National Energy Board

Reasons for Decision

AG-Energy, L.P.

Canadian Hydrocarbons Marketing Inc.

Canadian-Montana Pipe Line Company

Esso Resources Canada Limited/
Esso Resources Canada/
Transco Energy Marketing Company/
CanStates Gas Marketing

Husky Oil Operations Ltd.

Petro-Canada

TransCanada PipeLines Limited

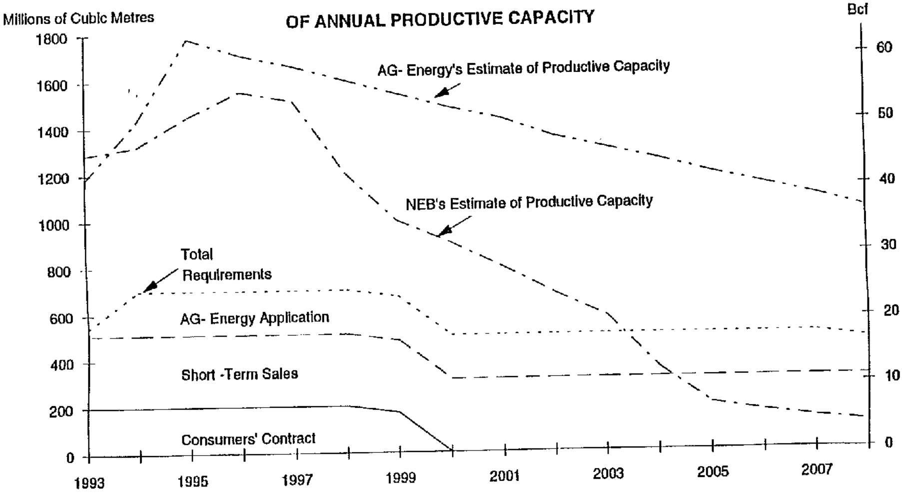
GH-1-92

June 1992

Volume I
Gas Exports

Figure 2-1

COMPARISON OF AG- ENERGY'S AND NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



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IN THE MATTER OF

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Canadian Hydrocarbons Marketing Inc.

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CanWest Gas Supply Inc.

Enserch Development Corporation, on behalf of Encogen Northwest, L.P.

Husky Oil Operations Ltd.

Kamine Natural Dam Cogen Co., Inc.

Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & ATCOR Ltd.

Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & Esso Resources Canada

Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & PanCanadian Petroleum Limited

New York State Electric & Gas Corporation

Petro-Canada

TransCanada PipeLines Limited

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

Esso Resources Canada Limited/Esso Resources Canada/
Transco Energy Marketing Company/CanStates Gas Marketing

Application Pursuant to Part I of the National Energy Board Act for the Transfer of a Licence to Export Natural Gas

GH-1-92

June 1992

Volume I
Gas Exports

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Recital and Appearances

IN THE MATTER OF the National Energy Board Act and the 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:

AG-Energy, L.P.; Canadian Hydrocarbons Marketing Inc.; Canadian-Montana Pipe Line Company; CanWest Gas Supply Inc.; Enserch Development Corporation, on behalf of Encogen Northwest, L.P.; Husky Oil Operations Ltd.; Kamine Natural Dam Cogen Co., Inc.; Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & ATCOR Ltd.; Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & Esso Resources Canada; Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. & PanCanadian Petroleum Limited; New York State Electric & Gas Corporation; Petro-Canada; and TransCanada PipeLines Limited

AND IN THE MATTER OF an application under Part I of the National Energy Board Act for the transfer of a licence to export natural gas by:

Esso Resources Canada Limited / Esso Resources Canada / Transco Energy Marketing Company / CanStates Gas Marketing

AND IN THE MATTER OF Hearing Order GH-1-92, as amended;

HEARD in Calgary, Alberta on 21, 22 and 23rd April 1992.

BEFORE:

A.B. Gilmour	Presiding Member
R.B. Horner, Q	Member
R.L. Andrew, Q	Member

APPEARANCES:

A.S. Hollingworth C.I. MacLean	AG-Energy, L.P.
P. J. McIntyre R.B. Brander	Canadian Hydrocarbons Marketing Inc.
A.R. O'Brien	Canadian-Montana Pipe Line Company
L.E. Smith N.M. Gretener	CanWest Gas Supply Inc.; and New York State Electric & Gas Corporation

D.W. Rowbotham	Enserch Development Corporation, on behalf of Encogen Northwest, L.P.
T.M. Hughes	Esso Resources Canada Limited / Esso Resources Canada / Transco Energy Marketing Company / CanStates Gas Marketing
S. Carscallen	CanStates Gas Marketing
J. Ebert	Transco Energy Marketing Company
D.A. Holgate	Husky Oil Operations Ltd.; and Kamine Natural Dam Cogen Co., Inc.
S.R. Miller	Petro-Canada
L.G. Keough	Makowski Selkirk, Inc. on behalf of: Selkirk Cogen Partners II, L.P. & ATCOR Ltd.; Selkirk Cogen Partners II, L.P. & Esso Resources Canada; and Selkirk Cogen Partners II, L.P. & PanCanadian Petroleum Limited
E.P. Varga	TransCanada PipeLines Limited
H.T. Soudek	The Consumers' Gas Company Ltd.; and St. Lawrence Gas Company, Inc.
R.R. Argamany	Mobil Oil Canada
K.L. Meyer	Pan-Alberta Gas Ltd.
R.B. Hillary	Paramount Resources Ltd.
J. Couch	ProGas Limited
E.B. McDougall	Washington Natural Gas Company
G. Britton	Western Gas Marketing Limited
J. Syme P. Noonan	National Energy Board

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Abbreviations

Act	National Energy Board Act
AG-Energy	AG-Energy, L.P. and/or the general partner of AG-Energy, L.P., AG-Energy, Inc.
ANG	Alberta Natural Gas Company Ltd.
ATCOR	ATCOR Ltd.
"Baseball style"	A method of arbitration whereby each party submits its best offer arbitration and an arbitrator chooses one of the offers.
Bcf	billion cubic feet
Board	National Energy Board
BPA	Bonneville Power Administration
BPOI	BP Exploration & Oil Inc.
CanWest	CanWest Gas Supply Inc.
Cascade	Cascade Natural Gas Corporation
CHMI	Canadian Hydrocarbons Marketing Inc.
CMG	Canadian–Montana Gas Company Ltd.
CMPL	Canadian–Montana Pipe Line Company
Consumers’	The Consumers’ Gas Company Ltd.
CSGM	CanStates Gas Marketing
DCQ	Daily Contract Quantity
Debolt	Mississippian Debolt Formation
DOE/FE	(United States of America) Department of Energy, Office of Fossil Energy
EARP Guidelines Order	Environmental Assessment and Review Process Guidelines Order
EIA	Export Impact Assessment

EMPR	(British Columbia) Ministry of Energy, Mines and Petroleum Resources
Encogen	Encogen Northwest, L.P.
ERC	Esso Resources Canada
ERCB	(Alberta) Energy Resources Conservation Board
ERCL	Esso Resources Canada Limited
Facility	a cogeneration facility
FERC	(United States of America) Federal Energy Regulatory Commission
FS	Firm Service
gas contract	contract for the purchase and sale of natural gas
GJ	gigajoule(s)
GLGT	Great Lakes Gas Transmission Limited Partnership
ha	hectares
Home	Home Oil Company Limited
Husky	Husky Oil Operations Ltd.
Hydro-Québec decision	the Federal Court of Appeal decision in the case of Attorney General of Québec v. National Energy Board (unreported, 9 July 1991, A—1057—90)
IGTS	Iroquois Gas Transmission System, L.P.
Joint Applicants	ERCL, ERC, TEMCO and CSGM
Kamine	Kamine Natural Dam Cogen Co., Inc.
Klua	the five Klua Pine Point pools supporting the Petro—Canada application
LDC	local distribution company
MDQ	Maximum Daily Quantity

MMBtu	million British thermal units
MMcf	million cubic feet
MPC	The Montana Power Company
NEB	National Energy Board
Niagara	Niagara Mohawk Power Corporation
Northwest	Northwest Pipeline Corporation
NOVA	NOVA Corporation of Alberta
Numac	Numac Oil and Gas Ltd.
NYPSC	New York Public Service Commission
NYSEG	New York State Electric and Gas Corporation
Open Access	Service under which former pipeline customers can contract directly with producers for supply and pipelines can provide "transportation only" service.
PanCanadian	PanCanadian Petroleum Limited
Part VI Regulations	National Energy Board Part VI Regulations
Puget	Puget Sound Power & Light Company
PURPA	(United States of America) Public Utility Regulatory Policies Act
QF	qualifying cogeneration facility
Selkirk	Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P.
SLPC	St. Lawrence Psychiatric Center
St. Lawrence Gas	St. Lawrence Gas Company, Inc.
Sulpetro	Sulpetro Limited
Taylor plant	the Taylor Processing Plant on the Westcoast system

Tenaska	Tenaska Gas Co. (which is acting as the natural gas aggregator) and/or Tenaska Washington Partners (a partnership formed to construct, own and operate the cogeneration facility).
TEMCO	Transco Energy Marketing Company
Tommy Lakes	the east portion of the Tommy Lakes Halfway A pool in northeast British Columbia
TransCanada	TransCanada PipeLines Limited
Transco	TransContinental Gas Pipe Line Corporation
U.S.	United States of America
Vancouver Island contract	Vancouver Island core market contract
WACOG	weighted average cost of gas
Westcoast	Westcoast Energy Inc.
WNG	Washington Natural Gas Company
WPL	Westcoast Petroleum Ltd.

Chapter 1

Part VI - Gas Export Licence Applications

1.1 The Applications

During the GH-1-92 proceeding, the National Energy Board ("the Board") examined 13 applications for gas export licences and one application for the transfer of a gas export licence. The applications were filed by the following companies:

1. AG-Energy, L.P. ("AG-Energy");

2. Canadian Hydrocarbons Marketing Inc. ("CHMI");

3. Canadian-Montana Pipe Line Company ("CMPL");

4. CanWest Gas Supply Inc. ("CanWest");

5. Enserch Development Corporation, on behalf of Encogen Northwest, L.P. ("Encogen");

6. Esso Resources Canada Limited ("ERCL") / Esso Resources Canada ("ERC") / Transco Energy Marketing Company ("TEMCO") / CanStates Gas Marketing ("CSGM") (collectively called "the Joint Applicants") for the transfer of Licence GH-136;

7. Husky Oil Operations Ltd. ("Husky");

8. Kamine Natural Dam Cogen Co., Inc. ("Kamine");

9. Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P. ("Selkirk") & ATCOR Ltd. ("ATCOR");[1]

10. Selkirk & ERC;[2]

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[1] During the Hearing, Selkirk requested that its applications be amended so that any licences granted be issued in the name, in part, of Selkirk Cogen Partners, L.P. instead of in the name, in part, of Makowski Selkirk, Inc. on behalf of Selkirk Cogen Partners II, L.P.

[2] By letter dated 9 June 1992, Selkirk and ERC requested that their application be amended so that any licence granted be issued in the name, in part, of Imperial Oil Resources, instead of in the name, in part, of Esso Resources Canada.

11. Selkirk & PanCanadian Petroleum Limited ("PanCanadian");

12. New York State Electric & Gas Corporation ("NYSEG");

13. Petro-Canada; and

14. TransCanada PipeLines Limited ("TransCanada").

Table 1-1 provides a summary of each export licence application reviewed during the GH-1-92 proceeding.

