National Energy Board

REASONS FOR DECISION NORTHERN PIPELINES

VOLUME 1

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Volume 1

Page 1-163, line 11
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Page 1-170, line 19
delete the comma after the word "Kingsgate" and replace with a period.

National Energy Board

REASONS FOR DECISION
NORTHERN PIPELINES

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VOLUME 1

VOLUME 2

VOLUME 3

National Energy Board

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VOLUME 1

CONTENTS

CONTENTS - VOLUME 1

TABLES

FIGURES

APPENDICES

CHAPTER 2

SUPPLY AND DEMAND

TABLES

TABLES

TABLES

FIGURES

FIGURES

CHAPTER 2 - Continued

APPENDICES

ROUTE MAPS

NATIONAL ENERGY BOARD

IN THE MATTER OF the National Energy Board Act;

AND IN THE MATTER OF an application by Canadian Arctic Gas Pipeline Limited for a certificate of public convenience and necessity for the construction and operation of a natural gas pipeline, under File No. 1555-C46-1;

AND IN THE MATTER OF applications by Foothills Pipe Lines Ltd., Westcoast Transmission Company Limited and The Alberta Gas Trunk Line (Canada) Limited for certificates of public convenience and necessity for the construction and operation of certain natural gas pipelines, under File Nos. 1555-F2-3, 1555-W5-49 and 1555-A34-1;

AND IN THE MATTER OF an application by Alberta Natural Gas Company Ltd. for a certificate of public convenience and necessity for the construction and operation of certain extensions to its natural gas pipeline, under File No. 1555-A2-10;

AND IN THE MATTER OF a submission by The Alberta Gas Trunk Line Company Limited, under File No. 1555-A5-2;

AND IN THE MATTER OF applications by Foothills Pipe Lines (Yukon) Ltd., Westcoast Transmission Company Limited and The Alberta Gas Trunk Line (Canada) Limited for certificates of public convenience and necessity for the construction and operation of certain natural gas pipelines, under File Nos. 1555-F6-1, 1555-W5-55 and 1555-A34-2;

AND IN THE MATTER OF a submission by The Alberta Gas Trunk Line Company Limited, under File No. 1555-A5-3.

HEARD at Ottawa, Ontario on 12, 13, 14, 15, 20, 21, 22, 23, 26, 27, 28, 29, 30 April 1976;

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Yellowknife, Northwest Territories on 4, 5, 6 October 1976; and

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Whitehorse, Yukon on 1, 2, 3, 4 March 1977; and

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1, 4, 5, 6, 7, 12, 13, 14, 15, 18, 19, 20, 21, 22, 25, 26, 27, 28, 29 April 1977;

2, 3, 4, 5, 9, 10, 11, 12 May 1977.

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GLOSSARY OF TERMS

ABBREVIATIONS OF NAMES

"Abitibi"	- Abitibi Paper Company Ltd.
"AERCB"	- Alberta Energy Resources Conservation Board
"Alaskan Arctic"	- Alaskan Arctic Gas Pipeline Company
"Alberta and Southern" or "A & S"	- Alberta and Southern Gas Co. Ltd.
"Alberta Natural" or "ANG"	- Alberta Natural Gas Company Ltd.
"Alcan"	- Alcan Pipeline Company
"Algoma Steel"	- The Algoma Steel Corporation, Limited
"API"	- American Petroleum Institute
"Arctic Canada" or "ACGTC"	- Arctic Canada Gas Transmission Company
"ASME"	- American Society of Mechanical Engineers
"Atlantic Richfield" or "ARCO"	- Atlantic Richfield Company
"Battelle"	- Battelle Memorial Institute of Columbus, Ohio
"B.C. Hydro"	- British Columbia Hydro and Power Authority
"Beaufort-Delta"	- Beaufort-Delta Oil Project Limited
"Berger Inquiry"	- Mackenzie Valley Pipeline Inquiry
"British Columbia"	- Minister of Transportation and Communications, British Columbia

"CAGPL"	- Canadian Arctic Gas Pipeline Limited
"CAGSL"	- Canadian Arctic Gas Study Limited
"Canadian Pittsburgh"	- Canadian Pittsburgh Industries
"Canadian Titanium"	- Canadian Titanium Pigments Limited
"Canadian-Montana"	- Canadian-Montana Pipe Line Company
"CARC"	- Canadian Arctic Resources Committee
"CGA"	- Canadian Gas Association
"Chevron"	- Chevron Standard Limited
"CIC"	- The Committee for an Independent Canada
"CICA"	- Canadian Institute of Chartered Accountants
"CIL"	- Canadian Industries Limited
"CJL"	- The Committee for Justice and Liberty Foundation
"CLC"	- Canadian Labour Congress
"CNT"	- Canadian National Telecommunications
"Columbia Gas"	- Columbia Gas Transmission Corporation
"Consolidated Natural"	- Consolidated Natural Gas Limited
"Consumers Glass"	- Consumers Glass Company, Limited

"Consumers' Association" or "CAC"	- Consumers' Association of Canada
"Consumers'"	- The Consumers' Gas Company
"COPE-ITC" or "COPE"	- Committee for Original Peoples Entitlement and Inuit Tapirisat of Canada
"CRND"	- Canadians for Responsible Northern Development
"CSA"	- Canadian Standards Association
"CWF"	- Canadian Wildlife Federation
"CYI" or "The Council"	- The Council for Yukon Indians
"DGGS"	- Division of Geological and Geophysical Surveys
"Dome"	- Dome Petroleum Limited
"Dominion Glass"	- Dominion Glass Company Limited
"Dominion Malting"	- Dominion Malting Limited
"Dow"	- Dow Chemical of Canada, Limited
"DuPont"	- DuPont of Canada Limited
"El Paso Alaska"	- El Paso Alaska Company
"Falconbridge"	- Falconbridge Nickel Mines Limited
"Foothills"	- Foothills Pipe Lines Ltd.
"Foothills (Yukon)"	- Foothills Pipe Lines (Yukon) Ltd.
"FPC"	- Federal Power Commission
"Gaz Métropolitain" or "Gaz Métro"	- Gaz Métropolitain, inc.

"GNWT"	- Government of the Northwest Territories
"Great Lakes"	- Great Lakes Gas Transmission Company
"Greater Winnipeg"	- Greater Winnipeg Gas Company
"Gulf"	- Gulf Oil Canada Limited
"GYT"	- Government of the Yukon Territory
"HUDAC"	- Housing and Urban Development Association of Canada
"Humble Oil"	- Humble Oil and Refining Company
"IGUA"	- Industrial Gas Users Association
"Imperial"	- Imperial Oil Limited
"Indian Brotherhood of the NWT" or "IBNWT"	- Indian Brotherhood of the Northwest Territories
"Inland"	- Inland Natural Gas Co. Ltd.
"Inland-Ocean Cement"	- Inland Cement Industries Limited and Ocean Cement Limited
"Inter-City"	- Inter-City Gas Limited
"Interprovincial Steel" or "IPSCO"	- Interprovincial Steel and Pipe Corporation Ltd.
"I-XL"	- I-XL Industries Ltd.
"Legislative Assembly of the NWT"	- The Legislative Assembly of the Northwest Territories
"Liquefaction"	- Liquefaction Limited

"Manitoba"	- Province of Manitoba
"Mannesmann"	- Mannesmann-Export AG
"Michigan Wisconsin"	- Michigan Wisconsin Pipe Line Company
"Midwestern"	- Midwestern Gas Transmission Company
"MVM Association"	- Motor Vehicle Manufacturers' Association
"MVPA"	- Mackenzie Valley Pipeline Authority
"Native Working Men"	- Native Working Men of the Northwest Territories
"Natural Gas of California" or "Natural Gas Corp."	- Natural Gas Corporation of California
"Natural Gas Pipe"	- Natural Gas Pipeline Company of America
"NEB" or "The Board"	- National Energy Board
"Niagara Gas"	- Niagara Gas Transmission Limited
"Noranda"	- Noranda Mines Limited
"Norcen"	- Norcen Energy Resources Limited
"Norman Wells" or "Settlement Council"	- Settlement Council of Norman Wells
"Northern and Central"	- Northern and Central Gas Corporation Limited
"Northern Border"	- Northern Border Pipeline Company
"Northern Natural"	- Northern Natural Gas Company
"Northwest"	- Northwest Pipeline Corporation

"Ontario"	- Ontario Minister of Energy for Ontario
"OPEC"	- Organization of Petroleum Exporting Countries
"Pacific Interstate"	- Pacific Interstate Transmission Company
"Pacific Lighting" or "PLGD"	- Pacific Lighting Gas Development Company
"Pacific Western" or "PWA"	- Pacific Western Airlines Ltd.
"Panarctic"	- Panarctic Oils Ltd.
"PG & E"	- Pacific Gas and Electric Company
"PGT"	- Pacific Gas Transmission Company
"Pilkington"	- Pilkington Brothers (Canada) Limited
"Polar Gas"	- Polar Gas Project
"Quebec"	- Attorney General for Quebec
"Saskatchewan"	- Attorney General for Saskatchewan
"Shell"	- Shell Canada Limited
"Shell Explorer"	- Shell Explorer Limited
"Shell Resources"	- Shell Canada Resources Limited
"SIDBEC"	- SIDBEC et ses Filiales
"So-Cal"	- Southern California Gas Company
"Sohio"	- Standard Oil Company of Ohio
"Soquip"	- Société Québecoise d'Initiatives Pétrolières
"St. Lawrence"	- St. Lawrence Gas Company, Inc.
"Steep Rock"	- Steep Rock Iron Mines Limited

"Stelco"	- The Steel Company of Canada Limited
"Sun Oil"	- Sun Oil Company Limited
"TAPS"	- Trans-Alaska Pipe Line
"Texas Eastern"	- Texas Eastern Transmission Corporation
"Texasgulf"	- Texasgulf Canada Ltd.
"The NWT Association of Municipalities"	- The Northwest Territories Association of Municipalities
"The NWT Chamber"	- The Northwest Territories Chamber of Commerce
"The Workgroup"	- Workgroup on Canadian Energy Policy
"TransCanada" or "TCPL"	- TransCanada PipeLines Limited
"Trunk Line (Canada)" or "AGTL (Canada)"	- The Alberta Gas Trunk Line (Canada) Limited
"Trunk Line" or "AGTL"	- The Alberta Gas Trunk Line Company Limited
"Union"	- Union Gas Limited
"United Association"	- United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada
"Westcoast"	- Westcoast Transmission Company Limited
"White Pass and Yukon" or "White Pass"	- The White Pass and Yukon Corporation Limited
"YASW"	- The Yukon Association of Social Workers
"YCS"	- Yukon Conservation Society

ABBREVIATIONS OF TERMS

AWG	-	American wire gauge
°	-	angular degree
bbls.	-	barrels; 1 barrel is equal to 34.9723 Imperial gallons
Bcf	-	billion cubic feet
Btu	-	British thermal unit
cf	-	cubic foot
CPI	-	Consumer Price Index
cu. mi.	-	cubic mile
C_V	-	Charpy V-notch Test Absorbed Energy
C_VT	-	Charpy V-notch Test Absorbed Energy at given temperature
C_V100	-	Charpy V-notch Test Absorbed Energy at 100 per cent Shear Area
°C	-	degree Celsius
dBA	-	sound pressure level in decibels weighted on the A-scale
DCF	-	discounted cash flow
DWTT	-	Drop Weight Tear Test
°F	-	degree Farenheit
GNP	-	Gross National Product
HP	-	horsepower
kV	-	kilovolt
kW	-	kilowatt

L.F.	-	load factor (average daily volume expressed as a percentage of maximum daily volume)
LNG	-	Liquefied Natural Gas
Mb/d	-	thousand barrels per day
Mcf	-	thousand cubic feet
Mcf/d	-	thousand cubic feet per day
MMcf	-	million cubic feet
MMcf/d	-	million cubic feet per day
MOP	-	maximum operating pressure
M.P.	-	milepost
O.D.	-	outer diameter
ppm	-	parts per million
psf (lbs/ft^2)	-	pounds per square foot
psi	-	pounds per square inch
psia	-	pounds per square inch absolute
psig	-	pounds per square inch gauge
quad	-	quadrillion Btu's (10^{15} Btu's)
RDP	-	Real Domestic Product
sq. mi.	-	square mile
SMYS	-	specified minimum yield strength
Tcf	-	trillion cubic feet
T-joint	-	joint of spiral and plate joining welds
V	-	volt
W	-	watt

DEFINITIONS

Established Reserves

The Board defines established reserves as those reserves which, on the basis of identified economic considerations and within a specified time frame, are considered to be recoverable with a high degree of certainty from known reservoirs, through the application of currently accepted recovery techniques. The Board's established reserves consist of its "proved" reserves together with some portion, generally one half, of its "probable" reserves.

Proved Reserves

Proved reserves are those reserves considered to exist with a high degree of certainty. Volumes are mathematically calculated using dependable and well-defined basic reservoir data.

The classification "proved" may be applied to any of in-place, recoverable and marketable reserves. Thus, for example, proved recoverable reserves are those considered to be recoverable with a high degree of certainty, on the basis of well-defined reservoir data.

Probable Reserves

Probable reserves also are considered to exist with a high degree of certainty, but the basic reservoir data used in their calculation are less well-defined. What constitutes proved reserves in contrast to probable is, to a considerable extent, a matter of professional judgment.

Again, this classification may be applied to in-place, recoverable or marketable reserves, indicating that less definitive reservoir data entered into their determination than for reserves in the proved category.

Possible Reserves

Possible reserves are those to which a considerable degree of uncertainty is attached. The basic data used in their determination are not well-defined, hence substantial speculation is implied. The Board does not recognize possible reserves because of their speculative nature.

Initial Reserves

Initial reserves are those present in a reservoir before any production from that reservoir has been deducted. Certain agencies use the synonomous terms "ultimate" or "original" reserves.

Remaining Reserves

Remaining reserves are those currently available from a reservoir at a particular point in time, making allowance for any volumes produced (i.e. cumulative production) to that time. Thus, remaining reserves equal initial reserves less cumulative production.

In-Place Reserves

In-place reserves (commonly termed "gas in place") represent the total volume of gaseous substance occurring naturally in a reservoir without consideration of what portion may be recoverable.

Recoverable Reserves

Recoverable reserves represent that portion of the gas-in-place which is producible from a reservoir under anticipated technological and economic conditions, taking into consideration the geological and engineering characteristics of that reservoir. The adjective "raw" is often applied to recoverable reserves to eliminate ambiguity with marketable reserves. The ratio of recoverable reserves to in-place reserves, expressed as a fraction, is termed the "recovery factor".

Marketable Reserves

Marketable reserves are those volumes of natural gas available to the transmission line after removal, to the extent necessary or desirable, of certain hydrocarbon and non-hydrocarbon compounds present in the raw volumes produced from the reservoir, and after allowance has been made for field and plant fuel and losses.

The ratio of marketable gas reserves to recoverable gas reserves, expressed as a fraction, is termed the "shrinkage factor".

Marketable gas is also commonly referred to as pipeline, residue or sales gas. Unless otherwise specified, established reserves of natural gas reported by the Board are marketable reserves.

Beyond Economic Reach Reserves

Reserves beyond economic reach are included in established reserves. As a rule they are located in areas where, under current and anticipated economic conditions, the prospect of their being marketed is unlikely.

Deferred Reserves

Deferred reserves are those volumes of established reserves which for a specific reason, usually because of involvement in a recycling or pressure maintenance project, are not now available for market.

Ultimate Potential

This is the volume of natural gas which it is anticipated will have been discovered in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and future economic factors. A high degree of speculation and uncertainty is implicit in an estimate of ultimate potential, generally in inverse proportion to the geological knowledge of the area. Included in ultimate potential are volumes discovered and produced as well as those remaining to be found. Use of the term "potential reserves" as a synonym for ultimate potential is discouraged by the Board, since no justification exists for classifying undiscovered volumes as reserves.

Reserves Base Pressure and Temperature

The Board presently calculates reserves at a pressure base of 14.73 psia and temperature of 60°F. Provincial agencies in Western Canada and the Canadian Petroleum Association use a pressure base of 14.65 psia. Reserves at 14.73 psia equate to reserves at 14.65 psia multiplied by a factor of 0.996. The standardization of reserves to a base of 1000 Btu/cf eliminates the need for reference to a specific pressure base and temperature and for this reason is preferred by the Board for reporting purposes.

Light Fuel Oil

In this report the term light fuel oil is used to include furnace fuel oil which is No. 2 fuel oil and stove oil which is No. 1 fuel oil. The major volume of light fuel oil used in Canada is furnace fuel oil.

Heavy Fuel Oil

In this report the term heavy fuel oil is used to include bunker fuel oils which are No. 5 and No. 6 fuel oils and also includes industrial fuel oil which is No. 4 fuel oil.

Rate of Take

The rate of take refers to the average daily rate of production of natural gas per unit volume of initial reserves. For example, 1:7,300 means one million standard cubic feet per day of production for each block of 7,300 million standard cubic feet of initial reserves.

In-Migration

In-migration is the term used to describe the process of individuals arriving from outside the impact area and taking up residence in the area, whether employed or not, but who stay in the area for the length or part of the construction period (or longer), generally requiring the same amenities as other northern residents. This, of course, excludes the pipeline workforce which is resident in camps.

Transients are persons arriving in the impact area from outside who only stay for a few days. They are not considered as in-migrants.

CHAPTER 1

BOARD DECISION

1.1 BACKGROUND

Long before the Canadian Western Sedimentary Basin had been defined, the presence of petroleum reserves in the Mackenzie Delta was known. As far back as 1789 when Alexander Mackenzie was exploring the northern part of the River he noted in his diary having seen "a continual dripping... like Petrolium...". A report of a special northern resources committee of the Canadian Senate in 1887-88 stated that "in the Mackenzie District the petroleum area is so extensive as to justify the belief that eventually it will supply the larger part of this continent...".

The area was too remote and the need not great enough to encourage exploration and development, and interest fluctuated. However, by 1914 geologists had staked claims 50 miles downstream of old Fort Norman; in 1919 drilling crews were sent in; in the summer of 1920 they struck oil; and in 1921 a small topping plant was set up at Norman Wells by Imperial Oil Limited ("Imperial"). Consideration was given to building a pipeline to Edmonton but the estimated cost of $40 million discouraged such thoughts at that time. Not until gold and uranium were discovered in the Territories was a market found for that oil.

Oil seeps had been discovered in Alaska in 1837 and in 1923 the North Slope petroleum reserve for the United States Navy was created.

Exploration activity was sporadic in the entire northern area, accelerating during World War II, petering out in the 50's and accelerating rapidly again after 1964, with increasing success. The discovery of natural gas in the Territories, and the increasing demand for supplies in southern markets encouraged the transmission companies and governments to look north.

After the April 1968 announcement of the discovery of major oil and gas reserves in the Prudhoe Bay area of Alaska, exploration activity in the Canadian Northwest extended to the Mackenzie Delta, Beaufort Sea and Arctic Islands.

By 1969 Canadian and United States transmission companies were encouraged by the flurry of exploration and discovery to consider seriously the economics of bringing hydrocarbons from the North to southern markets. Engineering experience had been gained from the Canol project, a pipeline built during World War II to carry oil from Norman Wells to a refinery in Whitehorse, but more experience was needed. Study groups proliferated. Every conceivable method of getting reserves to markets was investigated.

THE PROJECTS

Northwest Project Study Group

In 1967 TransCanada PipeLines Limited ("TransCanada" or "TCPL") and two United States transmission companies, Michigan Wisconsin Pipe Line Company ("Michigan Wisconsin") and Natural Gas Pipeline Company of America ("Natural Gas Pipe"), had set up the Northwest Project to conduct engineering and feasibility studies for a natural gas pipeline to transport supplies from the Pointed Mountain area in the Northwest Territories to southern markets.

Research was conducted on operation and maintenance procedures, the ecology and precautions necessary to protect the environment.

The Northwest Project was extended to include studies for a pipeline from Alaska and the Mackenzie Delta, and participation in Mackenzie Valley Pipe Line Research Limited. The Project evolved into the Northwest Project Study Group and membership included the original three, TransCanada, Michigan Wisconsin and Natural Gas Pipe, plus Standard Oil Company of Ohio ("Sohio"), Atlantic Richfield Company ("Atlantic Richfield" or "Arco") and Humble Oil & Refining Company ("Humble Oil").

Mackenzie Valley Pipe Line Research Limited

The Mackenzie Valley Pipe Line Research Limited was formed under the Canada Corporations Act by Letters Patent dated 2 June 1969. It was initiated by Interprovincial Pipe Line Company and Trans Mountain Oil Pipe Line Company to determine the technological and economic feasibility of constructing a large diameter crude oil pipeline from Prudhoe Bay, Alaska, and the Mackenzie Delta to Edmonton to connect with their existing pipelines. Within a year, twelve oil exploration and production companies had also become shareholders.

Alyeska Pipeline

In February 1969 three companies announced their intention to build a pipeline through Alaska from Prudhoe Bay to a site on the Gulf of Alaska. The companies making the announcement were Atlantic Pipe Line Company, a subsidiary of Atlantic Richfield; BP Pipe Line Corporation, a subsidiary of BP Oil Corporation; and Humble Pipe Line Company, a subsidiary of Humble Oil, which is a subsidiary of Standard Oil Company of Ohio. Five more companies joined the project in 1970.

During the planning stages the project was known as the Trans-Alaska Pipe Line, or TAPS, although TAPS was not a corporate entity. In August 1970 the Alyeska Pipeline Service Company was formed by the owner companies as the corporation responsible for the TAPS project.

The plan which evolved was for crude oil to be transported from Prudhoe Bay through a 789-mile 48-inch diameter pipeline to Valdez on the southern coast of Alaska. It would then be shipped by tanker to refineries in the lower 48 states. This plan received United States Congressional approval on 13 November 1973 and Presidential approval on 16 November 1973.

Construction was started immediately and first flow of oil through the pipeline commenced on 20 June 1977.

Mountain Pacific Project

Another project commenced in 1969 when Westcoast Transmission Company Limited ("Westcoast") and Canadian Bechtel Limited, after discussion on feasibility studies, obtained the Mountain Pacific Special Act Charter and enlisted the co-operation of three United States companies. These were El Paso Natural Gas Company, Pacific Lighting Corporation (and its subsidiary, Pacific Lighting Service Company) and Southern California Edison Company, the principal customer of Pacific Lighting Corporation. The Task Force for this project studied methods of transporting Arctic and Alaskan gas to United States markets.

Gas Arctic Project

Staff studies were also conducted in 1969 by the Alberta Gas Trunk Line Company Limited ("Trunk Line" or "AGTL") which resulted in Trunk Line's sponsorship of the Gas Arctic Project. The initial proposal considered was the construction of a 1,550-mile pipeline from Prudhoe Bay, Alaska, to connect with Trunk Line's facilities near Grande Prairie, Alberta. The project was developed by the Gas Arctic Studies Group which included Trunk Line, Canadian National Railways, Columbia Gas Systems, Inc. ("Columbia Gas"), Northern Natural Gas Company ("Northern Natural"), and Texas Eastern Transmission Corporation ("Texas Eastern").

Pacific Lighting Gas Development Company ("PLGD") joined the Study Group in 1971.

Studies for the three projects, Northwest, Mountain Pacific and Gas Arctic, continued independently until 1972 when the groups changed appreciably.

Canadian Arctic Gas Studies Limited

The Gas Arctic Project (with six members) merged with the Northwest Project (also with six members) to become Gas Arctic-Northwest Project Study Group. The new combined group became known by its service corporation name, Canadian Arctic Gas Studies Limited ("CAGSL"). By early 1973 CAGSL had 25 participants.

In March 1974 CAGSL filed an application with the Board in the name of a new corporate entity, Canadian Arctic Gas Pipeline Limited ("CAGPL"), for a certificate to construct a pipeline to move Alaskan and Mackenzie Delta gas to United States and Canadian markets respectively.

Mountain Pacific pursued its studies separately from CAGSL but events were taking place which were affecting the membership of this group.

Westcoast had obtained the rights to the gas in the Pointed Mountain area of the Northwest Territories which had sparked the 1967 Northwest Project. By April 1972 it had completed construction of a pipeline which connected that field to its main system and had gained experience of value to its Mountain Pacific Project studies.

El Paso Alaska Company

In 1972 El Paso Natural Gas Company announced that it was conducting feasibility studies for the movement of liquefied natural gas ("LNG") by tanker from Alaska to United States markets.

Foothills and Foothills (Yukon) Projects

After the first filing of the CAGPL application in March 1974, Trunk Line withdrew from the CAGPL group. Trunk Line then joined with Westcoast to prepare the Foothills Project (sometimes called the "Maple Leaf Project"), to move Mackenzie Delta gas to Canadian markets. These applications were filed with the Board in the spring of 1975.

The Foothills (Yukon) Project (sometimes called the "Alaska Highway Project") to move Alaskan gas to United States markets evolved later, during the course of the hearing, with applications being filed in August and September, 1976, and amended in February, 1977.

Regulatory Proceedings

The various plans to transport Alaskan and/or Mackenzie Delta gas to southern markets involved the jurisdictions of not only the State and Territorial governments, but also those of various departments within both federal governments. The Canadian interests were covered by Guidelines for Northern Pipelines issued in 1970 and expanded in 1972; by the establishment of the Mackenzie Valley Pipeline Inquiry after an application by CAGPL had been filed with the National Energy Board and Department of Indian Affairs and Northern Development in March 1974; and by a hearing under the National Energy Board Act, the subject of this report. The United States national interest was covered by a hearing before the Federal Power Commission ("FPC") under the Natural Gas Act, and, after its enactment, under the Alaska Natural Gas Transportation Act of 1976. The interests of the two federal governments were reflected in an Agreement Concerning Transit Pipelines, a treaty initialled by both governments in 1976 but not yet ratified.

Mackenzie Valley Pipeline Inquiry

The Mackenzie Valley Pipeline Inquiry was established on 21 March 1974 by Order in Council and Mr. Justice T.R. Berger was appointed as Commissioner of Inquiry to inquire into and report upon the social, environmental and economic impact regionally of the construction, operation and subsequent abandonment of a pipeline. He was asked to suggest terms and conditions to be imposed in respect of any right-of-way granted across Crown lands in the Yukon and Northwest Territories for any Mackenzie Valley pipeline. The Commissioner was also asked for proposals to meet specific environmental and social concerns set out in the Expanded Guidelines.

