two percent per year	

WiGas

Term	-	commencing on 1 November 1993 and ending on 31 October 2002	
Point of Export	-	Emerson, Manitoba	
Maximum Daily Quantity	-	187.4 10^3m^3	(6.6 MMcf)
Maximum Annual Quantity	-	68.4 10^6m^3	(2.4 Bcf)
Maximum Term Quantity	-	615.6 10^6m^3	(21.7 Bcf)
Tolerances	-	ten percent per day and two percent per year	

In the same application, ProGas also requested an amendment, pursuant to subsection 21(2) of the Act, of Licence GL-98 as follows:

(i) amending Condition 2(d) to provide that, for the period commencing 1 November 1993 and ending on 31 October 2000, the total quantity authorized for export in any one day shall be reduced from 5 634 900 m^3 to 5 221 143 m^3 and the quantity authorized for export in any consecutive twelve (12) month period shall be 1 560 268 000 m^3 reduced from 1 711 289 000 m^3; and

(ii) amending Condition 2(e) by reducing the total quantity of gas that may be exported during the term from 31 626 100 000 m^3 to 30 680 030 000 m^3.

ProGas will provide the gas for the proposed exports from its contracted supply pool. The gas would be transported by NOVA and TransCanada to the international border at Emerson, Manitoba. The proposed gas export would then be transported on the ANR system to WiGas and WPSC. Gas has been exported to WiGas and WPSC under short-term export authorization since 1 November 1993.

As discussed in Section 4.1 of these Reasons, WPSC and WiGas, in addition to other LDCs, were purchasing gas from ANR who in turn obtained its gas supply pursuant to Licence GL-98. The proposed exports to WPSC and WiGas will, in part, displace exports previously authorized under Licence GL-98.

6.2 Gas Supply

A description of ProGas' supply is provided in Section 4.2 of these Reasons.

6.3 Transportation

ProGas will utilize its existing FS capacity on the NOVA system to transport the proposed export volumes to Empress. The gas would then be shipped on the TransCanada system under ProGas' FS contract with TransCanada to Emerson. WPSC and WiGas would transport the gas on the Viking system for delivery to their respective service areas under their existing transportation arrangements. No new facilities are required for the export.

6.4 Markets

Descriptions of the WPSC and WiGas markets are provided in Section 4.4 of these Reasons.

6.5 Gas Sales Contracts

ProGas executed gas sales agreements with WPSC and WiGas on 17 September 1993 and 27 September 1993, respectively. Both contracts commenced on 1 November 1993. The contract with WPSC provides for a DCQ of 226 10^3m^3 (8.0 MMcf) and expires on 31 October 1997. The contract with WiGas provides for a DCQ of 187 10^3m^3 (6.6 MMcf) and expires on 31 October 2002. ProGas stated the agreements were negotiated at arm's length.

WPSC and WiGas must each purchase a minimum ACQ ("Annual Contract Quantity") equal to 50 percent of their respective DCQ's. Each buyer can annually choose an ACQ between 50 and 100 percent of the DCQ prior to the next contract year. WPSC and WiGas must pay a GIC which varies from 1.5 to four percent of the monthly commodity charge depending on which ACQ was chosen.

If ProGas fails to deliver the nominated quantities, WPSC and WiGas may be compensated for incremental costs for the alternate supplies.

The contract price consists of a demand charge, a commodity charge and the GIC. The monthly demand charge is equal to demand tolls multiplied by the DCQ and the number of days in a month, and is non-negotiable for upstream Canadian pipelines. The monthly commodity charge is equal to the Adjusted Commodity Charge ("ACC"), less any commodity charge volume discount, multiplied by the volumes taken. The initial ACC would be $U.S. 1.71/GJ ($U.S. 1.80/MMBtu) and would be adjusted monthly by the change in the spot price (from April 1993) for gas delivered into ANR from Louisiana and Oklahoma.

The contracts provide for re-negotiation and binding arbitration of the commodity charge in the event that ProGas and the buyers are unable to agree on a replacement index used to calculate the monthly commodity charge. Arbitration would be in accordance to the rules of the British Columbia International Commercial Arbitration Centre.

ProGas submitted that, in December 1993, the Alberta border price would have been $Cdn. 2.70/GJ ($Cdn. 2.80/MMBtu) under the terms of the contracts.

6.6 Status of Regulatory Authorizations

ProGas will apply to the ERCB for an amendment to its existing removal permit. WiGas & WPSC have received their DOE/FE import authorizations. A finding of producer support was obtained from the AMPC.

Views of the Board

The Board notes that WPSC and WiGas must nominate at least 50 percent of their DCQs. The Board also notes that there is a deficient take penalty on the remaining balance after a one year make-up period. The Board also recognizes that the markets for the gas have been and are likely to continue to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes sought to be licensed will be taken.

The Board has noted the market-oriented approach, including binding arbitration, used to determine the commodity prices on a monthly basis. As well, the Board takes comfort in ProGas' evidence that it is unlikely that any circumstances would occur that would cause ProGas and the buyers to terminate the gas sales contracts. The Board is thus satisfied that the gas sales contracts will remain attractive to the parties over the proposed terms, and are therefore durable.

The Board has reviewed the gas sales contracts and notes that they have been negotiated at arm's length. As well, a finding of producer support was obtained from the APMC.