Table 1-1

Summary of Applied-for Licences

GH-1-92

	Application	Buyer (Type of market)	Term	Export Point	Maximum Quantities Applied For		
					Daily 103m3 (MMcf)	Annual 106m3 (Bcf)	Term 106m3 (Bcf)
1.	AG-Energy	AG-Energy (cogen. plant)	1 Sept. 1993 to 31 Oct. 2008	Iroquois, Ontario	467.0 (16.5)	170.6 (6.0)	2 587.0 (91.3)
2.	CHMI	WNG (system supply)	1 Nov. 1992 to 31 Oct. 2002	Huntingdon, British Columbia	273.9 (9.7)	100.0 (3.5)	1 000.3 (35.3)
3.	CMPL	MPC (system supply)	1 Nov. 1992 to 31 Oct. 2006	Aden, Alberta	1 416.4 (50.0)	283.3 (10.0)	3 966.2 (140.0)
4.	CanWest	Northwest (system supply)	for 12 years following 1st del.	Huntingdon, British Columbia	2 606.0 (92.0)	952.0 (34.0)	11 415.0 (403.0)
5.	Encogen	Encogen (cogen. plant)	1 April 1993 to 31 March 2008	Huntingdon, British Columbia	271.8 (9.6)	99.1 (3.5)	1 441.3 (50.9)
6.	ERC/ERCL/ TEMCO/CSGM	TEMCO (system supply)	1 Nov. 1990 to 31 Oct. 2002	Niagara, Falls Ontario	2 125.0 (75.0)	775.6 (27.4)	9 307.5 (328.6)
7.	Husky	Tenaska (cogen. plant)	for 17.25 years following 1st del.	Huntingdon, British Columbia	366.2 (13.0)	133.7 (4.8)	2 306.6 (81.9)
8.	Kamine	Kamine (cogen. plant)	1 Nov. 1993 to 31 Oct. 2008	Iroquois, Ontario	339.8 (12.0)	117.8 (4.2)	1 767.1 (62.4)
9.	Selkirk & ATCOR	Selkirk (cogen. plant)	1 June 1994 to 31 Oct. 2009	Iroquois, Ontario	479.0 (17.0)	176.1 (6.2)	2 712.0 (95.8)
10.	Selkirk & ERC	Selkirk (cogen. plant)	1 June 1994 to 31 Oct. 2009	Iroquois, Ontario	538.2 (19.0)	196.6 (6.9)	3 031.0 (107.0)
11.	Selkirk & PanCanadian	Selkirk (cogen. plant)	1 June 1994 to 31 Oct. 2009	Iroquois, Ontario	538.2 (19.0)	196.6 (6.9)	3 031.0 (107.0)
12.	NYSEG	NYSEG (system supply)	for 12 years following 1st del.	Napierville, Québec	255.0 (9.0)	93.1 (3.3)	1 117.0 (39.6)
13.	Petro–Canada	Tenaska (cogen. plant)	for 17.25 years following 1st del.	Huntingdon, British Columbia	409.6 (14.1)	150.0 (5.1)	2 580.9 (91.1)
14.	TransCanada	GLGT (fuel gas)	1 Feb. 1992 to 31 Oct. 2005	Emerson, Manitoba	2 785.0 (98.4)	875.0 (30.9)	12 035.0 (424.9)

The Joint Applicants, ERC/ERCL/TEMCO/CSGM, requested that the Board issue its decision at as early a date as possible. The Joint Applicants made this request due to certain contractual provisions that required Governor in Council approval of the transfer of Licence GL-136 prior to 1 September 1992. Consequently, the Board has decided to publish its GH-1-92 Reasons for Decision in two volumes. This volume, Volume I, deals with the applications by AG-Energy, CHMI, CMPL, the Joint Applicants, Husky, Petro-Canada and TransCanada.

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

1.2 Market-Based Procedure

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

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. The following discussion of the Board's Market-Based Procedure is general in nature and applies to each application heard in the GH-1-92 proceeding.

The Market-Based Procedure provides that the Board consider:

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

In GHW-1-91, the Board advised interested parties of proposed changes to be made to the Market-Based Procedure. These proposed changes affect the application of the Complaints Procedure and the other public interest considerations. Comments from parties were requested to be filed on 15 October 1991 with reply comment by 20 December 1991.

As the GHW-1-91 proceeding was not completed at the time the Board examined the 14 applications heard in GH-1-92, the Board relied upon the existing procedure for its assessment of the applications.

1.2.1 Complaints Procedure

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

There were no complaints made with respect to the applications for export licences in the GH-1-92 proceeding.

1.2.2 Export Impact Assessment

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

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

The seven applicants included in this volume adopted the Board's EIA.

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

1.2.3 Other Factors Relevant to the Public Interest

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

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

1.2.3.1 Gas Supply

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

Each applicant provides an estimate of remaining 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 marketable gas reserves.

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

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

1.2.3.2 Market, Commercial Arrangements and Regulatory Status

The Board conducts a review of the market, commercial arrangements and regulatory status underpinning projects to assist it in determining whether the proposed exports are in the public interest. The applications dealt with in GH-1-92 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 market types included consideration of the following for each market type:

- for exports for system supply, it included 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, defined as a facility that produces electricity and thermal energy for use in commercial or industrial operations, an examination of the contractual chain, from the gas sales contract to the power and thermal sales contracts, was conducted. In this regard the Board looked to the status of project financing, construction schedules and qualifying cogeneration facility ("QF") certification under the Public Utility Regulatory Policies Act ("PURPA") of the United States of America ("U.S.").

The TransCanada application was for the export of gas for use as compressor fuel and associated gas on the Great Lakes Gas Transmission Limited Partnership ("GLGT") system for the transportation of natural gas destined for consumption in Canada.

For each type of end–use market, the review included consideration, among other items, of the load factors at which the proposed exports are expected to flow and the status of pertinent regulatory authorizations in Canada and the U.S.

The Board's review of the commercial arrangements included consideration of information each applicant was required to file in accordance with the Part VI Regulations and in response to Board information requests issued during the hearing. This information included the following:

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

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

- any resale arrangements that occur beyond the international boundary sale point, where such arrangements have a direct effect on the international sales agreement, including filing of these downstream contracts; and

- for cogeneration facilities, the contractual obligations between the cogeneration facility and the electric utility and the steam host.

In its review of the gas sales contracts between the Canadian sellers and the U.S. buyers, the

Board made the following determinations:

- whether the contracts are likely to recover associated Canadian intraprovincial and interprovincial transportation costs;

- whether the contracts contain provisions which permit adjustments to reflect changing market conditions over the life of the contract;

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

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

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

1.3 Sunset Clauses

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

1.4 Environmental Screening

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

The purpose of the environmental screening is to enable the Board to reach one of the conclusions required by section 12 of the EARP Guidelines Order. To that end, the Board performed a screening, pursuant to Hearing Order GH-1-92, as amended, wherein it considered submissions from each applicant and from interested parties to GH-1-92.

On 9 July 1991, the Federal Court of Appeal issued its decision in the case of Attorney General of Québec v. National Energy Board (unreported, 9 July 1991, A-1057-90) (the "Hydro-Québec decision"). The Court held that the Board's jurisdiction over exports (in this case, electricity exports) did not extend to the facilities used for the production of the good for export. Accordingly, as was stated by Mr. Justice Marceau, speaking on behalf of the Court (at page 6):[1]

> "The factors which may be relevant in considering an application for leave to export electricity and the conditions which the Board may place on its leave clearly cannot relate to anything but the export of electricity".

The Board is of the view that the Hydro-Québec decision applies to the regulation of gas exports as well as electricity exports.

Each applicant filed with the Board information concerning the potential environmental effects and the social effects directly related to those environmental effects that would be caused by the moving of gas from Canada. All interested parties were served with these written submissions.

Mr. R.E. Wolf provided public interest evidence in regard to each of the applications. Mr. Wolf expressed concern that biodiversity was being destroyed as a result of seismic exploration, access road, well site and pipeline right-of-way development without considering the environmental consequences of such actions. Mr. Wolf stated that wildlife resources and habitat need to be protected and was also concerned that low natural gas prices would prevent producers from properly restoring drill sites and from protecting ground water, which could be contaminated by the contents of the drilling sumps.

In his letter of comment filed in the proceeding, Dr. Brian Horejsi, representing the Speak Up For Wildlife Foundation, objected to the granting of gas export licences until the upstream effects on biodiversity, ecosystem viability and sustainability, and wildlife conservation are addressed in a comprehensive and public environmental assessment process. Dr. Horejsi wrote that this process must be based on an independently controlled environmental impact statement that considers:

(a) the various regions from which gas is extracted for export;
(b) the cumulative effects of energy developments and other kinds of developments; and
(c) an ecosystem approach to assessment.

As well, the environmental impact statement should be subject to a full, public review through a clearly defined, written administrative and/or legislated process.

NYSEG and CanWest submitted that concerns relating to upstream environmental matters, which appeared to be the focus of Mr. Wolf's and Dr. Horejsi's objections, are matters outside of the Board's jurisdiction and are more correctly dealt with by the individual provincial regulators.

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[1] On 11 June 1992, Leave to Appeal the Hydro-Québec decision was granted to the Québec Cree by the Supreme Court of Canada.

NYSEG and CanWest further submitted that the environmental effects of facilities which are required to transport the gas are properly and correctly dealt with by the Board in comprehensive Part III, not Part VI, proceedings.

The Board, by means of a screening pursuant to the EARP Guidelines Order, has concluded that the applications of CMPL and TransCanada fall within the ambit of Note 3 of the Board's EARP Guidelines Order Automatic Exclusion List and therefore require no further examination. For the remaining applications, the Board has completed its environmental screening and has concluded that the potentially adverse environmental effects and the social effects directly related thereto are insignificant or mitigable with known technology.

The Board acknowledged Mr. Wolf's and Dr. Horejsi's concerns regarding the effects of natural gas development upon the environment and the wildlife. However, matters dealing with permitting and drilling of natural gas resources are outside the Board's jurisdiction. Such concerns are correctly dealt with by provincial regulators within their legislative mandate. The Board is also of the view that the environmental effects of facilities which are required to transport the gas are properly and correctly dealt with by the Board in comprehensive Part III proceedings.

Chapter 2

AG-Energy, L.P.

2.1 Application Summary

By application dated 15 January 1992, AG-Energy sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	a period of 15 years and two months commencing on or after 1 September 1993 and ending on or before 31 October 2009
Point of Export	-	near Iroquois, Ontario
Maximum Daily Quantity	-	467 103m3 (16.5 MMcf)
Maximum Annual Quantity	-	171 106m3 (6.0 Bcf)
Maximum Term Quantity	-	2 535 106m3 (89.9 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas proposed for export would be produced from pools in Alberta owned by Home Oil Company Limited ("Home"). The gas would be transported on the NOVA Corporation of Alberta ("NOVA") system for delivery to the TransCanada inlet near Empress, Alberta. The gas would be shipped by TransCanada to the international border near Iroquois, Ontario. The gas would then flow on the Iroquois Gas Transmission System, L.P. ("IGTS") and St. Lawrence Gas Company, Inc. ("St. Lawrence Gas") systems for final delivery to AG-Energy’s proposed cogeneration facility. The facility will be situated at the St.Lawrence Psychiatric Center ("SLPC") in the City of Ogdensburg, New York. Electricity and steam generated at the facility would be sold to Niagara Mohawk Power Corporation ("Niagara") and SLPC, respectively.

2.2 Gas Supply

2.2.1 Supply Contracts

AG-Energy has executed a 15-year contract with Home for a portion of Home’s undedicated corporate supply pool. A discussion of this contract is provided in section 2.3.3 of these Reasons.

2.2.2 Reserves

AG-Energy submitted Alberta Energy Resources Conservation Board ("ERCB") estimates of reserves for Home’s undedicated pools. These reserves represent approximately 30percent of Home’s total corporate supply as at the end of 1990.

Table 2-1 shows that the Board’s estimate of AG-Energy’s established reserves is marginally higher than AG-Energy’s estimate and that both estimates substantially exceed the applied-for volumes. During the proposed licence period, other commitments on this gas supply include the remainder of a contract with TheConsumers’ Gas Company Ltd. ("Consumers’") for 1 550 106m3 (55 Bcf) and Home’s expected short-term sales of 4650106m3 (164.2 Bcf). These two commitments total 6200106m3 (219.2 Bcf), leaving a

Table 2-1

Comparison of Estimates of AG-Energy's Established Gas Reserves With the Applied-for Term Volume

106m3 (Bcf)

AG-Energy[2]	NEB[3]	Applied-for[4] Volume
9 690 (342)	9 825 (347)	2 535 (89.9)

margin of only some 1034 106m3 (36.5 Bcf), roughly 12percent of the Board's estimate, after supplying the proposed export.

About 45 percent of the gas supply is located in Devonian and Lower Cretaceous pools in Blackstone and Leismer respectively. Eighty percent of the reserves under contract to AG—Energy are found in Devonian and Lower Cretaceous horizons. Some 40 percent of these pools are currently producing.

The Board's estimate of AG-Energy's reserves is slightly higher than AG-Energy's estimate. This is due primarily to the cumulative effect of several differences in small pools and a 31 percent higher estimate by the Board for the Blackstone Beaverhill Lake A pool. The Board's estimate for this pool is based on a material balance analysis of recent pressure data.

In summary, the Board's estimate of gas supply exceeds the total requirements by 12 percent.

2.2.3 Productive Capacity

Shown in Figure 2-1 is a comparison of the Board's and AG-Energy's projections of productive capacity with the total requirements for the Home supply pool. The requirements include the applied-for quantities, the Consumers' contract quantities and Home's estimated shor-—term sales.

The Board's projection suggests that Home's supply pool could not satisfy total requirements beyond 2003. If Home were to reduce or eliminate its short-term sales after 2003, then its supply

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[2] Estimates of reserves are as of December 1990; land control as of April 1992.

[3] As of December 1990.

[4] Total requirements are 8 735 106m3 (308.4 Bcf), including a Consumers' contract of 1 550 106m3 (55Bcf) and Home's expected short—term sales of 4 650 106m3 (164.2 Bcf).

would be adequate to enable AG-Energy to meet its export commitments over the proposed 15-year term.

2.3 Market, Commercial Arrangements and Regulatory Status

2.3.1 Market

The gas proposed for export would be used to fuel a 79 MW cogeneration facility. Home would be the sole supplier of gas. AG-Energy, the owner of the facility, is a limited partnership registered in the State of Delaware and headquartered in New York City.

The thermal host, SLPC, provides mental health services in upstate New York. The cogeneration facility would assume all the process and heating needs of SLPC and displace the need to operate existing boilers. Back-up steam would be provided from a package boiler system.