To construct a pipeline across Crown lands in Northern Canada, a grant of right-of-way must be obtained under authority of the Territorial Lands Act. Of the three proposals dealt with in this report, two (CAGPL and Foothills) were examined by the Berger Inquiry in extensive public hearings. Hearings were held in all northern communities likely to be affected, as well as in major centres in Southern Canada. The first volume of a two-volume report by Mr. Justice Berger was submitted to the Minister of Indian Affairs and Northern Development on 9 May 1977.

Those matters affected by the third proposal made in 1976 (the Foothills (Yukon) Project) were made the subject of a new Inquiry under the chairmanship of Mr. Kenneth Lysyk with respect to socio-economic matters. A Panel under the chairmanship of Dr. Harry Hill will inquire into environmental aspects of the Foothills (Yukon) proposal. Reports are to be made to the Government by 1 August 1977.

Federal Power Commission Hearing

Applications under the Natural Gas Act to move Alaskan gas to markets in the lower 48 states were heard by the FPC from early 1975 to late 1976. A pre-hearing conference was held on 7 April 1975, the formal hearings began on 5 May 1975, and the record was closed on 12 November 1976.

Competing applications were filed by Alaskan Arctic Gas Pipeline ("Alaskan Arctic") (the United States counterpart of CAGPL), El Paso Alaska, and Alcan Pipeline Company ("Alcan") (the United States counterpart of Foothills (Yukon)). At the same time, in connection with these projects, the Commission considered applications for additional facilities from Northern Border Pipeline Company ("Northern Border"), and Pacific Gas Transmission Company ("PGT").

On 22 October 1976 the Alaska Natural Gas Transportation Act of 1976 was enacted by the United States Congress with the intent of expediting the selection and possible construction of a transportation system for Alaskan natural gas. The new act suspends proceedings under the Natural Gas Act for a specified time, limits administrative and jurisdictional procedures before a Presidential decision is made and sets time limits for procedures. Under this Act, dates by which actions must be taken include: 1 May 1977 for the FPC to submit its recommendation to the President; 1 July 1977 for all written comments and reports to be submitted to the President by federal or state authorities or other interested persons including the Council on Environmental Quality; and 1 September 1977 for the President to issue a decision on the matter. The President may delay issuing his decision for up to 90 days, for specified reasons. The President has authority under the Act to reject all transportation systems. A positive decision by the President requires Congressional approval. Congress has 60 sitting days within which to enact a joint resolution approving the President's decision. Absent such a joint resolution, the President may, within a further 30 days, propose a new decision which must differ materially from his previous decision. This new decision is also subject to Congressional approval within 60 days after receipt. The Act also specifies time limits and the grounds for judicial review of the final decision.

On 1 February 1977 Presiding Administrative Law Judge Nahum Litt of the FPC issued his initial decision on the competing applications which had been the subject of the FPC hearing.

On 2 May 1977 the FPC published its Recommendation to the President and its reasons for that recommendation, as required under Section 5 of the Alaska Natural Gas Transportation Act of 1976. The Commission included in its considerations an alternate proposal (the 48-inch case) filed by Alcan on 8 March 1977 which was not part of the hearing before Judge Litt.

National Energy Board Hearings

The first volumes of the application of CAGPL were submitted to the Board in March of 1974. Supplementary material was filed in January, March and May 1975. The Foothills Project applications were filed in March, April and May 1975. On 17 April 1975, the Board appointed a three-member panel to hear the applications. Panel Members were M.A. Crowe, Chairman; and J. Farmer and W.A. Scotland, Board Members.

When responses to deficiency letters had been received and the Board considered the applications complete enough to set down for hearing, Order GH-2-75 was issued, on 23 May 1975, setting the applications down for hearing in the autumn of 1975. By that Order a pre-hearing conference was held on 8-9 July 1975 to determine procedures to be followed.

After the pre-hearing conference, on 9 July 1975, CAGPL expressed concern that objections might be made by interested persons if Mr. Crowe were a member of the Panel hearing the applications.

Mr. Crowe had, at one time, been Chairman of the Canada Development Corporation, which had been one of the members of CAGSL, and he had participated in the work of this Study Group. These facts were set out in Mr. Crowe's opening statement at the beginning of the hearing in October of 1975. Five parties to the hearing objected to the presence of Mr. Crowe on the Panel. As a result of these objections, the Board itself referred the following question to the Federal Court of Appeal for determination:

> "Would the Board err in rejecting the objections and in holding that Mr. Crowe was not disqualified from being a member of the panel on grounds of reasonable apprehension or reasonable likelihood of bias?"

In December of 1975, the Federal Court of Appeal answered the question in the negative.

Following the Federal Court of Appeal's decision, three parties before that Court, namely the Committee for Justice and Liberty Foundation ("CJL"), the Consumers' Association of Canada ("Consumers' Association") and the Canadian Arctic Resources Committee ("CARC"), having obtained leave to do so, appealed the decision of the Federal Court of Appeal to the Supreme Court of Canada.

The Supreme Court of Canada, after hearing three days of argument on the matter on 8, 9 and 10 March 1976, on 11 March allowed the appeal, set aside the decision of the Federal Court of Appeal and declared that the question which had been put to that Court should be answered in the affirmative. The Supreme Court subsequently gave extensive reasons for its judgment with dissents to the majority opinion being expressed by three Members of the Court which consisted of eight judges.

Mr. Crowe then withdrew completely from any participation in the hearing of the applications, as did the two other Board Members, Mr. Scotland and Mr. Farmer. A different Panel comprising J.G. Stabback, Vice-Chairman, C.G. Edge, Associate Vice-Chairman, and R.F. Brooks, Board Member, was appointed by the Board to hear the applications.

As set out in Board Order GH-1-76, a new public hearing commenced in Ottawa on 12 April 1976 and the competing applications were heard jointly in various phases. Facilities aspects were discussed first, followed by contracts and financial matters. Economic, socio-economic and environmental matters were dealt with next, and sittings on these aspects were also held in Inuvik, Whitehorse and Yellowknife in the fall of 1976 to permit intervenors resident north of the 60th parallel to present their views to the Board. In September 1976 the Board incorporated the Foothills (Yukon) Project into the hearing by Order AO-9-GH-1-76 and evidence on the aforementioned aspects was heard on this application. Further sittings were held in Whitehorse in March 1977 on socio-economic and environmental aspects of the Foothills (Yukon) Project. Supply and requirements matters were dealt with as the last phase of the hearing in Ottawa before final argument and reply.

In late February 1977, the Foothills (Yukon) Group submitted applications for a "48-inch alternative" proposal, or "express line", and on 16 March 1977 withdrew its applications for the 42-inch pipeline proposal which would have used existing facilities of Westcoast and Trunk Line.

This report deals with the various applications as amended either before or during the hearing.

The Board held 214 days of public hearing and received some 1,200 exhibits and some 900 public documents. The transcript of the proceedings ran to over 37,000 pages.

The main subjects covered in this report are an analysis of whether a pipeline is needed, based on forecasts of supply and requirements; technical feasibility and engineering specifications of facilities; contracts, financial and economic matters; and socio-economic and environmental matters. Under each of the main headings or sub-headings, the CAGPL application is dealt with first, followed by the Foothills Group and then the Foothills (Yukon) Group applications. Alberta Natural Gas Company Ltd. ("Alberta Natural" or "ANG") is included within the CAGPL Project sections.

1.2 THE APPLICATIONS

This chapter outlines the main elements of the applications to be dealt with in this report. Specific details of the facilities for which certificates were sought are set forth in Chapter 3.

CANADIAN ARCTIC GAS PIPELINE LIMITED PROJECT

The first application to move northern gas to southern markets was submitted to the Board in March 1974. The proposed project included a new main pipeline system, to be built by CAGPL, and interconnections with existing and proposed new facilities.

General details of the applications are set out below.

Canadian Arctic Gas Pipeline Limited

The company was incorporated in 1972 by letters patent under the Canada Corporations Act, to construct and operate a pipeline beyond the limits of a province for the transmission of gas. Its incorporation was sponsored by the Gas Arctic-Northwest Project Study Group.

CAGPL applied to the Board in March 1974 under Part III of the National Energy Board Act for a certificate of public convenience and necessity to construct gas pipelines and works connected therewith, to transport gas found in the Mackenzie Delta and the Beaufort Basin in Northern Canada to market areas in Canada and to transport gas found at Prudhoe Bay, Alaska from the Alaska-Yukon border to markets in the lower 48 states of the United States.

More particularly, the Applicant proposed to construct a 48-inch O.D. (outside diameter) supply line approximately 178 miles in length from the interconnecting facilities of Alaskan Arctic at the Alaska-Yukon border, to proceed southeastward through the Yukon and the Northwest Territories to Tununuk Junction. A second 48-inch O.D. supply line would be constructed from the Taglu Field on the north shore of Richards Island, Northwest Territories southward for approximately 19 miles to connect at Tununuk Junction with the line from Alaska. The 48-inch O.D. mainline would continue south for approximately 36 miles to Parsons Lake Junction where it would be joined by a 30-inch O.D. supply lateral from Parsons Lake on the east.

The 48-inch O.D. mainline would then proceed south along the Mackenzie River Valley into Alberta where, near Caroline, it would be split into two delivery lines. The western delivery line, of 36-inch O.D. pipe, would connect with the pipeline of Alberta Natural near Coleman, Alberta for the onward transmission of gas to the international boundary near Kingsgate, British Columbia. The eastern delivery line would proceed to the international boundary near Monchy, Saskatchewan and, en route, would provide facilities for an interconnection with the pipeline of TransCanada near Empress, Alberta. The proposed facilities are described in detail and shown on a map at the end of this Volume.

The Applicant proposed to be a contract carrier for the owners of Canadian and Alaskan gas to be transported through the proposed facilities.

Alberta Natural Gas Company Ltd.

Alberta Natural is a company incorporated by Special Act of the Parliament of Canada and continued as a company by Letters Patent pursuant to the provisions of the Canada Corporations Act. It is affiliated with PGT which owns 45 per cent of Alberta Natural. PGT is in turn a subsidiary of Pacific Gas and Electric Company ("PG & E") of San Francisco, a distributor of gas in the northern part of the State of California.

Under Certificates GC-12, GC-26, GC-33, and GC-40, issued by the Board, ANG operates a 36-inch O.D. gas pipeline transmission system approximately 106 miles in length connecting the facilities of Trunk Line near Coleman, Alberta with those of PGT at the international boundary near Kingsgate, British Columbia.

In June 1975 Alberta Natural applied to the Board for a certificate to construct additional facilities required to transport gas to be obtained through the proposed CAGPL system. The gas would be acquired in Alaska for Natural Gas Corporation of California, another subsidiary of PG & E. The Applicant submitted four alternatives, varying with the volumes of gas available. On 1 September 1976, the Company elected the 36-inch O.D., lower pressure, main line looping plan as its application.

TransCanada PipeLines Limited

TransCanada, a company incorporated by Special Act of the Parliament of Canada, operates a large diameter natural gas pipeline system extending eastward from the Alberta-Saskatchewan border to serve communities within the Provinces of Saskatchewan, Manitoba, Ontario and Quebec, with connections on the international boundary near Emerson, Manitoba, Sault Ste. Marie, Sarnia and Niagara Falls, Ontario and Philipsburgh, Quebec.

TransCanada was a founding member of the Northwest Project Study Group, had obtained a gas purchase contract in the Delta and Beaufort Basin, and supported CAGPL.

In May 1976, TransCanada filed an amendment to its submission and intervention of 27 June 1975. The amendment outlined TransCanada's plans to loop its system to carry gas obtained from CAGPL. Applications for certificates for the actual construction would be filed as required.

Westcoast Transmission Company Limited

Westcoast, a company incorporated by Special Act of the Parliament of Canada, operates a natural gas pipeline transmission system, with appurtenant gathering and processing facilities, from the Pointed Mountain area in the Northwest Territories and the Fort Nelson and Fort St. John areas of British Columbia. The line extends southward through the interior of British Columbia to a point at the international boundary between Canada and the United States near Huntingdon, British Columbia, where it connects with the facilities of Northwest Pipeline Corporation ("Northwest").

Originally in the hearing Westcoast submitted an application with respect to an extension of its main line as a companion application in the Foothills Project, as set out below. By supplement 1, dated 1 July 1976, to the addendum of the same date to its application of 1 April 1975, the Company proposed to extend its facilities to interconnect with those of CAGPL if the CAGPL Project were approved.

FOOTHILLS PROJECT

The second set of applications to move northern gas to southern markets was submitted to the Board in the spring of 1975. It constituted a proposal to move Mackenzie Delta gas to Canadian markets. The project included a new pipeline system to be constructed by Foothills Pipe Lines Ltd. ("Foothills"), with interconnections with proposed new facilities and existing facilities and would involve approximately 1,240 miles of new main line and looping.

Foothills, Westcoast and The Alberta Gas Trunk Line (Canada) Limited ("Trunk Line (Canada)") applied for certificates of public convenience and necessity for new pipeline facilities, and Trunk Line filed an associated submission as part of this project. These applications were identified as the "Foothills Group" applications in the Board Order setting them down for hearing along with the applications of CAGPL and Alberta Natural.

General details of the applications are set out below. They are more particularly described in Chapter 3 and shown on a map at the end of this Volume.

Foothills Pipe Lines Ltd.

Foothills is a company incorporated by Special Act of the Parliament of Canada in 1959 for the purpose of operating, **inter alia**, an interprovincial gas transmission pipeline and works connected therewith. Trunk Line and Westcoast are sponsors and shareholders of Foothills.

Foothills applied to the Board in March 1975 for a certificate of public convenience and necessity to construct and operate a pipeline and works connected therewith for the transmission of natural gas from the Beaufort Basin of the Western Arctic to southern Canadian markets and to communities in the Northwest Territories. The proposed pipeline would connect with facilities of Trunk Line (Canada) and Westcoast.

The Applicant proposed to construct approximately 817 miles of 42-inch O.D. transmission line from Richards Island southward along the Mackenzie River Valley to a point of interconnection with Trunk Line (Canada) approximately 6.5 miles north of the 60th parallel. Foothills also proposed to construct 15 miles of 30-inch O.D. line as a lateral connection from a point east of Parsons Lake in the Northwest Territories to a point of connection with the main transmission line approximately 51 miles south of the Richards Island point of commencement of that main line.

Foothills intended that the proposed pipeline be used as a contract carrier of gas.

Westcoast Transmission Company Limited

Westcoast, a company described previously, originally applied to the Board on 1 April 1975 for a certificate of public convenience and necessity for the construction of a 140.6-mile 30-inch O.D. extension of its mainline facilities and approximately 201.1 miles of 36-inch O.D. looping of its existing line. The new facilities, referred to as the Territories Extension, would be constructed from Westcoast's existing Fort Nelson mainline system adjacent to milepost 285 on the Alaska Highway and extend northeasterly to an interconnection with the proposed Foothills system. (See map at the end of this Volume.) The proposed looping of the mainline facilities was contingent on approval of the Foothills application. The facilities are more particularly described in Chapter 3 herein. A submission was also filed on the possibility of a connection with the CAGPL system, should that system be approved.

The Alberta Gas Trunk Line (Canada) Limited

Trunk Line (Canada) is a company incorporated by Letters Patent under the provisions of the Canada Corporations Act to construct and operate, inter alia, a gas transmission line extending beyond the Province of Alberta. It is a wholly-owned subsidiary of Trunk Line, an Alberta company.

In May 1975, Trunk Line (Canada) applied to the Board for a certificate to construct and operate approximately 81 miles of 42-inch O.D. gas pipeline from a point in the Northwest Territories approximately 6.5 miles north of the 60th parallel at an interconnection with proposed Foothills facilities, extending southerly into northern Alberta to connect near Zama Lake with existing facilities of Trunk Line.

The Alberta Gas Trunk Line Company Limited

Trunk Line is an Alberta company which owns and operates a natural gas gathering and transmission system within the

Province. It did not file an application but in a submission dated May 1975 it undertook to construct and operate certain facilities of Trunk Line (Canada) subject to federal jurisdiction. Integral to this proposal was the transmission of Delta gas through Trunk Line's facilities in Alberta until new Trunk Line (Canada) facilities were built through Alberta. Trunk Line acknowledged federal jurisdiction over Delta gas moving through the system.

FOOTHILLS (YUKON) PROJECT

In August and September 1976, a third set of applications for certificates for pipeline construction was filed with the Board by a group of associated companies proposing to move Alaskan gas through Canada to markets in the lower 48 states. These applications, from Foothills Pipe Lines (Yukon) Ltd. ("Foothills (Yukon)"), Westcoast and Trunk Line (Canada) were considered together as the "Foothills (Yukon) Group" applications. The new proposal was included in the hearing as of 18 October 1976 by the Mackenzie Valley-Yukon Hearing Order AO-9-GH-1-76 (Appendix 1-2).

This proposal included construction of a Foothills (Yukon) 42-inch O.D. line from an interconnection with Alcan Pipeline Company at the Alaska-Yukon border, through the Yukon to the British Columbia border, where it would connect with a 42-inch O.D. extension of Westcoast; a 36-inch O.D. Trunk Line (Canada) line would interconnect existing facilities of Trunk Line in Alberta with another extension of Westcoast; and a Foothills (Yukon) 36-inch O.D. line would be constructed from Trunk Line's facilities at Empress, Alberta to the international border near Monchy, Saskatchewan.

In late February 1977 the Foothills (Yukon) Group filed with the Board an alternative proposal to construct a 48-inch O.D. pipeline system for the same purpose, without using the existing Westcoast and Trunk Line facilities. It involved the construction of an "express line" through Yukon, northern British Columbia and Alberta, generally along existing routes, plus a new Westcoast line parallel to the existing ANG route in southeastern British Columbia. Subsequently, on 16 March 1977, the Group withdrew the applications for the 42-inch O.D. pipeline system.

In this report, therefore, the only Foothills (Yukon) Group applications considered are those for the 48-inch O.D. interconnecting system, which would move Alaskan gas through Canada to other United States markets. It would involve the construction of approximately 2,020 miles of new pipeline.

The Canadian proponents of this project were Foothills (Yukon), Trunk Line (Canada) and Westcoast. Each Company would own and operate its respective sections of the pipeline system: Foothills (Yukon) - the sections in the Yukon and Saskatchewan; Westcoast - the sections in British Columbia; and Trunk Line (Canada) - the section in Alberta.

The applications, described generally below, are more particularly described in Chapter 3 and shown on a map at the end of this Volume.

Foothills Pipe Lines (Yukon) Ltd.

Foothills (Yukon) is a company incorporated by Special Act of the Parliament of Canada in 1964 under the corporate name of Meota Pipe Lines Ltd. Though it is wholly owned by Foothills, Trunk Line and Westcoast are sponsors and proposed shareholders of Foothills (Yukon).

From an interconnection with Alcan Pipeline Company at the Alaska-Yukon border the proposed route for the 48-inch O.D. line follows the Alaska Highway corridor to the British Columbia-Yukon border near Watson Lake. That portion of the proposed system would be approximately 512 miles in length. It would connect at the Yukon-British Columbia border with the facilities of Westcoast.

The proposed second section of the Foothills (Yukon) line would consist of 160 miles of 42-inch O.D. pipeline from Empress, Alberta running southeasterly to a point on the international boundary near Monchy, Saskatchewan. It would connect at Empress with new facilities in Alberta to be constructed by Trunk Line (Canada), and at Monchy with facilities to be built in the United States by Northern Border Pipeline Corporation.

Westcoast Transmission Company Limited

As part of the proposal to move Alaskan gas to United States markets, Westcoast proposed to construct approximately 438 miles of new 48-inch O.D. mainline from a location near Watson Lake, Yukon Territory to the Alberta-British Columbia border near Boundary Lake. It would transport Alaskan gas from the Foothills

(Yukon) 48-inch O.D. line to new facilities proposed to be built by Trunk Line (Canada) hereinafter described.

From the western terminus of the said new facilities of Trunk Line (Canada) near Coleman in the Crow's Nest Pass region, Westcoast also proposed to construct approximately 106 miles of 36-inch O.D. mainline extension southwestward to the international boundary at Kingsgate, British Columbia.

The Alberta Gas Trunk Line (Canada) Limited

As an integral part of the proposal to move Alaskan gas to United States markets, Trunk Line (Canada) sought authorization to construct and operate a new line through Alberta, composed of:

(a) a 48-inch O.D. gas pipeline approximately 395 miles in length commencing at a point on the Alberta-British Columbia border near Boundary Lake where it would connect with the pipeline extension proposed by Westcoast, then southeastward into Alberta to Gold Creek and thence parallel to the existing right-of-way of Trunk Line to James River near Caroline;

(b) from James River, a 42-inch O.D. gas pipeline approximately 235 miles in length, in a southeasterly direction, parallel to the existing right-of-way of Trunk Line, to Empress on the Alberta-Saskatchewan border; and

(c) also from James River, a 36-inch O.D. gas pipeline approximately 176 miles in length, in a southwesterly direction, parallel to the existing right-of-way of Trunk Line to the Alberta-British Columbia border at a point near Coleman in the Crow's Nest Pass area where it would connect with the facilities of Westcoast described above.

1.3 INTERVENTIONS

The material in this section is intended to summarize the basic position of each intervenor. It is not intended to reflect the degree of participation at the hearing by such intervenors, many of whom made substantial contributions to specific discussion on subjects or applications.

The representations made by intervenors formally and otherwise have all been carefully considered and are discussed in more detail in later sections of this report.

A total of 110 companies, associations and individuals filed submissions with the Board as "intervenors" or "interested persons" before and during the course of the hearing. In an attempt to simplify the hearing procedure and to avoid duplication of cross-examination by parties having similar interests, these intervenors were grouped together in accordance with the nature of their operations or interests. (See Appendices 1-1 and 1-2: Hearing Orders GH-1-76, Appendix 2, and AO-9-GH-1-76, Appendix 2.) The intervenors accepted such grouping for the order of appearances and cross-examination during the hearing, but some reserved the right to cross-examine independently when their interests diverged from those of the group. During the Board's sittings in Whitehorse, Yukon, several persons made informal submissions concerning socio-economic and environmental issues.

THE CAGPL GROUP

In addition to the related applications filed by Canadian companies, submissions or interventions were filed by those United States corporations which formed an integral part of the CAGPL Project.

Alaskan Arctic Gas Pipeline Company

Alaskan Arctic, a company incorporated in the State of Alaska, had filed with the FPC a related application for authority to construct and operate a pipeline system in Alaska to move gas from Prudhoe Bay on the North Slope of Alaska, to an interconnection at the Alaska-Yukon border with the proposed CAGPL facilities for onward transmission to markets in the lower 48 states. Alaskan Arctic supported the CAGPL application.

Northern Border Pipeline Company

Northern Border is a general partnership formed pursuant to the Delaware Uniform Partnership Act of the State of Delaware by six interstate gas pipeline companies. Northern Border participants had filed a joint application with the FPC for the requisite certificate and other necessary authority to construct and operate a natural gas pipeline from the international boundary near Monchy, Saskatchewan at a point of interconnection with the proposed facilities of CAGPL, southeastward through the Midwestern States to a point near Chicago, Illinois, and by means of its proposed pipeline, to render a transportation service for various shippers of natural gas.

The proposals of Northern Border and CAGPL are interrelated and Northern Border intervened in support of CAGPL, as did its member partners, as set out below. The only member of the partnership which did not intervene on its own behalf was Panhandle Eastern Pipe Line Company.

Columbia Gas Transmission Corporation

Columbia Gas is a corporation organized and existing under the laws of the State of Delaware and is a charter member of Northern Border. The company had entered into an agreement to purchase Alaskan gas which it proposed to have transported through the Alaskan Arctic-CAGPL-Northern Border system to its markets in the Eastern United States.

Columbia Gas intervened in support of the CAGPL Project.

Michigan Wisconsin Pipe Line Company

Michigan Wisconsin is a corporation organized and existing under the laws of the State of Delaware, with its principal place of business in Detroit, Michigan. It is a natural gas transmission company engaged in interstate commerce in the United States and it imports gas from Canada through TransCanada, Midwestern Gas Transmission Company ("Midwestern") and Great Lakes Gas Transmission Company ("Great Lakes") under gas export Licences GL-1, GL-18, GL-37 and GL-38 issued by the NEB.

Michigan Wisconsin was a founding member of the Northwest Project Study Group, predecessor of the Canadian Arctic Gas Study Group. It was also a founding member of the Northern Border

Pipeline Study Group and intervened in support of the CAGPL Project.

Natural Gas Pipe Line Company of America

Natural Gas Pipe is an interstate gas pipeline transmission company incorporated under the laws of the State of Delaware, with head offices in Chicago, Illinois. It was a founding member of the Northwest Project Study Group and is a member company of Northern Border. Natural Gas Pipe had a purchase agreement with Imperial to obtain gas from the Beaufort-Delta area for export to its markets in the United States. Natural Gas Pipe supported the CAGPL Project.

Northern Natural Gas Company and Consolidated Natural Gas Limited

Northern Natural, a natural gas transmission company incorporated under the laws of the State of Delaware and having its head office in Omaha, Nebraska, owns and operates an integrated pipeline system in the United States and sells gas within the areas served by its pipeline.

Consolidated Natural Gas Limited ("Consolidated"), a subsidiary of Northern Natural, is a body incorporated under the provisions of the Canada Corporations Act having the power, **inter alia**, to purchase, sell and deal in natural gas and related hydrocarbons. Northern Natural purchases gas in the Tiger Ridge field in Montana and Consolidated imports it at Willow Creek, Saskatchewan under Licence GLI-5. The imported quantity is injected into the TransCanada system and a like quantity is exported at Emerson, Manitoba under Licence GL-44 through the Great Lakes system to Northern Natural.

These two companies intervened jointly in favour of the CAGPL Project. Northern Natural has made purchase arrangements for Alaskan gas.

Texas Eastern Transmission Corporation

Texas Eastern is a natural gas transmission company incorporated under the laws of the State of Delaware, and its head office is in Houston, Texas. Texas Eastern was an early participant in the Gas Arctic Study Group, formed part of the CAGPL proposal and is a partner in Northern Border.

The Company had entered into a Gas Advance Payment Agreement with Atlantic Richfield for Prudhoe Bay gas which it planned to transport through the CAGPL system to its markets in Southern California, Texas and the Midwestern States.

The Texas Eastern intervention was filed in support of the CAGPL Project.

Pacific Lighting Gas Development Company

PLGD is a California corporation formed for the purpose of funding gas exloration and development activities to provide new sources of supply for Southern California Gas Company ("So-Cal"), an affiliated gas distribution company. Pacific Interstate Transmission Company ("Pacific Interstate"), a regulated natural gas company under FPC jurisdiction, is another affiliate, and all three companies are subsidiaries of Pacific Lighting Corporation.