The Board notes that the contract price contains a non-negotiable demand charge component equal to ProGas' demand charge obligations on all upstream pipelines. Therefore, the Board is satisfied that there are provisions in the gas sales contracts for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contracts.

The Board's estimate of reserves exceeds ProGas' total requirements by 23 percent. Additionally, the Board's estimate of productive capacity shows that ProGas can meet its requirements throughout the proposed export terms. The Board notes that an application to the ERCB for an amendment to ProGas' removal permit is to be made. Import authorizations from DOE/FE have been received and all other regulatory authorizations are in place. The Board also recognizes that transportation on all required pipelines has been arranged. The terms of these authorizations, transportation arrangements and of the gas sales contracts are consistent with the proposed terms of the licence. The Board is therefore satisfied that the requested licence terms are appropriate.

Finally, the Board notes that ProGas has applied for commencement dates of 1 November 1993. Since the Board does not backdate its licences, the applied-for term volumes must be adjusted to account for a shorter term. Assuming a commencement date of 1 May 1994 for each licence, the Board has reduced the applied-for term volumes by commensurate amounts. These volume reductions are the product of the individual DCQs and the number of days between 1 November 1993 and 1 May 1994. ProGas agreed with the method of calculating these necessary reductions in the applied-for volumes.

Decision

The Board has decided to issue two gas export licences to ProGas, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licences to be issued.

Shell Canada Limited

7.1 Application Summary

By application dated 22 October 1993, Shell sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	for 15 years following the later of 1 April 1996 or the date of first deliveries
Point of Export	-	Huntingdon, British Columbia
Maximum Daily Quantity	-	609.0 10^3m^3 (21.5 MMcf)
Maximum Annual Quantity	-	223.0 10^6m^3 (7.9 Bcf)
Maximum Term Quantity	-	3 002 10^6m^3 (106.0 Bcf)
Tolerances	-	ten percent per day and two percent per year

Shell would provide the gas proposed for export from its supply in British Columbia. The gas would be transported on the Westcoast system for delivery to Tenaska Washington Partners near Huntingdon, British Columbia. The gas would then flow on either or both of the Northwest or Cascade systems for delivery to an independent power production facility near Tacoma, Washington. Electricity from the cogeneration facility would be sold to Bonneville.

7.2 Gas Supply

Shell intends to supply the proposed export from its West Bullmoose Baldonnel pool in northeast British Columbia. Shell submitted data in this proceeding for one pool at West Bullmoose and stated that, since this supply would be sufficient to satisfy only a portion of the proposed export, additional supply would have to be developed in northeast British Columbia. However, Shell chose to provide information regarding only the West Bullmoose pool. Shell also stated that it would rely on its corporate Alberta supply if the northeast British Columbia supply was not developed sufficiently.

7.2.1 Supply Contracts

The supply for the proposed export is to be provided from Shell's West Bullmoose pool which is presently producing to short-term sales from its one well at d-83-G/93-P-4. Shell stated that these sales will continue, and it provided an estimate of production that would likely occur from commencement of production of the well to project start-up. In addition, Shell stated that in order to optimize its financial position, deliverability from the well in excess of the Tenaska requirements would be sold elsewhere. The pool at West Bullmoose is not contractually dedicated to the Tenaska sale.

7.2.2 Reserves

Table 7-1 shows the Board's estimate of Shell's gas reserves for the West Bullmoose pool is

11 percent lower than that of Shell's and ten percent lower than the proposed export; however, this estimate is based on initial gas reserves. Shell submitted evidence that it expects to produce 919 10^6m^3 (32.4 Bcf) of gas from West Bullmoose, primarily to short-term markets, before project start-up in 1996. This results in an estimate of remaining gas reserves at project start-up of 2 089 10^6m^3 (73.7 Bcf) for Shell and 1 771 10^6m^3 (62.5 Bcf) for the Board. Therefore, Shell's and the Board's estimates of reserves will be 70 and 59 percent, respectively, of the proposed export volume of 3 002 10^6m^3 (106.0 Bcf).

Shell submitted an estimate of reserves based on a volumetric analysis of its West Bullmoose pool. Proven reserves were assigned to two gas spacing units using reservoir parameters determined from the d-83-G well. Shell assigned probable reserves to two zones which are underlying and adjacent to the proven area. The two zones include one above and one within a transition zone, below which a free water level has been defined. These areas of probable reserves, defined by three-dimensional seismic, were assigned 452 hectares and 940 hectares, respectively. Both zones were also assigned 32.5 metres of net pay. Shell stated that it would drill a second well in 1994, near the first well, that could result in 50 percent of the probable reserves being converted to proven reserves.

In its analysis of Shell's reserves, the Board also employed volumetric analysis to estimate gas reserves for the pool. While, the Board's estimate of proven reserves is slightly higher than Shell's estimate, the Board's estimate of probable reserves is less than Shell's, mainly due to lower estimates of net pay and a smaller area. The Board mapped the area of probable reserves underlying its proven reserves and in addition, mapped an adjacent area of probable reserves above Shell's transition zone.

In addition to the estimates of reserves submitted, Shell commented on the potential for additional supply in the forelimbs of the structure or overlapping thrust sheets.