The power purchaser, Niagara, is the second largest public utility in New York. It provides electric service to more than 1.4 million residential, commercial and industrial customers, and has a peak electrical demand exceeding 6,200 MW. Its four major markets are the cities of Buffalo, Syracuse, Albany and Watertown. Watertown is the newest major growth area.

In recent years Niagara has faced annual reductions in its ability to draw power generated by the Power Authority of the State of New York. Increasing load growth has required Niagara to seek additional sources of power.

At the time of the hearing, AG-Energy anticipated that project financing would close at the end of June or the beginning of July 1992. Construction is expected to commence upon financial closing and the facility start-up is scheduled for November 1993.

Based on their gas turbine experience, AG-Energy expects facility availability to average 94 percent.

2.3.2 Transportation

The gas proposed for export would be obtained from Home's pools in Alberta. The gas would be shipped on NOVA to Empress, Alberta, where AG-Energy would take possession of the gas, under Home's existing firm service ("FS") arrangements. The gas would then be shipped on TransCanada to the interconnection with IGTS near Iroquois, Ontario. St.Lawrence Gas would deliver the gas to the cogeneration facility.

AG-Energy has signed precedent agreements with TransCanada, IGTS and St. Lawrence Gas for periods ranging from 15 years to 20 years for the full export volume. New facilities required for this export are included in TransCanada's 1993/94 facilities application.

AG-Energy is directly responsible for all transportation charges on TransCanada. Home is responsible for charges on NOVA but recovers these through the gas sales contract.

2.3.3 Gas Sales Contract

Home and AG-Energy executed a gas sales contract dated 14 October 1991. The contract term begins with the commencement of firm deliveries and continues for 15 years. Commencement of firm deliveries is anticipated between 1 November 1993 and 31 March 1994. The contract provides for a maximum daily quantity ("MDQ") of 467 103m3 (16.5MMcf) and is subject to the completion of all necessary contractual arrangements and the receipt of all regulatory approvals by 30 November 1992. AG–Energy stated that the contract was negotiated at arm's length.

AG-Energy is required to take an average of 80 percent of the MDQ during the November to April and May to October periods. Should AG-Energy nominate less than this amount, it is obligated to pay a $0.24/GJ ($0.25/MMBtu) reservation charge on the deficient volumes. This charge escalates at a compound rate of four percent per annum after 1 November 1994. Either party may reduce the MDQ to 120 percent of the actual take level in a contract year if Home fails to deliver or AG-Energy fails to take 65 percent of the annual minimum take quantity.

Home is liable for any incremental costs that AG-Energy incurs in obtaining replacement fuel for volumes not delivered by Home. Home is also liable for Canadian demand charges attributable to any undelivered volumes below the 65 percent annual minimum take.

The contractual price is comprised of a commodity charge and a transportation charge. The commodity charge escalates at approximately 6.8 percent per annum from an initial charge of $Cdn. 1.73/GJ ($Cdn.1.82/MMBtu) in 1993/94 to $Cdn. 4.33/GJ ($Cdn.4.56/MMBtu) in 2007/08. AG-Energy stated that the commodity charge schedule reflects the parties' reasonable assessment of future gas market conditions compatible with long-term electricity sales and prices to Niagara.

The transportation charge includes a monthly demand charge and a commodity charge for service on NOVA and a charge for fuel gas on TransCanada, IGTS and St. Lawrence Gas. AG-Energy is required to pay the NOVA demand charge regardless of actual takes. The NOVA commodity charge applies to the actual volumes of gas delivered by Home.

There is no provision for renegotiation of the contract. However, the contract does provide for dispute resolution through arbitration under the Rules of the British Columbia International Commercial Arbitration Centre.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 January 1992 was $Cdn. 1.81/GJ ($Cdn. 1.91 MMBtu).

2.3.4 Power Purchase Agreement

The sale of electricity from the cogeneration facility would be pursuant to an agreement, dated 24December 1987, as amended, between AG-Energy and Niagara. The term of the agreement continues for a period of 25 years from the date of commercial operation and is automatically renewed annually thereafter until terminated by either party. Delivery of the electricity would occur where the cogeneration facility's transmission line meets Niagara's 115 kV transmission system. The agreement, as amended, was approved by the New York Public Service Commission ("NYPSC").

The agreement sets three separate periods for the calculation of the price to be paid for the electricity. The price during the first period would be 6¢/kW.h. The price during the second and third periods would be set at 93 and 90 percent respectively of Niagara's avoided cost of producing electricity, as specified in Attachment II to the purchase agreement. The avoided cost contained in Attachment II requires the approval of the NYPSC. The projected avoided costs would be determined pursuant to the terms of the purchase agreement should the NYPSC cease to review the avoided cost calculation. The avoided cost calculation would include projected avoided production, capacity and transmission costs and losses.

Should the U.S. Federal Energy Regulatory Commission ("FERC") rescind the facility's QF status, then AG-Energy is required to seek FERC approval of the purchase agreement. As well, the rates paid under the agreement would be reduced by 15 percent should QF status be rescinded.

Should Niagara be able to produce electricity for less than the cost of purchasing electricity from the facility, then Niagara could curtail purchases from the facility. However, Niagara is required to obtain NYPSC approval for the curtailment and is required to make payments to AG-Energy as if no curtailment had occurred until that approval is received.

2.3.5 Thermal Energy Sales Agreement

The sale of thermal energy from the cogeneration facility would occur pursuant to the Steam Sale Agreement, dated 8 August 1991, between AG-Energy and the State of New York, acting through the New York State Office of Mental Health. The agreement continues for a term of 25 years from the commercial operation date of the facility and may be extended with the total term not exceeding 35 years. The agreement requires the State to purchase all of the facility's steam requirements. As well, purchases are not to fall below the minimum quantity necessary for the facility to maintain its PURPA QF status. If the minimum quantity cannot be maintained then the State may include the steam requirements of the Riverview Correctional Facility, a medium–security prison located on the same site. AG-Energy also has the right to obtain additional thermal hosts should minimum quantities not be maintained.

The contractual price for the first 219 million pounds of steam delivered per annum is $1.75 per thousand pounds. For deliveries exceeding 219 million pounds, the price includes an amount that would otherwise have been received under the power purchase agreement if AG-Energy had utilized such steam to generate additional electricity. Revenue from the steam host is expected to account for less than five percent of the facility's total revenues.

2.3.6 Regulatory Status

AG-Energy applied for a removal permit from the ERCB on 2 December 1991 for a term and volume commensurate with that applied-for hereunder. Approval of the application is pending.

Regarding U.S. federal authorizations, AG-Energy informed the Board that an application for QF status was being prepared for submission to FERC. As well, on 18 February 1992, AG–Energy applied for U.S. Department of Energy, Office of Fossil Energy ("DOE/FE") import authorization. Decisions on these applications are pending and AG–Energy has undertaken to inform the Board upon their receipt.

The only outstanding State approval is from the Comptroller of the State of New York for the steam sales contract. AG-Energy anticipates approval from the Comptroller shortly. No difficulties are foreseen regarding approvals from local authorities for the facility construction.

2.4 Views of the Board

The Board is satisfied with the adequacy of the supply underpinning the proposed export. The Board’s estimate of reserves is similar to AG-Energy’s and both estimates exceed the total projected commitments of the supply pool by about 12 percent. The Board’s projection of productive capacity for the supply pool suggests that AG-Energy’s applied-for export volumes could be met throughout the proposed export term if Home were to reduce or eliminate its short-term sales in the latter part of the term. The Board expects that Home would do so if shortfalls were imminent and is therefore satisfied as to the adequacy of gas supply available for the proposed export.

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

The Board is satisfied with the markets supporting the proposed export. The Board notes that the power purchaser, Niagara, has experienced an increase in demand for electricity in its service area in recent years. As well, the facility’s QF status is assured by the steam sales agreement with the State of New York.

In the Board’s view, the contractual provisions regarding deficiency payments, demand charges, Home’s position as the sole gas supplier and its ability to reduce delivery obligations ensure adequate take levels under the gas sales contract. The Board notes that the contract contains a fixed price escalator but considers the contract durable in light of the assured market.

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

The Board notes that the Alberta removal permit, DOE/FE import authorization, QFcertification, State approval of the steam sales contract and various siting approvals are pending. The Board recognizes that these applications are well advanced and does not foresee difficulties in this regard.

Producer support was demonstrated by the fact that Home executed the contract with AG-Energy.

2.5 Decision

The Board has decided to issue a gas export licence to AG-Energy, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 September 1993 and shall end on 1 November 1995, unless exports have commenced under the licence on or before 1 November 1995, in which case the term would end the earlier of 15 years and two months following commencement of deliveries or 31 October 2009.

Chapter 3

Canadian Hydrocarbons Marketing Inc.

3.1 Application Summary

By application dated 31 October 1991, CHMI sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	1 November 1992 to 31 October 2002
Point of Export	-	Huntingdon, British Columbia
Maximum Daily Quantity	-	273.9 10^3m^3 (9.7 MMcf)
Maximum Annual Quantity	-	100 10^6m^3 (3.5 Bcf)
Maximum Term Quantity	-	1 000 10^6m^3 (35.3 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas reserves supporting the proposed export would be produced from the east portion of the Tommy Lakes Halfway A pool in northeast British Columbia ("Tommy Lakes"). The gas would be transported on Westcoast Energy Inc. ("Westcoast") to the Huntingdon, British Columbia export point. From the international border, the gas would be shipped on Northwest Pipeline Corporation ("Northwest") for use as system supply by Washington Natural Gas Company ("WNG").

3.2 Gas Supply

3.2.1 Supply Contracts

CHMI has executed gas purchase contracts with two producers, Westcoast Petroleum Ltd. ("WPL") and Numac Oil and Gas Ltd. ("Numac"), for 60 percent of the Tommy Lakes gas reserves. WPL and Numac control 100 percent of the reserves by virtue of their 15-year reserves dedication agreement with Amoco Canada Resources Limited for its share of Tommy Lakes. CHMI would purchase the gas from WPL and Numac at the outlet of the Taylor Processing Plant ("Taylor plant").

3.2.2 Reserves

Table 3-1 shows that the Board’s estimate of CHMI’s established reserves is approximately 26 percent lower than CHMI’s estimate but is 26 percent higher than the applied-for volume.

CHMI's estimate of reserves refers to its 60 percent working interest in Tommy Lakes. CHMI estimates 1385 106m3 (48.9 Bcf) of proven reserves and 312 106m3 (11.0 Bcf) of probable reserves for its share of the pool for a total of 1 697 106m3 (59.9 Bcf) of established reserves. CHMI did not assign a risk factor to the probable reserves primarily because there was reasonable well control and a proposed development drilling program.

Table 3-1

Comparison of Estimates of CHMI's Established Gas Reserves[1]
With the Applied-for Term Volume

106m3 (Bcf)

CHMI	NEB	Applied-for Volume
1 697 (60)	1 260 (45)	1 000 (35)

CHMI also submitted a 20-year simulation study for its area of interest in Tommy Lakes. This study indicated that 65 percent of the gas in place could be produced over the period. The study concluded that production rates could still be higher than projected abandonment rates at the end of the period. CHMI thus assumed that a 75 percent recovery factor for the pool would be reasonable.

The Board's petrophysical analysis of the pool revealed increased water saturations in the southern portion of the reservoir and water production from certain wells in this area during initial production tests. The Board does not believe that CHMI's simulation study adequately addressed the possibility of water production problems. Because of low initial reservoir pressures, low production rates due to low permeability, and possible water problems, the Board has assumed lower recovery factors than CHMI. The Board assumed a 60 percent recovery factor for the proven area and a 40 percent recovery factor for the probable area.

The Board's estimate of established reserves is some 25 percent lower than CHMI's estimate but still exceeds the total applied-for volume by about 30 percent. The Board also acknowledges that there is potential for additional development in the pool.

3.2.3 Productive Capacity

CHMI provided a projection of productive capacity that demonstrated adequate supply to support the proposed export of 100 106m3 (3.5 Bcf) per year for a ten-year period (Figure 3-1). The Board's estimate of productive capacity shows that CHMI's working interest could provide

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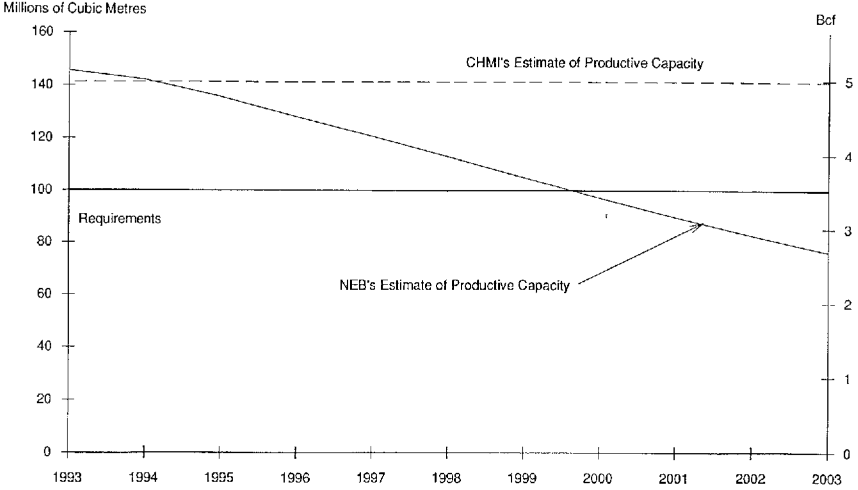
[1] As of December 1990.