In 1972 Pacific Lighting Gas Development Company became a member of the Gas Arctic Study Group. Subsequently PLGD and Alberta and Southern Gas Co. Ltd. ("Alberta and Southern" or "A & S"), a wholly-owned subsidiary of Pacific Gas and Electric Company ("PG & E"), entered into agreements to provide financing assistance to exploration companies working in the Delta and North Slope areas.

PLGD is an integral part of the overall CAGPL Project and proposed to use the CAGPL facilities, those of Alberta Natural, PGT and PG & E to move northern gas to So-Cal's market areas.

Alberta and Southern Gas Co. Ltd.

Alberta and Southern is a company incorporated under the laws of the Province of Alberta. It is a wholly-owned subsidiary of PG & E of San Francisco which distributes gas in the northern and central parts of the State of California. A & S purchases gas in Alberta primarily for its parent company and exports it through the facilities of Alberta Natural at Kingsgate, British Columbia under Licences GL-3, GL-16, GL-24 and GL-35. It also purchases gas for Canadian-Montana Pipe Line Company ("Canadian-Montana") which is exported at Cardston and Aden, Alberta. (Licences GL-5, 17, 25 & 36)

A & S had entered into contracts with Gulf Oil Canada Limited ("Gulf") and Shell Canada ("Shell") and Shell Explorer Limited ("Shell Explorer") for the purchase of Mackenzie Delta gas (see also Pacific Lighting above). A & S intervened on behalf of the CAGPL proposal but more specifically in support of the application filed by Alberta Natural, its affiliated transmission company. It opposed the other applications.

Natural Gas Corporation of California

This intervenor ("Natural Gas Corp."), a California corporation and another subsidiary of PG & E, operates a public utility distributing gas and electricity in northern and central California. It planned to acquire, by assignment, PG & E's interest in Alaskan gas and use the CAGPL and ANG facilities to transport the gas to United States markets. Natural Gas Corp. intervened in support of the CAGPL proposal and of the Alberta Natural application specifically. It opposed the Foothills and associated applications.

Gaz Métropolitain, inc.

Gaz Métropolitain, inc. ("Gaz Métro") is a regulated Quebec natural gas distribution company operating on the Island of Montreal and in adjacent areas. It is a partly-owned affiliate of Norcen Energy Resources Limited ("Norcen"). It relies predominantly on TransCanada for supplies. Originally Gaz Métro expressed concern that any pipeline built from the Mackenzie Delta be obligated to transport gas for third parties. Subsequently, in April 1976, Gaz Métro joined other distributor customers of TransCanada in support of CAGPL.

Greater Winnipeg Gas Company

Greater Winnipeg Gas Company ("Greater Winnipeg") is a gas distribution utility operating in and around the Winnipeg area, is a wholly-owned subsidiary of Norcen and is affiliated with Northern and Central Gas Corporation Limited ("Northern and Central"). It obtains its gas from TransCanada. Greater Winnipeg supported the expeditious construction of a northern pipeline and recorded a preference for the CAGPL proposal.

Northern and Central Gas Corporation Limited

An Ontario corporation, Northern and Central is a natural gas distribution company operating in the western, central and eastern portions of Ontario. It is wholly owned by Norcen. It relies entirely on TransCanada for its current supplies of natural gas.

Northern and Central is a member of the CAGPL consortium and participated in the Study Group.

The Consumers' Gas Company

The Consumers' Gas Company ("Consumers'") is an Ontario corporation. It is one of the largest distributors of gas in Canada and is wholly dependent on Canadian sources for its gas supply, almost all of which is purchased from TransCanada. Directly, or through its subsidiaries, it serves areas in central and eastern Ontario; principally Greater Metropolitan Toronto, the Niagara Peninsula, Ottawa and Brockville, Ontario and Hull, Quebec and adjacent municipalities, and St. Lawrence County in New York State.

Consumers' participated in the Study Group, is a member of the CAGPL consortium and has an undertaking to subscribe to the common shares of CAGPL if it is certificated.

Union Gas Limited

Union Gas Limited ("Union") is an Ontario corporation which owns and operates a fully integrated natural gas transmission and distribution system, with related production and underground gas storage facilities. It serves most of southwestern Ontario and areas as far north as Owen Sound and Goderich. Union obtains over 90 per cent of its supplies from TransCanada.

It was a member of the Study Group and has an undertaking to subscribe to the common shares of CAGPL if it is certificated. Union supported the CAGPL application.

FOOTHILLS (YUKON) GROUP

Northwest Pipeline Corporation

Northwest is a United States company incorporated in the State of Delaware and has its head office in Salt Lake City, Utah. It owns and operates a natural gas pipeline system in the western part of the United States delivering gas to distribution companies, municipalities and industrial customers in Colorado, Utah, Wyoming, Idaho, Nevada, Oregon and Washington. Approximately two-thirds of its gas supply is Canadian, obtained from Westcoast under Licences GL-4 and GL-41.

Because of its own increasing supply problems, in 1976, Northwest had incorporated Alcan Pipeline Company, in order to establish an entity to transport natural gas from Alaska to the lower 48 states.

Alcan Pipeline Company

Alcan is a Delaware corporation wholly owned by Northwest Pipeline Corporation.

In order to move gas from Alaska to its market areas, Alcan and Northwest entered into a Definitive Agreement in July 1976 with the members of the Foothills (Yukon) Project. Pursuant to that agreement, Alcan proposed to construct a 42-inch O.D. pipeline from Prudhoe Bay on the North Slope of Alaska approximately 730 miles to the Alaska-Yukon border. The original project involved transportation through Foothills (Yukon) facilities and others as well as through existing facilities of Trunk Line in Alberta. The associated application before the Federal Power Commission for the "Alcan Pipeline Project" was filed by Alcan and Northwest in July 1976.

Subsequently, in February 1977, the consortium submitted to both the NEB and the FPC applications for a project to construct an express line (largely 48-inch O.D.) from Prudhoe Bay to other United States markets, without the commingling of Canadian gas, and the application to construct a 42-inch diameter pipeline was withdrawn. Alcan is an integral part of the Foothills (Yukon) Project.

EXPLORATION COMPANIES

Chevron Standard Limited

Chevron Standard Limited ("Chevron") is engaged in exploration for and development of natural gas in the Mackenzie Delta in conjunction with Sun Oil Company Limited ("Sun Oil"). Chevron Standard Limited is an affiliate of Chevron Canada Limited. Chevron intervened in support of a pipeline and gave evidence on reserves estimates.

Dome Petroleum Limited

Dome Petroleum Limited ("Dome") is a federally incorporated company engaged in, **inter alia**, exploration for oil and gas in the Beaufort Sea and Mackenzie Delta.

Dome supported the construction and operation of a pipeline for the transportation of gas from Northern Canada to southern markets but did not support a specific project.

Gulf Oil Canada Limited

Gulf is an integrated Canadian company operating as an exploration and production company in the Mackenzie Delta and Beaufort Sea areas of Northern Canada. Gulf intervened in support of CAGPL, provided technical and other information to and for CAGPL, before and during the hearing, and gave evidence of its intention to participate in the equity financing of the CAGPL system. Gulf's participation in various phases of the hearing is discussed more fully under the appropriate chapter headings.

Imperial Oil Limited

Imperial is an integrated Canadian oil company carrying out exploration and production operations in the Mackenzie-Beaufort area. It is a sponsor of CAGPL and its proposed gathering and processing facilities in its northern operations areas formed one base upon which the CAGPL Project was planned. Imperial provided technical evidence and witnesses at the hearing. Its participation in the hearing is discussed more fully under appropriate chapter headings later in this report.

Panarctic Oils Ltd.

Incorporated under the Canada Corporations Act, Panarctic Oils Ltd. ("Panarctic") has exploration rights in the Canadian Arctic Islands and has been actively engaged in exploration in that area since 1968. Panarctic is an active participant in the Polar Gas Project ("Polar Gas") which plans to transport Arctic gas to mainland markets.

Panarctic did not support or oppose any of the subject applications.

Shell Canada Limited

Shell, an integrated Canadian oil company, has, through a subsidiary, engaged in exploration in the Mackenzie Delta-Beaufort area. It proposed to construct gathering and processing facilities for the gas reserves at its disposal in the area. Shell is a sponsor of the CAGPL Project and intervened in support of it. Details of Shell's participation in the hearing are discussed more fully in following chapters.

Soquip

The Société Québécoise d'Initiatives Pétrolières ("Soquip") is a Quebec corporation wholly owned by the Government of Quebec. Its operations range from exploration for hydrocarbons to transmission and sale within the Province. Soquip did not support any one project but held that third party gas should be given priority transmission through any system approved by the Board.

Sun Oil Company Limited

Sun Oil has oil and natural gas rights holdings in the Mackenzie Delta-Beaufort Sea area of Canada. It did not support a particular project, but gave evidence on reserves estimates of natural gas available to a pipeline.

OTHER DISTRIBUTION AND TRANSMISSION COMPANIES

British Columbia Hydro and Power Authority

British Columbia Hydro and Power Authority ("B.C. Hydro") is a provincial Crown agency which is the largest distributor of natural gas in the Province of British Columbia. Westcoast is its sole source of supply. Support was not given to any one of the projects.

Canadian-Montana Pipe Line Company

Canadian-Montana is a Canadian corporation which is a wholly-owned subsidiary of Montana Power. Canadian-Montana purchases gas from Alberta & Southern and obtains a substantial amount from the Pakowki Lake area, both in Alberta. It exports gas at Cardston and Aden, Alberta under Board licences to its parent company in Montana. This intervenor had, through A & S, contributed financially to the development of Arctic gas and was interested in purchasing additional supplies. Canadian-Montana supported the CAGPL Project.

Great Lakes Gas Transmission Company

Great Lakes is a Delaware corporation which is jointly owned by TransCanada and American Natural Gas Company. It operates a gas transmission line from an interconnection with TransCanada at Emerson, Manitoba, through the States of North Dakota, Minnesota and Michigan to Sault Ste. Marie and to Sarnia, Ontario. Great Lakes was constructed as an integral part of the TransCanada pipeline system. Its gas supplies are all purchased from TransCanada, some being sold to markets in Minnesota and Michigan and the remainder being transported for TransCanada for delivery to Eastern Canada. Great Lakes supported the CAGPL Project.

Inland Natural Gas Co. Ltd.

Inland Natural Gas Co. Ltd. ("Inland") is a public utility distribution company supplying natural gas to the north central areas of British Columbia. It is a customer of Westcoast and has a gas purchase contract with Alberta and Southern as well.

Inland intervened in support of a northern pipeline, the Foothills Project specifically.

Inter-City Gas Limited

Inter-City Gas Limited ("Inter-City"), a Manitoba corporation, and its subsidiaries provide a gas transmission service in Manitoba, Minnesota and northern Ontario. Its Canadian markets and some of its Minnesota markets are supplied by gas purchased from TransCanada. Inter-City supported CAGPL.

Midwestern Gas Transmission Company

Midwestern is a natural gas transmission company engaged in interstate commerce in the United States where it operates two main transmission systems. Its Northern System extends from a point of interconnection with the TransCanada system near Emerson, Manitoba to a point near Marshfield, Wisconsin. TransCanada is the sole source of supply for the Northern System.

Midwestern expressed a desire to continue purchasing gas from TransCanada when its current licences expire, and supported CAGPL. However, if Foothills (Yukon) were certificated, Midwestern would consider becoming a customer of that company.

St. Lawrence Gas Company, Inc.

St. Lawrence Gas Company, Inc. ("St. Lawrence") is a distribution company incorporated under the laws of the State of New York and serves market areas in the northern sector of the State. It is a wholly-owned subsidiary of Consumers', obtains its gas through Niagara Gas Transmission Limited ("Niagara Gas")(also a wholly-owned subsidiary of Consumers') and is dependent on Canadian sources for its gas supply. St. Lawrence supported the concept of a northern pipeline as an urgent and vital necessity and supported the CAGPL proposal as the most efficient and expeditious.

INDUSTRIAL CUSTOMERS OR ASSOCIATIONS OF SUCH CUSTOMERS

Industrial Customers

Interventions were received from or on behalf of over 20 industrial customers of distribution companies served by TransCanada. The companies grouped in the Hearing Order as Industrial Customers are heavily dependent on natural gas for industrial use, and are concerned with supply to meet their present and future requirements. All supported early construction of a northern pipeline. Five of them (starred below) were specific in support of CAGPL. Some presented evidence on Canadian requirements for natural gas.

The intervenors in this group were:

Abitibi Paper Company Ltd. ("Abitibi")
Algoma Steel Corporation Limited ("Algoma Steel")
Canadian Industries Limited ("CIL")
Canadian Pittsburgh Industries ("Canadian Pittsburgh")
Canadian Titanium Pigments Limited ("Canadian Titanium")
Consumers Glass Company, Limited ("Consumers Glass")
Dominion Glass Company Limited ("Dominion Glass")
Dominion Malting Limited ("Dominion Malting")
Dow Chemical of Canada, Limited ("Dow")
DuPont of Canada Limited ("DuPont")
* Falconbridge Nickel Mines Limited ("Falconbridge")
Inland Cement Industries Limited - Ocean Cement Limited ("Inland-Ocean Cement")

* Noranda Mines Limited ("Noranda")
* Pilkington Brothers (Canada) Limited ("Pilkington")
* I-XL Industries Ltd. ("I-XL")

SIDBEC

* Steep Rock Iron Mines Limited ("Steep Rock")

The Steel Company of Canada Limited ("Stelco")

Texasgulf Canada Limited ("Texasgulf")

Industrial Gas Users Association

This Association, known as IGUA, is an 18-member organization of industrial users of natural gas in the Provinces of Ontario and Quebec. Gas is obtained from distributor customers of TransCanada. The Association intervened in support of a Mackenzie Valley pipeline, but not of a particular project. IGUA participated actively in the hearing.

The members of the Association as of 1 January 1977 were:

Abitibi Paper Company Ltd.

Acier Atlas Steel

Allied Chemical Canada Ltd.

Canadian Industries Limited

Cyanamid of Canada Limited

Domtar Limited

DuPont of Canada Limited

Genstar Chemical Limited

Great Lakes Paper Company Limited

International Minerals & Chemical Corporation (Canada) Limited

INCO Limited

Noranda Mines Limited

Ontario Paper Company Limited

Polysar Limited

Quebec Metal Powders Limited

Reed Ltd.

Spruce Falls Power & Paper Co. Limited

Union Carbide Canada Limited

Motor Vehicle Manufacturers Association

The Motor Vehicle Manufacturers Association ("The MVM Association") represents eight major Canadian manufacturers heavily dependent on natural gas in their operations. The MVM Association intervened in support of a pipeline as an expeditious means of providing gas from the Western Arctic and the Delta for markets in Eastern Canada.

NATIVE PEOPLES GROUPS

Committee for Original Peoples Entitlement ("COPE") and Inuit Tapirisat of Canada ("ITC")

COPE was formed in 1969 as a liaison group for Northern Peoples in dealing with government and industry because of the fast pace of exploration and development in Northern Canada. Its primary concerns are with socio-economic and environmental impact. COPE represented Inuit Tapirisat in this hearing. The emphasis in the intervention was on the settlement of land claims before commencement of any pipeline construction in the North.

The Council for Yukon Indians

The Council for Yukon Indians ("The Council" or "CYI") represents all people of Indian ancestry in the Yukon Territory. It was formed in 1973 primarily to negotiate land claims settlements. The Council strongly opposed any pipeline construction in the northern Yukon at any time and held that settlement of land claims must precede construction through the southern Yukon.

Indian Association of Alberta

This Association represents approximately 30,000 treaty Indians residing in Alberta. The intervention expressed concern about the impact of a pipeline on Indian communities. It did not support or oppose any of the applications.

Indian Brotherhood of the Northwest Territories

A society incorporated in the Northwest Territories, the Indian Brotherhood of the Northwest Territories ("Indian Brotherhood" or "IBNWT") claims title to all lands in the Mackenzie District south of the tree line. It opposed construction of any pipeline prior to settlement of Indian land claims.

Native Working Men of the Northwest Territories

Mr. Joseph Mercredi, a resident of Fort Simpson and the spokesman for this group, intervened in favour of orderly development for Northern Natives. In his testimony, Mr.Mercredi stated that a pipeline should be built.

Tabitha and William Smith

This intervention opposed any interference with the ecology in the area of Old Crow. It claimed that the area was outside the jurisdiction of the Parliament of Canada. By telex on 20 April 1976, the intervention was withdrawn.

NORTHERN INTEREST GROUPS

Tom Butters M.L.A., Northwest Territories

Mr. Butters intervened to emphasize the positive effects of a northern pipeline. He supported the CAGPL proposal and suggested Foothills be invited to participate in it.

The City of Yellowknife

This City supported the construction of a Mackenzie Valley pipeline and the consequent economic development of the North, with proper control to minimize adverse effects.

The Northwest Territories Association of Municipalities

This Association represents ten municipalities which contain 70 per cent of the population in the Northwest Territories and 80 per cent of the population in the Mackenzie District. It supported the CAGPL application, but wanted adverse environmental effects controlled and minimized.

The Northwest Territories Chamber of Commerce

The Northwest Territories Chamber of Commerce ("NWT Chamber") is an independent body representing the organized Chambers of Commerce from Fort Smith, Frobisher Bay, Hay River, Inuvik, Norman Wells, Tuktoyaktuk and Yellowknife. It supported construction of a pipeline, but did not support one application over another. Primary concerns expressed included protection of the environment, compensation for those adversely affected, optimum involvement of northern residents in all aspects of planning, and employment of Northerners.

Pacific Western Airlines Ltd.

Pacific Western Airlines Ltd. ("PWA") has operated a charter service from Edmonton to communities in the Arctic since the 1950's and now operates a scheduled air service for passengers and freight, in addition to charters, between points in the Northwest Territories as well as from Edmonton to five major centres. The PWA intervention favoured construction of a pipeline to encourage social progress and economic growth in the North.

Settlement Council of Norman Wells

The Settlement Council of Norman Wells ("the Settlement Council"), representing a petroleum industry-based community on the Mackenzie River, favoured any pipeline project that would encourage social progress in its community.

Town of Inuvik

The Town favoured construction of a pipeline and development of resources in the Territories. It expressed concern that the municipalities not be required to bear the additional social costs resulting from rapid expansion. During the hearing it supported CAGPL.

Robert G. McCandless

Mr. McCandless, who resides east of Whitehorse, opposed the Foothills (Yukon) application on various grounds that the pipeline was not economically feasible and would result in no benefits to Yukon residents.

Robert Sharp

A former resident of Old Crow, in the Yukon Territory, now residing in Whitehorse, Mr. Sharp opposed construction of a pipeline along the Mackenzie Valley on the grounds that costs had been underestimated, and the social accounting processes and assurance of regional net benefits were inadequate. He also intervened in opposition to the Foothills (Yukon) application, through the Yukon Conservation Society.

Whitehorse Chamber of Commerce

Whitehorse representatives supported the Foothills (Yukon) Project and opposed any pipeline route through the area around Old Crow. This Chamber of Commerce favoured controlled development and expansion of the communities.

The White Pass and Yukon Corporation Limited

The White Pass and Yukon Corporation Limited ("White Pass") operates an integrated transport service in the northwest of Canada and Alaska. It is also involved in pipeline transportation of petroleum products. White Pass supported early construction of a natural gas pipeline from Prudhoe Bay and the Delta, but not a specific project.

Yukon Association of Municipalities

The Association, representing Dawson, Faro and Whitehorse, supported the Foothills (Yukon) application provided assurances were given that social and economic lifestyles were safeguarded and that the communities were not held financially responsible for over-extended services.

Yukon Conservation Society

The Yukon Conservation Society ("YCS") intervened in opposition to the Foothills (Yukon) application. The YCS claimed that the Foothills (Yukon) Project, although potentially less damaging than that of CAGPL, was still unacceptable.

Yukon Teachers' Association

This Teachers' Association expressed concern about disruption of the school systems associated with in-migration during pipeline construction. The Association did not object to a pipeline being built but wanted the pipeline company to share responsibility for minimizing negative effects on the communities.

PUBLIC INTEREST GROUPS

Canadian Arctic Resources Committee

Canadian Arctic Resources Committee ("CARC") is a public interest group consisting of scientists, officials of native and conservation organizations, lawyers, businessmen and other citizens. It was established in 1972 and has been active in focusing attention on many aspects of northern development. Its intervention was based on the public interest aspects of the environmental, social, economic and financial costs of the pipeline projects. The Committee did not oppose or support any project or present evidence.

Canadians for Responsible Northern Development

A Canadian citizens' organization registered in Alberta, with head office in Edmonton, this group has a wide range of objections to a pipeline from the Delta and the export of gas. Its intervention was intended to influence governments to modify the pace of northern development in the interest of resource conservation and the well-being of the northern peoples. It was represented at the hearings by its Director, Mr. G.F. Paschen.

Canadian Wildlife Federation

The Canadian Wildlife Federation ("CWF") opposed northern construction generally. It intervened in most phases of the hearing, and presented evidence on several different aspects.

Committee for an Independent Canada

The Committee for an Independent Canada ("CIC") is a national organization which has been involved, **inter alia**, in research on the potential development of a Mackenzie Valley pipeline since 1971. Its intervention expressed concern for the socio-economic and macro-economic effects of a Mackenzie Valley pipeline and stressed a need to consider the Canadian public interest as paramount. CIC participated actively throughout most of the hearing.

The Committee for Justice and Liberty Foundation

A national group incorporated in 1963 in Ontario, the Foundation represents a cross-section of Canadian society.

CJL opposed construction of a pipeline or any other form of conveyance of northern gas to southern markets. It stressed the necessity for settlement of land claims before any construction was undertaken and urged social justice for the Dene and Inuit. CJL participated actively in various phases of the hearing.

The Consumers' Association of Canada

The CAC, a national organization incorporated under the Canada Corporations Act, opposed any proposal to move Delta or Alaskan gas to markets in Southern Canada or the United States until it was proved that it was essential, financially worthwhile and that the social costs were offset by social benefits.

Energy Probe

Energy Probe is a project of Pollution Probe Foundation. It is a federal foundation with its centre of operations at the University of Toronto; its membership is national and its funding largely from the corporate sector.

In its intervention Energy Probe expressed its concerns for settlement of land claims, examination of all possible consequences of a pipeline, and a long-term energy policy based on conservation and use of alternative forms of energy.

Workgroup on Canadian Energy Policy

The Workgroup on Canadian Energy Policy ("the Workgroup") was established by graduate students of York University to assist and do research for public interest groups in the energy field. It wants a re-examination of energy policies. The activity of the Workgroup is related to that of and sponsored by Energy Probe. These two intervenors participated jointly in some parts of the hearing.

TERRITORIAL GOVERNMENTS

The Legislative Assembly of the Northwest Territories

The attitude of the Legislative Assembly was that the Territories required the economic stimulus of pipeline construction, and resource development. Certain concerns were registered: optimum participation by the Territorial Government in all phases of planning; optimum employment of Northerners; compensation for persons adversely affected; and protection of the environment.

Government of the Yukon Territory

The Government welcomed development projects, with safeguards for the environment and for land claims. It supported the Foothills (Yukon) Project as being more advantageous to Yukon, but wanted involvement in negotiations before terms and conditions for a pipeline certificate were determined.

PROVINCES

British Columbia

The Attorney General for the Province, and later the Minister of Transportation and Communications, ("British Columbia") intervened in opposition to moving northern gas to southern markets until it was demonstrated that it was in the public interest to do so.

Manitoba

The Province of Manitoba did not support or oppose any of the applications. Its concern was with the timing of initial development of frontier reserves, the impact on the economy and alternative means of alleviating the shortfall in supply.

Ontario

The Minister of Energy intervened for the Province ("Ontario"). Concern was expressed for an assured gas supply, and for best utilization of all resources. CAGPL was viewed as the most complete project. A co-ordinated approach by all Applicants was recommended.

Quebec

The Attorney General for Quebec ("Quebec") intervened on behalf of the Province in support of a means of ensuring supply for the Province, without preference for one project over another.

Saskatchewan

The Attorney General for the Province of Saskatchewan ("Saskatchewan") supported construction of a Mackenzie Valley pipeline which would be publicly owned and serve only Canadian markets. It supported the Foothills line over CAGPL as less likely to result in substantial exports of Canadian gas. Saskatchewan opposed further exports of Canadian gas. It recommended that no decision be made on these projects until the Polar Gas proposal had been considered.

GENERAL INTERVENORS

Arctic Canada Gas Transmission Company

Arctic Canada Gas Transmission Company ("ACGTC") is a partnership of Pentane Investments Limited and Titanic Construction Limited which planned to transport liquefied natural gas by tanker from the Arctic Islands to the Delta and to eastern Canadian markets. The intervention was filed to put on record the possibility of supplies of northern gas being available to Eastern Canada in greater volumes than would be transported by any of the proposed pipelines. By letter of 4 May 1977 this intervention was withdrawn.

Beaufort-Delta Oil Project Limited

Beaufort-Delta Oil Project Limited ("Beaufort-Delta") was an interested party because of its involvement in a plan, now in abeyance, to transport oil from the Delta to the Edmonton area. The intervention was withdrawn on 15 April 1977.

R.A. Bradley

Mr. Bradley is a Professional Engineer who had developed a proposal to transport northern gas and oil to southern markets by conveyor. He claimed the pipeline proposals were more expensive than his project would be.

Canadian Gas Association

As the representative of all segments of the natural gas industry in Canada, the Canadian Gas Association ("CGA") intervened in favour of a pipeline from the Mackenzie Delta. It did not support a particular project nor did it present evidence.

Canadian Labour Congress

As the representative of 1.9 million Canadian members, the Canadian Labour Congress ("CLC") opposed construction of the CAGPL or any pipeline in the north. It advocated consideration of specific aspects of the public interest.

El Paso Alaska Company

El Paso Alaska Company is the subsidiary of El Paso Natural Gas Company which had before the FPC a competing application to move natural gas from Alaska to the Southwestern United States by pipeline across Alaska and by LNG tanker down the West Coast. El Paso Alaska intervened in all the applications and expressed opposition to the CAGPL Project specifically.

Interprovincial Steel and Pipe Corporation Ltd.

This intervenor ("Interprovincial Steel" or "IPSCO"), based in Regina, asked for government assurance that any pipeline project approved be required to utilize maximum Canadian components. On 9 November 1976, the Company withdrew its intervention.