Table 7-1
Comparison of Estimates of Shell's Established Gas Reserves with the Applied-for Term Volume

10^6m^3
(Bcf)

Shell[1,2]	NEB[2,3]	Applied-for Volume
3 008 (106.2)	2 690 (95.0)	3 002 (106.0)

1. As of 22 July 1993.
2. Estimates of remaining established reserves would be approximately 919 10^6m^3 (32 Bcf) less than shown if adjusted for estimated production to 1 April 1996.
3. As of 1 November 1993.

Commenting on its drilling program in northeast British Columbia, Shell stated that several wells will be drilled in the next few years. None of these wells will be drilled at West Bullmoose, and Shell did not specify in which areas of northeast British Columbia it planned to drill.

7.2.3 Productive Capacity

Figure 7-1 compares the Board's and Shell's projections of productive capacity for Shell's West Bullmoose pool with Shell's Tenaska requirement. These forecasts represent the productive capacity for the current d-83-G well only. The Board's analysis suggests that Shell will only be able to meet its Tenaska requirement for three years of the proposed 15-year term.

Shell plans to drill a second well during 1994; however, this well is primarily expected to enhance deliverability and would not improve Shell's ability to meet its Tenaska requirement. Moreover, the additional well would accelerate the decline in productive capacity for the pool.

Shell submitted evidence regarding its corporate Alberta supply which could be used to backstop the British Columbia supply. Shell's Alberta supply pool currently has surplus reserves and deliverability that Shell could use in the event of shortages of its British Columbia supply. Shell did state, however, that it maximizes profits by selling excess deliverability on the short-term market whenever possible. This could result in surplus supply not being available to mitigate any shortfalls in the British Columbia supply when needed during the term of the proposed export.

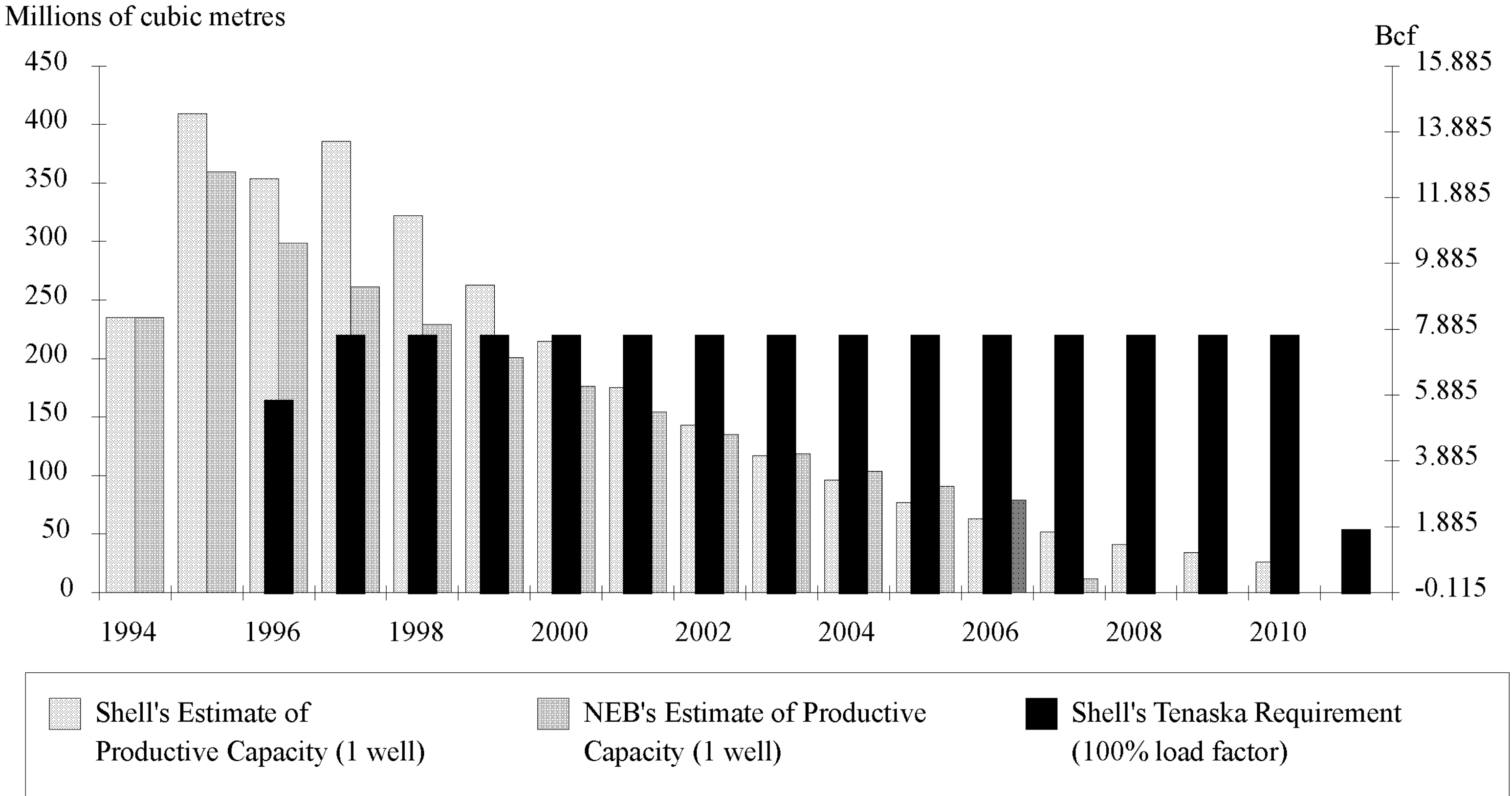
Figure 7-1
Comparison of Shell's and NEB's Estimates of Annual Productive Capacity

Shell commented on its possible arrangements for transporting the Alberta supply to the Westcoast system. It stated that if it became necessary, it would make transportation or displacement arrangements with NOVA and Westcoast for pipeline capacity on the Gordondale lateral.