Figure 3-1

COMPARISON OF NEB'S & CHMI'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



adequate productive capacity to supply the required volume during only the first seven years of the ten-year contract.

CHMI stated that potential shortfalls in productive capacity could be eliminated either by increasing its dedicated interest in the pool or by adding new reserves from areas upstream of the Taylor plant. WPL and Numac respectively hold 1133 106m3 (40Bcf) and 708 106m3 (25 Bcf) of gas reserves in those areas that could be dedicated to the export project.

3.3 Market, Commercial Arrangements and Regulatory Status

3.3.1 Market

The gas proposed for export would be sold to WNG, a local distribution company ("LDC") whose market in northwest Washington includes Seattle and Tacoma. WNG would use the gas as system supply.

WNG distributes gas to more than 380,000 customers. The gas it proposes to purchase from CHMI would be used to replace supply that it previously purchased from Northwest. In June 1988, Northwest became an "open access" carrier, that is, customers could contract directly with producers for supply and could contract with Northwest strictly for transportation. Under this open access, WNG has elected to convert its Northwest sales service to transportation service and has accordingly sought alternate supply sources.

WNG's total projected sales requirement for 1992 was 2051 106m3 (72.4 Bcf), consisting of 1626 106m3 (57.4 Bcf) for FS customers and 425 106m3 (15.0 Bcf) for interruptible customers. WNG serves residential, commercial and industrial customers and has forecast that over the period 1991 to 2001 these customer classifications will account for 84 to 87 percent of its total sales. The remaining portion of its sales will be to transportation customers. During this same forecast period, sales are projected to increase from 1960 106m3 (69.2 Bcf) in 1991 to 2802 106m3 (98.9 Bcf) in 2001, a 43percent increase. WNG attributes this increase to significant customer growth (primarily in the residential sector), a strong and steady local economy, a steady influx of new residents into the Pacific Northwest region, an increase in the number of conversions from electricity and oil to gas, and an increase in gas' share of the new home construction market from 75 percent to over 95 percent.

WNG purchases 57 percent of its firm peak day requirements from Canadian sources and the remaining 43 percent from U.S. sources. The 9500 GJ (10,000 MMBtu) that WNG intends to purchase from CHMI represents approximately nine percent of WNG's total firm peak day requirement.

WNG expects that purchases from CHMI will occur at an 85percent load factor. This forecast is based upon WNG's current load factors, WNG's growth projections for its market, the competitiveness of the contract's gas commodity price, WNG's obligation to pay demand charges regardless of takes and WNG's obligation to pay a reservation fee on load factors of less than 100 percent.

CHMI has been exporting gas to WNG under short-term order since 1 November 1991.

3.3.2 Transportation

The gas proposed for export will be produced in Tommy Lakes, where WPL and Numac will construct gathering and compression facilities. WPL has executed an FStransportation agreement with Westcoast for raw gas transmission of the Numac and WPL volumes from Tommy Lakes to the Taylor plant for processing. The FS agreement includes treatment and liquids recovery and provides for a daily contract quantity ("DCQ") of 486 103m3 (17.2 MMcf). In its GH-2-92 Reasons for Decision, the Board approved construction of the new facilities on the Westcoast system required for this export.

The gas would be transported from the Taylor plant to Huntingdon, British Columbia under an existing long-term transportation agreement between CHMI and Westcoast. From the international boundary, the gas would be shipped, under an existing FS contract between WNG and Northwest, to an interconnection with WNG's system. These agreements are for terms and volumes commensurate with those applied for herein.

3.3.3 Gas Sales Contract

CHMI and WNG executed a ten-year sales contract dated 1 February 1991 for up to 9500GJ (10,000MMBtu) per day for a period commencing 1 November 1992. The contract is subject to receipt of all necessary long-term Canadian and U.S. authorizations by 1 August 1992, unless the parties mutually agree to continue sales pursuant to existing short-term authorizations.[2]

The contract price consists of four components: a Westcoast demand charge, a gas commodity charge, a fuel gas charge and a reservation fee.

The Westcoast demand charge itself consists of two components. The first component is the net Westcoast demand tolls for firm raw gas transmission, treatment and liquids recovery. The second component is the Westcoast demand charges for firm transportation from the Taylor plant to the Huntingdon, British Columbia export point.

The commodity charge is to be negotiated annually. In the event that the parties are unable to reach a negotiated settlement, the contract provides for "baseball style" arbitration. Under this form of arbitration, each party submits its best offer to an arbitrator. The arbitrator is then required to select one of the offers. The commodity charge will be determined by ensuring that the total delivered price remains "reasonably equivalent" to prices paid by other LDC's off the Northwest system in the state of Washington under contracts comparable to the CHMI/WNG contract. The contract does not include a commodity price for the period commencing 1 November 1992, but does provide for an interim price of $U.S. 1.16/GJ ($U.S. 1.22/MMBtu) for

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[2] By letter dated 16 June 1992, CHMI informed the Board that the deadline for receipt of long-term authorizations had been extended to 31 March 1993.

the period 1November 1991 to 31 October 1992.

The fuel gas charge is the product of the amount of gas consumed by Westcoast for fuel and unaccounted for gas losses and the commodity charge under the sales contract for transportation from the Taylor plant to the export point. The reservation fee equals 15percent of the commodity charge and will be charged monthly for takes below 100percent of the DCQ.

CHMI estimated that the price that would have occurred under the terms of this contract at the British Columbia border as of 1 January 1992 was equal to $Cdn. 1.98/GJ ($Cdn.2.08/MMBtu).

The contract provides for a reduction in the DCQ in the event of a supply failure. In that event, WNG would be entitled to reduce the DCQ until the end of the next contract year by an amount equal to the average daily shortfall over any 90-day period.

3.3.4 Regulatory Status

WNG filed for DOE/FE import authorization on 30 October 1991. At the time of the hearing, the decision was still pending.[3] A decision is also pending regarding the long–term provincial removal permit from British Columbia.

3.4 Views of the Board

The Board's estimate of CHMI's dedicated reserves is about 26 percent higher than the applied–for volume. However, the Board's estimate of productive capacity suggests possible deficiencies in the last three years of the applied-for ten-year term. The Board agrees with CHMI that CHMI could alleviate these potential supply shortfalls by increasing its working interest in Tommy Lakes or by acquiring other reserves in the area. Therefore, the Board is satisfied with the adequacy of gas supply for the proposed export.

The Board is also satisfied that the LDC market of WNG is a stable long-term market for Canadian gas. The Board notes that this sale would be used to replace supply that WNG previously purchased from Northwest and that gas has already been flowing under short-term arrangements. As well, CHMI's sale represents approximately nine percent of WNG's total firm peak day requirement and, therefore, it is unlikely that changes in WNG's demand would redound wholly to this export.

The Board notes that transportation has been arranged on all required pipelines. Further, the Board is satisfied that the demand charge component of the price will ensure full recovery of all fixed Canadian transportation costs associated with this export.

The Board believes that the annual commodity charge renegotiation would ensure that the commodity charge will remain sensitive to changing market conditions. As well, the Board is

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[3] By letter dated 16 June 1992, CHMI informed the Board that DOE/FE approval was granted 24 April 1992

of the view that the contractual provisions providing for the payment of demand charges regardless of the take level and the payment of a reservation fee for takes below 100 percent of the DCQ plus the competitive nature of the commodity charge would ensure consistently high takes under the contract.

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

The Board notes that the gas supply would come from WPL and Numac, which either own or control the resources supporting the applied-for volumes. WPL and Numac, having executed gas purchase agreements with CHMI, support the proposed export.

Finally, the Board considers that the applications for the remaining necessary regulatory authorizations are sufficiently well-advanced to be unlikely to cause difficulty for the proposed export.

3.5 Decision

The Board has decided to issue a gas export licence to CHMI, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1992 and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end on 31 October 2002.

Chapter 4

Canadian—Montana Pipe Line Company

4.1 Application Summary

By application dated 21 March 1991, CMPL sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	upon Governor in Council approval to 31 October 2006
Point of Export	-	near Aden, Alberta
Maximum Daily Quantity	-	1 416 103m3 (50 MMcf)
Maximum Annual Quantity	-	283 106m3 (10 Bcf)
Maximum Term Quantity	-	3 996 106m3 (140 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas proposed for export would come from pools in southeast Alberta. The gas would be transported on CMPL's system to the export point near Aden, Alberta. The gas would then be delivered by The Montana Power Company ("MPC") to its market areas in Montana. The gas would be used as system supply by MPC and other LDCs in Montana. The applied—for licence is intended to replace existing export authorizations.

4.2 Gas Supply

4.2.1 Supply Contracts

CMPL obtains its gas supply from an affiliated company, Canadian-Montana Gas Company Ltd. ("CMG"). CMG owns approximately 75 percent of this supply and obtains the remaining volumes from other producers under long-term contracts.

4.2.2 Reserves

Table 4-1 shows that the Board's estimate of CMPL's established gas reserves exceeds the applied-for volume by 25 percent. The Board's estimate is three percent lower than CMPL's estimate.

In its analysis of CMPL's gas supply, the Board recognized 150 gas pools in nine fields in southeastern Alberta. Eighty-nine percent of the pools are in the Cretaceous sands while the remainder are Jurassic and Mississippian pools. Eighty-three percent of the total reserves come from 25 pools larger than 100 106m3 (3.5 Bcf) in size, all with mature production history.

Table 4-1

Comparison of Estimates of CMPL Established Gas Reserves
With the Applied-for Term Volume

106m3 (Bcf)

CMPL[4]	NEB[5]	Applied-for Volume
5 136 (181)	4 984 (176)	3996 (140)

For the most part CMPL followed ERCB/NEB nomenclature, but there were many instances where a single CMPL pool represented two or more pools, as defined by ERCB/NEB. In order to assess CMPL's gas supply, the Board reviewed the pools it had identified on CMPL's submitted lands.

Differences in estimates of reserves relate primarily to recovery factor estimates for the larger pools. The Board generally has used recovery factors consistent with similar pools in southeastern Alberta. The Board has considered the evidence submitted by CMPL and has increased its recovery factors in some cases, but not to the extent suggested by CMPL. For example, the Board has assigned a 57 percent recovery factor for the Lait Lower Mannville B pool because production has been steadily declining and water gas ratios have been increasing. The evidence submitted by CMPL did not persuade the Board that a higher recovery factor was warranted for this pool.

In summary, the Board's estimate of reserves is similar to that of CMPL's and both estimates exceed the applied–for volume by between 25 and 28 percent. The minor difference in estimates of reserves arises primarily from differences in recovery factors.

4.2.3 Productive Capacity

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[4] As of 1 December 1990.

[5] As of 31 December 1990.

Shown in Figure 4-1 is a comparison of the Board's and CMPL's projections of productive capacity with the applied-for volumes. The Board's projection suggests deficiencies in productive capacity commencing in 1999. CMPL's projection indicates adequate productive capacity until 2001 declining annually thereafter at a rate somewhat greater than the Board's projection.

CMPL stated that projected shortfalls in productive capacity could be remedied by contracting for additional reserves. In this regard CMPL noted that it has historically added about 39 106m3 (1.4 Bcf) of productive capacity annually. Further, CMPL stated that approximately 500 106m3 (17.7 Bcf) of uncontracted gas was currently available in its producing areas.

Regarding the projected shortfall in productive capacity, the Board notes that there is uncertainty in a number of areas regarding CMPL's ability to remedy any deficiencies. These areas are:

- the existence and availability of adequate uncontracted gas volumes in the future;
- the amount of deliverability from any such uncontracted gas; and,
- CMPL's ability to contract for the volumes required to make up the foreseen shortfall.

4.3 Market, Commercial Arrangements and Regulatory Status

4.3.1 Market

MPC is a regulated public utility supplying gas to core and non—core customers on a firm and interruptible basis, respectively. MPC sells gas to 100,000 customers in its market area and to other LDCs serving western Montana. In 1990, MPC's gas sales totalled 746.5 106m3 (26.3 Bcf).

Exports of Canadian gas to MPC originally commenced in 1952. These sales are presently being made under Licence GL-72 and Order GO-64-91, both of which expire 31 October 1992.

On 1 November 1991, MPC implemented open access transportation for its non-core customers and other LDCs. MPC projected that its non-core customers and most LDCs would purchase their gas supply directly by 1994. Hence, MPC anticipates that its gas sales would be confined to essentially core market customers.