John F. Helliwell

Professor Helliwell is with the Department of Economics of the University of British Columbia. He and a group of researchers have been studying the economic impact of a Mackenzie Valley pipeline. He did not support or oppose any project but did indicate that a pipeline might not be needed before the early 1990's.

Housing and Urban Development Association

The Association ("HUDAC") filed a submission supporting early delivery of frontier gas to markets.

Liquefaction Limited

This intervention opposed the CAGPL proposal to transport gas as a vapour rather than as a liquid.

Pipeline Contractors Association of Canada

This national industry association ("PCAC") supported the concept of a northern pipeline and urged that work on one proceed without delay.

The Polar Gas Project

Polar Gas is involved in a project which plans to bring gas from the Arctic Islands to market. It therefore intervened as an interested party.

Ken Rubin

Mr. Rubin, a private individual, registered concern for native land claims and for orderly development of the North.

United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada

The American counterpart of this labour union ("the United Association") intervened before the FPC in favour of the competing El Paso proposal and in opposition to CAGPL. The Canadian body supported CAGPL and opposed the Foothills Project.

1.4 REASONS FOR DECISION

1.4.1 Introduction

Never before has the Board been faced with such a complex and difficult task in making a decision on applications before it. This is not only because of the immensity of the projects themselves and their importance to all Canadians, but also because of the magnitude of the potential socio-economic impact on the peoples of the north and the critical concerns related to the protection of the Arctic environment. Confounding the situation were late filings, introduction of the Foothills (Yukon) application part way through the proceedings, amendments of applications, the eleventh hour filing of applications for a 48-inch Foothills (Yukon) alternative system, and research still in progress on the question of mitigative measures to offset frost heave and thaw settlement in the sensitive discontinuous permafrost areas. The data supporting the applications suffered, inter alia, from the lack of material such as contracts for the sale and transportation of both Alaska gas and Delta gas, and from lack of a detailed assessment of the potential socio-economic and environmental impacts in the case of the Foothills (Yukon) project.

The producers were unwilling to commit to the construction of Delta gas processing plants until the long awaited government land regulations were published, and/or until a pipeline had been certificated.

Adding to the complexities, since parts of the proposed pipeline system would lie in the United States and parts in Canada, the ultimate decisions of each country should be compatible both as to the nature of the decisions and also as to the timing thereof if Canada were to approve a pipeline to move Alaska gas. It has been evident for some time that the United States is critically short of natural gas and the emergencies this past winter point to the fact that the United States Government intends to move expeditiously on a decision to connect Alaska gas to United States markets in the south. Of the three alternatives being considered by that government, one does not involve Canada. Undue delay in reaching a decision in Canada would have the effect of foreclosing the opportunity for Canadians to choose, from among several options, a course of action which would be beneficial to this nation.

A specific area which renders a decision by the Board immensely difficult relates to the settlement of native land claims. While the Board is not involved in the merits of claims per se, the issue of a land claims settlement dominates the Northerners' thinking on the pipeline question.

There is an apparent incompatibility between the urgent United States need to reach a decision on the connection of Alaska gas and the Canadian need to take more time to reach wise decisions in resolving the difficult and complex problems of northern land claim settlements. In such highly-charged circumstances it appears that the pipeline issue is being used as a pawn in the land claims negotiations. As a consequence, some of the current public statements by native groups on pipeline issues may turn out to be different from the positions such groups may wish to adopt at a later time, when the climate in respect of land claims may have changed.

Such is the milieu which has faced the Board in reaching its decision.

The proceedings have been long and costly, with the Board in session continuously for over a year. In the Board's opinion, no time has been wasted and valuable insights have been gained through the vigorous cross-examination of one applicant by another, which has caused weaknesses to be revealed and often remedied, further research to be undertaken and amendments to applications made in order to put them on a sounder basis. Public interest groups have made major contributions, not only in the cross-examination of the Applicants, but also in the presentation of their evidence on the need for, and timing of, a pipeline and in particular on the socio-economic and environmental consequences of having one. The decision and the reasons on which it is based would surely have been less comprehensive and might have been different had a public hearing of such depth not taken place; nor would the public have been as well-informed on the issues and as able to appraise the outcome. For projects of such magnitude, touching on almost every facet of the lives of Canadians, such a thorough investigation through the public hearing process was, in the Board's view, absolutely essential.

Since the proceedings and evidence before the Board have been somewhat unusual, and each facet of the hearing is interdependent with all the others, it appears appropriate to indicate some of the essential evidence applicants are normally expected to put before the Board when seeking certificates of public convenience and necessity for the construction and operation of natural gas pipelines and to which the Board may have regard before the construction can begin.

1. Proven and probable reserves of natural gas are a basis for determining the capacity and capital cost of a pipeline. Depending on the reliability of the estimates,

some weight can be given to future additions (i.e., trend gas) in that determination.

2. These reserves form the basis of realistic deliverability schedules of the natural gas on a year-by-year basis.
3. Deliverability schedules provide the basis of the producer-shipper contracts which should, in most circumstances, match the deliverability schedules.
4. Producer-shipper contracts form the basis for quantities specified in the transportation contracts between the shippers and the pipeline companies.
5. The transportation contracts form the basis for the financial projections of the pipeline company both as to revenues and costs and also for the return on rate base.
6. Producer-shipper contracts and transportation contracts form the basis of the financing of the pipeline and are usually required to be pledged as security for the debt to be issued.

All links of the chain must normally be in place before a certificate of public convenience and necessity issued by the Board can be fully effective.

In the case at hand the evidence was not put before the Board in the sequence just outlined and it was not therefore possible to test each link in the chain as the case progressed. Because one of the major unknowns in the case was the extent of Delta reserves, and because drilling to define them was continuing and results were being updated, the Board scheduled the hearing of this evidence in the latest possible phase of the proceedings.

Each earlier phase of the hearing dealt with certain assumptions, rather than facts, concerning the level of reserves and deliverability; as the hearing closed, all of the assumed reserves had not materialized. It is clear now that the producer expectations in the Delta have not been fulfilled and that deliverability from the established reserves in that area could not support some of the financial projections placed before the Board. The relationship between each essential link in the chain therefore needs to be kept in mind in the discussion of the evidence and conclusions on each aspect reviewed hereafter.

While no definitive contracts existed for Alaska gas and only one for Delta gas at the time the hearing closed, the Board has fewer concerns about the absence of Alaska contracts than with the lack of Delta contracts.

There appears to be little dispute about the size of reserves of Alaska gas, and the recent completion of a unitization agreement between the producers, which is likely to be approved by the State of Alaska, suggests that the initial deliveries will be in the area of 2.0 Bcf per day and that contracts for the sale and transportation of gas will in fact materialize.

The situation in the Delta is less certain. The amount of gas found in the Delta has been below the expectations of the producers. The conclusion of the Board is that the established reserves in the Delta are only 5.3 Tcf. However, this situation should not have influenced the producers from ensuring that the reserves already found were contracted to Canadian buyers and that those contracts were available for examination in the hearing. Several years ago the producers had contracted the gas they expected to find in the Delta to United States buyers in exchange for funds advanced by companies for exploration and development programs in the Delta. However, the Board's report in 1975 on the Supply and Requirements for Natural Gas issued after lengthy public hearings, made it evident that there was no prospect of exports from the initial reserves discovered in the Delta. Despite the fact that over two years have passed, the disengagement from United States contracts had not been completed when the hearing ended and contracts with Canadian shippers had not come into effect and could not be examined. The Board has difficulty understanding why the producers failed to provide the evidence on one of the most vital links in the chain for a project in which they were sponsors. The Board does, however, understand the areas of uncertainty facing the producers. Reserves found so far are marginal to justify building gas plants, particularly for Shell. The long awaited land regulations have not yet been promulgated, prices which will prevail in the market place when the gas is sold cannot be discerned clearly, and the netbacks to be received by the producers depend on conditions imposed by the National Energy Board in any certificate which may be issued, on conditions attached to a right-of-way permit and on conditions relating to permits to construct the gas plants. Presumably for these reasons, the producers indicated that they would not make a commitment to build the gas plants and finalize gas sales contracts until the late summer or the fall of 1977. But in making their decisions within this time frame, they were well aware that the Board's hearing would likely conclude in May, that President Carter would probably make his decision on the options available to the United States by 1 September 1977, and that before then the Canadian Government would want to enter into discussions with the United States Government, and that parliamentary debate on the Board's report was likely. In these circumstances, it is clear that the actions of the producers in the Delta have not been conducive to an orderly decision-making process in such a large and complex project of national and international scope.

1.4.2 Is a Pipeline Needed and If so, When?

The need to connect Alaska gas to United States markets would appear to be self-evident. Two questions amongst others which the Board considered, and which are addressed later in these reasons, in determining if a certificate of public convenience and necessity should be issued, the effect of which would be to provide a land bridge either up the Mackenzie Valley or along the Alaska Highway are: first, would the benefits outweigh the costs to Canada in providing an accommodation to its neighbour and, secondly, would such a pipeline facilitate or hinder the connection of Mackenzie Delta reserves to markets, both as to cost and timing?

In the assessment of whether a pipeline is and will be required by the present and future public convenience and necessity to carry Mackenzie Delta gas to Canadian markets, the question is bedevilled by the inability to accurately predict demand and supply; this difficulty is compounded by the long lead times needed to connect major new sources of supply to market. It may take five to ten years, or even more, between the inception of a project and its completion, and an error in forecasting of demand and supply leading to a shortage cannot therefore be quickly remedied. In addition, lead times cannot be accurately estimated because of the complexity of the decision-making process on major public issues as shown by, for example, the scheduling of the Alyeska project and the current projects herein being considered. The severe cold of Canadian winters, combined with lessons from recent shortages of natural gas suffered by our neighbour to the south, make it prudent for Canada to provide for itself a safety margin in connecting new sources of supply earlier than an uncertain forecast may indicate a need.

There are problems inherent in forecasting demand and supply and some of the problems can readily be illustrated. The demand for natural gas has been passing through unsettled times since the early 1970's. This has arisen partly from the fact that, until recently, Canadian consumers were unable to obtain new supplies from Alberta on terms acceptable to that province, partly from the uncertainty relating to the connection of Delta gas, partly from the radically higher prices now prevailing and which will increase further in the future, and partly from the emerging, but still ill-defined, changes in life styles and the conservation ethic.

Some intervenors urged the Board to deny new sources of supply in order to force Canadians to more rapid progress towards a "conserver" society, arguing that a two per cent annual rate of growth of demand for energy and natural gas was in the public interest. The Board is firmly of the view that a vigorous conservation program should be a prime goal of a Canadian energy policy, and that conservation appears to offer the lowest cost option for balancing the energy budget in the near term, but it believes that conservation alone cannot close the gap. New supplies will be needed to replace the declining deliverability of oil and gas from the Western Provinces. The Board recognizes that restricting supply does decrease demand, and this is demonstrated by the experience of the period from 1973 to the present time. Nevertheless, conservation is a complex issue not solely related to policies of federal and provincial governments for the encouragement of restraint and curtailment of demand, but more importantly to choices freely made by the public at large on life styles and on social goals, as well as to economic considerations. Changes normally proceed more slowly than some elements in society wish, and the Board under the National Energy Board Act clearly has no mandate to force changes in the manner sought by certain public interest groups. Rather, the Board has sought to perceive the rate of change which will probably occur in the complex milieu of Canadian society and to reflect this perception in its forecast of demand. The Board's recognition of these changes is one of the prime reasons why the Board's present forecast is significantly lower than its 1975 forecast. In that forecast, demand was intentionally not restricted by supply and the problem being addressed at that time was whether exports could be maintained at authorized levels in the face of the unsettled conditions then prevailing in the gas industry.

The Board recently released its report on Canadian Oil Supply and Requirements which contained a forecast of the demand for primary energy and for natural gas based on public hearings last fall. The forecast in the oil report is somewhat lower than the forecast contained in this report. The growth in the demand for energy from 1975 to 1995 in the oil report reflected an annual average growth rate of 2.8 per cent compared with 3.6 per cent in the present forecast and requirements for natural gas were about six per cent lower over the period. These differences primarily reflect a slightly higher prediction of economic activity, particularly in the period after 1985, and an upward revision based on later information on gas required for petrochemical feedstocks and on the growth rate in the demand for electricity and coal.

On the supply side, reservoir engineering is not an exact science and knowledge of how much, and when, new gas will be found is even more inexact. The failure of the large Beaver River field in northern British Columbia in recent years, which was virtually impossible to predict, illustrates the need for a safety margin in the early connection of new sources of supply.

On the other hand, significantly higher producer prices in the last two years have provided a powerful incentive to find new gas in the Western Provinces. There are some preliminary indications that more of this gas may be available earlier than originally contemplated, but whether the quantities and timing will be such as to significantly delay the need for frontier supplies is another question and this is examined later.

A further problem, to some, relates to the source of information on gas supply. There are those who imply that the Board is gullible because it relies on industry data. In fact, there are no other data. It is the oil and gas companies who carry out seismic activity, who drill the wells and who collect reservoir data. But the Board does not simply accept the industry's interpretation of this data; most of it is available for analysis by the Board's own staff of professional geologists and reservoir engineers. In addition, the Board has access to assessments by the professional staffs of provincial governments and their agencies.

There are some intervenors who put forward gas supply projections of such a nature as to imply that the gas industry operates largely as if controlled by a single decision maker. Such an illusion is dangerous and completely at odds with the reality of the imperfections in industry decision making, with the political reality that the objectives of producing and consuming provinces do not always coincide. It ignores the fact that the hundreds of existing gas purchase contracts result in inflexibility, and that provinces have protection formulae for reserves required to meet the provinces' future needs. Models generate instantaneous results and decisions regardless of the presence or absence of all of the facts, or the accuracy thereof. In reality, it takes time to make decisions, and this is aptly illustrated by the applications now before us; models, while valuable in providing insights into the future, cannot be expected to include all the complexities of real life situations.

Other forecasts appear to be based on simplistic assumptions on how the natural gas industry functions and, in the Board's view, paint an unrealistic picture of when shortages will occur and then erect a series of policies from this misleading and unsupportable initial position.

The natural gas industry is complex and the Board has endeavoured to show, in the supply and demand part of this report, the intricate derivation of the deliverability schedule needed to meet the expected demand and which is only valid for that particular demand forecast.

Turning now to the demand for and supply of energy and options available, determination of the need for a pipeline from the Delta must start with a forecast of the demand for natural gas, a forecast of the deliverability of gas from the Western Provinces and an evaluation of when shortages will begin to occur before considering new sources of supply. Since the pipeline relates to the medium term, the focus in this forecast of supply and demand is primarily on the period 1980-1995. The forecast is reviewed in depth in Supply and Demand, Chapter 2 of the report; the highlights of the findings are summarized as follows:

1. Demand for energy is not expected to grow as quickly as in the past, reflecting the increasing impetus to move towards a conserver society. The key variables in the Board's forecast are shown below.

Average Annual Compound Percentage Changes

	1960-65	1965-70	1970-75	1975-80	1980-85	1985-90	1990-95
Population	1.9	1.6	1.4	1.2	1.1	1.1	1.1
GNP Real Terms	5.6	4.8	4.3	4.9	4.3	4.3	3.9
Consumer Price Index	1.6	3.8	7.4	6.7	5.5	5.5	5.5
Primary Energy	5.6	5.7	4.0	4.5	3.3	3.5	3.4
of which							
Gas	13.5	10.7	6.2	5.4	3.7	2.9	2.9
Oil	5.9	5.0	3.4	3.3	1.9	1.8	2.0
Hydro/Nuclear	3.1	5.8	5.9	4.8	5.2	5.5	4.6
Coal	3.0	2.0	-2.0	7.5	4.0	3.7	4.0

Market Shares of Secondary Energy: Gas Competitive Sectors*
(%)

	1960	1965	1970	1975	1980	1985	1990	1995
Gas	15	20	25	30	32	33	33	33
Oil **	45	47	47	43	40	37	35	34
Coal ***	23	15	9	6	5	5	4	4
Electricity	17	18	19	21	23	25	27	28
Solar	0	0	0	0	0	0	1	1

* Includes demands in the residential, commercial, industrial and non-energy use (including petrochemical) sectors. Excludes transportation sector demands, energy supply industry requirements and energy requirements for electricity generation.

** Includes LPG's.

*** Includes coke oven gas

2. Canada's indigenous oil deficiency continues to increase and the expected pace of development of oil sand plants is unlikely to significantly change this trend. Some limited substitution of natural gas for oil may therefore become desirable. It is doubtful, however, that sufficient price incentive could be provided to cause this to happen without rendering Delta gas uneconomical to produce. Therefore such a policy, if desirable, is likely to have to be reinforced by government action.

3. Economic undeveloped hydro-electric sites for generating electric power are limited, but nuclear and coal generated electricity can meet future increases in demand. However, electricity is unlikely to penetrate a substantial part of the natural gas market.

4. As another possible new source of gas, coal gasification is technically feasible but, because of the economics of the process, is unlikely to contribute significantly in the next decade.

5. New sources of energy are emerging, such as solar and wind power, biomass, etc. These are in the early development stage and further

major research is needed, and this is endorsed by the Board. However, it is the Board's view, based on the evidence adduced, that they are unlikely to capture in the next decade a sufficiently large share of the market to constitute a dominant factor in the decision regarding the need for Delta gas. The Board is of the view that a reasonable estimate of the likely penetration of solar energy by 1990 is something less than two per cent of total energy consumption.

A table showing the approximate cost of the various potential new energy supplies follows. It indicates that Delta gas is about the lowest cost new large source of energy.

Table 2-22

COST OF ENERGY ALTERNATIVES

Energy Type	Order of Magnitude Cost of New Supply in Market Place ($ 1976) (per Mcf equivalent) (1), (2)
Electrical Energy	
- coal-fired plants	$5.00 to $6.50
- nuclear plants	$7.00 to $8.00
- hydro plants	$3.50 to $8.00
Synthetic Gas	$4.00 to $5.00
Imported Oil	$2.35 (4)
Oil Sands and Heavy Oil	$2.25 to $3.25 (4)
Arctic Island Gas	(3)
Mackenzie Delta Gas (on-shore)	$2.00 to $2.35

(1) If prospects were to be compared on a "real" cost basis, and taxes and royalties were to be excluded, then indigenous hydrocarbon developments would show a greater advantage relative to electrical energy and to imported oil.

(2) Direct comparison of costs must also be adjusted for different end-use efficiencies.

(3) No direct evidence was introduced on this cost. Because of the location and geological structures involved and the formidable transportation problems to be overcome, the Board expects these costs will be higher than those for on-shore Mackenzie Delta gas.

(4) Plus refinery margin.

The Board's "most likely" demand and supply forecast for natural gas is shown in Figure 2-9 which follows.

GAS SUPPLY/DEMAND BALANCE FOR CONVENTIONAL PRODUCING AREAS
NEB MOST LIKELY FORECAST

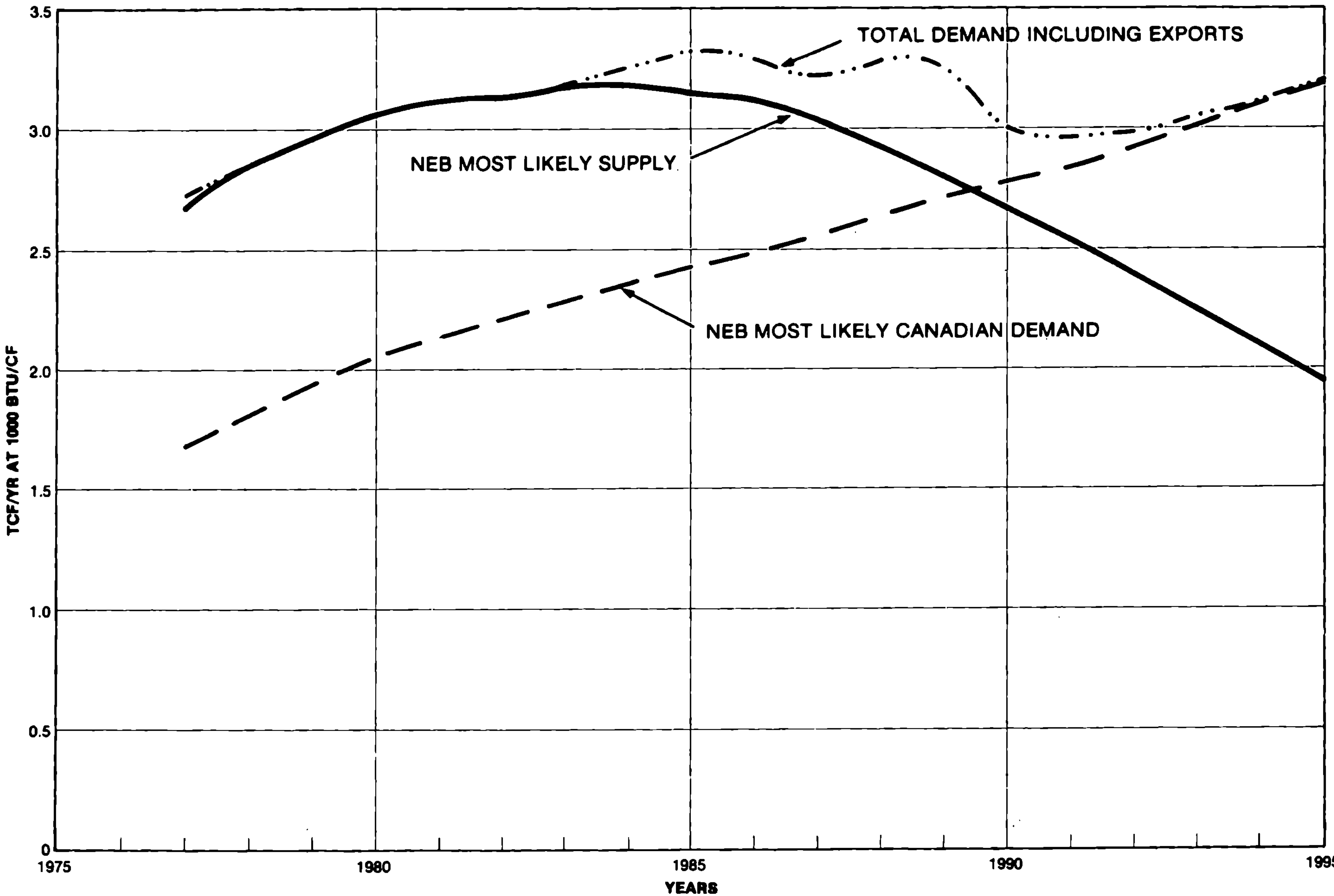

FIGURE 2-9

The Board's analysis indicates that if existing export licences were to be fully utilized, the year in which a deficiency, even though small, of natural gas from conventional sources first appears would be 1983. A persistent deficiency in the Westcoast system with respect to its exports under Licence GL-41 was originally caused by a deficiency in the production from wells in northeastern British Columbia but more recently it results from limitations in pipeline delivery capacity from Alberta to British Columbia. It is assumed that ways of eliminating the deficiency will be found in the near future. This assessment is reflected in Figure 2-9. It must be stressed that there are major uncertainties in the predictions of the year of first shortage. If one allows for the range of accuracy of forecasts, it might be as early as 1982 or as late as 1985. The graph also shows that if exports were phased down after 1983 because of lack of supply from conventional sources then frontier gas would not be needed until 1989.

However, the graph does not reflect the constraints imposed by the Government of Alberta on the removal of gas from the province in order to protect the future needs of its citizens. These constraints, usually referred to as the Alberta Energy Resources Conservation Board's protection formula, have recently been tightened but are not a restraining factor under present circumstances in which Canadian distributors are not increasing their purchases of gas in the absence of the assurance of long-term contracts and given the restriction of existing export licences. If the current Alberta policy were rigidly applied then the first shortage could appear as early as 1981. The likely future policy of the Government of Alberta was debated in the hearing. It is the Board's assessment that the Government of Alberta would not likely foster the earliest possible connection of Delta gas since this could cause the shut-in of some Alberta gas; therefore, in the face of this outlook and the pressure of Alberta producers to remove more gas from the province in order to provide more cash for exploration, it seems reasonable to anticipate some relaxation of restrictions by the Government of Alberta.

A further factor to be weighed is that the chart depicts an annual situation and that shortages are likely to occur on peak days in the winter before they appear on charts showing annual data.