7.3 Transportation

Figure 7-1

Comparison of Shell's and NEB's Estimates
of Annual Productive Capacity



Shell holds renewable capacity on Westcoast for short-haul T-North service. Shell's firm one-year renewable T-South service was assigned to a third party, but will be permanently re-assigned to Shell in time to meet the requirements of the gas sales contract. Shell has not yet requested either Westcoast or NOVA capacity to transport the backstop supply since, according to Shell, such transportation would not be required until the year 2000 at the earliest. If such supply arrangements become necessary, the Westcoast and NOVA capacity would be requested in 1997.

Salmon Resources Ltd. ("Salmon"), a wholly-owned subsidiary of Shell, has contracted for 31 970 GJ (30,300 MMBtu) of daily firm capacity on Northwest. Salmon has agreed to assign this capacity to Tenaska. A description of alternate transportation on the Cascade system is provided in Section 3.3 of these Reasons.

Delivery of gas from Northwest to the cogeneration facility requires construction of a 610 metre (2,000 foot) interconnecting pipeline.

7.4 Market

Shell anticipates a load factor of 75 percent for the term of the export sale. The market and the power purchase agreement are discussed in Section 3.4 of these Reasons.

7.5 Gas Sales Contract

Shell executed a gas sales contract dated 30 April 1993 with Tenaska Washington Partners. The primary term of the contract is 20 years and commences on the Contract Commitment Date, which shall not be prior to 1 April 1996. Shell stated that the contract was negotiated at arm's length.

The contract provides for an MDQ of 22 600 GJ (21,433 MMBtu) plus the fuel requirement on Northwest for transporting such amount from the point of delivery to the cogeneration facility. The points of delivery are defined as the interconnection of the Westcoast system near Huntingdon, British Columbia with each of Northwest and Cascade.

The contract contains conditions precedent requiring the parties to obtain certain regulatory authorizations and to Tenaska obtaining construction financing by 1 November 1995. As well, Tenaska is to provide written notice that the cogeneration facility is capable of delivering energy in accordance with the provisions of the power purchase agreement by 30 June 1998 and is to pay Shell a non-refundable lump sum payment of U.S. $2,670,000 upon the earlier of securing construction financing or 31 October 1995. The contract may be terminated if a condition precedent is not satisfied by its deadline.

Tenaska may reduce the MDQ for up to two months in each twelve-month period commencing 1 May. Any reduction of the MDQ will be a pro-rata reduction to the extent of the exercise by Bonneville of its right of base level displacement under the power purchase agreement. The purpose of this reduction is to match the gas supply to the operational needs of the cogeneration facility.

Should Bonneville exercise its right for additional displacement under the power purchase agreement, then Tenaska has the right to reduce the MDQ in the gas sales contract by an amount known as the DSQ. Tenaska's determination of the DSQ will be on a pro-rata basis relative to Bonneville's additional displacement level. In the case of disagreement as to an alternative publication or index for the purposes of determining the Canadian spot gas price, the parties may submit to binding arbitration.

Commencing 1 January 1996, the price will be \$U.S. 1.96/GJ (\$U.S. 2.059/MMBtu) at the international border and will escalate at 5.5 percent annually thereafter. The price is notionally divided into a demand charge payment and a commodity charge payment, representing 27 and 73 percent, respectively, of the sale price. The demand charge payable to Shell in the gas sales contract may, at times, be less than the demand charge on Westcoast for transportation service due to temporary reductions in the MDQ. However, Shell expects the gas sales contract demand charge payment to be greater, in aggregate, than any anticipated demand charges on Westcoast's facilities.

Should Tenaska's purchases in any year be less than the Minimum Annual Quantity ("MAQ"), then it must make a deficiency payment on the difference between actual takes and the MAQ. The MAQ is defined as 90 percent of the MDQ summed over the year, adjusted for force majeure, delivery shortfalls, scheduled facility maintenance and the DSQ summed over the year. The deficiency payment is based upon the difference between the weighted average price of Canadian spot gas delivered to Northwest and the contractual commodity charge volume weighted for the months in that year when the market price was less than the commodity charge and Tenaska took less than its maximum entitlement.

Should the cogeneration facility experience an unscheduled temporary reduction or suspension of operation on account of a documented operational condition other than force majeure, then Tenaska may divert any unused gas for use at a location or locations other than the facility. The price for such gas would equal the spot market price for Canadian gas delivered to Northwest less the demand charge.

Shell submitted that, on 1 January 1994, the British Columbia border price that would have been in effect under the terms of this contract was \$Cdn. 2.35/GJ (\$Cdn. 2.48/MMBtu).

7.6 Status of Regulatory Authorizations

Shell will file an application with the EMPR in the first quarter of 1994 for a long-term energy removal certificate. The application will be for a term and volume commensurate with the gas sales contract. The status of various U.S. federal, state and local regulatory authorizations required for the cogeneration facility are discussed in Sections 3.4 and 3.6 of these Reasons.