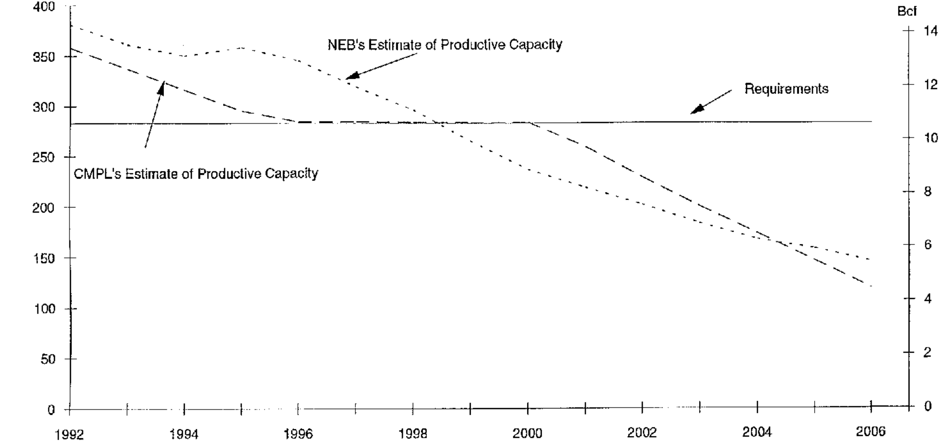
For its core market, MPC anticipated a 1.8 percent compound growth rate to the end of 1996 due to a projected increase in the number of customers. This forecast was extrapolated from historical normalized core load growth rates of three percent for residential customers and two percent for commercial customers.

MPC's growth projections have not yet been fixed due to a number of variables, including:

- the potential loss of up to 20 percent of its non—core market;
- anticipated increased competition for potential new core market customers; and,

Figure 4-1

COMPARISON OF CMPL'S AND NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



·   the limited potential for market growth given the maturity of the market.

MPC's purchases from all Canadian sources have increased from 26 percent of its total gas supply in 1986 to 37 percent in 1991. In recent years, MPC has reduced its purchases from the Aden area, as a percentage of its total Canadian gas supply, from a high of 98percent in 1986 to a low of 85.7 percent in 1991. The applied-for export represents 38percent of MPC's total requirements in 1990.

The average load factor on the CMPL system for 1986 to 1991 was 82 percent. Sales to MPC by CMPL in 1991 occurred at an 89 percent load factor. CMPL projected annual load factors of 82 percent to 92percent for the years 1992 to 1995 and of 100 percent for the remaining term of the applied–for licence.

4.3.2 Transportation

The gas proposed for export would be transported on CMPL to the interconnection with MPC at the international boundary near Aden, Alberta. MPC would then transport the gas to various end–use and LDC customers. As CMPL is a wholly-owned subsidiary of MPC, no transportation contracts are required. No new facilities are required.

4.3.3 Gas Sales Contract

Sales between CMPL and MPC are made pursuant to a gas purchase contract dated 30 October 1984. The latest amendment to the pricing provisions of the contract was made on 1 August 1989. The contract will be extended for another 14 years effective 1November 1992 and is subject to Canadian and U.S. regulatory approvals. The only contractual provision for renegotiation and arbitration during the contract term pertains to price.

The contract provides for an MDQ of up to 1416 103m3 (50 MMcf) at the interconnection of the CMPL and MPC systems near Aden, Alberta.

The contract stipulates a minimum take quantity of 60 percent of the annual contract quantity. MPC is obligated to either take or pay for this minimum volume. The contract also includes a make–up provision for gas paid for but not taken during the term.

The price of gas sold to MPC is to be determined by negotiations between MPC and its subsidiary, CMPL. This price is subject to review and renegotiation between 15 August and 1 September in each contract year to reflect changing market conditions. CMPL stated that the weighted average cost of gas ("WACOG") purchased from other Montana producers is approximately $U.S. 1.71/GJ ($U.S.1.80/MMBtu) to $U.S. 1.76/GJ ($U.S.1.85/MMBtu). CMPL further stated that the export price was established by comparing price quotes from Canadian energy companies.

The contract does not include a separate monthly demand charge component.

The estimated price that would have been in effect under the terms of this contract at the Alberta border as of 1 January 1992 was $Cdn. 1.85/GJ ($Cdn. 1.95 MMBtu).

4.3.4 Regulatory Status

CMPL received a 14-year removal permit (CM-80-5B) from the ERCB on 10 February 1992 for a term volume of 3 852 106m3 (136 Bcf), which is slightly less than the term volume applied for in this application.

MPC received import authorization (No. CP 74-188) from the DOE/FE on 23 October 1991. This authorization expires 31 October 2006.

4.4 Views of the Board

Although the Board's estimate of reserves exceeds the applied-for volume, its projection of productive capacity indicates deficiencies commencing as early as 1999. This compares to CMPL's projection which suggests shortfalls in productive capacity may commence in 2001. In order to remedy any supply deficiencies, CMPL will be relying heavily on its ability to contract additional reserves. As noted in section 4.2.3, the Board has a number of concerns regarding CMPL's ability to make up any shortfalls. Consequently, the Board is of the view that CMPL has not demonstrated an adequate gas supply to support the applied-for term volume.

Producer support is evidenced by the fact that CMG executed a contract with CMPL and that the independent Canadian producers executed contracts with CMG. The Board agrees with CMPL's position that this provides evidence of producer support for this export.

The Board recognizes that MPC, through its subsidiaries CMPL and CMG, has been a long–term and reliable customer and developer of Canadian gas in the Aden area. The Board expects this relationship to continue in the future. The Board also notes that MPC has steadily increased its purchases of Canadian gas to meet its market demand.

The Board is satisfied that all fixed transportation costs in Canada associated with the export would be recovered.

The Board had particular regard to the terms of the gas sales contract because it was not at arm's length. The Board is satisfied that the sales arrangement adequately reflects normal commercial criteria and practice.

In the view of the Board, the contractual take-or-pay provision would ensure adequate take levels under the gas sales contract.

The Board notes that all Canadian and U.S. regulatory authorizations are in place.

4.5 Decision

The Board has decided to issue a gas export licence to CMPL, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1992 and shall end on 1 November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end on 31 October 2004.

For the reasons discussed in section 4.2.3, namely, the shortfall in productive capacity beginning as early as 1999, the Board has decided to issue a licence to CMPL for a 12-year term rather than for a 14-year term, as requested.

Chapter 5

Esso Resources Canada Limited/ Esso Resources Canada/ Transco Energy Marketing Company/ CanStates Gas Marketing

5.1 Application Summary and Background

By application dated 30 December 1991, the Joint Applicants sought, pursuant to Part I of the Act, the transfer of Licence GL-136 from ERCL and TEMCO to CSGM and TEMCO. The licence contains the following terms and conditions:

Term	-	commencing on Governor in Council approval and ending on 31October 2002
Point of Export	-	Niagara Falls, Ontario
Maximum Daily Quantity	-	2 125 103m3 (75.0 MMcf)
Maximum Annual Quantity	-	775.6 106m3 (27.4 Bcf)
Maximum Term Quantity	-	9 308 106m3 (328.6 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

This export arrangement dates back to 1979 when the Board issued gas export Licence GL-57 to Sulpetro Limited ("Sulpetro") for a sale to TransContinental Gas Pipe Line Corporation ("Transco"). In 1982, Sulpetro was issued Licence GL-82, which replaced the expired GL-57. In 1987, Transco assigned its rights under the sales contract with Sulpetro to TEMCO. Later that same year, ERCL purchased Sulpetro's assets and Sulpetro assigned its rights in the sales contract with TEMCO to ERCL. In April 1988, the Board approved the assignment of Licence GL-82 from Sulpetro to ERCL. Finally, following the GH-6-89 proceeding, the Board approved the assignment of Licence GL-82 from ERCL by issuing Licence GL-136 to ERCL/TEMCO and revoking GL-82.

Effective 31 January 1991, ERCL reorganized its corporate assets and transferred to ERC, inter alia, its interest in the gas sales contract with TEMCO and the producing properties supplying the gas to the sales contract. The transfer took place under the terms and conditions of a novation agreement dated 1December 1991 between ERCL, ERC and TEMCO. The asset contribution agreement dated 31 January 1991 provides for the transfer of ERCL's interests in its upstream oil and gas assets to ERC.

The Joint Applicants executed a restructuring agreement, dated 27 June 1991, to transfer and assign ERC's interest in the gas sales contract to CSGM. The restructuring agreement also assigns ERCL's interest in Licence GL-136 to CSGM and contains certain other consequential amendments to the gas sales contract. The restructuring agreement also provides for the assignment to CSGM of ERC's interest in a transportation agreement dated 9 July 1979 with TransCanada. The effective date of the restructuring agreement will be the first day of the month following Governor in Council approval of the transfer of Licence GL-136. In the event that such approval has not been received by 1 September 1992, then any party may declare its intention to terminate the restructuring agreement.

CSGM and TEMCO will, effective on the date that the restructuring agreement is finalized, enter into a licence operating agreement for Licence GL-136. The existing licence operating agreement between ERCL and TEMCO will terminate on the same date.

Since 31 January 1991 no export volumes have been reported under Licence GL-136. All exports have been made pursuant to short-term export Order GO-17-91, issued to ERC/TEMCO.

5.2 Gas Supply

5.2.1 Supply Contracts

CSGM has executed gas supply contracts with the following eighteen producers: Atlantis Resources Ltd., Barrington Petroleum Ltd., Belview Holdings Ltd., Bow Valley Industries, Canor Energy Ltd., Canadian Natural Resources Limited, Dorset Exploration Ltd., Enron Oil Canada Ltd., Fletcher Challenge Petroleum Inc., Lasmo Canada Inc., Mannville Oil and Gas Limited, Morrison Petroleum Ltd., NuGas Limited, PERL Marketing Limited, Phillips Petroleum Resources Ltd., Rife Resources Ltd., Signalta Resources Limited and Tarragon Oil and Gas Limited. These contracts have terms extending up to 31October 2002.

Under the provisions of the contracts, each producer has dedicated specific lands to CSGM. Each producer has also issued an individual corporate warranty to deliver its respective portion of the DCQ. To provide additional assurance to TEMCO that CSGM will fulfill its obligations under the terms of the export contract, CSGM has arranged that Alberta Natural Gas Company Ltd. ("ANG") will fulfill CSGM's obligations if it is unable to do so.

5.2.2 Reserves

Table 5-1 shows that the Board's estimate of CSGM's established reserves is seven percent lower than CSGM's, but exceeds the applied–for volume by four percent. CSGM's reserves estimate does not incorporate any potential for reserves appreciation although CSGM believes that this will likely occur. The Board concurs that some appreciation may occur, but is concerned that it may occur on lands not currently under contract to CSGM.

Table 5-1

Comparison of Estimates of CSGM Established Gas Reserves With the Applied-for Term Volume

106m3 (Bcf)

CSGM[6]	NEB[7]	Applied-for[8] Volume
9 806 (348)	9 111 (322)	8 790 (310)

CSGM's contracted supply can be categorized as follows:

(1) Alberta reserves for which CSGM submitted ERCB reserves estimates;

(2) Alberta reserves, not yet in the ERCB database, that Liddle Engineering Ltd. evaluated or CSGM ; and,

(3) Saskatchewan and Northwest Territories reserves.

Over half of CSGM's contracted reserves are in the first category. The Board's estimate of CSGM's contracted reserves in the first category is 5 400 106m3 (191 Bcf). This represents 90 percent of the corresponding CSGM estimate. The major differences in estimates occur in the Chigwell Mannville pool and the West Cove Nordegg pool. The Board's estimate for the Chigwell Mannville pool is approximately 30 percent less than the ERCB's due mainly to a smaller value for net pay. The Board's estimate for the West Cove Nordegg pool is about 60 percent less than the ERCB's mainly because of a differing interpretation of net pay and pool area.

The Board's estimate of reserves for the second category of pools is 1362 106m3 (48 Bcf) or 91 percent of CSGM's estimate. The differences in estimates occur primarily in the Dimsdale Halfway pool and Nestow Wabamun pool. CSGM's estimate for the Dimsdale Halfway pool reflects the results of a recently drilled well. The Board applied a risk factor to these pools because it does not have access to the recent drilling results. For the Nestow Wabamun pool,

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[6] As of 1 May 1992.

[7] As of 31 December 1990.

[8] Reflects volumes remaining as of 1 July 1991 for Licence GL-136 (TEMCO).

the difference in estimates is mainly due to a lower estimate of net pay by the Board.

The Board's reserves estimate for 38 pools in the third category is 2 349 106m3 (83 Bcf). This is 103percent of CSGM's estimate.

The Board recognizes 239 pools distributed throughout Alberta, southwestern Saskatchewan and the southern Northwest Territories. All but 38 pools are located in Alberta. The pools included in CSGM's application represent most of the major producing zones in the Western Canada Sedimentary Basin, with most of the pools concentrated in Cretaceous zones. Ninety‒three percent of CSGM's pools are less than 100 106m3 (3.5 Bcf) in size.

In summary, the Board's estimate of CSGM's contracted supply is somewhat lower than that of CSGM but is marginally higher than the applied‒for volume for the TEMCO sale.

5.2.3 Productive Capacity

A comparison of the Board's and CSGM's projections of productive capacity with the applied-for annual volume, including fuel, is shown in Figure 5-1. The Board's projection indicates deficiencies in productive capacity commencing in the 1996 contract year, with increasingly larger shortfalls thereafter. CSGM's projection is very similar to the Board's except that deficiencies are not expected until the 1997 contract year with subsequent shortfalls predicted to be somewhat larger than the Board's projection.

CSGM notes that the projected deficiencies from the dedicated reserves would be mitigated by the corporate warranties from each producer. CSGM also stated that it could either rely on the supply assurances provided by ANG or purchase third-party gas.