One policy advocated by some intervenors was to curtail exports immediately, reserve this gas now for Canadian use, and defer a pipeline decision indefinitely. This situation is depicted in Figure 2-14. The rate of

GAS SUPPLY/DEMAND BALANCE FOR CONVENTIONAL PRODUCING AREAS EFFECT OF ELIMINATING EXPORTS IN NEB MOST LIKELY FORECAST

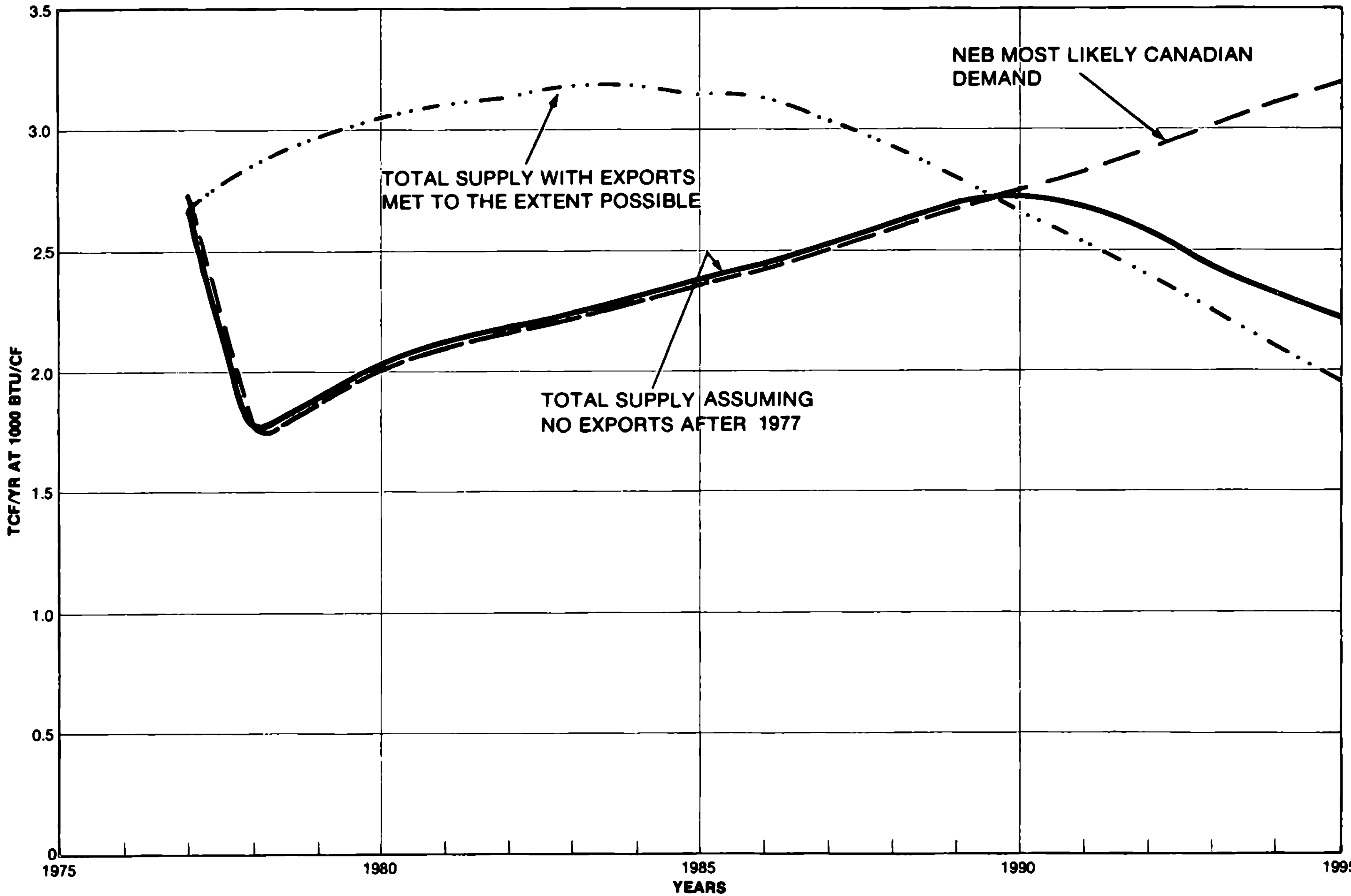

FIGURE 2-14

deliverability depicted is based on the likelihood that there would be a significant reduction in drilling and exploration activity in Alberta in the absence of the prospect of early cash returns and that the industry decision-making process would, in these circumstances, be slowed down. The chart, perhaps surprisingly to some, indicates that the year of first deficiency would be about 1990. This would be approximately the same point in time as would correspond with phasing down exports to levels which could be met from conventional sources of supply. The reason is that because of reservoir characteristics a unit of production foregone early in the production history of a pool can be produced later only at reduced rates, over a longer period of time. This, plus an anticipated lower rate of exploration resulting from reduced market opportunity, would mean that most of the gas would not be available until the 1990's and beyond.

In any case, the Board regards it as quite unrealistic to think that the Canadian Government would cut off exports of natural gas in their entirety at this time, when gas to meet these requirements is available. In the face of shortages and hardships in the United States clearly in evidence last winter, and which are likely to become more acute until Prudhoe Bay gas is connected, the Board could not recommend such action.

The extent of the additional deliverability temporarily available from Alberta, sometimes referred to as the "gas bubble", is shown in Figure 2-11. It can be seen that there could be about 400 Bcf more gas produced in 1977 and a similar amount in 1978 if markets were available, but the excess dwindles and disappears by 1985. There is no significant pipeline capacity available to transport the gas but it could be moved by pre-building in Alberta and Saskatchewan facilities which would be needed for Alaska or Delta gas.

A further situation examined was whether the deficiency of supply to meet demand between 1983 and 1988 could be bridged, and this is illustrated in Figure 2-11. This figure shows the deliverability which, in the Board's view, could be achieved if the gas could be sold. It will be seen that when some of the major export licences expire, the deficiency of supply from conventional sources is not large. In the study of the problem of whether the gap could be closed, the Board examined whether it was possible to stimulate additional deliverability from the present and anticipated reserves sufficiently to close the gap. The greatest disincentive to the producers at this time is the existence of gas available for sale and which cannot be sold. This both reduces the cash the producers would have

GAS SUPPLY/DEMAND BALANCE FOR CONVENTIONAL PRODUCING AREAS NEB MAXIMUM CAPABILITY FORECAST

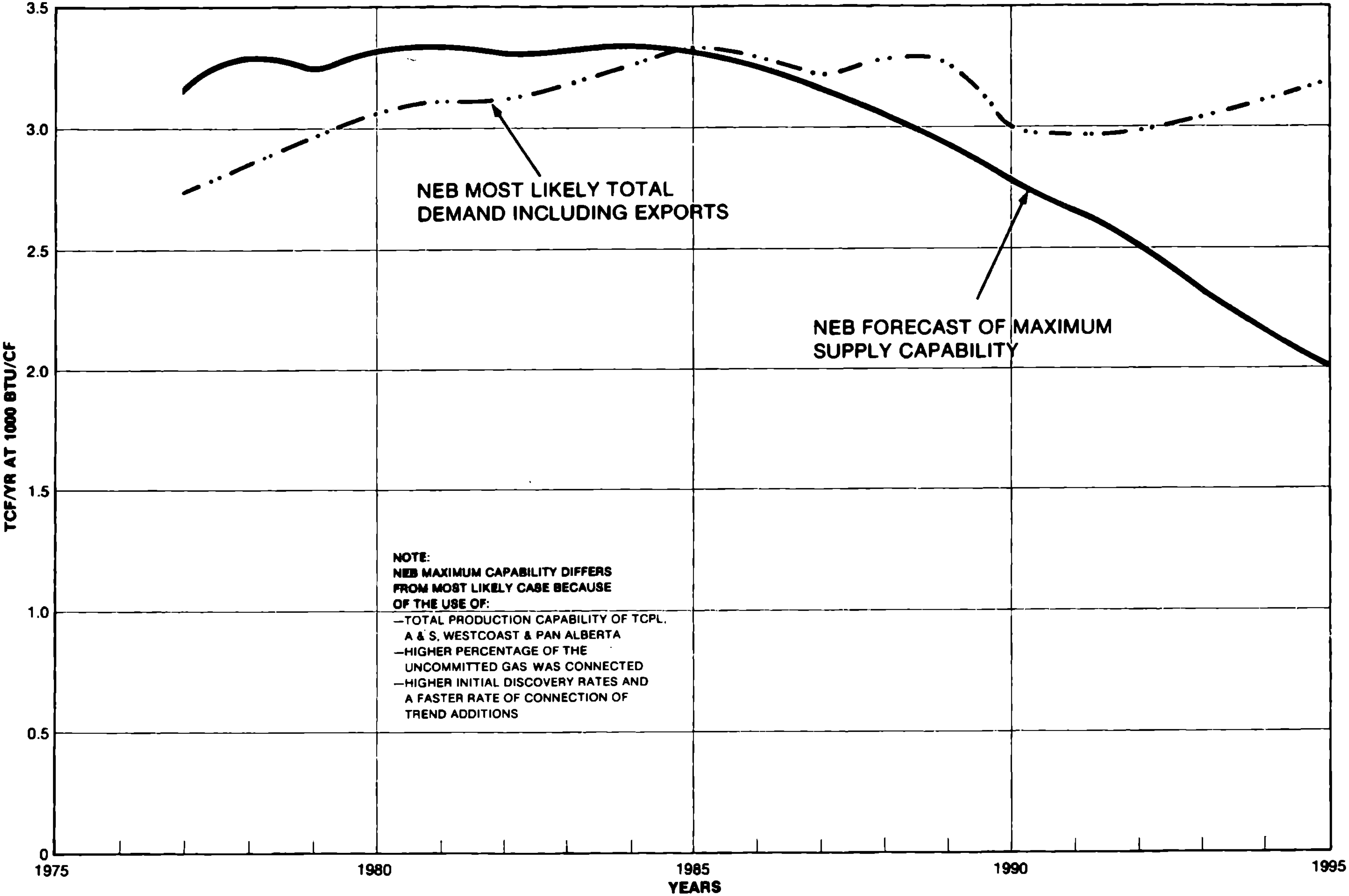

FIGURE 2-11

otherwise for investment in new drilling and reduces the incentive to do so if the gas resulting from successful drilling cannot be sold for some years. If, therefore, a way could be found to sell the "gas bubble" to existing export customers and offset it against export contract commitments in the period from 1984 to 1990, this would provide the producers with adequate incentives to help close the gas gap in that period.

A further matter to be considered is the effect of major curtailment of oil and gas activity in the Western Arctic if the connection of Delta gas is deferred indefinitely. This would probably destabilize employment in that area, reinstitute the "boom and bust" cycle, and eliminate or severely reduce one of the major activities contributing to steady wage employment in the Delta and nearby areas.

The question arises, are Delta reserves large enough to warrant connection to market. There can be no doubt that the reserves found on land have been disappointing, only 5.3 Tcf established reserves as estimated by the Board, and it cannot rely on the expectation that there will be large finds of gas in the near future in the Beaufort Sea. The Board is of the view that on present knowledge, if the market price of natural gas on a Btu equivalence basis is in the range of 85-100 per cent of the world price of crude oil, it would be economic to connect Imperial's Taglu reserves and Gulf's Parsons Lake reserves, and probably Shell's smaller reserves at Niglintgak, but this is only on the assumption that they are connected to a large diameter pipeline carrying Alaska gas up the Mackenzie Valley or, alternatively, are connected via a lateral to a large diameter pipeline carrying Alaska gas along the Alaska Highway. Evidence adduced at the hearing clearly indicated that a separate pipeline from the Delta could not be financed on the basis of the reserves discovered to date. The option for connecting Delta reserves via a lateral to an Alaska Highway pipeline could be considered at a date later than under the Mackenzie Valley alternative. If all licenced export quantities could not be met in the early 1980's it is possible that arrangements might be made for the earlier release of Alberta gas which could be later "replaced" by Alaska gas.

Another view is that any Delta reserves already discovered should not be connected to market until all potential, and as yet undiscovered, reserves in the Western Provinces are found and delivered to market. While this view might have some purely economic support, the Board considers it to be wise strategy to have the ability to draw on alternative sources of supply. It therefore cannot recommend exhausting all potential western provincial reserves before connecting Delta gas.

A further option would be to shut in Delta gas and defer connection of new sources until Polar Gas might be available in the mid or late 1980's. The Board recognizes that the minimum plant gate price necessary to connect gas from the Arctic Islands might possibly be less than in the Delta because of the larger pools, but some of the gas is off-shore and on balance it is probable it would cost more than on-shore Delta gas. Furthermore, there are major technological feats to be achieved in transporting Arctic Island gas to markets. While these may appear resolvable, experience in the processing of the present applications has demonstrated that major unforeseen difficulties may be discovered in the searching examination during a public hearing. Overall, and recognizing the limited information available, it would appear likely that Arctic Islands gas delivered to market will cost more than on-shore Delta gas. Furthermore, Panarctic reduced its estimate of "most likely" reserves at a late stage of this hearing from 16 Tcf to 13 Tcf; the Board's assessment, on the basis used by it, is only some 7 Tcf of established reserves, well below the threshold required for a pipeline. On balance, the Board considers it a wiser strategy at this time to place greater reliance on the lesser uncertainties relating to the now well examined technological problems of connecting

Delta gas to markets, rather than on the untried technology likely to be proposed in a future Polar Gas project. The level of reserves discovered in the Arctic Islands in relation to threshold levels to support a pipeline places further doubt on the wisdom of relying too heavily on gas from the Arctic Islands at this time.

In addition, projects are being studied to bring natural gas from the Arctic Islands to market by liquefying it and transporting it by ship. These appear to be more in the nature of pilot projects at this stage, and it is unlikely that the delivered cost could be competitive with that of Delta gas delivered by pipeline in existing Canadian and United States markets. Therefore such projects cannot, at this time, be considered as alternatives to Delta gas.

The foregoing discussion can be brought into focus by considering the policy strongly urged by several public interest groups. It was one of advocating strong conservation measures thereby limiting the growth in the demand for energy to about two per cent per year, combined with the denial of a pipeline to connect Mackenzie Delta gas to market so as to reinforce the limitation in the rate of growth of the demand for energy. The Board accepts the first part of the policy - a vigorous conservation policy - but rejects the second, the denial of the connection of

Delta gas to markets. This rejection is because new sources of energy will still be needed to meet a growth rate of as low as two per cent per year and Delta gas appears to be a relatively low cost new source of supply. OPEC oil is likely to become increasingly unreliable and high priced in the mid-1980's onwards and, except for Delta gas, other indigenous sources of energy will cost as much as or more than OPEC oil. In these circumstances, to refuse to connect Delta gas primarily to reinforce conservation does not seem to the Board to be a prudent policy; it would be neither economic nor safe.

The Board therefore concludes that a case has been established for the connection of Delta gas as early as 1982 providing it can benefit from being transported in association with the larger volumes of Alaska gas. This is not to say that a delay of two or three years in deciding on the proposed connection of Delta gas might not be beneficial. It might bring into sharper focus the potential of additional supplies from the Western Provinces, the size of Delta and Beaufort reserves and the prospects for the Polar Gas project, as well as providing more time for resolving matters relating to native land claims. Such a delay in connecting Delta reserves would probably require the co-operation of the Province of Alberta in relaxing its removal restrictions or would involve some scaling down or stretching out of existing export contracts, some "swapping" of gas or some combination of these actions. The natural gas transmission and distribution industry needs to be certain of long-term supply if it is to develop in a normal way. There has been no such certainty for the past five years and the industry urgently needs to be assured that new sources of supply will be connected by 1985 at the latest.

The question of whether or when a pipeline is needed is answered, in the Board's view, by its finding that additional gas is needed for Canadian markets during the first half of the 1980's. There are those who would advocate placing sole reliance for satisfying such needs on extra stimulation of deliverability from conventional areas or would advocate radical reductions in energy consumption brought about by forcing the pace of conservation. The Board considers that such approaches would be, at best, uncertain of success and would involve considerable risk in that, should these measures be unsuccessful, the failure would not likely become apparent soon enough to arrange for alternative supplies. Furthermore, the conservation approach would require the development and implementation by federal and provincial governments, industry and all citizens, of programs to significantly alter basic energy consuming patterns and life styles;

all this would have to occur almost immediately and on an unprecedented scale, so as to cut the average annual growth rate of energy consumption to about half its current level by about 1985. No matter how desirable an objective this might be, the Board considers its accomplishment highly unlikely. Accordingly, in the Board's view, Delta gas needs to be available during the first half of the 1980's.

The choice of whether it is wiser to seek to connect gas earlier under the CAGPL proposal, or to take more time and connect gas probably by a lateral to the proposed Foothills (Yukon) pipeline at a later date, depends on a variety of factors surrounding these options including economic matters, and socio-economic and environmental impacts.

1.4.3 Design, Engineering and Related Matters

1.4.3.1 CAGPL

The design of the CAGPL proposed pipeline from the Alaska-Yukon border to the Delta and south through Canada to the Canada-United States border contains several innovative features, embracing as it does a planned regime of operation beyond the technological limits of gas pipelines now operating in Canada. The key features are:

(a) the high design operating pressure of 1680 psig requiring a wall thickness of 0.72 inches for the 48-inch diameter Grade 70 pipe selected;

(b) the installation of a crack-arresting device every 300 feet along the pipeline to limit the length of a possible ductile propagating fracture, the prevention of which could not be assured through pipe metallurgical specifications;

(c) the design features to mitigate frost heave in regions of discontinuous permafrost, where the gas would be carried at freezing temperatures, including insulation and the use of electrical heat tracing and heat

probes involving the construction
of a 398-mile above-ground electric
power transmission line.

Much testimony was heard concerning the design, which generally was more innovative than that of Foothills or Foothills (Yukon). Cross-examination was vigorous and during the course of the hearing some design changes were made related to frost heave and thaw settlement.

The Board recognizes that with improvements in metallurgy, pipe manufacturing and welding materials and procedures, the frontiers of pipeline design have been gradually pushed in the direction of larger diameter and higher pressure pipelines, with resulting improvements in the cost of transmission. In a project of the magnitude of those now under consideration, involving such great distances from sources to markets, unit cost of transmission is important. Also important, however, having in mind the terrain and weather involved, is the integrity of the pipeline, safety in operation, and the ability to quickly make any needed repairs.

The Board is of the opinion that CAGPL has presented a feasible design but is not yet completely satisfied with all aspects, particularly with the design related to the mitigation of frost heave.

CAGPL proposed the construction of its pipeline over three winter seasons and two summer seasons, with the critical northern portion of the line being constructed in the winter. Here, again, CAGPL displayed innovation in its construction plan with the proposed use of an Arctic ditching machine, currently being developed, but as yet untried. CAGPL also proposed the use of artificial snow-making equipment to supplement natural snow for snow roads and work pads, on a scale not hitherto employed. It also planned to use portable artificial lighting equipment to provide illumination for men and equipment on the right-of-way during the Arctic winter. The Board believes that any uncertainty in CAGPL's construction plan related to these or other features of the plan does not render the plan infeasible, but does cause concern regarding potential for cost overruns necessary to correct any shortcomings in manpower or equipment, or cost overruns relating to a possible delay in completion of the pipeline caused by somewhat rigid logistics requirements and by weather.

The Board was impressed with the calibre of the team of management and project supervision personnel which CAGPL had so far assembled for the implementation of its project.

The Board is of the opinion that if it were to issue a certificate to CAGPL, the Applicant would likely be able to satisfy the Board in the final design process with respect to design and plan of construction.

1.4.3.2 Foothills

Foothills' proposed design for a pipeline to transmit Mackenzie Delta gas to the 60th parallel for interconnection with facilities of AGTL (Canada) and Westcoast for onward transmission to Canadian markets was more conventional than that of CAGPL. It is proposed to employ Grade 70 pipe of 42-inch diameter and 0.54-inch wall thickness operating at 1250 psig (below its potential operating pressure of 1440 psig), little different from sizes and pressures being employed in the South. At the operating pressure proposed and with the pipe toughness contained in its specifications, Foothills saw no need for crack arrestors to limit the length of a possible ductile propagating fracture.

Foothills did propose design measures to mitigate frost heave and thaw settlement problems. The former involved the use of insulation and an increase in the weight of over-burden through deeper burial and the latter involved the use of weights to create negative buoyancy, and the use of piles to provide pipeline support where required.

It was evident that design had not been considered in as much detail as had that of CAGPL. The Board, however, believes the design to be feasible, but would require further design studies related to the mitigation of frost heave.

Foothills' construction plan involved summer construction with the use of a gravel work pad for the northernmost 50 miles where winter weather conditions were considered to be too severe for construction during that season. The balance of the pipeline would be constructed during three late winter construction seasons, using snow roads and work pads. Again, it appeared to the Board that less time was devoted by Foothills to developing its construction plan and, accordingly, costs could be substantially greater than estimated by the Applicant.

Before the Board would be prepared to approve summer construction on the northernmost 50 miles of pipeline, it would require the Applicant to provide a detailed construction plan, including assessment of the quantities of granular material required and its availability and accessibility. In all other respects the Board believes that the Foothills design and construction plan is basically sound. However, if a certificate were issued to Foothills, the Board would require, inter alia, additional studies to support the design measures proposed for mitigation of frost heave and thaw settlement.

1.4.3.3 Foothills (Yukon)

Foothills (Yukon) applied to construct a 48-inch diameter pipeline through Yukon, generally along the Alaska Highway, as part of a system to transport Prudhoe Bay gas from Alaska to the Canada-United States border. The design pressure of the pipeline would be 1260 psig, with the operating pressure in the first 15 months not to exceed 1100 psig. The wall thickness of the pipe would be 0.60 inches and 0.54 inches, respectively, for the refrigerated and non-refrigerated portions of the pipeline. Generally, the design of the Foothills (Yukon) line, using this conventional pipe, followed the parameters of the Foothills pipeline, taking into account the different terrain and geotechnical conditions. Only some 40 miles would be operated in the refrigerated mode, and frost heave problems were expected to be minimal. The generally mountainous nature of the route led Foothills (Yukon) to believe that thaw settlement problems would also be minimal.

Foothills (Yukon) indicated that it would monitor the pipeline during the period of operation at lower pressure to ascertain potential frost heave and thaw settlement problems and, if necessary, corrective measures would be taken. Special design provisions were made for possible seismic activity where the route crossed the Shakwak Fault in western Yukon.

Foothills (Yukon) indicated that prior to final design it would carry out a full-scale burst test of its proposed pipe to determine the self-arresting properties of the pipe in case of failure and the potential need for crack-arresting devices.

It was apparent that even less time had been devoted to design studies by Foothills (Yukon) than by Foothills for its pipeline. In the Board's view, the extent of the problems related to frost heave and thaw settlement would be greater than Foothills (Yukon) asserted. It is clear that additional geotechnical and other studies would be required for completion of final design, and any certificate issued would be so conditioned.

The portion of the pipeline system which Foothills (Yukon) would construct from Empress to Monchy, Saskatchewan, would be of 42-inch O.D. pipe, with 0.473-inch wall thickness, operating at 1260 psig. The proposed design and operating conditions of this section of the system are not inconsistent with present practice in Southern Canada.

The construction schedule proposed by Foothills (Yukon) would see construction commence in the summer of 1979 with two spreads, and be completed by April 1981, with an in-service date of 1 October 1981 proposed. The Saskatchewan portion of the pipeline would be constructed with one spread over two summer seasons. All pipeline construction would be accessible from existing highway systems.

The Board believes it highly unlikely that all necessary authorizations, additional studies leading to approval of final design, including possible changes in route, and co-ordination with other pipeline companies participating in the project in purchasing materials and awarding contracts, could lead to implementation of the timetable proposed. It is probable that additional costs related to more detailed design studies, as well as route diversions and construction delays, would result. Nonetheless, the Board believes the construction plan, modified as required, would be feasible.

1.4.3.4 Alberta Natural, Westcoast and Trunk Line (Canada)

Alberta Natural proposes to construct facilities to connect with CAGPL facilities at Coleman, Alberta, for the transmission of gas to the international border at Kingsgate, B.C. and its design is generally consistent with existing facilities along the route.

Westcoast and AGTL (Canada) propose to construct pipelines which would interconnect with Foothills at the 60th parallel for the onward transmission of Delta gas to Canadian markets and with Foothills (Yukon) for the onward transmission of Alaska gas to United States markets. In the case of deliveries to eastern United States markets, the Saskatchewan portion of Foothills (Yukon) would serve as a link between Empress and Monchy, while deliveries to western United States markets would be made through a Westcoast southern British Columbia line between Coleman and Kingsgate.

The designs of each of these pipeline segments would be generally consistent with those of the upstream segments of the Foothills and Foothills (Yukon) systems. However, there were some noticeable differences in selection of grade and wall thickness of pipe, selection of compressor unit size and type and in other specifications, undoubtedly related to the past experience of each of the Applicants in constructing and operating pipelines in Alberta and British Columbia.

The Board believes there would be some advantage to having a co-ordinated design throughout the entire Canadian portion of any system which might be certificated.

The construction plans of the system segments in Alberta and British Columbia as submitted appear to the Board to be reasonable and obviously have been prepared by the companies concerned in light of their past experience in constructing pipelines in these areas.

If certificates were issued, the Board would wish to ensure that the final designs as submitted for Board approval were carefully co-ordinated with the other segments of the approved pipeline project.

The Foothills project in Alberta, apart from the most northerly 81 miles, is to be carried out by Trunk Line (Canada), involving the leasing of facilities or spare capacity from its parent, Trunk Line.

In summary, the proposed arrangement between Trunk Line (Canada) and Trunk Line would involve, inter alia

(a) joint use of right-of-way and facilities;

(b) use by Trunk Line (Canada) of compressor stations owned by Trunk Line;

(c) operation and maintenance of Trunk Line (Canada) facilities by Trunk Line; and

(d) transportation of northern gas in facilities under provincial control (Schedule "C" and joint use facilities).

The proposed lease of facilities and spare capacity by Trunk Line (Canada) from Trunk Line involves an exceedingly complicated system beset by both conceptual and practical regulatory problems. Such a proposal would require the movement on an indefinite basis of natural gas from the north through a system not regulated by this Board. The Board does not look with favour on these aspects of the arrangement proposed by Trunk Line (Canada) and Trunk Line for the movement of Mackenzie Delta-Beaufort Basin gas to markets in Eastern Canada.

In the Board's view any transportation of northern gas to southern markets should be in facilities under exclusive jurisdiction of this Board. Accommodation for movement of other natural gas through these facilities could be made by lease of capacity or by other means. If submitted, the Board would examine the proposed terms of such arrangement at the appropriate time in the future.

1.4.4 Contractual, Financial and Economic Matters

1.4.4.1 Contracts

The Board's views on the lack of contracts to support the pipeline projects have been stated elsewhere and only a brief summary is given here.

No definitive contracts for the sale and transportation of Alaska gas exist, but an initial throughput of 2.0 Bcf per day appears virtually assured. Contracts supporting throughputs of about this level are likely to come into existence in the near future.

Only one contract for the sale of Delta gas to Canadian shippers was placed in evidence. In the final stages of the hearing, it became evident that contracts supporting a throughput of 700 to 800 MMcf per day were likely to come into existence by the summer or fall of 1977. However, it was indicated that there were still major issues to be resolved relating to pricing, to the "all events" tariff and to take-or-pay clauses.

1.4.4.2 Financing

Each of the three project groups recognized the difficulty of financing such a vast undertaking; each recognized the difficulty of placing in evidence concrete financing plans in the absence of gas contracts for purchases and sales and for transportation; each relied heavily on projections of financial statements based on quickly achieving pipeline capacity rather than based on quantities which would likely be specified in transportation contracts which could be pledged for financing purposes; each relied on new and innovative tariff proposals and prepayments to facilitate to the greatest extent possible financing in the private sector; each provided for additional financing in the event of cost overruns; and each recognized that payments by shippers to investors would have to commence either when the pipeline was ready to receive gas, even though none was flowing, or when a specified number of years had elapsed from the start of construction, whether or not the pipeline was complete.

CAGPL would rely entirely on project financing. This means that the project would be executed by a new corporate entity with no financial history and no credit standing, with all the funds having to be committed in advance of the start of construction.

The Foothills project would rely on project financing for Foothills north of the 60th parallel and on "going concern" financing south of that point, using the credit strength of the well-established Alberta Gas Trunk Line and Westcoast to finance the project-related expansion of their own existing systems.

The Foothills (Yukon) project would use project financing by Foothills (Yukon), and in Alberta and British Columbia would use the "going concern" credit capacity of Trunk Line and Westcoast to build their respective sections of the new 48-inch diameter pipeline.