Views of the Board

The Board notes that Tenaska is subject to a deficiency payment should it take less than the MAQ. The Board is also cognizant that the market for the electricity is likely to be long-term and stable. The Board is therefore satisfied that there is a reasonable expectation that the volumes sought to be licensed will be taken.

The Board observes that the escalation provisions under the gas sales contract and the power purchase contract are similar and that the gas sales contract is subject to binding arbitration. The Board is thus satisfied that the gas sales contract will remain attractive to the parties over its proposed term, and is therefore likely to be durable.

The Board has reviewed the gas purchase agreement and notes that it has been negotiated at arm's length.

Since Shell owns the gas supporting this export licence application, a finding of producer support is not necessary.

The Board notes that the contract price contains a demand charge component for the recovery of Canadian demand charges throughout the term of the contract. As well, Shell has testified that it will continue to receive the sale price through the provisions of the suspension of payment sections of the gas sales contract. Therefore, the Board is satisfied that there are provisions in the gas sales contract for the payment of the associated transportation demand charges on Canadian pipelines over the term of the gas sales contract.

The Board's estimate of reserves for the primary supply source, the West Bullmoose pool, is approximately 40 percent less than the applied-for term volume. Furthermore, the Board's analysis indicates that productive capacity would be adequate for only three years of the proposed 15-year term. The Board notes that Shell provided some comments on its northeast British Columbia exploration and development program but, without precise information, the Board cannot be assured that any additional supply will be forthcoming when required. Similarly, the Board is not prepared to rely on current projections of the long-term adequacy of Shell's Alberta supply without transportation arrangements to deliver the gas from Alberta to Tenaska. In summary, considering the magnitude of the shortfalls in the primary gas supply source, and the lack of evidence on alternate gas supply sources, the Board is not satisfied with the adequacy of Shell's gas supply. The Board observes that the terms of the transportation, gas sales and power purchase contracts and of the applied-for regulatory authorizations are for a term consistent with the requested licence.

Decision

The Board has decided to issue a gas export licence to Shell, subject to the approval of the Governor in Council. Since the Board is not satisfied with the adequacy of Shell's gas supply, the Board has decided to reduce the applied-for term volume by one-third. Appendix I contains the terms and conditions of the licence to be issued.

Western Gas Marketing Limited

8.1 Application Summary

By application dated 22 October 1993, Western Gas sought, pursuant to Part VI of the Act, five licences for the export of natural gas for sale to five LDCs in the State of Wisconsin, with the following terms and conditions:

<u>WiGas</u>

Term	-	commencing on the date of issuance of the licence and ending on 31 October 2003
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	2 533 10^3m^3 (89.4 MMcf)
Maximum Annual Quantity	-	927 10^6m^3 (32.7 Bcf)
Maximum Term Quantity	-	9 270 10^6m^3 (327.0 Bcf)
Tolerances	-	ten percent per day and two percent per year

<u>WPSC</u>

Term	-	commencing on the date of issuance of the licence and ending on 31 October 2003
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	776 10^3m^3 (27.4 MMcf)
Maximum Annual Quantity	-	283 10^6m^3 (10.0 Bcf)
Maximum Term Quantity	-	2 830 10^6m^3 (100.0 Bcf)
Tolerances	-	ten percent per day and two percent per year

<u>WNG</u>

Term	-	commencing on the date of issuance of the licence and ending on 31 October 2003
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	752 10^3m^3 (26.5 MMcf)
Maximum Annual Quantity	-	275 10^6m^3 (9.7 Bcf)
Maximum Term Quantity	-	2 750 10^6m^3 (97.1 Bcf)
Tolerances	-	ten percent per day and two percent per year

<u>WP&L</u>

Term	-	commencing on the date of issuance of the licence and ending on 31 October 2003
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	237 10^3m^3 (8.4 MMcf)
Maximum Annual Quantity	-	86.7 10^6m^3 (3.1 Bcf)
Maximum Term Quantity	-	867 10^6m^3 (30.6 Bcf)
Tolerances	-	ten percent per day and two percent per year

<u>WF&L</u>

Term	-	commencing on the date of issuance of the licence and ending on 31 October 2003	
Point of Export	-	Emerson, Manitoba	
Maximum Daily Quantity	-	210 10^3m^3	(7.4 MMcf)
Maximum Annual Quantity	-	76.8 10^6m^3	(2.7 Bcf)
Maximum Term Quantity	-	768 10^6m^3	(27.1 Bcf)
Tolerances	-	ten percent per day and two percent per year	

Western Gas would provide the gas proposed for export from its contracted supply pool in Alberta. The gas would be transported on NOVA to the Alberta border at Empress. TransCanada would then deliver the gas to the export point at Emerson, Manitoba. From the international border, the gas would be shipped on either Great Lakes Gas Transmission Limited Partnership ("GLGT") or Viking and then on ANR for delivery to each of the five LDCs.

TransCanada and Western Gas have for several years been suppliers to ANR which in turn supplied many LDCs including the five Wisconsin LDCs contained in this application. The underlying gas export licences expired in 1989 and since that time TransCanada and Western Gas have met their contractual commitments to ANR under short-term export authorizations. As a result of FERC Order 636, several of ANR’s customers, including the five Wisconsin LDCs, have decided to contract directly with suppliers for their gas requirements. The new export arrangements contained in this application represent a conversion of a portion of the historical Western Gas/ANR agreement into direct sales by Western Gas to certain of ANR’s former customers.