5.3 Market, Commercial Arrangements and Regulatory Status

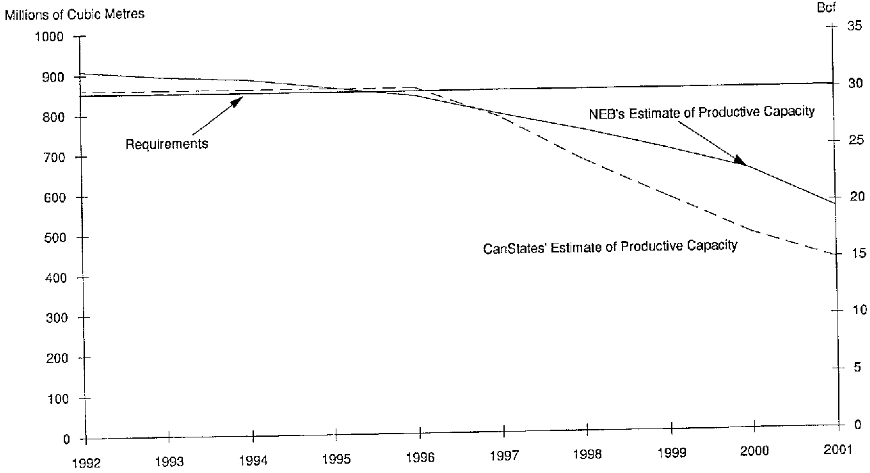
The Joint Applicants have requested that gas export Licence GL-136 be transferred from the current licence-holders, ERCL and TEMCO, to TEMCO and CSGM. CSGM is a partnership consisting of CanStates Energy and Gas Trading Inc. CanStates Energy is also a partnership having two partners, namely, ANG Resource Marketing Ltd. and 375660 Alberta Ltd. Insofar as the markets, transportation and sales arrangement will not be changed by the proposed transfer and were reviewed in the GH-6-89 proceeding pursuant to which Licence GL-136 was issued, the Board does not intend to address these areas in this Reasons for Decision.

With respect to regulatory status, the Board notes the Joint Applicants' evidence that no affirmative action or confirmation was required from DOE/FE and no FERC notification or approval was necessary to effect the change in TEMCO's gas supply arrangements from ERC to CSGM. In Canada, CSGM has applied to the ERCB for a long-term removal permit. For the gas produced in Saskatchewan, Bow Valley Industries Ltd. and Rife Resources Ltd., have made application to the Saskatchewan Department of Energy and Mines for long‒term removal permits. The Alberta and Saskatchewan applications were pending at the time of the hearing.

CSGM and TEMCO jointly hold short-term order GO-95-91, under which they have been

Figure 5-1

COMPARISON OF NEB'S & CANSTATES' ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



exporting gas since 1 November 1991.

5.4 Request for Subsection 35(2) Approval

As part of its application, the Joint Applicants requested Board approval, pursuant to subsection 35(2) of the Part VI Regulations, of the assignment by ERC to CSGM of ERC's interest in the existing gas sales contract dated 11 December 1980, as amended, and of certain amendments to the contract contained in an amending agreement dated 30August 1991. The amending agreement requires that ANG be made a party to the gas sale contract. ANG would provide certain assurances to TEMCO of the performance of CSGM under the sales contract. In addition, the amending agreement provides that ANG also would be a party to the licence-operating agreement with CSGM and TEMCO. ANG is the ultimate owner of two of the three CSGM partners.

5.5 Views of the Board

The Board is satisfied that any deficiency in productive capacity from the dedicated reserves would be mitigated by the corporate warranties of the individual producers or by ANG. The Board is therefore satisfied as to the adequacy of CSGM's gas supply.

The Joint Applicants requested the assignment of Licence GL-136 from ERCL and TEMCO to TEMCO and GasTrade Inc.; ANG Resource Marketing Ltd.; and 375660Alberta Ltd., carrying on business together in partnership under the firm name of CanStates Gas Marketing. The Board considers the proposed assignment to be an extension of an existing sales arrangement that has seen gas flowing to TEMCO for almost 12 years. The markets and commercial arrangement remain essentially unchanged and the Board is satisfied that, under the restructuring arrangement, the effect of the proposed assignment will be simply to replace ERCL with CSGM. The most significant change relates to gas supply and, as noted, the Board is satisfied with the new supply portfolio.

The Board is also satisfied with the proposed assignment by ERC to CSGM of ERC's interest in the gas sales contract dated 11 December 1980, as amended, and the provisions of the amending agreement dated 30 August 1991.

5.6 Decision

The Board has decided to authorize the transfer of gas export Licence GL-136 to CSGM/TEMCO from ERCL/TEMCO, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the transfer of the licence shall become effective on Governor in Council approval of the transfer and shall end on 1 November 1995, unless exports have commenced under the licence on or before 1 November 1995.

Chapter 6

Husky Oil Operations Ltd.

6.1 Application Summary

By application dated 10 December 1991, Husky sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	17 years and 3 months commencing as early as 1 October 1993, but no later than 31 October 1995
Point of Export	-	Huntingdon, British Columbia
Maximum Daily Quantity	-	366 103m3 (13 MMcf)
Maximum Annual Quantity	-	134 106m3 (4.75 Bcf)
Maximum Term Quantity	-	2 307 106m3 (81.9 Bcf)
Tolerances	-	2 percent per day and 2 percent per month

The gas supplying the proposed export would originate from fields located in British Columbia. The gas would be transported on Westcoast to the international border at Huntingdon, British Columbia and then forwarded by Cascade Natural Gas Corporation ("Cascade") for final delivery to a cogeneration facility near Ferndale, Washington.

6.2 Gas Supply

6.2.1 Supply Contracts

No gas supply contracts were required as Husky submitted a list of its own pools from which it intends to provide the requisite volumes for the proposed export. The Board notes that no specific pools were contractually dedicated to the proposed export as Husky would be providing the gas from its corporate supply pool in British Columbia. To demonstrate that it had an adequate supply, Husky relied primarily on two British Columbia gas pools, which were identified in its application.

6.2.2 Reserves

As shown in Table 6-1, Husky's estimate of reserves is approximately the same as the applied-for export volume. The Board's estimate of reserves is 17 percent less than that of Husky's and 14 percent less than the applied-for volume.

Table 6-1

Comparison of Estimates of Husky's Established Gas Reserves With the Applied-for Term Volume

106m3 (Bcf)

Husky[9]	NEB[1]	Applied-for Volume
2 383 (84.2)	1 980 (69.9)	2 307 (81.9)

Husky intends to supply the applied-for export volumes from the Grassy and Pocketknife pools in northeast British Columbia. The two reservoirs are contained in fractured dolomites of the Mississippian Debolt Formation ("Debolt"). Debolt gas is trapped in broad anticlinal structures formed by thrust faults during the Laramide orogeny. Both reservoirs are underlaid by water, but it is not yet known if the aquifers are active. Husky indicated that there may be additional potential for gas in the Triassic Halfway sands of these areas, but has claimed only those reserves in the Debolt zone in its application.

Husky's total reserves estimate consists of proven reserves of 1235.4 106m3 (43.6 Bcf), probable reserves of 530.3 106m3 (18.7 Bcf) and potential reserves of 617.7 106m3 (21.8 Bcf). Husky has applied an engineering risk factor of 25 percent to its estimate of probable reserves and 50 percent to its estimate of potential reserves. The Board's estimate of these reserves consists of 1 272 106m3 (44.9 Bcf) of proven reserves and 707.9 106m3 (25.0 Bcf) of probable reserves. The Board considers Husky's estimate of probable and potential reserves to be probable reserves. Therefore, the Board has assigned a risk factor of 50 percent to these reserves.

Husky stated that it intends to drill an additional well in each pool in 1993 to verify its estimate of probable and potential reserves. The pools are not expected to begin production until 1993.

In the Grassy pool, Husky recognized a 210 ha area around the c-32-E discovery well as containing proven reserves of 707 106m3 (25.0 Bcf). A second 210 ha area around the drilled but untested d-53-E well was estimated to contain probable reserves of 530.3 106m3 (18.7 Bcf). The remainder of the structural feature was assigned potential reserves of 353.5 106m3 (12.5 Bcf). The Board, on the other hand, recognized a total area of 400 ha for both

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9 As of 31 December 1991.

wells, with proven reserves of 911 106m3 (32.2 Bcf) and assigned probable reserves of 304 106m3 (10.7 Bcf) to the remainder of the structural feature.

A comparison of these reserves estimates for the Grassy pool shows that the Board's estimate is only 72percent of Husky's. This is due primarily to differences in estimates of net pay. Husky applied a net pay value equal to the approximate average for the two wells to its area assignments whereas the Board mapped the pool and calculated an average net pay that was 25 percent less than Husky's.

In the Pocketknife pool, Husky recognized a 210 ha area around the d-56-E discovery well as containing proven reserves of 528.4 106m3 (18.7 Bcf) and a second 210 ha area as containing potential reserves of 264.2 106m3 (9.3 Bcf). The Board, on the other hand, recognized a 200 ha area around the well as containing proven reserves of 361.4 106m3 (12.8 Bcf) and the remainder of the structural feature as containing probable reserves of 403.8 106m3 (14.3 Bcf).

A comparison of these reserves estimates for the Pocketknife pool shows that the Board's estimate is 11percent larger than Husky's. This difference follows from the Board assigning 757 ha to the pool compared to Husky's 420 ha assignment. The difference in estimates is tempered somewhat because the Board's calculated average net pay is about 30 percent lower than Husky's.

The Board acknowledges that its use of a 50 percent risk factor for probable reserves may be conservative. The Board concurs with Husky that geological risk in the area is low because the structure has been seismically defined and gas/water interfaces are known. The only risk is whether wells in the undrilled areas will flow gas. Since the structure is in a narrow trend parallel to the thrust faults, fracturing known to exist in the drilled wells should be present in the undrilled areas. This fracturing tends to enhance productivity and reduces the risk that gas will not flow. As a result, the Board's estimate of reserves could be increased.

In summary, the Board's estimate of reserves is less than that of Husky's and is lower than the applied-for volume. This is due primarily to the Board's applying risk factors, using lower assignments of area and smaller net pay values. The Board acknowledges that its current estimate of established reserves could be increased upon further successful development in the two pools. The Board notes that Husky has provided a corporate warranty to supply any possible shortfalls from its other uncommitted gas reserves in British Columbia.

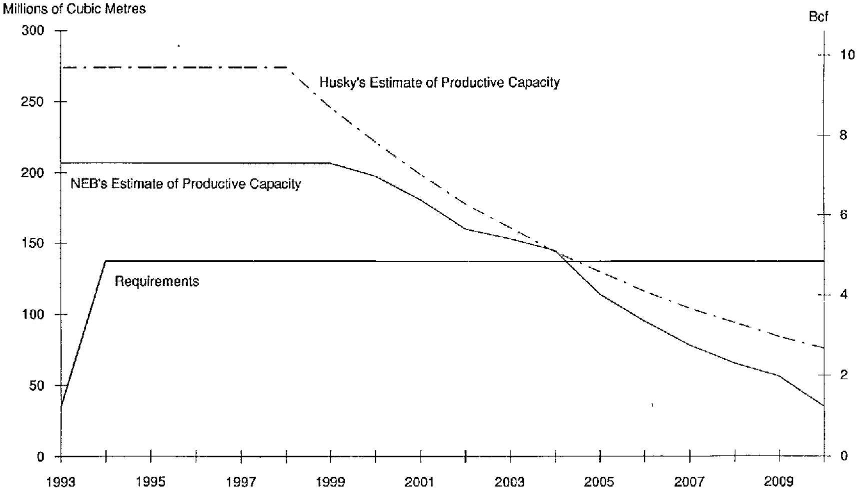
6.2.3 Productive Capacity

A comparison of the Board's and Husky's projections of productive capacity with the applied–for annual volume, including fuel, is shown in Figure 6-1. Both the Board and Husky project shortfalls in productive capacity commencing about 2005, with increasingly larger deficiencies thereafter.

The Board notes that Husky intends to use gas from its corporate pool, including other reserves in the Grassy/Pocketknife area, to remedy any deficiencies. In this regard, Husky

Figure 6-1

COMPARISON OF HUSKY'S & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



provided a corporate supply/demand balance demonstrating that an adequate supply would be available throughout the term of the proposed export. Husky also stated that its corporate supply pool would be supplemented in the future by its ongoing exploration and development activities.

6.3 Market, Commercial Arrangements and Regulatory Status

6.3.1 Market

The gas proposed for export would be used to fuel a 245 MW gas-fired cogeneration facility to be constructed near Ferndale, Washington. The cogeneration facility would be located at the BP Exploration & Oil Inc. ("BPOI") refinery on land zoned for heavy-impact industry. The BPOI refinery, the thermal energy purchaser, would utilize the thermal energy for its own large steam load.

Puget Sound Power & Light Company ("Puget"), the power purchaser, generates, purchases, transmits, distributes and sells electric power in the northwest U.S. Puget serves a population estimated at 1.7million people. The utility’s 1990 peak load net capability was approximately 4,743 MW.