Each of the project groups recognized that financing would require undoubted security to investors with regard to

(a) completion guarantees;

(b) major interruption of operations; and

(c) abandonment either before or after completion, but before repayment of debt.

CAGPL would rely on its innovative tariff to obtain the maximum private sector capability but stated categorically that it required both United States and Canadian Government backstopping as a last resort underpinning for its financial plan. Despite the Federal Power Commission's recommendations to the President that it was not prepared to recommend government backstopping, and the United States Treasury's adamant position that private sector financing alone should be relied on, CAGPL reiterated in the closing days of the National Energy Board hearing that, in its view, government backstopping would be needed as the last resort underpinning of the project.

Foothills stated that government backstopping was not sought, but admitted that if the project could not be financed in the private sector, then a Crown corporation could build the northern portion of the line.

Foothills (Yukon) stated that it was not seeking government financing and relied entirely on private sector financing, the "all events" tariff with tracking and contractual arrangements whereby payments by shippers would commence by a date certain, even before the tariff began. The project would rely heavily on the credit strength of Trunk Line and Westcoast.

The Board believes that innovative tariffs are needed to provide the opportunity for maximum private sector financing. To this end, for this project, it endorses the principle of the "all events" tariff and the need for supplemental agreements with shippers covering the period before the tariff proper comes into effect. Certain of the principles necessary for an "all events" tariff are endorsed by the Board in Chapter 4 on financial and economic matters; others must await definitive contracts, knowledge of U.S. regulatory procedures relative to an "all events" tariff and further information concerning government backstopping and proof of financing.

The Board accepts the preliminary financing plan outlined by CAGPL as being imaginative and responsive to the difficult financing problem to be faced and having the potential for successful financing of the project. There are two exceptions to this. The first is that CAGPL would have to provide for majority Canadian control of the equity of its company. Secondly, the Board cannot endorse, and categorically rejects, the recommendation of CAGPL that the Canadian Government should provide backstopping to the project. The project primarily would provide a land bridge for the transportation of United States gas through Canada at, in the Board's view, a lower cost and with greater security of supply than the El Paso project; at the same time, by connecting Delta gas, it would provide greater likelihood that exports could continue at levels permitted by existing licences. In these circumstances, the Board cannot recommend that the Canadian taxpayer be required to underpin the project. The Board takes no position on the requirement for underpinning of the project by the United States Government, but clearly recognizes that the credit strength of the United States shipper contracts is the key to the financeability of the project.

The financial advisors to the Foothills project stated that it could not be financed at this time on the basis of the reserves already discovered and could not be justified on economic grounds. The Board shares this view.

The Foothills (Yukon) project group did not request backstopping by the Canadian Government and this, therefore, is not an issue. There are, however, matters of fundamental concern to the Board in the financing and ownership of the Foothills (Yukon) project. The first of these is that the financing plan relies very heavily on the credit strength of Trunk Line and Westcoast. The assets of these companies on completion of the project would increase to two to three times the current level. There is considerable evidence that costs could significantly overrun because of known risks to the project, and there may well be further potential for overrun for reasons not foreseen at the hearing. The Board is seriously concerned that the credit capability of these Canadian companies would be overstrained and possibly impaired by this situation, particularly by the unequivocal undertakings of these companies to complete the project irrespective of cost overruns. Having regard to the financial responsibility and the financial structure of these companies, the Board is concerned with the magnitudes of the potential risks in providing a land bridge through Canada to carry Alaska gas to United States markets.

There is also some concern that Trunk Line (Canada) might be unduly fettered as a designated subsidiary of Trunk Line, a company exposed to risks in the chemical industry and regulated by provincial authorities with regard to its pipeline activities.

Again, some unease has been expressed that the lack of a clear separation of the financing of the new 48-inch diameter line by Westcoast and by Trunk Line from their other activities might result in a situation detrimental to United States shippers.

An unsatisfactory feature of the Foothills (Yukon) proposal, as filed, was the lack of provision for the potential future connection of Delta gas. It was placed in evidence that providing for a future Dempster Highway link would make the financing of the Foothills (Yukon) project more difficult and the Board accepts this fact. It was further placed in evidence that, if the Foothills (Yukon) project proceeded without providing for a future Dempster link, the consent of investors might be needed at the time of proceeding with the link, and this could be difficult to obtain. But the availability of a Dempster Highway link as a potential means to connect Delta gas to the 48-inch diameter Foothills (Yukon) pipeline would be one of the principal benefits to Canada of providing a land bridge for carrying Alaska gas through Canadian territory. Westcoast and Trunk Line expressed a willingness under certain conditions to covenant to build such a link. It appears to the Board to be mandatory that the financial plan of the Foothills (Yukon) project should exclude any possible inhibition in providing a Dempster Highway link and, further, the investment community at this stage should be apprised of this potential eventuality. For financial planning, it would be wise to consider the Foothills (Yukon) project with a Dempster link as a single project, constructed and financed in two stages with a recognition of the need for the second stage to proceed if the National Energy Board certificated it.

A further question relates to who should build the pipeline in southeastern British Columbia. Foothills (Yukon) expressed repeatedly in the hearing the advantages, compared with CAGPL, of having the existing pipeline companies construct the new 48-inch diameter pipeline in terrain which they knew well and particularly where the new 48-inch diameter line would use, or be adjacent to, the existing rights-of-way. This logic would make Alberta Natural the obvious choice to construct the line in southeastern British Columbia. Mr. Phillips, the Chief Executive Officer of Westcoast, conceded this point and admitted that the only reason for not providing for this was that Alberta Natural was one of the sponsors of the CAGPL project. The Board does not consider this an adequate reason for foregoing the advantages of having Alberta Natural construct the line.

In addressing itself to the foregoing problems, the Board has given consideration to whether some other form of corporate ownership for the Foothills (Yukon) project would be beneficial.

Both Trunk Line and Westcoast have acknowledged that their prime purpose is to optimize the existing and proposed pipelines under their respective corporate ownerships. Both companies operate wholly, or almost wholly, within provincial boundaries and have close links to the governments of those provinces. While the companies' objectives may be consistent with the broader purposes of an integrated interprovincial and international pipeline, there is no assurance that this would be so. One way of providing such assurance would be to require the Foothills (Yukon) project to be owned by a single entity and use project financing. This, however, might adversely affect the benefits of having Trunk Line (Canada), Westcoast and ANG construct and operate pipelines in the terrain and conditions with which each is well experienced. The Board therefore considered solutions which could combine the benefit of a single corporate purpose and uniformity of design and tariffs with decentralization of construction and operation to those companies operating pipelines in the same area while, at the same time, drawing on their capital-raising capabilities without overexposing and overstraining their credit.

These objectives the Board believes could be achieved by having the pipeline to be constructed south of the 60th parallel owned by federally incorporated subsidiaries of Foothills (Yukon) with, say 51 per cent ownership, and the remaining ownership, say 49 per cent, vested in the pipeline company now operating in the area concerned. The subsidiaries would construct and operate the pipelines under overall guidelines and controls developed by Foothills (Yukon) but under the management and control of the affiliated companies. For example, in Alberta this subsidiary could be Foothills (Alberta), which would be owned 51 per cent by Foothills (Yukon) with Trunk Line owning 49 per cent directly and a further 10.2 per cent indirectly (through Trunk Line's 20 per cent ownership of Foothills (Yukon)). Trunk Line would manage the construction and operation and could use its credit capacity to provide equity and some debt financing - but would not have an unlimited commitment to finance cost overruns or to complete the line.

Similar situations could prevail with respect to Westcoast for the line in northern British Columbia and to ANG in southeastern British Columbia. In the event that such a proposal was not acceptable to ANG within a specified time, the Board could withhold the issuance of such certificate to ANG and include that portion of the line to be constructed in southeastern British Columbia in any certificate issued for the northern British Columbia line.

The Foothills (Yukon) project, as proposed, provided for majority Canadian equity control because the common shares would be owned by Trunk Line and Westcoast and the preferred stock, which would be issued to United States shippers, would be non-voting. The Board considers it to be unnecessarily rigid to prevent the parties providing the underpinning of the credit support for the project, the United States shippers, from having voting rights and being represented on the Board of Directors of Foothills (Yukon). The Board would condition any certificate it might issue to require majority Canadian voting control of the equity in each pipeline company.

The Board believes that such a scheme as outlined above would facilitate the support of United States shippers and interests, which is fundamental to the success of the project.

The Board would anticipate that before certificates were issued, unless the Board otherwise directed, the corporate organization or reorganization would be completed establishing the corporate ownership along the lines outlined above or on any other basis which would achieve similar objectives and be acceptable to the Board, and financing arranged accordingly. Certificates would then be issued in the name of these corporations.

On one final point, the Board is of the view that a project of such national proportions could require, and should have, the combined construction and operating know-how and financial support of all three major gas transmission companies in Canada. This could provide a broader Canadian equity participation in Foothills (Yukon) and the Board would look with favour on the construction and operation of the pipeline segment in Saskatchewan by TransCanada on a basis similar to that outlined for Trunk Line, Westcoast and ANG.

While the inclusion of a Dempster link may pose some problems in implementing the financing of the Foothills (Yukon) project, in the Board's view the project with the inclusion of the link is economically sound and has the strength of experienced major Canadian transmission companies behind it. This, together with the support of United States shippers and other investors, and the approval of both governments, should ensure that the funds to finance it would be forthcoming.

1.4.4.3 Comparative Costs of Transportation

CAGPL, Foothills and Foothills (Yukon) presented extensive evidence to support their various calculations of cost of service. They also presented evidence which purported to demonstrate the underestimation of the competing project's cost of service calculations.

At the request of the Board, Foothills (Yukon) filed unit cost estimates relating to the transportation of Delta gas via a Dempster Highway route connecting with the Foothills (Yukon) 48-inch diameter line at either Dawson or Whitehorse. These cost estimates were necessarily preliminary.

Near the close of its hearing, the Federal Power Commission requested each Applicant to recompute its cost of service under a consistent set of assumptions. The results, as indicated in the FPC's Recommendation to the President, showed that the Alaskan Arctic-CAGPL project would be able to transport Alaska gas from Prudhoe Bay to various delivery points in the lower 48 states at slightly lower unit costs than the Alcan-Foothills (Yukon) project. In addition, the FPC was of the opinion that Alcan's statement of unit costs may have been low due to optimistic estimates of construction costs and scheduling.

The Board has set out in the following table unit transportation cost estimates as filed by the Applicants. The Board cautions that the figures in this table have to be viewed in relation to the Board's assessment of the risk of capital cost overruns discussed in the following section.

Examples, in cents per MMBtu, are shown for Alaska gas from Prudhoe Bay to the 49th parallel and for Mackenzie Delta gas from the Delta to Empress, Alberta - the point of interconnection with TransCanada PipeLines Limited. The costs, as presented, are based both on the initial throughputs which can be supported by gas already found (0.7 to 0.8 Bcf per day for Delta gas and 2.0 Bcf per day for Alaska gas) and on throughputs related to a fairly rapid progression to the design capacity of the pipeline. While the Board places more weight on cases related to the throughputs approximating reserves already found, the unit costs at design capacity provide insights into the economics of expansibility of throughput and, in some cases, into the economics of the pipeline system.

TABLE 4-1

COMPARATIVE UNIT TRANSPORTATION COST IN CENTS PER MMBTU[(1) (2)]

(supply volumes in Bcf/d)

LINE NO.	ITEM	1982 Vol.	1982 ¢/MMBtu	1983 Vol.	1983 ¢/MMBtu	1984 Vol.	1984 ¢/MMBtu	1985 Vol.	1985 ¢/MMBtu	1986 Vol.	1986 ¢/MMBtu	1967 Vol.	1967 ¢/MMBtu
	DELTA TO EMPRESS												
	Based on Reserves Discovered												
1	Foothills 42"	-	-	.80	216	.80	219	.80	208	.80	201	.80	196
2	CAGPL (Alaskan 2.0 Bcfd)	.70	179	.70	161	.70	136	.70	132	.70	128	.70	145
	No Expansion Cases												
3	Foothills 42"	-	-	.80	211	1.20	166	1.20	153	1.20	147	1.20	142
4	Foothills 30"	-	-	.80	175	1.20	154	1.20	149	1.20	144	1.20	139
5	Foothills (Yukon) Dempster-Whitehorse	-	-	.80	152	1.20	137	1.20	133	1.20	128	1.20	123
6	Foothills (Yukon) Dempster-Dawson	-	-	.80	138	1.20	125	1.20	121	1.20	117	1.20	113
7	CAGPL	1.25	159	1.25	152	1.25	138	1.25	129	1.25	124	1.25	122
	Base Cases												
8	Foothills 42"	.13	165	.87	206	1.27	155	1.67	129	2.07	117	2.40	102
9	CAGPL	1.25	133	1.25	124	1.50	113	1.75	121	2.25	122	2.25	115
	PRUDHOE BAY TO 49TH PARALLEL[(3)]												
10	Foothills (Yukon) Only	1.60	246	2.40	166	2.40	161	2.40	156	2.40	150	2.40	145
11	Foothills (Yukon) Dempster-Whitehorse	1.60	246	2.40	165	2.40	158	2.40	152	2.40	146	2.40	141
12	Foothills (Yukon) Dempster-Dawson	1.60	263	2.40	175	2.40	168	2.40	162	2.40	156	2.40	150
13	CAGPL No Expansion Case	-	-	2.00	181	2.00	178	2.00	165	2.00	158	2.00	156
14	CAGPL Base Case	-	-	2.00	149	2.00	151	2.25	156	2.25	155	2.25	146

(1) All unit costs shown are based on material found in exhibits by the Applicants. These unit costs are based on 1976 costs escalated. Unit Transportation Cost Exhibit Reference Tables with summary are provided in Appendix 4-1.

(2) The unit transportation cost, as shown for each case, excludes the fuel cost.

(3) Unit transportation costs to the 49th parallel are the weighted averages of the unit transportation cost to Kingsgate, British Columbia and Monchy, Saskatchewan.

There was a good deal of discussion in the hearing on whether the unit costs should be compared on the basis as filed by each Applicant or should be adjusted to a common basis. The Board has decided that it is adequate for its purpose to use the unit costs of transportation as filed by the Applicants. In using these unit costs, the Board recognizes that there are limitations in the data as filed. It is of the opinion that the unit costs for the Foothills (Yukon) project may be somewhat understated compared with those for the CAGPL project, in contrast to what might have been shown had there been strict comparability. The Board also recognizes that any number of factors such as construction delays, capital cost overruns, additions to proven reserves or modifications to proposed accounting methods could result in higher or, in some cases, lower unit costs for each project. The Board does not accept the magnitude of the adjustments made by CAGPL to the costs of the Foothills and Foothills (Yukon) projects as filed.

The Board, after taking the above matters into consideration draws the following conclusions:

1. For the transportation of Alaska gas from Prudhoe Bay to the 49th parallel, the differences in the unit costs of transportation of the various projects are

relatively small, whereas for the transportation of Delta gas via the Mackenzie Valley to Empress they are more significant.

2. The CAGPL project would provide significantly lower unit costs for the transportation of Delta gas to Empress than the Foothills project and would probably provide slightly lower unit transportation costs for the delivery of Alaska gas from Prudhoe Bay to the 49th parallel than would the Foothills (Yukon) project.

3. The link to Dawson, which would involve rerouting the Foothills (Yukon) 48-inch diameter pipeline in the Yukon, would probably result in a lower unit cost to Empress than would the alternate link to Whitehorse.

4. A Foothills (Yukon) pipeline with a Dempster link to Whitehorse for Delta gas would produce a moderately lower unit cost for Alaska gas delivered to the 49th parallel than would a Foothills (Yukon) only project.

5. Providing a Dempster link to Dawson instead of Whitehorse may increase the unit cost of transporting Prudhoe Bay gas to the lower 48 states only slightly, while achieving a significantly lower unit cost to Canadians for shipping Delta gas. This latter difference may be sufficient to ensure that the Delta gas plants are built since at least one of them appears to be marginally economic at this time.
6. With a throughput of 1.2 Bcf per day from the Delta and 2.0 Bcf per day from Alaska, the cost of transmission of Delta gas to Empress, taking into account the preliminary nature of the estimate for the Dempster line, appears to be approximately the same for the Foothills (Yukon) and the CAGPL projects.

1.4.4.4 Risk of Cost Overruns

The Board required each of the project groups to submit an assessment of the risk of cost overruns, since these could be critical to the financability of the pipeline and to the viability of the Mackenzie Delta gas plants.

All three projects are very complex, massive engineering undertakings featuring difficult climatic and terrain conditions. Their successful completion in a timely fashion and within budget would depend not only on careful and detailed cost estimates, but also on factors largely outside the Applicants' control such as the rate of inflation, regulatory stipulations for socio-economic and environmental reasons, foreign exchange fluctuations and strikes or other difficulties affecting key supplies or segments of the transportation sector. The Board cannot pretend to make a precise assessment of all of these factors.

The Board was impressed by the thoroughness of the CAGPL estimates and by the competence of the project team. Nevertheless, the Board believes that due to the difficult conditions for the northern Yukon and Cross Delta sections, a delay of eight months to one year could occur and that the effect of inflationary influences could exceed the provision made for them. The Board could visualize an overrun of 20 per cent to 35 per cent occurring on the CAGPL project.

In respect to the Foothills (Yukon) project, the terrain and climatic conditions would be less severe and south of the 60th parallel the Applicants have had experience with the actual conditions. However, the Board judges that the cost of construction in the Yukon has been significantly under-estimated. In addition, less preliminary work has been completed compared to CAGPL and more delay could be anticipated before construction would be authorized. A delay of one year from the filed date of completion of 1 October 1981 is envisaged by the Board. For these reasons, the Board judges that a cost overrun of 20 per cent to 30 per cent could occur.

The Board, in making the foregoing estimate, has endeavoured to take into account all known factors which might have an impact on the project. It is, of course, impossible for anyone to foresee all events which could conceivably occur and the Board's assessment must therefore be viewed with this in mind.

Earlier, reference was made to testimony indicating that, based on reserves already discovered, the Foothills project could not be financed; accordingly, there would be no point in attempting to assess the risk of cost overruns.

1.4.4.5 Canadian Content

The National Energy Board Act states that in reviewing an application for a certificate, the Board may have regard to the extent to which Canadians will have the opportunity of participating in the financing, engineering, and construction of the line for which certification is sought. Canadian content means materials, supplies, services and financial arrangements which are acquired in Canada from a Canadian citizen or corporation; the definition being more particularly set forth in the National Energy Board Rules of Practice and Procedure, Section 2.(d.1).

The financing of the project was dealt with in an earlier section which indicated that Canadian and United States financial markets would be fully used for both the CAGPL and the Foothills (Yukon) projects. The problem therefore is rather one of not overstraining the available capacity of Canadian financial markets.

Turning now to other aspects of Canadian content, in general an industry located in Canada provides greater benefits to the nation when it is not only based here and supplying domestic markets, but when it also possesses technological advantages which enhance its competitive position in export markets. The greater the degree of Canadian ownership, control and content of the product of such an industry, the greater the contribution to the Canadian economy.

There can be many variations of the methods used for estimating Canadian content in a project. However, in any approach taken, there must be an examination of the chain of events which occurs in purchasing a product or service, to determine the origin of each of the components and the final destination of the dollars spent.

Because the proposed pipelines would be Canadian by location, substantial portions of project content would almost certainly be Canadian in origin, particularly with respect to labour, transportation services and certain essential raw materials such as lumber, gravel and other items of that nature. In addition to such services and raw materials, there are types of manufactured goods which would undoubtedly be acquired locally. Beyond these it is the Board's conclusion that the areas in which the Canadian content of the subject projects have the most potential for benefiting the nation are as follows: project and construction management, engineering, construction, compression equipment, valves and fittings, pipe, and to a lesser extent, construction equipment.

In the area of project and construction management and engineering, the differences between the proposals are small; however, the Board considers that Foothills and Foothills (Yukon), along with those associated with these projects, have taken an approach likely to provide somewhat more Canadian content benefits than would the CAGPL approach.

Any of the projects, if certificated, would, according to the evidence, use pipeline construction contractors resident in Canada. The peak project manpower requirement would probably approach 8,000. Estimates by the Applicants indicated that all of the projects would have Canadian labour contents close to 90 per cent. It is the Board's view that any of the proposed projects would yield significant benefits to the Canadian pipeline construction industry and the Canadian labour force.

In respect of Canadian content of compression equipment, given the evidence that selections as to manufacturer had not been made by any of the project groups, the Board finds no substantive difference between the approaches put forward by the Applicants.

With respect to valves and fittings, particularly large ball valves and large fittings, the Board concludes that the emphasis placed on maximizing Canadian content in these components by Foothills and Foothills (Yukon) was greater than that exhibited by CAGPL.

The pipe requirements for the proposed projects would represent by far the largest demands ever to arise in Canada. CAGPL's higher pressure design, necessitating the use of thicker wall pipe, represents a somewhat greater manufacturing challenge. Partly for this reason, the supply of its total pipe requirement of almost 2.0 million tons would be split, about 70 per cent to come from Canada and the remaining 30 per cent from foreign suppliers. Foothills and Foothills (Yukon), with a lower-pressure, thinner wall pipe design, propose to obtain all of their requirements, 1.1 and 1.3 million tons respectively, in Canada. They are able to take this approach because of the anticipated greater Canadian manufacturing capability for pipe of the type required by their proposed projects as compared to that for CAGPL's proposed heavier pipe. Thus the evidence put before the Board indicated that the pipe for the Foothills and Foothills (Yukon) projects would have a higher percentage of Canadian content than that of the CAGPL project, although the total tonnages of pipe produced in Canada would be approximately the same for the CAGPL and the Foothills projects.

Turning to the potential for Canadian content in construction equipment, the Board sees little to choose between the projects. Given that a very large portion of the construction machinery historically and currently is imported, there is theoretically a major potential for developing a Canadian industry in this area. The Board considers this worthy of serious consideration by any successful Applicant, but cautions that such consideration must be comprehensive, and must examine, amongst other things, the likelihood of Canadian demand for such equipment being able to sustain a manufacturing venture in the long term.

The overall levels of Canadian content estimated by the Applicants were relatively high, in the range of 80 to 90 per cent. Applications associated with the Foothills and Foothills (Yukon) projects showed overall Canadian content estimates averaging somewhat higher than those indicated by CAGPL for its project. The Board's overall assessment is that the Foothills and Foothills (Yukon) policy and approach to Canadian content would, in fact, yield somewhat greater benefits to Canada than the corresponding proposals of CAGPL.

While the potential benefits from high Canadian content in the proposed pipeline projects are significant, the achievement of these benefits would depend on the successful Applicant following through on its declared intention. To assure such follow-through, the Board will attach to any certificate it might issue a condition in respect of Canadian content.

1.4.4.6 Overview of Economic Issues

The approach by the Board to the assessment of the economics of the proposed pipeline projects has been from various directions. These have ranged from the question of commercial feasibility of natural gas production in the Delta to consideration of the net economic benefits to Canada arising from the pipeline projects. The pipeline proposals, being so large, have been examined to determine their macro-economic impacts. In addition, the implications for individual Canadian industries, insofar as they may obtain orders for components of the pipeline project, have been examined.

The cost-benefit analysis examines whether the connection and production of Delta gas is likely to yield net economic benefits to Canada. Such an analysis depends crucially upon cost and cost overrun estimates in pipeline and in gas production facilities, upon market prices assumed for the delivered gas, and upon the assumptions as to gas reserves and pipeline throughputs. Generally speaking the cost-benefit analysis indicates whether net economic benefits are likely to be positive for Canada if a project is put in place to deliver natural gas to market at a price approximating the price of world oil. Such an analysis, however, does not include transfer payments such as income taxes and royalties as a cost of producing and delivering the natural gas. Essentially, if net economic benefits are estimated to be positive, it means that the real costs of labour, capital and resources incorporated into the project are less than the revenues from natural gas in the market-place based upon the world oil price. Benefits to Canada from the transmission of Alaska gas to United States markets are also estimated.

The cost-benefit analysis does not provide a total overview because difficult-to-quantify costs and benefits are not included. For example, environmental costs have not been included in the cost-benefit analysis. Also, the social impacts on the regional economies north of the 60th parallel, both good and bad, do not lend themselves easily to quantification. Furthermore, the possible impacts upon Canadian industry such as the possible growth of high technology industry in Canada over the long term cannot be strictly quantified.

Finally, the economic assessment includes estimating the effect upon the components of the Canadian macro-economy. In particular, econometric analysis is used to estimate whether the pipeline projects could put pressures upon areas such as the rate of inflation, interest rates and the foreign exchange rate. The Board after considering the evidence pertaining to the Canadian economy made a macro-economic forecast and used it to assess the macro-economic impact of the projects.

All of the above represent economic considerations for the testing of the economic desirability of a pipeline project from a total Canadian point of view. In addition, the Board's economic analysis has addressed itself to the commercial viability of the projects. In particular, this has focused upon the commercial viability of private company development and production of the existing Delta gas reserves. As mentioned, the essential difference between analysis in the Canadian context and that for commercial feasibility is that commercial feasibility demands that all taxes and royalties, etc. can be paid by the participating companies and the companies can still earn a satisfactory return on investment.

Turning now to the Board's assessment of these issues, the evidence of the hearing was remarkably uniform in assessing that it would be extremely unlikely that severe problems would result in the macro-economy as a result of any of the projects. All of the assessments came to the same general conclusion on the effect of a pipeline on the economy. It could be likened to the effect of throwing a rock into a large pond. The resulting ripple was discernible but not unduly disturbing and the ripple from one project was barely distinguishable from that of others.

The Applicants provided evidence of impacts under conditions where the economy was assumed to be fairly fully employed. The Board's economic forecast, underlying its impact analysis, assumed some slack in the economy in the initial period which would be slowly reduced to the point where the economy would be close to full potential by 1985. The construction of a pipeline would cause only a small increase in interest rates and in the rate of inflation. In the analysis of the Board, increments to employment and GNP were also estimated to occur. The only area of noteworthy impact was that of the foreign exchange rate. The Applicants estimated that the exchange rate might appreciate some two percentage points, and in the final analysis with the natural gas throughputs estimated from the existing 5.1 Tcf of Delta reserves, the Board was in agreement. If throughputs were higher, the pressure for the exchange rate to appreciate would be greater. In light of Canada's existing and growing trade deficit and the tendency for the exchange rate to depreciate if indigenous gas does not replace imported oil, this possibility does not appear to present problems.