8.2 Gas Supply

In support of its application, Western Gas relied upon the gas supply analysis that it provided to the Board during the GH-6-92 proceedings. The Board's assessment of Western Gas' gas supply reflects the Board's current estimate of reserves for all gas reserves under control of Western Gas. The reserves under control are based on the ERCB's assessment of pool interests as of 31 December 1992.

8.2.1 Supply Contracts

Western Gas intends to supply the proposed export from its contracted supply pool. Accordingly, no specific pools have been contractually dedicated to the sale. Should Western Gas' remaining reserves to production ratio fall below ten, it cannot enter into or renew any sales contracts. If it still cannot meet its obligations, Western Gas is first required to curtail deliveries under its short-term sales contracts. Then if the curtailment of all short-term sales contracts is still not sufficient to remedy the situation, Western Gas is required to pro-rate the daily quantities thus available from its supply pool among all of the long-term sales contracts.

Western Gas updated the evidence provided in GH-6-92 regarding the outlook for terminations of producers' supply contracts. The notices received will affect Western Gas' supply in the current and next four contract years. Western Gas commenced the process of contracting for new supplies in November 1993 and it expects that additional supply will become available in 1994.

8.2.2 Reserves

Table 8-1 shows that the Board's estimate of gas reserves is 15 percent lower than Western Gas' estimate. The Board's estimate of Western Gas' reserves is about 60 percent greater than Western Gas' total contracted requirements to the year 2011.

8.2.3 Productive Capacity

Figure 8-1 is a comparison of the Board's and Western Gas' estimates of productive capacity with its contracted requirements, including fuel and shrinkage. The Board's estimate of productive capacity is based on contract terminations that Western Gas has received to 31 October 1993. Figure 8-1 shows that Western Gas has sufficient supply to meet its current contracted requirements, including those applied for in this application, throughout the forecast period.

Table 8-1
Comparison of Estimates of Western Gas' Established Gas Reserves with the Applied-for Term Volume

10^9m^3
(Tcf)

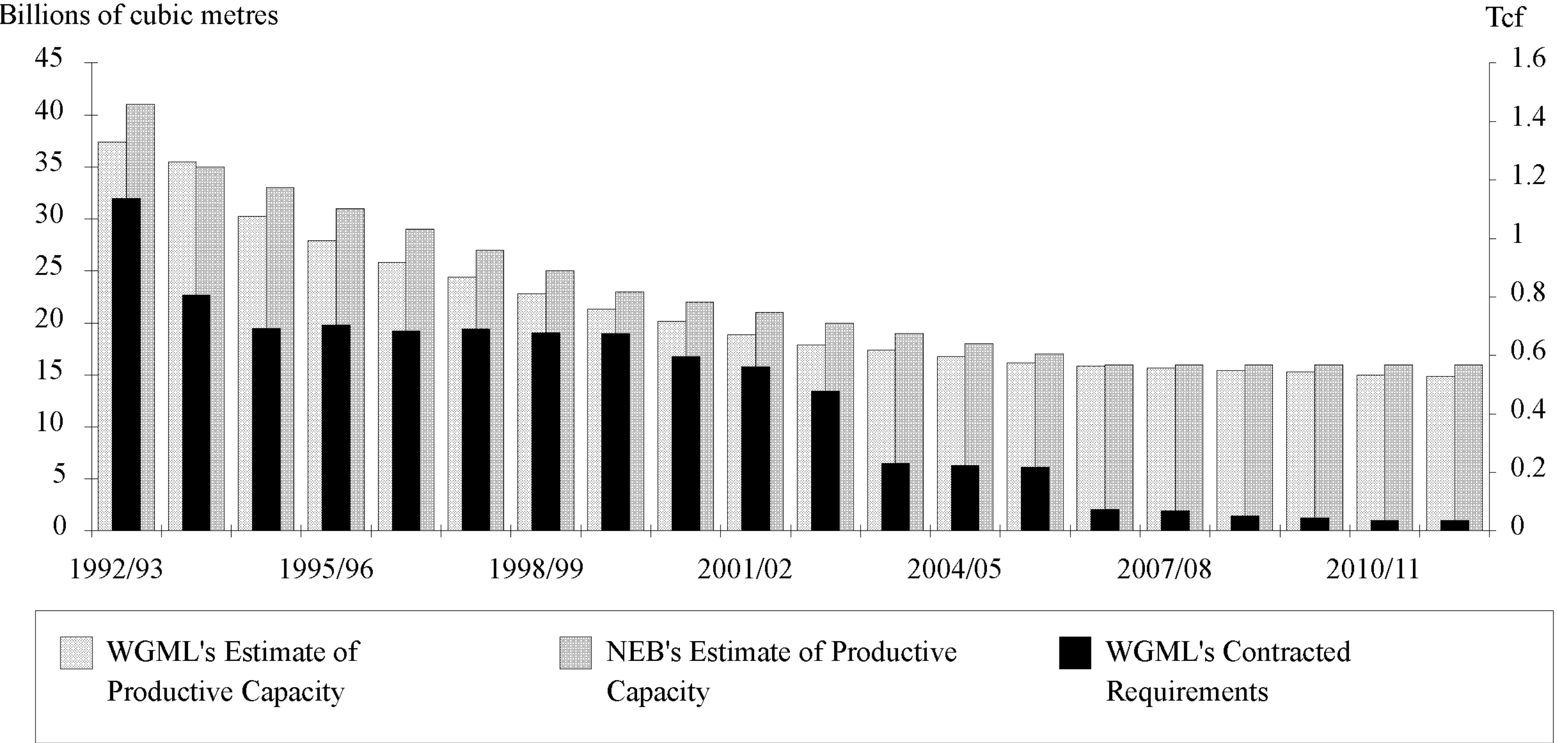
Western Gas[1]	NEB[1]	Applied-for[2] Volume
476 (16.8)	402 (14.2)	16.5 (0.58)