The Bonneville Power Administration ("BPA") has issued an alert concerning a potential voltage collapse in the Puget Sound area. According to BPA, if the load continues to grow, the area’s power system could be overloaded in normal winter conditions. Conservation, demand management, new transmission and generation are all likely to be included in the long-term solution to Puget Sound’s need for power and BPA’s concerns over regional black-outs.

At the time of the Hearing, Tenaska Washington Partners ("Tenaska") and the Chase Manhattan Bank were finalizing financing for the facility. Financial closing is expected in May 1992, with start-up of the cogeneration facility scheduled for 10 October 1993.

The cogeneration facility has received self-certified PURPA QF status. In order to satisfy the Chase Manhattan Bank, full FERC certification has been applied for. Husky and Petro-Canada, another supplier to the facility, have undertaken to file evidence of this certification with the Board.

The facility would utilize natural gas as its primary fuel and Number 2 fuel oil as back up fuel. The facility is expected to operate at an electricity capacity factor of 90 percent.

6.3.2 Transportation

The gas proposed for export would originate in British Columbia. Transportation from Husky's supply areas to the international boundary at Huntingdon, British Columbia would be on the facilities of Westcoast. Husky and Westcoast have existing firm contractual arrangements that would be utilized to ship the proposed export volumes. No new facilities on Westcoast are required.

Cascade would transport the gas from Sumas, Washington to the cogeneration facility receipt point. Tenaska and Cascade have a 20-year firm transportation agreement in place.

Cascade will upgrade its pipeline system to accommodate the proposed transportation. A three-mile, 20-inch diameter pipeline connecting Cascade's and Westcoast's systems at the Canada-U.S. border near Sumas, Washington is required. Cascade will also construct and operate a six-mile, 20-inch diameter pipeline connecting its system to the cogeneration facility. Cascade has made all requisite applications to the FERC, Washington State Public Service Commission, Washington Department of Ecology and Corps of Engineers for the authorizations to construct and operate the two pipeline segments. Final approvals from the above agencies had not been received at the time of the hearing.

6.3.3 Gas Sales Contract

Husky and Tenaska executed a gas purchase agreement dated 4 November 1991 for the sale of up to 12350 GJ (13,000 MMBtu) per day. Deliveries under the contract are to commence no later than 1November 1995 and continue until the earlier of 31 December of the seventeenth year following the commencement of commercial operations of the cogeneration facility or 31 December 2011.

The contract establishes a price for the 1993 calendar year of $U.S. 1.81/GJ ($U.S.1.90/MMBtu) and provides for annual escalation of five percent over the remaining term of the agreement. With the commencement of commercial operations, the contract price would be assessed a demand charge and a commodity charge component. The demand charge would equal 20 percent of the contract price and would be charged against the full DCQ. According to Husky, the assessed demand charge would equal $Cdn.0.43/GJ ($Cdn. 0.45/MMBtu) in the first year of the contract. Westcoast's current interim toll for transportation of the proposed export volumes from the Taylor plant to Huntingdon, British Columbia is $Cdn. 0.26/GJ ($Cdn. 0.27/MMBtu). The commodity charge would equal 80 percent of the contract price for all volumes taken.

Husky estimated that the contract price at the British Columbia border under the terms of this contract as at 1 January 1992 would have been $Cdn. 2.02/GJ ($Cdn. 2.13/MMBtu). Husky calculated this price by deflating the 1993 price contained in the contract, $U.S.1.81/GJ ($U.S. 1.90/MMBtu), by the contractual escalation rate of five percent.

The contract provides for a minimum monthly take of gas equal to 80 percent of the DCQ multiplied by the number of days in the month. Should Tenaska not take the full monthly minimum, then it must pay a deficiency charge on the difference between the actual take and the 80 percent minimum level. The deficiency charge is calculated as the contract commodity charge less the spot price. The spot price is defined as the index value for the Northwest price quotation for gas at the Canadian border as published in Inside F.E.R's Gas Market Report.

6.3.4 Power Purchase Agreement

The sale of electricity from the cogeneration facility would be pursuant to the Agreement for Firm Power Purchase, dated 20 March 1991, between Puget and Tenaska. The power purchase agreement expires the earlier of 31 December of the 17th year after the commercial operation date or on 31 December 2011. The agreement may be extended for up to eight years. A redacted copy of the power purchase agreement was filed with the Board. The Washington Utilities and Transportation Commission has approved the agreement.

The purchase agreement was structured to encourage Tenaska to operate the facility at as high a capacity factor as possible. Purchases are for 215 MW of annual average energy and 245 MW of firm capacity. The energy capability is limited to 215 MW to allow Puget to coordinate the facility's output with the utility's hydroelectric operations.

The price of electricity is negotiated and may differ from the rate that PURPA would otherwise require. The price incorporates a partially levelized rate that results in a contract price exceeding non–levelized rates during certain portions of the operating period. Puget may reduce purchases during May due to decreased demand and increased supply from hydraulic sources. Accordingly, facility maintenance will be conducted in May. Puget will design, own and upgrade the transmission line required to interconnect with the facility.

6.3.5 Thermal Energy Sales Agreement

At the time of the Hearing, Tenaska had not yet obtained nor filed an executed thermal energy agreement with the Board. Husky and Petro–Canada stated that the agreement is in final form and is currently in London, England awaiting the signature of British Petroleum. Tenaska is confident that the agreement will be signed shortly as BP Resources Canada Limited has also become a gas supplier to the project. Upon execution of the thermal energy agreement, Husky has undertaken to file a redacted copy with the Board.

The BPOI refinery has a steam load exceeding the minimum load needed to qualify as a PURPA QF. The minimum steam deliveries proposed would ensure the maintenance of the cogeneration facility's QF status. Steam sales exceeding the minimum QF volume would be priced below BPOI's avoided steam costs to provide the refinery with an economic incentive to take the energy.

6.3.6 Regulatory Status

By application dated 31 January 1992, Husky applied for an energy removal permit from the British Columbia Ministry of Energy, Mines and Petroleum Resources ("EMPR"). A decision from EMPR was pending at the time of the hearing.

Tenaska applied 22 November 1991 for an import authorization from the DOE/FE. Cascade's facility expansion authorizations are described in section 6.3.2 of these Reasons.

6.4 Views of the Board

While its estimate of reserves is somewhat less than the applied-for volumes, the Board recognizes that its current estimate of reserves in the Grassy/Pocketknife area could be increased. Based on the specific pool information submitted and evidence of additional supply available from other reserves in the area, the Board is satisfied with the adequacy of Husky's gas supply position.

The Board is satisfied that the Husky/Tenaska contractual arrangements were negotiated at arm's length. The Board is also satisfied that the export will recover its full fixed cost of transportation on Westcoast's system. The Board notes that the demand charge is assessed at 20 percent of the then current contract price for the full DCQ.

The contract contains a fixed annual escalator of five percent. The Board considers that this would likely permit adjustment to reflect changing market conditions given that the project has direct contractual links between its other commercial arrangements and the gas sales contract.

The Board is also of the view that the demand charge obligation and the 80 percent minimum monthly take provision would ensure a high rate of take. Husky estimated that the load factor would be between 73 and 91.5 percent. The Board feels that this estimate is reasonable.

Given that Husky is the sole supplier and owner of the gas proposed for export, a finding of producer support is not necessary for this application.

The Board is satisfied that the applied—for licence term is appropriate given the available gas supply and the other supporting contractual arrangements.

Regarding the outstanding regulatory authorizations, the Board is of the view that the applications are well advanced and does not foresee difficulties in this regard.

Finally, Husky initially requested a daily and monthly tolerance of two percent. The standard tolerance granted by the Board is ten percent per day and two percent per year. The Board notes that Husky has stated that the standard tolerances would be acceptable.

6.5 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, including a condition that the term of the licence shall commence on 1 October 1993 and shall end on 1

November 1996, unless exports have commenced under the licence on or before 1 November 1996, in which case the term would end on the earlier of the 31st of December of the 17th year following first deliveries or 31 October 2011.

Chapter 7

Petro-Canada

7.1 Application Summary

By application dated 28 November 1991, Petro-Canada sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	commencing 1 October 1993 and ending the earlier of the 31st of December of the 17th year following commencement of commercial operation of the cogeneration facility or 31December 2011
Point of Export	-	Huntingdon, British Columbia
Maximum Daily Quantity	-	409.6 103m3 (14.1 MMcf)
Maximum Annual Quantity	-	the product of the number of days during the twelve month period and 409.6 106m3 (14.1 Bcf)
Maximum Term Quantity	-	2 580.9 106m3 (91.1 Bcf)
Tolerances	-	10 percent per day and 2 percent per year
	-	adjustments due to variations in the actual conversion factor

The gas supply for the proposed export would originate from fields located in British Columbia. The gas would be transported on Westcoast to the international border at Huntingdon, British Columbia and forwarded from there by Cascade for delivery to a cogeneration facility near Ferndale, Washington.

7.2 Gas Supply

7.2.1 Supply Contracts

Gas supply contracts were not required since Petro-Canada intends to supply the proposed export with gas from its own non-dedicated pools in British Columbia. Among Petro-Canada’s non-dedicated pools are five Klua Pine Point pools ("Klua") that were submitted to demonstrate that Petro-Canada has adequate supply for the proposed export. Part of the reserves in these pools will also be used to supply a Vancouver Island core market contract ("Vancouver Island contract") between Petro-Canada and Centra Gas British Columbia Inc.

The Vancouver Island contract has an MDQ of 85 103m3 (3 MMcf) over 15years.

In the gas sales contract for the proposed export, Petro-Canada warrants that it has or will have sufficient reserves and deliverability under its ownership or control to satisfy its obligations under the contract. Article IV of the sales contract states that Petro-Canada may be required to dedicate reserves to the contract if Petro-Canada's net worth falls below $Cdn. 178 million ($U.S. 150 million). In its 1991 annual report, Petro-Canada's net worth was shown to be $Cdn. 2.5 billion ($U.S. 2.1 billion).

7.2.2 Reserves

Table 7-1 shows that the Board's estimate of established reserves in Klua is 11 percent lower than Petro-Canada's estimate and three percent lower than the applied-for volume. However, the Board's estimate of reserves is 22 percent lower than Petro-Canada's total requirement for Klua including its commitment to the Vancouver Island contract from those pools.

Table 7-1

Comparison of Estimates of Petro-Canada's Established Gas Reserves[10]
With the Applied-for Term Volume

106m3 (Bcf)

Petro-Canada	NEB	Applied-for Volume
2 826 (100)	2 504 (88)	2 581[11] (91)

The difference in reserves estimates is the result of different values for pool parameters in four of the five pools. For the a-76-J/94-J-8 pool, the Board's estimate of proven net pay was 40 percent lower than Petro-Canada's. For the a-72-J/94-J-8 pool, the Board's estimate of net pay was 77 percent higher than Petro-Canada's. The Board's estimate of the recovery factors for the b-97-J/94-J-8 and a-6-B/94-J-9 pools is approximately 12percent lower than Petro-Canada's. This difference is primarily due to consideration of possible water production problems from the

10 As of October 1991.

11 In addition to the applied-for volume, Petro-Canada may sell a maximum of 465 106m3 (16 Bcf) under the Vancouver Island contract from these pools.

underlying water zone. In addition to the lower recovery factor assignment, the Board's estimate of porosity for the a-6-B/94-J-9 pool was 28 percent lower than Petro-Canada's. However, the Board does recognize that its estimate of reserves could increase, provided water production problems do not occur.

7.2.3 Productive Capacity

Shown in Figure 7-1 is a comparison of the Board's and Petro-Canada's projections of productive capacity with the total requirements to be met by Klua, including the Vancouver Island contract. Petro-Canada estimated that productive capacity would be about 400 106m3 (14.1 Bcf) per annum, the current allowable rate restriction authorized by the EMPR, throughout the period applied for. By comparison, the Board's projection suggests that productive capacity would be at or near the allowable rate during the initial years, followed by a decline resulting in a deficiency commencing about 2003. Petro-Canada stated that its deliverability could be supplemented by purchasing third-party gas, de-contracting gas from CanWest, or by future development and exploration opportunities in British Columbia. As further evidence that it could satisfy any possible shortfalls, Petro-Canada submitted a supply/demand profile demonstrating the adequacy of its non-dedicated corporate supply pool in B to meet its contractual commitments.

7.3 Market, Commercial Arrangements and Regulatory Status

7.3.1 Market

A discussion of the market and of the power purchase and thermal energy sales agreements entered into by Tenaska is provided in sections 6.3.1, 6.3.4 and 6.3.5 respectively of these Reasons.

7.3.2 Transportation

The gas proposed for export would be produced from various fields in northeastern British Columbia. Westcoast would transport the gas to the Huntingdon, British Columbia export point. Petro–Canada has an executed FS agreement with Westcoast to provide for the gathering, processing and transportation of the proposed export volumes.