The Canadian industrial impacts analysis concluded that serious bottlenecks are not likely to emerge and that generally any of the projects will provide a healthy fillip to industry. It may be noted that very considerable quantities of steel pipe would be obtained from Canadian sources, in quantities greater than one million tons. Overall, the Applicants have estimated that very high levels of Canadian content could be achieved for the projects, in the 80 per cent to 90 per cent range.

Concerning employment, the proposed projects are relatively capital intensive, both in construction and operation. Over the five-year period, 1978 to 1982, direct employment for the CAGPL pipeline and for gas plants might amount to 25,000 man years, with an additional induced increase in employment of 222,000 man years estimated by the Board. While the employment will peak during construction, it would average about 50,000 man years a year over the five-year period. The employment in the Delta and related areas would extend over a longer period and generate about 2,000 permanent jobs and another 1,000 seasonal ones. A large number of these would be avilable to qualified Northerners. None of the proposals would provide tremendous amounts of employment, but they would provide some substantial income to Canada and Canadians through returns on investment, through income taxes and other taxes and royalties.

Turning now to cost-benefit analysis, the first conclusion is that the Foothills project, with the existing established Delta reserves, would not provide positive net economic benefits. The evidence on net economic benefits by Foothills assumed that some 32 Tcf of gas reserves would be connected to the pipeline over its lifetime. Considerable doubt exists as to when or whether such reserves will be discovered. More importantly, the size of the existing established reserves is not sufficient to provide throughputs which would yield net economic benefits. In the view of the Board, the crucial cost-benefit test for the projects is one where each project is examined to estimate whether net economic benefits are positive under the assumption that only established reserves of 5.1 Tcf of Delta gas would be available.

The Foothills (Yukon) project alone, without a pipeline link between the Delta and Dawson, may be considered as a first step on the basis that it is independent of Delta reserves. Analysis of the Foothills (Yukon) project shows that it has limited potential for net economic gain to Canada, but also has limited risks provided that the difficult-to-quantify social or environmental costs are covered. There would be net economic benefits to Canada, however, which stem from payments made by United States customers for the transmission of Alaska gas. These benefits would primarily be in the form of corporation and other taxes included in the cost of service. However, while the Foothills (Yukon) project separately is estimated to provide positive net economic benefits to Canada, these benefits increase significantly with the inclusion of a future Dempster Highway link. The Foothills (Yukon), plus Dempster link, is estimated to provide approximately 1.0 billion dollars of net economic benefits at a ten per cent discount rate, and 3.5 billion dollars at a five per cent discount rate.

The CAGPL project, with 5.1 Tcf of Delta reserves, is estimated by the Board to provide about 1.3 billion dollars of net economic benefits at a discount rate of ten per cent. This estimate assumes, as does the estimate for the Dempster link mentioned above, that natural gas is priced in Toronto markets at Btu equivalence with oil and that no pipeline or gas production cost overruns occur. Assuming a five per cent discount rate, the net economic benefits are estimated at some 4.7 billion dollars.

From the point of view of this cost-benefit analysis alone, and keeping in mind the previously noted caveat that the cost-benefit analysis excluded environmental and social costs - which would differ between the two main projects - the CAGPL project appears to have an advantage. The CAGPL proposal provided for the earlier connection of Delta gas and, by its pipe sizing, more flexibility for expansion than would be available with a 30-inch O.D. Dempster connection. In addition, at throughputs of 700 to 800 MMcf per day, the cost of the spare capacity would be, to a large extent, allocated to United States shippers. Furthermore, because Alaska gas would travel a longer distance in Canada compared to the Foothills (Yukon) route, the Canadian taxes included in the cost of service paid by United States shippers would be greater.

The evidence and the Board's overall assessment indicate that Delta gas production would be commercially feasible from the existing reserves, and probably from any sizable reserves in the shallow water of the Beaufort Sea, or from other on-shore discoveries, if transmitted in a large diameter pipeline, in conjunction with Alaska gas, and the cost overruns are less than 25 per cent. With pipeline throughputs from existing reserves, the Taglu and Parsons Lake fields are likely to be profitable to the companies, but according to the evidence the Niglintgak field could be a marginal proposition.

Summarizing the foregoing, it is the view of the Board that the CAGPL and Foothills (Yukon) plus Dempster link proposals contain the ingredients for providing projects with net economic benefits which could be accommodated by the economy and which would probably lead to some significant industrial benefits. Furthermore, it appears likely that both projects could provide transmission of Delta gas to Canadian markets on a basis which would ensure the commercial viability of Delta gas plants.

It should be mentioned that a pricing policy for natural gas in Canada providing for close to world oil price equivalence (85 per cent to 100 per cent parity) is necessary for the profitability of Delta production.

Finally, there are some policy actions which could be considered on the pricing of Delta gas to make it economically more attractive. The economics of the CAGPL project are based on all Delta gas being sold at a price equivalent to the price of gas in the Toronto market. However, the prices received by producers in the Western Provinces are based on both the netback from sales in Canada and the higher netback from export sales due to higher prices and lower transportation costs. While the differential between the netback from the exports and domestic shipments is likely to diminish, a case could be made for Delta producers sharing in the benefits which producers elsewhere receive from export sales.

1.4.5 Regional Socio-Economic Impact

It was evident that CAGPL had carried out thorough and extensive research on socio-economic, environmental design and engineering matters. However, the Board believes that a fundamental assessment of the underlying socio-economic and environmental factors inherent in the choice of route should be given more weight than simply the amount of research carried out so far on each project; provided of course that there is reasonable assurance that any deficiencies in research can be remedied before construction is permitted to begin and that the Board can be satisfied that socio-economic and environmental impacts can be held to tolerable levels by means of effective mitigative measures, monitoring and controls.

No description of the potential socio-economic impact of a pipeline could begin without referring to the issue which now dominates the lives of Northerners - the settlement of land claims. The Board in its hearing did not consider the merits of the claims or their settlement since these are matters under direct negotiation between the native people and the federal government. But the Board is vitally concerned with the interrelation of the resolution of a land claims settlement with perceptions of Northerners on whether a pipeline should be built, and if so, where and when.

It is the Board's understanding that all native peoples' organizations with the possible exception of the Métis, desire a settlement of land claims before a pipeline is constructed. The Inuit of the Western Arctic live in the area where most of the hydrocarbons are likely to be found. The Inuit do not appear to vehemently oppose pipeline and related developments, provided that their land claims are settled, that the development of oil and gas is strictly controlled in terms of adverse environmental and socio-economic impacts and that they participate in such control, and that they share in the wealth generated, e.g., royalties. The

Dene, on the other hand, generally oppose the pipeline development - at least for ten years - and wish in that time to devote themselves to shaping Dene institutions and building a renewable resource based economy without being disturbed by the upheaval of pipeline construction. George Erasmus, their leader, claims that construction of a pipeline now could cause the cultural genocide of the Dene. The Métis Association favours construction of a pipeline because it sees business and job opportunities being created by it. The Council for Yukon Indians opposes in perpetuity the construction of a pipeline across the northern Yukon and wishes land claims to be settled and implemented before a pipeline is built in southern Yukon. Its position on a Dempster link was unclear at the time of the hearing but there is a motion of the Council indicating opposition to development activities in the vicinity of the Dempster Highway.

Undoubtedly the Board's socio-economic assessment will be compared with that made by the Berger Inquiry. It should thus be noted that the terms of reference are not identical. Justice Berger was specifically required to have regard to "any proposals to meet the specific environmental and social concerns set out in the Expanded Guidelines for Northern Pipelines as tabled in the House of Commons on June 28, 1972 by the Minister". These guidelines envisaged an energy corridor including a future oil pipeline. The Board was not constrained by these guidelines, and five years later the expectation of large finds of oil and gas in the Delta and Beaufort Sea are much reduced, although major discoveries are still possible. However, at this time, the prospect of an oil pipeline and hence an energy corridor appears to be somewhat remote.

Finally, by way of introduction, the Board shares Justice Berger's view that statistics on the north are relatively sparse and somewhat unreliable, and that views of professional sociologists and economists often differ on solutions to the major problems which exist in the north today. The Board's assessment is, therefore, one of broad judgment.

The north at this time may be said to be a land in transition. The move of natives away from the traditional way of life, living in small groups and relying almost entirely on hunting and fishing, is a recognized fact. Many native northerners now live in communities where schools and social services are available. Hunting and trapping still take place, but more on a seasonal basis.

Little wage employment has been created and many of the people receive welfare payments. The problems of crime, alcoholism and health greatly exceed those of the south. For the individual native northerner, the situation seems to be one of turmoil caused by fear of further white encroachment, a striving to retain the essentials of a life close to the land from a non-viable base in a community, a difficulty in adapting to modern technology but more and more exposed to it and, at the same time, a search for radical changes in political institutions to protect and safeguard native culture and ways of living. It is therefore not surprising that the added problems relating to the possible construction of a pipeline only confound an already confused situation.

The situation in the Yukon is similar in many respects to that in the Northwest Territories. However, the opening up of the Alaska Highway in 1942 and the fact that the Yukon economy and institutions are more developed, and that the land claim negotiations appear to be more advanced in the Yukon, offer more potential for the earlier resolution of difficult and complex problems associated with a land claims settlement.

The outlook of white residents of the north, particularly the entrepreneur and the small business man, is generally pro-development, although with some fear of being overwhelmed by the large companies from the south. Municipalities generally feel a need to grow and broaden their tax base if they are to provide the services their inhabitants are increasingly demanding, although they recognized and expressed concern over the heavy burdens which might be imposed in the absence of sufficient lead time and financial support. Finally, a large component of the white population is comprised of territorial and federal public servants.

The territorial governments appear to look with favour upon developments such as those proposed by the Applicants. A major consideration for the territorial governments would seem to be that these developments would provide them with much needed increased revenues as well as contributing significantly to closing the wide gap between federal government expenditures required to maintain the north in a viable state and revenues originating in the territory.

Turning now to the CAGPL and Foothills applications, the socio-economic impact of these projects along the Mackenzie Valley would be broadly similar and will be considered together. The common features of the socio-economic impact and measures proposed by the Applicants to mitigate it include:

1. Willingness to train and hire Northerners for employment, but recognition that opportunities in the construction phase are limited and mainly related to unskilled and semi-skilled jobs.

2. The main job creation opportunity for Northerners arises from hydrocarbon exploration and development rather than the pipeline itself - but without a pipeline or the expectation of one these jobs would not be available.
3. Mitigative measures include the isolation of construction camps from communities, preference in hiring to be given to "Northerners", a term still lacking precise definition, the hiring of non-northern workers solely from union hiring halls south of the 60th parallel, provision of most of the pipeline company's own services such as transportation and barging, self-containment of camps, etc.
4. Assistance to municipalities and communities where the impact can be identified with the pipeline; e.g., employee housing.
5. Provision of gas to communities.

Construction south of the 60th parallel would follow the pattern traditionally associated with pipelines and no unusual problems were identified.

The undertakings made by CAGPL and Foothills on the socio-economic impact are contained in Appendices 5.1 and 5.2, as well as in evidence given in the hearing.

The Foothills (Yukon) project is basically similar to CAGPL and Foothills except that it would be carried out adjacent to an existing highway system. There can therefore be less containment of construction camps compared with that for camps in the Mackenzie Valley, and there would be more impact on some of the communities along the highway. On the other hand, it appears that a smaller number of inhabitants would be affected.

The Foothills (Yukon) undertakings are contained in Appendix 5.2.

The Board, in making its assessment of the socio-economic impact of the applications, assumed that if a pipeline were built the certificate would be conditioned with respect to the following requirements or that, where applicable, the requirements would be contained in agreements with the federal government.

1. Preferential hiring treatment for Northerners with the definition of a "Northerner" to be determined by and acceptable to the Government of Canada.
2. Southern hiring halls to be used for non-northerners working on the pipeline.

3. Union contracts would contain provisions responsive to the avoidance of work stoppages.

4. Applicants to abide by undertakings made on socio-economic matters.

5. Indirect costs north of the 60th parallel to be paid by the pipeline company.

6. An effective governmental monitoring system for socio-economic matters to be in place prior to the start of construction.

The Board's assessment of the socio-economic impacts which may flow from a pipeline project in the north follow. In the view of the Board, regional problems related to the possible large in-migration to the north, associated local inflation, and possible direct and indirect interference with the traditional sectors of the economy, are three of the main regional costs which may occur and which must be mitigated. Also, there would be territorial and federal government costs which have not been fully assessed. Short-run regional benefits will emerge from business opportunities, increased employment opportunities during the construction period and in the longer term, those associated with oil and gas exploration and development, and their consequent increases in real incomes to residents of the affected areas. Transportation and communication systems would also be improved in the regions. The petroleum industry in the Delta area would be provided with substantial impetus. Perhaps the largest long-run impact upon the territories could be the possibility of their receiving income taxes and royalties associated with natural gas production and transmission. If Delta gas pipeline throughputs rise to levels estimated by the Applicants, these government income flows could go a long way towards providing an economic basis for territorial self-sufficiency.

The pipeline and related projects would do little to ameliorate the endemic social problems of the north. Job creation, particularly hydrocarbon exploration and development, should be beneficial but the transition to wage employment entails its own brand of social difficulties. Certainly, in the Board's view, the construction period would exacerbate social problems, particularly in the Mackenzie Valley. On balance, pipeline projects probably have a negative social impact.

However, the assessment of the net impacts on the pipeline corridors is greatly complicated by the diverse interests of the various residents and the quite different social and economic impacts on them.

The Inuit would tend to gain from the main job-creating activities being in the Delta and adjoining areas, but they nevertheless fear the disruption to their traditional way of life and are concerned about the effectiveness of control measures.

The Métis would gain by their willingness to participate in pipeline development.

The Dene might participate in some of the unskilled and semi-skilled jobs during construction, but on balance the construction would have negative impacts since it would frustrate their attempt to develop their own institutions based on a renewable resource based economy and the operations phase would have little to offer the Dene. (It is assumed that all Northerners would directly or indirectly benefit through royalty and taxation income generated by hydrocarbon activities in the north).

Likewise, the Indian communities along the Alaska Highway would be adversely affected. However, they are fewer in number - about 3,000 inhabitants versus approximately 13,000 in the Mackenzie Valley corridor.

The white segments of society would, in the Board's view, gain from pipeline developments, particularly local businesses. Municipalities would welcome an opportunity to broaden their base and develop more services which economic development would make possible.

The territorial governments would benefit from the broadening of the economic base but with a concomitant requirement for increased and more diverse government services.

Comparing the Mackenzie Valley and Alaska Highway impact corridors, the Yukon has a more developed economic infrastructure, transportation network and business base which would enable it to handle the impact of a pipeline more easily; but the Yukon is more accessible and therefore more vulnerable to in-migration and the containment of construction would be more difficult. On the other hand, the native population which would be affected is smaller than in the Mackenzie Valley and has been in contact with modern society for a longer period commencing with the opening of the Alaska Highway. Furthermore, the Yukon Indians do not appear to be passing through the phase of a major restructuring of their society, as the Dene appear to be; the latter's transitional activities could be severely prejudiced by the construction of a pipeline. The Board concludes that the socio-economic impact on the pipeline corridors would on balance be more favourable along the Alaska Highway than in the Mackenzie Valley.

The major economic gain in the north would arise primarily from hydrocarbon development in the Mackenzie

Delta and related areas. This gain can only occur if the gas is connected to market and the Board has already indicated that it is desirable to do so if the socio-economic and environmental conditions of connecting it can be made acceptable. Since the adverse socio-economic impact of constructing a pipeline along the Mackenzie Valley at this time is of serious concern to the Board, it is necessary to examine in a preliminary way the socio-economic consequences of choosing instead a route through Dawson and a link from the Delta along the Dempster Highway to Dawson. Both the re-routing and the link would follow established highways. Only a small part of the land inhabited by the Dene would be involved, but there are important communities at Fort McPherson and Arctic Red River. In the Yukon, there are large native communities at Dawson, Stewart Crossing, Pelly Crossing and Carmacks. In total, the native population affected would be about 1,000 to 1,500 more than with the Alaska Highway route without a Dempster link. Nevertheless, the total native population impacted with a line through Dawson and a Dempster link would still be only about one-third that in the Mackenzie Valley. Also, the Dawson alternative has the potential for supplying natural gas to facilitate mining activities.

The Board finds that the potential adverse socio-economic impacts are less in the Yukon than in the Mackenzie Valley, and the economic benefits of the CAGPL and Foothills (Yukon) projects are probably about the same assuming a Dempster link were ultimately to become part of the latter.

The Board concludes that the social and economic impact of the Foothills (Yukon) project could be held to tolerable levels. It holds this view despite the fears expressed in the hearing that the problems of the socio-economic impact of Alyeska could be repeated in the Yukon, and despite the recognition that no conditioning of a certificate or monitoring system can be fully effective. The Board's assessment as indicated earlier is predicated on conditions to be incorporated into a certificate of public convenience and necessity, on undertakings given by the Applicant and its apparent willingness to translate socio-economic principles enunciated in the hearing into specific programs by the time of final design, on these programs being developed in co-operation with both the federal and territorial governments and local communities and organizations, and is influenced by the likely creation by the government of a new monitoring agency for socio-economic matters.

Turning first to the subject of payment of indirect costs by the Applicant, the Board believes that identifiable indirect costs of the project north of the 60th parallel should be borne by the pipeline companies. These costs would be many and varied whether related to in-migration, to transportation services, to additional crime and alcoholism problems, to social and health services, to inflationary impacts on the poorer segments of the community, to strains on municipal services or to costs incurred in mitigating the adverse impacts in communities in the pipeline corridor. These costs are difficult to measure with precision even after the fact, but even more so at this stage. While the amount cannot now be estimated with any degree of accuracy, the Board recognizes that the Applicant would want to know the upper limit of the obligation it might incur before financing can be completed. The Board, therefore, recommends that the upper limit be set at $200 million and recommends to the Governor in Council that before approval of a certificate is given, the Applicant enter into an agreement with the federal government to provide the funds to cover these costs. This fund would cover indirect costs for socio-economic impacts but would exclude costs of the monitoring authority.

In the hearing of a certificate application, the Board deals with and takes into account all relevant matters on a broad basis and these must be translated into specific programs for approval by the Board at the final design stage. Before these could be developed, it is clear that the Applicant would need to carry out further research and studies and would need to hold extensive discussions with the federal and territorial governments, as well as with all segments of the communities. It is, therefore, unreasonable at this time to begin to appraise the minutiae of the Applicant's programs but this would be done before authorizing construction.

On the need for a government agency to monitor socio-economic matters, this is a new and vital feature of pipeline construction and the Board strongly recommends that the government create immediately effective machinery for this purpose.

In this regard, the Board shares the view of Interdisciplinary Systems Ltd., as set forth in its Initial Environmental Evaluation of the Proposed Alaska Highway Gas Pipeline, Yukon Territory, dated May 1977, and filed as a public document at the hearing.

> "It was concluded from this preliminary review that much of the adverse social and economic impact which characterized construction of the Alyeska pipeline can be avoided in the Yukon with proper planning and controls. The pipeline project, while having considerable potential to adversely affect the Yukon, also presents a unique opportunity to improve the status quo."

> "To introduce a project of this size into the Yukon could strain all existing governmental services and control mechanisms beyond their breaking points. This would be brought about partly because of the influx of construction workers but more particularly because of the free access to the Territory by the Alaska Highway and to a lesser degree, the airports and landing strips. Therefore, the control mechanisms that will limit the impact on the human and animal environments will be the key to limiting environmental change to an acceptable degree. The procedures for implementing and integrating these controls into a comprehensive planning framework for both government and the applicant have not yet been developed."

In the Board's view, it would be essential that the central role in socio-economic monitoring be carried out by an agency of the government since the effects would be widespread and a number of territorial and federal government departments would be involved; but the Applicant would also have to play a major constructive and co-operative role. As stated previously, effective controls would have to be designed and installed before construction started so that the project could move smoothly on schedule to its completion. The Board is of the view that if this problem is tackled vigorously and immediately, there is adequate time to have in place an effective monitoring system within the time identified in the construction schedule. The Board assumes that this can be done and would be done. The monitoring authority would, in the Board's view, act in a complementary and co-operative manner with the Board in the exercise of the Board's statutory powers in all phases of construction.

Further views on the need for a monitoring authority are contained later in these Reasons for Decision, and the areas of concern which it is recommended be dealt with by the monitoring authority are contained in Chapter 5.

1.4.6 Environmental Impact

The Board recognizes that any project of the type and size of those proposed by CAGPL and Foothills would affect the environment. Some effects may be acceptable; those which are not may be broadly divided into two categories for the purpose of making environmental assessments. In the first category would be those impacts which could not be avoided, which could not be accepted, and for which mitigative measures are unknown or uncertain of development. In the second category would be those impacts which, though unacceptable or undesirable in the early stage of a project, could be avoided by reasonable changes in routes, plans and designs or mitigated by known or clearly developable measures.

Based on the evidence put before it, the Board has concluded that the CAGPL Prime Route, both the northern Yukon coastal and the Cross-Delta sections, would be environmentally unacceptable, having impacts of a type falling into the first category defined in the preceding paragraph. The main concerns underlying the environmental unacceptability of the northern section of the Prime Route are centered around the Porcupine caribou herd in the Yukon coastal area and the Beluga whales, snow geese and swans in Shallow Bay. These concerns are discussed elsewhere, but, in summary, the Board is not convinced that mitigative measures could adequately assure protection of this wildlife. The possibility of elimination or significant diminution of the numbers of these mammals and birds is too great a risk to accept if it can be avoided.

The CAGPL off-shore and Circum-Delta variations of the northern route segment would, at best, offer no significant advantages to offset the overriding concerns about the Prime Route, and consequently no further comment is necessary on these variations.

The CAGPL Interior Route would skirt the southern edge of Old Crow Flats, a 1500 square mile area noted for the density and variety of its wildlife population. The route would pass only about five miles north of the Old Crow settlement, well known for its social sensitivities and its firm stand against having a pipeline in that area. The evidence submitted by the Applicant was insufficient to enable the Board to make a finding that the Interior Route would be environmentally acceptable.

In the Board's view, the Mackenzie Valley corridor, which was proposed by CAGPL for part of its Prime Route and by Foothills for its project, would be environmentally acceptable for a pipeline, with concerns being totally within the second impact category; that is, capable of amelioration by avoidance or mitigative measures. Any certificate which might be issued for a pipeline in this corridor would have attached to it a comprehensive set of conditions relating to environmental restrictions and mitigative measures.

The most prominent feature of the Foothills (Yukon) proposed Alaska Highway route is its alignment generally along the existing highway transportation corridor. The

Board has concluded, as discussed in detail elsewhere, that the environmental concerns associated with this route relate to impacts which fall into the second category, that is, they can be overcome by avoidance or mitigative measures. The Board would condition any certificate which it might issue for a pipeline along this route to assure such avoidance and mitigation.

Having concluded that the proposed pipeline of the Foothills (Yukon) group along the Alaska Highway would be environmentally acceptable, the Board has had to consider with concern and care for Canadians the future need for a connection to that line, from the Delta, at either Whitehorse or Dawson. A connection at Dawson would entail a realignment of the currently proposed route of the Alaska Highway line. No application was made to the Board for a pipeline from the Delta to Dawson or Whitehorse, although Foothills did put in evidence the results of studies it had done on alternative means of connecting Delta gas to Canadian markets, including a Dempster link. Environmental information on such a link is sparse. In these circumstances, the important point to recognize at this time is that, in the Board's view, any certification of an Alaska Highway 48-inch diameter pipeline to initially transport United States gas should have associated with it an agreement to generate an application for a certificate to construct and operate a pipeline from the

Delta to connect with such 48-inch diameter pipeline. This in turn would necessitate that the realignment of the 48-inch diameter pipeline, the point of interconnection of the Dempster link and the related environmental impacts should receive immediate study with subsequent filing of the results of such studies.

Turning briefly to the sections of the proposed pipeline which would be located in British Columbia, Alberta or Saskatchewan, depending on the project certificated, the environmental considerations in these sections would be conventional. Based on the evidence, the conclusion of the Board is that any and all proposed routes south of the 60th parallel, while featuring advantages and disadvantages in various respects, are environmentally acceptable; any certificate the Board might issue would be fully conditioned to safeguard the environment.

1.4.7 Need for Monitoring Authority for this Project

Evidence was led in both this hearing and in the Berger Inquiry on the need for a government authority to facilitate the execution, control and monitoring of the project. It is therefore appropriate to express the Board's views on this subject.

The construction of a pipeline to connect Alaskan and Delta gas to markets is both similar to and different from previous pipeline projects in respect to government activities required to facilitate and monitor the project.

It is similar to other pipeline projects in the sense that the National Energy Board Act makes it mandatory for the Board to approve the design and to ensure that the pipeline is built safely, with minimum impact on the environment, and that all of the Board's regulations and requirements in these matters are complied with. In the discharge of its duties, the Board has on occasion relied on expert advice from departments of the federal government such as Environment and Agriculture and has had excellent co-operation from various provincial government departments.

On the other hand, the problems north of the 60th parallel are different in magnitude and in other respects. The environment is more fragile and the problems of construction due to climate and terrain are much greater. More importantly, the socio-economic impacts bring a new dimension to the problem. The Board has already referred to the need to provide preference to Northerners to work on the pipeline, to use southern hiring halls for other construction workers, to discourage access to the area by in-migrants and to fund indirect costs of the project to mitigate hardship on northern communities adversely affected by the pipeline. The sensitivity of issues related to land claims makes it imperative to have careful monitoring of project activities, construction in particular.

The broad issues relating to the provision and co-ordination of government services to facilitate project activities, to monitor the socio-economic impact of the project and to ensure that adverse socio-economic and environmental effects on the affected corridors north of the 60th parallel are minimized, appear to the Board to warrant special and urgent consideration. These matters may lie outside the Board's normal sphere of activities.

It is the Board's impression that most, if not all, of the required powers exist under present legislation. What would seem to be needed are Cabinet directives on the priorities to be attached to the work of the monitoring authority. The special and unusual circumstances dictate the establishment of the machinery for project co-ordination, probably under the newly-appointed Commissioner for Pipelines, and the establishment at a central location in the north of a staff of key federal and territorial government officials with the power to act. The Board, while carrying out its mandatory obligations under the National Energy Board Act in relation to design, engineering, safety, environmental and related responsibilities associated with the pipeline, its right-of-way, and related facilities, would co-operate with such an authority and would provide such assistance by representation, support staff or liaison as may be necessary. Such a huge and sensitive project would require not only the full support of the Applicant to mitigate adverse impacts, but also the co-ordinated capability of the federal and territorial governments. The Board, therefore, recommends that such an authority be created at an early date so that the responsibility for co-ordination could start concurrently with approval in principle by the Governor in Council of any pipeline which the Board may be prepared to certificate. In the Board's view, effective control would need to be established before the final design would be approved by the Board and construction permitted to begin. Leave to commence construction might be delayed until the effective monitoring system is in place.