1. As of 31 December 1992.
2. These volumes represent only a portion of Western Gas' total requirements that must be provided from its supply pool. Western Gas' total contracted requirements over the forecast period, including the applied-for volumes, are 245 10^9m^3 (8.7 Tcf).

Figure 8-1
Comparison of Western Gas' and NEB's Estimates of Annual Productive Capacity

Figure 8-1

Comparison of Western Gas' and NEB's Estimates of Annual Productive Capacity



8.3 Transportation

The gas proposed for export would be aggregated within Alberta and delivered to Empress, Alberta under Western Gas' existing FS arrangements on NOVA. Western Gas would transport the volumes to Emerson, Manitoba pursuant to a firm transportation contract with TransCanada. The five Wisconsin LDCs would take delivery of the gas at the international border and transport it on either GLGT or Viking and then on ANR under existing transportation agreements.

8.4 Markets

A description of the Wisconsin LDC's markets is provided in Section 4.4 of these Reasons.

8.5 Gas Sales Contracts

Western Gas executed gas sales contracts with each of the five Wisconsin LDCs dated 20 October 1993. Except for the different volume obligations, the contracts are essentially the same. The term of the agreements commences on the date of the issuance of the licences and continues until 31 October 2003. The contracts provide for an extension of the term.

The contracts provide for a DCQ of 2 533 10^3m^3 (89.4 MMcf) for WiGas, 776 10^3m^3 (27.4 MMcf) for WPSC, 752 10^3m^3 (26.5 MMcf) for WNG, 237 10^3m^3 (8.4 MMcf) for WP&L and 210 10^3m^3 (7.4 MMcf) for WF&L.

While there are no minimum take provisions in the agreements, Western Gas stated that a number of factors would result in the contracts being operated at high load factors. First, the LDCs pay a monthly GIC equal to three percent of the commodity charge. Second, if the LDCs fail to purchase at least 20 percent of the DCQ, they must pay a deficiency charge of $U.S. 0.05/mcf on the difference between 20 percent of the DCQ and the volumes actually taken. Third, Western Gas stated that there was a higher proportion of fixed costs relative to total costs for Canadian gas, as compared with alternative U.S. supplies. It was likely, therefore, that Canadian supplies would be used before U.S. gas.

The contract price consists of four components: a demand charge, a GIC, a minimum deficiency charge and a commodity charge. The demand charge comprises the monthly demand tolls on NOVA and TransCanada. The GIC and minimum take deficiency charge were described above. The commodity charge is equal to a base price of $U.S. 1.73/GJ ($U.S. 1.82/MMBtu) and is adjusted monthly using selected indices reflecting the price of spot gas supplies in Louisiana and Oklahoma. In the case of the WF&L contract, the index also includes the spot price of Alberta gas.

The commodity charge and the price indices may be renegotiated for the contract year commencing 1 November 1995 and for every second year thereafter. If necessary, the contracts provide for binding arbitration.

Western Gas estimated that the prices under the terms of the contracts, on 1 January 1994 at the Alberta border, would have been approximately $Cdn. 2.40/GJ ($Cdn. 2.52/MMBtu).

8.6 Status of Regulatory Authorizations

DOE/FE has authorized the import of the applied-for export volumes and a finding of producer support was obtained from the APMC. Gas would be removed from Alberta under authority of ERCB removal permit GR 91-9.

Views of the Board

The Board notes that Canadian gas has been flowing to the five Wisconsin LDCs for several years. The Board also notes that there are provisions in the contracts for the payment of a monthly GIC and minimum take deficiency charge. The Board is, therefore, satisfied that there is a reasonable expectation that the volumes sought to be licensed will be taken.

The Board notes the market-oriented approach, including binding arbitration, used to determine the commodity charges and price indices. The Board is thus satisfied that the gas sales contracts will remain attractive to the parties over their proposed terms and are therefore durable.

The Board has reviewed the gas sales contracts between Western Gas and the five LDCs and is satisfied that they have been negotiated at arm's length.

The Board notes that Western Gas received a finding of producer support from the APMC.

The gas sales contracts require the LDCs to reimburse Western Gas for demand charges on NOVA and TransCanada. The Board is, therefore, satisfied that there are provisions in the gas sales contracts for the payment of the associated transportation charges on Canadian pipelines over the term of the gas sales contracts.

The Board's estimate of Western Gas' reserves exceeds the applicant's total contracted requirements, including the applied-for volumes. Additionally, the Board's projections of productive capacity show that Western Gas should be able to meet its contracted requirements throughout the proposed export terms. The Board notes that the terms of the gas sales contracts are identical to the applied-for terms of the proposed exports. Transportation has been arranged on all required pipelines for the proposed export terms. The Board also notes that the regulatory authorizations are for a term and volume commensurate with the requested licences. The Board is, therefore, satisfied that the term for the five licences is appropriate.