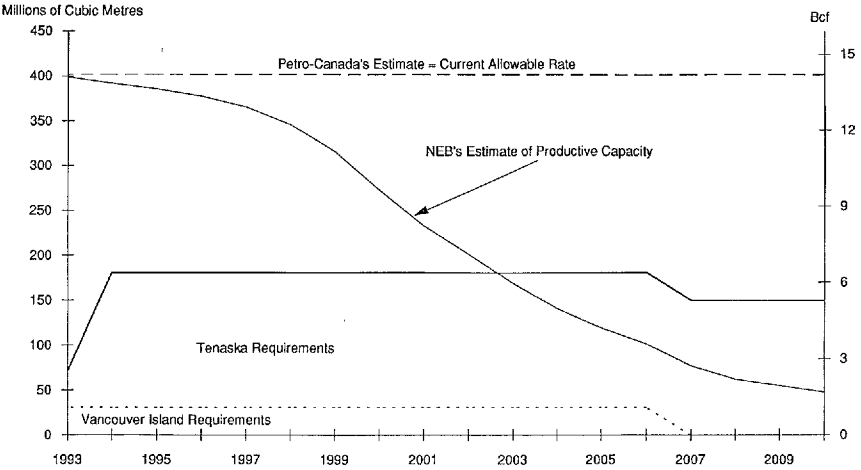
At the international boundary, the gas would be sold to Tenaska for ultimate shipment to the cogeneration facility located near Ferndale, Washington. Tenaska's transportation arrangements are described in section 6.3.2 of these Reasons.

:7.3.3 Gas Sales Contract

Petro-Canada and Tenaska executed a gas sales contract dated 29 July 1991, as amended, for the sale of up to 14250 GJ (15,000 MMBtu) per day. Deliveries are to commence under the contract no later than 1November 1995 and continue until the earlier of 31December of the seventeenth year following the commencement of commercial operations of the cogeneration facility or 31

Figure 7-1

COMPARISON OF NEB'S & PETRO-CANADA'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



December 2011. The contract provides Tenaska with the right to terminate the agreement on 60 days notice in the event that the power purchase contract is terminated.

The DCQ in the contract can, on one year's notice, be decreased by Tenaska in the third, fourth or fifth contract year by up to 33 percent. In addition, Tenaska has the right to reduce the DCQ to zero during May, when power sales would likely be curtailed.

The contractual price is determined by two equally weighted components. The first component is set at 136 percent of the weighted average spot price at Sumas, Washington and Opal, Wyoming. This component is bounded by a ceiling price of $U.S. 1.95/GJ ($U.S.2.05/MMBtu) in 1993 escalated at 8.25percent per year and a floor price of $U.S.1.95/GJ ($U.S. 2.05/MMBtu) escalated at four percent per year. The second component is set at a fixed price in October 1993 of $U.S. 1.90/GJ ($U.S.2.00/MMBtu) and escalated at 0.5percent per month.

Thirty-five percent of the contract price is deemed to represent the demand charge component while the remainder represents the commodity charge component. The monthly demand payment is the product of the demand charge, the DCQ and the number of days in the month. The demand charge is estimated to be $U.S. 0.67/GJ ($U.S.0.70/MMBtu) in the first year of the contract. The estimated price that would have been in effect under the terms of this contract at the British Columbia border as at 1January 1992 was $Cdn. 2.09/GJ ($Cdn. 2.20/MMBtu).

The sales contract includes a requirement that Tenaska take a minimum of 80 percent of the DCQ each month. Should Tenaska take less than this minimum, it would be required to make a deficiency payment. This payment is based upon the difference in the commodity portion of the contract price and the spot price for that month.

The weighted average spot price used to calculate both the contract price and the deficiency payment are subject to "baseball style" arbitration.

7.3.4 Regulatory Status

Petro-Canada, by its application dated 20 November 1991, has applied to the EMPR for an energy removal certificate. Petro-Canada has also requested an acquisition order from the British Columbia Petroleum Corporation. Both applications were pending at the time of the hearing.

In the U.S., Tenaska applied on 6 August 1991 for long-term import authorization. The decision was pending at the time of the hearing. As noted in section 6.3.2, Cascade has applied for separate federal and state approvals for the construction and operation of the new pipeline facilities.

7.4 Views of the Board

The Board's estimate of reserves for the specific pools submitted by Petro-Canada in support of its application is slightly less than the applied-for term volume. The Board's estimate is also 22 percent lower than the total market requirements to be supplied by those pools. Further, the Board's assessment of Petro-Canada's productive capacity indicates deficiencies relative to requirements over the latter portion of the proposed export term. The Board has considered Petro-Canada's evidence regarding its non-dedicated supply pool in British Columbia and is of the view that possible shortfalls in productive capacity could be satisfied from that non-dedicated corporate pool. The Board is therefore satisfied as to the adequacy of the gas supply available for the proposed export.

The Board is of the view that the Petro-Canada/Tenaska sales agreement was negotiated at arm's length. The Board notes that the 35 percent allocation of the contract price to the demand charge results in a first year demand charge estimated to be $Cdn. 0.78/GJ ($Cdn. 0.82/MMBtu). Westcoast's current interim toll for the transportation of the proposed export volumes would be approximately $Cdn. 0.26/GJ ($Cdn.0.27/MMBtu). Therefore, the Board is satisfied that the contract would provide for the recovery of the associated Canadian fixed costs of transportation.

The Board is also satisfied that the pricing formula contained in the contract would ensure that the contract remains market responsive and durable over its term. The formula provides for a range between a floor and ceiling price and then establishes a price within that range based on current market spot prices plus associated escalators. As well, the Board is satisfied that there would be a reasonable level of take over the life of the contract because of the minimum monthly purchase requirement, the competitive aspects of the pricing formula and the interlocking obligations on the Tenaska facility's operations relative to the production of electricity and steam. Petro-Canada has estimated that the annual load factor for its proposed sale to Tenaska would be 90 percent. The Board is of the view that, under the terms of the sales contract, a 90 percent load factor estimate is reasonable.

With respect to producer support, the Board notes that the gas required to serve the proposed export would come from reserves in British Columbia that are owned, operated and controlled by Petro-Canada. Therefore no finding of producer support was necessary.

Petro-Canada has requested a licence term commencing no later than 1 November 1995 and continuing until the earlier of 31 December of the seventeenth year following the commencement of commercial operations of the cogeneration facility or 31 December 2011. The Board is satisfied that this would be an appropriate licence term considering the available gas supply and the supporting commercial arrangements.

With respect to the outstanding regulatory authorizations from British Columbia, FERC and state regulators, the Board recognizes that the applications are well-advanced and does not foresee difficulties in this regard.

Finally, Petro-Canada requested that the Board include in the licence a condition recognizing that all volumes at Huntingdon, British Columbia are based on a heating conversion factor of 38.62 MJ/m3. Petro-Canada was concerned that the Board's standard volumetric tolerances would not accommodate significant variations in the heating content of the gas being exported. Should this occur, then Petro–Canada could not satisfy its contractual commitment to Tenaska, which is on an energy content basis. The Board finds that such a condition would be acceptable.

7.5 Decision

The Board has decided to issue a gas export licence to Petro-Canada, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 October 1993 and shall end on 1 November 1995, unless exports have commenced under the licence on or before 1 November 1995, in which case the term would end on the earlier of the 31st of December of the 17th year following first deliveries or 31 October 2011.

Chapter 8

TransCanada PipeLines Limited

8.1 Application Summary and Background

By application dated 3 January 1992, TransCanada sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	-	1 February 1992 to 31 October 2005
Point of Export	-	Emerson, Manitoba
Maximum Daily Quantity	-	2 785 103m3 (98.35 MMcf)
Maximum Annual Quantity	-	875 106m3 (30.9 Bcf)
Maximum Term Quantity	-	12 035 106m3 (424.9 Bcf)
Tolerances	-	10 percent per day and 2 percent per year

The gas for this proposed export would be supplied by shippers on TransCanada and would be delivered by TransCanada to GLGT at the Emerson, Manitoba export point. The gas would be used as compressor fuel and associated gas on GLGT.

TransCanada and GLGT executed FS transportation contracts dated 12 September 1967 (the "T-4 Contract") and 19 September 1990 (the "FT004 Contract"), both of which expire 31 October 2005. Under these agreements, TransCanada provides GLGT gas for compressor fuel and certain other company uses. GLGT uses these volumes to transport gas that TransCanada exports from Canada and subsequently imports back into Canada under Order GOL-2-91.

Previously, the transportation and fuel gas arrangements occurred under three separate Board authorizations. Exports for subsequent import were made pursuant to Licences GL-21 and GL-42, while fuel gas requirements were exported pursuant to Licence GL-43. Licences GL-21 and GL-43 expired on 31 October 1991 and the Board approved TransCanada’s application to revoke Licence GL-42 on 20December 1991. Prior to their expiry, Licences GL-21 and GL-42 were consolidated and renewed under Order GOL-2-91, which was issued on 28 October 1991. Following the expiry of Licence GL-43, TransCanada has been exporting the fuel gas under short-term export order GO-37-91.

8.2 Gas Supply

The fuel gas volumes to be exported for use by GLGT in transporting gas on behalf of

TransCanada would be provided by each shipper on the TransCanada system. The shippers would supply the required volumes to TransCanada pursuant to the transportation service fuel ratios in TransCanada's Transportation Tariff. Fuel gas volumes usually constitute less than seven percent of each shipper's total volumes.

For volumes that are exported for subsequent import, the Board is not required to make a finding on gas supply. However, the Board's review of TransCanada's facilities applications does include an examination of the adequacy of TransCanada's system supply to meet overall requirements, including fuel. Fuel requirements for transporting domestic gas on the GLGT system constitute part of those requirements.

8.3 Views of the Board

The Board is satisfied with the gas supply for this application as it has been examined in TransCanada's facilities applications.

The Board recognizes that the arrangements under which TransCanada provides fuel gas on GLGT have been in place for a significant period of time. The Board also notes that these arrangements are expected to continue to 31 October 2005, the expiry date of the T4 and FT004 TransCanada/GLGT transportation agreements and the DOE/FE import authorizations. The purpose of this application is to ensure that the necessary fuel gas requirements receive similar long-term regulatory authorization.

The Board agrees with TransCanada that this application is not typical of applications normally filed under the Part VI category for export licences, and, as such, the normal filing requirements do not apply. In particular, the Board agrees that information related to the requirements under the Board's Market-Based Procedure, including an EIA, need not be filed.

8.4 Decision

The Board has decided to issue a gas export licence to TransCanada, subject to the approval of the Governor in Council. Appendix I contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on Governor in Council approval and shall end on 1November 1994, unless exports have commenced under the licence on or before 1 November 1994, in which case the term would end on 31October 2005.

Chapter 9

Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of those applications heard by the Board in the GH-1-92 proceedings and included in this Volume.

A.B. Gilmour
Presiding Member

R.B. Horner, Q
Member

R.L. Andrew, Q
Member

Calgary, Canada
June 1992

Appendix I

Terms and Conditions of the
Licences to be Issued

Terms and Conditions of the Licence to be Issued to AG-Energy, L.P.

1. The term of this Licence shall commence on 1 September 1993, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end the earlier of 15 years and two months following the commencement of deliveries or 31 October 2009.

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

   (a) 467 000 cubic metres in any one day;

   (b) 170 600 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 587 000 000 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 Canadian Hydrocarbons Marketing Inc.

1. The term of this Licence shall commence on 1 November 1992, and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end 31 October 2002.

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

(a) 273 900 cubic metres in any one day;

(b) 100 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 1 000 300 000 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 Licence to be Issued to Canadian-Montana Pipe Line Company.

1. The term of this Licence shall commence on 1 November 1992, and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end on 31 October 2004.

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

   (a) 1 416 400 cubic metres in any one day;

   (b) 283 300 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 3 966 200 000 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 Aden, Alberta.

Terms and Conditions of the Licence to be Transferred to Transco Energy Marketing Company/CanStates Gas Marketing.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end on 31 October 2002.

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

(a) 2 125 000 cubic metres in any one day;

(b) 775 625 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 9 307 500 000 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 Licence to be Issued to Husky Oil Operations Ltd.

1. The term of this Licence shall commence on the date of first deliveries, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end 17 years and three months following the commencement of the term of this Licence, but no later than 31 December 2011.

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

(a) 366 200 cubic metres in any one day;

(b) 133 700 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 2 306 600 000 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 Licence to be Issued to Petro-Canada.

1. The term of this Licence shall commence on the date of first deliveries, and shall end on 1 November 1995 unless exports commence hereunder on or before 1 November 1995, in which case the term will end 17 years and three months following the commencement of the term of this Licence, but no later than 31 December 2011.

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

   (a) 409 600 cubic metres in any one day;

   (b) 149 606 400 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 580 900 000 cubic metres during the term of this Licence.

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

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

   (c) As a tolerance, the amount that may be exported under the authority of this Licence may vary from the annual limitations imposed in Condition 2 as necessitated by variation in the actual heating conversion factor from the heating conversion factor of 38.62 MJ/m3 upon which the licensed volumes are based.

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 Licence to be Issued to TransCanada PipeLines Limited.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof, and shall end on 1 November 1994 unless exports commence hereunder on or before 1 November 1994, in which case the term will end 31 October 2005.

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

   (a) 2 785 000 cubic metres in any one day;

(b) 875 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 12 035 000 000 cubic metres during the term of this Licence.

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

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

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