Finally, the Board notes that Western Gas has applied for commencement dates of 1 November 1993. Since the Board does not backdate its licences, the applied-for term volumes must be adjusted to account for a shorter term. Assuming a commencement date of 1 May 1994, the Board has reduced the applied-for term volumes by commensurate amounts. These volumes are the product of the DCQ and the number of days between 1 November 1993 and 1 May 1994. Western Gas agreed with the Board's method of calculating this reduction in the applied-for term volumes.

Decision

The Board has decided to issue five 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 to be issued.

Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of those applications heard by the Board in the GH-5-93 proceeding.

R.L. Andrew, Q.C.
Presiding Member

R. Priddle
Member

R. Illing
Member

Calgary, Alberta
February 1994

Terms and Conditions of the Licences to be Issued

Terms and Conditions of the Licence to be Issued to Brooklyn Navy Yard Cogeneration Partners, L.P.

1. (a) Subject to condition 1(b) the term of this Licence shall commence on the date of first deliveries and shall end 15 years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 November 1997 unless exports commence hereunder on or before that date.

2. Subject to condition 3, the quantity of gas that Navy Yard Partners may export under the authority of this Licence shall not exceed:

   (a) 750 000 cubic metres in any one day;

   (b) 274 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 4 110 000 000 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 Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to Husky Oil Operations Ltd.

1. (a) Subject to condition 1(b) the term of this Licence shall commence on the date of first deliveries and shall end 15 years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 December 1998 unless exports commence hereunder on or before that date.

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

   (a) 398 000 cubic metres in any one day;

(b) 145 270 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 2 179 050 000 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 Huntingdon, British Columbia.

Terms and Conditions of the Six Licences to be Issued to ProGas Limited for Sale to the ANR Customer Group

Licence A. "Michigan Gas Utilities"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2000.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 75 700 cubic metres in any one day;

   (b) 27 648 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 179 827 000 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 B. "Wisconsin Fuel & Light"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 84 800 cubic metres in any one day;

   (b) 30 967 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 294 318 000 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. "Wisconsin Gas Company"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2000.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 807 100 cubic metres in any one day;

   (b) 294 577 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 915 961 000 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 D "Wisconsin Natural Gas Company"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 304 000 cubic metres in any one day;

   (b) 110 965 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 054 626 000 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 E. "Wisconsin Power & Light Company"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 95 900 cubic metres in any one day;

   (b) 35 020 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 332 838 000 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 F. "Wisconsin Public Service Corporation"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 313 800 cubic metres in any one day;

   (b) 114 532 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 088 529 000 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.

Amendments to the Conditions of Licence GL-98 held by ProGas Limited

Conditions 2(c) and 2(d) are revoked and replaced with the following:

2. (c) for the period commencing on 1 November 1993 and ending on 31 October 1996, 5 221 145 cubic metres in any one day or 1 560 270 000 cubic metres in any consecutive twelve-month period ending on 31 October; and for the period commencing on 1 November 1996 and ending on 31 October 1999, 5 447 513 cubic metres in any one day or 1 642 894 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(d) during the term hereof, 30 680 000 000 cubic metres less the total quantity of gas exported under Licence GL-56 until the date of repeal thereof.

Amendment to the Conditions of Licence GL-129 held by ProGas Limited

1. The term of this Licence shall be extended to 31 October 2013.

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

   (a) 2 039 600 cubic metres in any one day;

   (b) 744 456 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 19 015 349 000 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 Niagara Falls, Ontario.

Terms and Conditions of the Two Licences to be Issued to ProGas Limited for Sale to WPSC and WiGas.

Licence A. "Wisconsin Public Service Corporation"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 1997.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 226 400 cubic metres in any one day;

   (b) 82 624 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 289 524 000 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 B. "Wisconsin Gas Company"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2002.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 187 400 cubic metres in any one day;

   (b) 68 397 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 581 656 000 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 Shell Canada Limited

1. (a) Subject to condition 1(b) the term of this Licence shall commence on the date of first deliveries and shall end 15 years following the commencement of the term of this Licence.

   (b) The term of this Licence shall end on 1 December 1998 unless exports commence hereunder on or before that date.

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

   (a) 609 000 cubic metres in any one day;

   (b) 223 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 2 001 331 000 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 two 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 Huntingdon, British Columbia.

Terms and Conditions of the Five Licences to be Issued to Western Gas Marketing Limited for Sale to the Wisconsin Customer Group

Licence A. "Wisconsin Gas Company"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 2 533 000 cubic metres in any one day;

   (b) 927 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 8 811 527 000 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 B. "Wisconsin Public Service Corporation"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 776 000 cubic metres in any one day;

   (b) 283 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 689 544 000 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 "Wisconsin Natural Gas Company"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 752 000 cubic metres in any one day;

   (b) 275 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 613 888 000 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 D. "Wisconsin Power & Light Company"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 237 000 cubic metres in any one day;

   (b) 86 700 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 824 103 000 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 E. "Wisconsin Fuel & Light Company"

1. (a) Subject to condition 1(b), the term of this Licence shall commence on 1 May 1994 and shall end on 31 October 2003.

   (b) The term of this Licence shall end on 1 November 1995 unless exports commence hereunder on or before that date.

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

   (a) 210 000 cubic metres in any one day;

   (b) 76 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 729 990 000 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.