1.5 DECISION

1.5.1 Preamble

As indicated earlier, the evidence of the native organizations before this Board was that resolution of the matter of land claims would take time and that any decision of the government to authorize pipelines in advance of an agreement in principle, final resolution and implementation of settlements would prejudice native land claims. The Board is fully appreciative of the views and representations of those directly concerned with native land claims and those who lent their support, and recognizes the importance to them of this issue. However, of equal importance and weight is whether the inability to conclude native land claim settlements should preclude a timely decision by Canada on questions of bringing Alaska and Canadian gas to markets, considering that many millions of individuals are involved throughout a large portion of the continent.

Any decision on these applications must be set in the context of reasonable energy objectives for Canada. The Board's views on several elements follow.

1. The Board strongly endorses vigorous conservation policies. There was growing support in the hearing by a number of public

interest groups for setting a target of a two per cent rate of growth in energy demand by about 1985,compared to achieving less than 3.5 per cent over the next ten years in An Energy Strategy for Canada, and the Board believes that a two per cent target,or something similar,could become a prime component of energy policy. However, at this time neither the federal nor provincial programs and legislation are fully in place to ensure that this will happen; neither is there an adequate, visible change in individual attitudes centered on avoiding wasteful use of energy. Therefore such a target at this time is uncertain of achievement and cannot be fully relied on in present planning for future energy supplies.

Secondly, if a target of a two per cent growth rate of primary energy were accepted, it is unclear what the appropriate growth rate should be for each individual fuel, taking into account those areas in end-use energy consumption where major conservation programs can be effected.

The Board notes that if a two per cent growth rate in natural gas were appropriate and could be achieved by 1985, then the need for a pipeline from the Mackenzie Delta might be able to be deferred until the late 1980's.

2. There is a surplus producibility of natural gas now in Alberta which, if it could be sold and delivered, would encourage exploration and development in that province thereby lifting the level of the deliverability curve over what it would otherwise be until certainly the late 1980's. At this time there is inadequate gas processing plant and pipeline gathering and transmission capacity to move the gas to market. As was clearly shown this past winter, the United States is suffering from a shortage of gas and will be until Prudhoe Bay gas is connected. By that time, Canada may have some difficulty in meeting its full export commitments from conventional sources of gas. Assuming, therefore, that Alaska gas is to be connected to markets by a land bridge through Canada, it could be

possible to pre-build some of the southern Canada and northern United States pipeline capacity to market gas which may be surplus to Canada's requirements in the late 1970's and early 1980's. This would require an "ironclad" guarantee that the gas would be replaced at a later date by Alaska gas dropped off in Canada, or alternatively by curtailing existing export commitments in later years to an equivalent extent. Either or both of these approaches could reduce the urgency of connecting Delta sources of supply. While there is an apparent reluctance of United States shippers of Canadian gas to accelerate their rate of take under existing export contracts, this may not be so once Alaska gas is committed to market under contract to specific shippers, and a time-table for connecting the gas to markets is assured.

Such a policy as outlined above, if adopted by the federal and Alberta governments, would further suggest that Delta gas may not need to be connected until about 1985.

3. Delta gas does appear to be one of the most economic new sources of energy to connect to market, and probably the most attractive one. In the Board's view, it will be needed by about the mid-1980's even if conservation policies are pursued vigorously. If very large discoveries of gas occur in the Mackenzie-Beaufort Basin in the near future they could be connected to markets via the Mackenzie Valley or, if the new discoveries were no greater than ~~25~~ 15 Tcf, it would probably be more economic to connect the gas via a Dempster link. It seems likely that the Foothills (Yukon) project could be constructed and in operation before construction of a Dempster link need begin. This would have the dual advantage of using the construction experience of Foothills (Yukon) and using the financial strength of Foothills (Yukon) when it is in operation to reduce the financial burden of a Dempster link. However, if the delay in the connection of Delta gas were lengthy, producer activities in the Delta and Beaufort Sea areas would evaporate quickly,

the 2,000 or so jobs in the Delta and vicinity which offer the only large and significant employment opportunities for native Northerners would also disappear, and small businesses in the North would languish. Also, a source of known supply for Canadian markets would be needlessly locked in.

1.5.2 Decision

In arriving at its decision, the Board has weighed very carefully all evidence adduced, and has taken into account all matters which to it appeared to be relevant.

The Board finds that the Foothills pipeline cannot be financed, that it is not economically justified, that it is not the lowest cost alternative available, that a pipeline should not be built along the Mackenzie Valley at this time, that this Applicant has asked for a decision to be deferred, and that there is no clear indication if and when sufficient reserves will be found to make the pipeline viable.

The Board finds that the CAGPL project is based on incompatible time constraints; on the one hand the urgent need to connect Alaska gas to United States markets, and on the other, the need for more time to resolve socio-economic concerns before a pipeline could be built along the Mackenzie Valley. In addition, the Prime Route of the pipeline along the coast of the northern Yukon is environmentally unacceptable to the Board, as is the Cross-Delta section of that route. The Interior Route would skirt the environmentally sensitive Old Crow Flats, and would pass near socially sensitive Old Crow itself. On the evidence before it, and having regard to all relevant matters taken into account, including particularly the environmental and socio-economic problems, the Board is not satisfied that a certificate should be issued.

In respect of the Foothills (Yukon) project, although further engineering design, environmental and socio-economic information is to be filed prior to approval of final design, on the evidence the Board finds that it offers the generally preferred route for moving Alaska gas. In coming to this conclusion, the Board was mindful of the stage of negotiation of land claim settlements and that the time frame in which construction would proceed differs from that proposed by the Council for Yukon Indians. The Board recognizes that special measures to mitigate undesirable impacts on native communities will have to be implemented. It believes these problems are soluble.

A crucial question in regard to any land bridge proposal for the transmission of United States gas through Canada is whether the project has the potential, with some degree of certainty, for bringing Canadian gas from the north to Canadian markets. The Foothills (Yukon) project has such potential in the form of a Dempster link. The precise timing of such a connection, and the socio-economic and environmental issues involved, are not matters which can now be dealt with. However, the fact that Canadian gas needs could require such a connection in the near future must be realistically taken into account now by those involved in the design, routing and financing of the Alaska Highway project. Therefore, the planning of that project as it develops today should be compatible in all respects with the addition of a Dempster link if certificated in the near future.

In the vein of the foregoing remarks, the potential Canadian need for a Dempster link creates a current need to consider a realignment through Dawson of the Foothills (Yukon) pipeline to ensure and to facilitate a more economic transmission of Delta gas to Canadian markets. The principals in the Foothills (Yukon) project are on record in the hearing as willing to undertake construction of a Dempster link should it be required and duly certificated by the Board. A logical, indeed a necessary complement to such undertakings, would seem to be a re-routing of the Alaska Highway line via Dawson. Northwest Pipeline, the United States co-sponsor of the Alaska Highway project, stated in argument, "A possible modification can be made, if determined to be in Canada's interests, by moving the line up to Dawson City, thus providing a closer connection for Delta gas".

The Dawson diversion would appear to be clearly in the Canadian interest. It would reduce the cost of transportation of Delta gas by about 12 cents per Mcf, which may be critical to the economic viability of the Delta gas plants and would only increase the cost of Prudhoe Bay gas by six cents or less compared with the Foothills (Yukon) project without the Dempster link, and the six cents per Mcf is small compared with the additional 30 cents (unescalated) estimated by the FPC if the El Paso project were selected.

Environmentally, the route would be in an existing transportation corridor and would avoid skirting the sensitive Kluane National Park and avoid the Shakwak Fault. From a socio-economic viewpoint, about a thousand more native inhabitants would be affected and additional mitigative measures may be needed. The diversion would bring a major new source of energy at reasonable prices to the mining activities in the vicinity of the Klondike Highway. Recognizing that the amount of engineering design work and environmental and socio-economic studies and planning needed to meet final design requirements on the Alaska Highway route would be substantial in any case, it is the Board's opinion that the Dawson diversion would not significantly alter the existing proposal or the construction schedule.

On the basis of the information now available to the Board, the Dawson diversion is, in the Board's opinion, preferred. Accordingly, the Board would condition a certificate to Foothills (Yukon) to require that the route of the said pipeline within Canada be that route as more particularly described in the said application, except that, and subject to further direction of the Board, commencing at the international boundary between the United States and Canada in the vicinity of Boundary, Alaska, the pipeline route shall proceed in an easterly direction along Highway 3, or as close thereto as practicable, to the City of Dawson in the Yukon Territory, from which point the pipeline shall proceed in a southeasterly direction along the Klondike Highway, or as close thereto as practicable, to the vicinity of the junction of the Klondike and Alaska Highways near the City of Whitehorse in the said Territory.

As a condition of a certificate the Board would require that the Applicant's commitment to carry out additional socio-economic and environmental studies be expanded to include studies of these aspects for the Dawson realignment. Before making a ruling on final route location, the Board would provide an opportunity for input of interested parties.

Turning now to southeastern British Columbia, the Board finds it preferable for ANG to construct the pipeline in that area, rather than Westcoast.

The Board dealt with proposed changes in corporate structure and organization of the Applicants for the sections of the pipeline project in Canada. The Board will recommend to the Governor in Council that approval to the issuance of certificates not be given until the Governor in Council is advised by the Board, by 26 August 1977, that appropriate amendments to existing applications have been filed as follows:

(a) for the issuance of a certificate for the Alberta section in the name of a federally incorporated subsidiary of Foothills (Yukon) in which 51 per cent of all issued and outstanding voting shares will be held by Foothills (Yukon) and the remaining 49 per cent by Trunk Line;

(b) for the issuance of a certificate for the section in British Columbia applied for by Westcoast (other than the southeast section more particularly dealt with in subsection (c)) in the name of a federally incorporated subsidiary of Foothills (Yukon) in which 51 per cent of all issued and outstanding voting shares will be held by Foothills (Yukon) and the remaining 49 per cent by Westcoast;

(c) for the issuance of a certificate for the portion of the pipeline in southeastern British Columbia extending from the Alberta border to Kingsgate, ANG shall have the right on or before 26 August 1977, to file with the Board an amendment to its application for the construction of that section of the pipeline by a federally incorporated company, of which

51 per cent of the issued and outstanding voting shares shall be held by Foothills (Yukon) and 49 per cent by ANG, failing which, or if such company is not so certificated, that section of the pipeline in southeastern British Columbia shall be certificated to the company certificated for the remaining portion of the pipeline project in British Columbia;

(d) for the issuance of separate certificates to Foothills (Yukon) for the sections of the pipeline in the Yukon Territories and in Saskatchewan.

Upon application, the Board will consider submissions for variations to the proposed corporate restructuring set forth in (a), (b), (c) and (d) above, which achieve similar objectives and, if approved, appropriate amendments may be made.

Subject to the foregoing, the Board will, by supplement, advise the Governor in Council of the names of the corporate entities and of the location of the section of pipeline project to be included in a certificate.

The Board will recommend to the Governor in Council that before approval of a certificate of public convenience and necessity, Foothills (Yukon) be required to enter into an agreement with the Government of Canada whereby it will undertake, inter alia, an immediate feasibility study of a Dempster link to Dawson for the transmission of Delta gas. Such agreement should provide for the filing of applications, on or before 1 July 1979, or such later date as may be acceptable to the government. It should be further provided that, once a certificate of public convenience and necessity is issued, construction should proceed in a timely manner. If, in line with the corporate organization and structure previously recommended in this report in relation to other parts of the system, a subsidiary is created, the application could be made and construction and operation carried out, by such subsidiary. This does not preclude the filing of applications by others.

In addition, by another agreement Foothills (Yukon) and its subsidiaries should undertake to provide capacity to transport Delta gas to interconnecting pipeline facilities.

Unless a certificate for the Dempster link is denied, these agreements should extend for a period of ten years from the date of issue by the Board of a certificate to Foothills (Yukon) for the construction of its 48-inch O.D. line and provide for requisite assurances, safeguards and monetary deposits or undertakings in a form satisfactory to the government for due performance and observance of the terms of the agreement.

Subject to the disposition of the Board's recommendations to the Governor in Council and to the corporate reorganization and the filing of amendments to the applications within the time prescribed, and subject also to the conditions to be attached to the certificates, the Board, having taken into account all matters that to it appear to be relevant, is satisfied that the Foothills (Yukon) project is and will be required by the present and future public convenience and necessity.

The Board is not satisfied that the pipeline for which CAGPL sought a certificate is and will be required by the present and future public convenience and necessity and the application is denied.

The Board is not satisfied that the pipeline for which Foothills, Westcoast, and Trunk Line (Canada) sought certificates for their respective portions of the Foothills project, is and will be required by the present and future public convenience and necessity and the applications are denied.

1.5.3 Recommendations to the Governor in Council

Should the Governor in Council see fit to approve the issuance of a certificate of public convenience and necessity pursuant to section 44 of the National Energy

Board Act to Foothills Pipe Lines (Yukon) Ltd. and to corporate entities to be organized in conformity with the Board's recommendation or as may otherwise be approved by this Board, the Board recommends to Your Excellency in Council that approval of the certificate be withheld until Foothills Pipe Lines (Yukon) Ltd. enters into binding agreements with the Government of Canada, which agreements would require, inter alia, the following to be done:

First Agreement

(a) Foothills (Yukon) or any successor company to conduct feasibility studies with respect to the construction of a natural gas pipeline of no less than 30-inch diameter from the Mackenzie Delta area parallel to the Dempster Highway connecting Delta gas to the Foothills (Yukon) mainline at Dawson City in the Yukon Territory - "the Dempster link".

(b) On or before 1 July 1979, or such later date as may be approved by the Government of Canada, Foothills (Yukon) or a subsidiary thereof to make or cause an application to be made to the National

Energy Board for a certificate of public convenience and necessity to authorize construction of a pipeline generally along the route of the Dempster Highway and to file all information and material required by the provisions of the NEB Act and directives of the Board, and if such certificate is issued to forthwith thereafter and in a timely manner construct and operate such a pipeline.

Second Agreement

Foothills (Yukon) or any subsidiary or successor company to undertake to provide in the 48-inch diameter pipeline operated by them for the transmission of Alaska gas to United States markets, throughput capacity in such quantity as the Government of Canada may require but not, in any event, to exeeed 1.2 Bcf per day for the transportation of Delta gas from the point of intersection of a Dempster link to such point or points in Canada as the Government of Canada may deem necessary to effect delivery of such Delta gas to southern markets in Canada, such capacity to be provided, if required, by 1 January 1984 or at such later date as the Government of Canada deems necessary.

Third Agreement

Foothills (Yukon) to pay or provide payment, upon request by the Government of Canada, of moneys which would be used by the Government of Canada to pay for the socio-economic indirect costs of the pipeline project in the area north of the 60th parallel incurred during a period expiring two years after a "leave to open" order has been granted, the scope of such indirect costs to be defined. The Government of Canada should use the moneys toward payment of social and economic costs generally attributable to the pipeline project. While the Board cannot now estimate the amounts involved, the project would otherwise burden Canadian taxpayers with substantial expenditures. The Board recommends that the obligation of the Applicant be limited to $200 million.

The Third Agreement does not encompass the costs of the monitoring authority, which should be a matter for separate consideration.

This Board has dealt with proposed changes of corporate structure and organization of the Applicants for the sections of the pipeline project in Canada. The Board therefore recommends to Your Excellency in Council that approval of certificates be withheld until appropriate amendments to existing applications are made on or before 26 August 1977, as follows:

(a) for the issuance of a certificate for the Alberta section in the name of a federally incorporated subsidiary of Foothills (Yukon) in which 51 per cent of all issued and outstanding voting shares will be held by Foothills (Yukon) and the remaining 49 per cent by Trunk Line;

(b) for the issuance of a certificate for the section in British Columbia applied for by Westcoast (other than the south-east section more particularly dealt with in subsection (c)) in the name of a federally incorporated subsidiary of Foothills (Yukon) in which 51 per cent of all issued and outstanding voting shares will be held by Foothills (Yukon) and the remaining 49 per cent by Westcoast;

(c) for the issuance of a certificate for the portion of the pipeline in south-eastern British Columbia extending from the Alberta border to Kingsgate. ANG shall have the right on or before 26 August 1977, to file with the Board an amendment to its application for the construction of that section of the pipeline by a federally incorporated company, of which 51 per cent of the issued and outstanding voting shares shall be held by Foothills (Yukon) and 49 per cent by ANG, failing which, or if such company is not so certificated, that section of the pipeline in south-eastern British Columbia shall be certificated to the company certificated for the remaining portion of the pipeline project in British Columbia;

(d) for the issuance of separate certificates to Foothills (Yukon) for the sections of the pipeline in the Yukon Territories and in Saskatchewan.

Upon application, the Board will consider submissions for variations to the proposed corporate restructuring set forth in (a), (b), (c) and (d) above, which achieve similar objectives and, if approved, appropriate amendments may be made.

Subject to the foregoing, the Board will, by supplement, advise Your Excellency in Council of the names of the corporate entities and of the location of the section of pipeline project to be included in a certificate.

1.5.4 Certificate Conditions

The general terms and conditions set forth hereafter apply, except as otherwise noted, to each certificate which the Board is prepared to issue. Directions as to the Board's detailed requirements for specific sections of certificated pipeline will be set forth in orders of the Board. Many of these orders will be issued upon certification; others will issue from time to time to implement the certificate conditions during the design, construction, pre-operational and operational phases of the project.

1. The pipeline respecting which the certificate is issued shall be the property of and shall be operated by the Company.

2. The Company shall cause the pipeline in respect of which this certificate is issued, to be designed, manufactured, located, constructed, installed and operated in accordance with those specifications, drawings and other information or data, including those relating to environmental and agricultural concerns, as set forth in the application, as amended, and given as undertakings during the Hearing, or as ordered, directed or approved, from time to time, by the Board with respect to the design, construction, pre-operational and operational phases of the project.

3. Without limiting the generality of Condition 2 the Company:

   (a) shall submit information satisfactory to the Board in support of final design, including the results of field tests and experiments and analyses thereof;

   (b) shall submit the final design of each portion of the pipeline to the Board for its approval, and shall not commence construction of such portion until approval is received;

   (c) shall provide, before construction commences, detailed construction specifications and procedures and inspection procedures satisfactory to the Board, and

   (d) shall provide, before operation commences, an operations and safety manual satisfactory to the Board.

4. The Company shall not vary specifications, drawings, other information or data, including those relating to environmental and agricultural concerns, and as ordered or directed pursuant to Condition 2 hereof, without the prior approval of the Board.

5. Forthwith upon execution, the Company shall file with the Board definitive contracts between producers and

shippers and between shippers and the Company, and substantive amendments thereto upon execution.

6. The Company shall, before the commencement of construction, file with the Board all documents establishing that financing has been obtained for the project. Such filing shall include all relevant contracts and instruments and evidence that:

   (i) voting control shall be exercised by Canadian citizens, landed immigrants, and/or by companies with over 50 per cent of their voting shares owned by Canadians and/or by companies controlled in Canada, and

   (ii) that all debt instruments issued by the Company and subsidiaries shall contain no provision prohibiting, limiting or inhibiting the financing of a Dempster link.

   Construction of the pipeline shall not be commenced until the Company has established to the satisfaction of the Board that financing has been obtained for the project.

7. Before the commencement of construction the Company shall submit to the Board, for its approval, contracts and undertakings relating to payments by shippers of

charges to be made prior to the commencement of the tariff, and when approved, such contracts or undertakings shall not be amended or supplemented without the prior approval of the Board.

8. The Company shall provide, in a form satisfactory to the Board, monthly information on the costs incurred and projected, financing and the progress of the project.

9. The Board shall have access to all financial records during construction, for audit purposes.

10. In respect to Canadian content:-

    (1) The Company shall so design its program for the procurement of goods and services for the project to assure that:

        (a) Canadians have a fair and competitive opportunity to participate in all facets of the project;

        (b) the level of Canadian content is optimized, so far as practicable, with respect to the origin of products, services, and their constituent components;

        (c) maximum advantage is taken of opportunities provided by the project to establish and expand supplier firms in Canada; and

(d) maximum advantage is taken of opportunities provided by the project to foster research and development and technological activities in Canada.

(2) The Company shall submit to the Board for its approval a report specifying the proposed contractual and purchasing arrangements for procuring goods and services for the project, such report to respond, in a manner to be detailed by the Board, to the requirements set forth in subsection (1) hereof.

(3) The report referred to in subsection (2) hereof shall be submitted not later than 1 January 1978 or such other date as the Board, upon application to it, may fix.

(4) Unless otherwise amended and approved, the report referred to in subsection (2) hereof, approved by the Board, shall constitute the Company's approved procurement policy and procedures.

(5) Prior to the filing and approval of the policy and procedures report referred to in subsection (4) hereof, the Company's major purchases and contractual commitments to purchase shall be subject to the approval of the Board.

11. The Company shall comply with its undertakings, in respect of socio-economic matters, contained in its application, as amended, and given in evidence during the Hearing, including those set forth in Appendix 5-2 of these Reasons.

12. The Company or its successor shall, prior to the approval of the final design of the pipeline, submit to the Board for its approval, the results of all further socio-economic and environmental studies in compliance with undertakings at the Hearing.

13. Prior to final design approval, for each portion of the pipeline the Company shall submit to the Board the recommendations of its environmental consultants for the protection of farm lands and the environment.

14. Pursuant to its undertaking, Foothills (Yukon) shall:
    (a) construct, if required, laterals from the pipeline to communities in the Yukon which can be economically served and have applied to the appropriate authority for such service, and,
    (b) make arrangements for the supply of such gas.

15. Forthwith upon execution, the Company shall file with the Board all contracts between the Company and the principal construction contractors, and all substantive amendments thereto.

16. The Company, having due regard to the importance of avoiding construction work stoppages, shall file with the Board labour union contracts pertaining to the project.

17. Foothills (Yukon) shall file labour union contracts with the Board which shall be responsive to:

    (a) avoiding work stoppages during construction of the project;

    (b) hiring preference to be given to Northerners; the term "Northerner" as defined by the federal government; and

    (c) the use of hiring halls south of the 60th parallel for hiring other than Northerners.

18. The Company shall file with the Board the contracts for the purchase of pipe, and any amendments thereto.

19. The Company shall provide the Board, prior to commencing construction, with proof of having obtained all regulatory approvals, including:

(a) right-of-way permits for Crown lands;

(b) export/import authorizations for Alaska gas, incorporating arrangements for the supply of such gas to Yukon communities and its replacement with Canadian gas;

(c) requisite United States federal and other regulatory approvals, including those affecting tariffs and rates.

20. The route of the said pipeline within Canada shall be that route as more particularly described in the said application, except that, and subject to further direction of the Board, commencing at the international boundary between the United States and Canada in the vicinity of Boundary, Alaska, the pipeline route shall proceed in an easterly direction along Highway 3, or as close thereto as practicable, to the City of Dawson in the Yukon Territory, from which point the pipeline shall proceed in a southeasterly direction along the Klondike Highway, or as close thereto as practicable, to the vicinity of the junction of the Klondike and Alaska Highways near the City of Whitehorse in the said Territory.

21. Foothills Pipe Lines (Yukon) Ltd. shall, not later than 1 January 1978, or such other date as the Board, upon application to it, may fix, prepare and file with the Board with respect to the Dawson realignment defined in Condition 20:

(a) details of design, route location, compressor station sites necessary and requisite for such route;

(b) particulars of cost and financing;

(c) an assessment of the probable environmental impact of the pipeline, including a description of the existing environment in the defined area and a statement of the measures proposed to mitigate such impact;

(d) an assessment of the probable socio-economic impact of the pipeline in the defined area and a statement of the measures proposed to be taken with respect to such impact.

Subject to all of the foregoing, the Board is prepared to issue certificates of public convenience and necessity to Foothills (Yukon), and its subsidiaries.

J. G. Stabback

J.G. Stabback,
Vice-Chairman

C. G. Edge

C. Geoffrey Edge,
Associate Vice-Chairman

R.F. Brooks,
Member

NATIONAL ENERGY BOARD — CANADA — OFFICE NATIONAL DE L'ÉNERGIE

GH-1-76

IN THE MATTER OF the National Energy Board Act;

AND IN THE MATTER OF an application by Canadian Arctic Gas Pipeline Limited for a certificate of public convenience and necessity for the construction and operation of a natural gas pipeline, under File No. 1555-C46-1;

AND IN THE MATTER OF applications by Foothills Pipe Lines Ltd., Westcoast Transmission Company Limited and the Alberta Gas Trunk Line (Canada) Limited for certificates of public convenience and necessity for the construction and operation of certain natural gas pipelines, under File Nos. 1555-F2-3, 1555-W5-49 and 1555-W5-49 and 1555-A34-1;

AND IN THE MATTER OF an application by Alberta Natural Gas Company Ltd. for a certificate of public convenience and necessity for the construction and operation of certain extensions to its natural gas pipeline, under File No. 1555-A2-10;

AND IN THE MATTER OF a submission by The Alberta Gas Trunk Line Company Limited, under File No. 1555-A5-2.

B E F O R E:

J.G. Stabback	)	
C.G. Edge	)	
	)	On Friday, the 19th day of
R.F. Brooks	)	March, 1976.
	)	

UPON Canadian Arctic Gas Pipeline Limited, hereinafter referred to as "CAGPL", having filed with the Board,

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an application which was subsequently amended for "a certificate of public convenience and necessity to construct a pipeline and works connected therewith" dated March 21, 1974, and in support of its application, having filed material dated March 21, 1974, and supplementary material, and the Board, upon considering the application and the material just described and having issued deficiency letters (hereinafter more particularly dealt with) and subject to responses received and to be received thereto and to other deficiency letters which may hereinafter be issued, all of which, that is to say, the application, the material supporting the application, the deficiency letters, responses thereto, any additional information which may be received and any amendments to any of them, hereinafter shall be referred to collectively as the "CAGPL application";

AND UPON IT APPEARING THAT the CAGPL application as amended is for the purpose of obtaining a certificate of public convenience and necessity to construct a pipeline and works to move natural gas found, *inter alia*, in the Mackenzie River Delta and Beaufort Basin area of Canada's Northwest Territories to markets in Southern Canada and as well to move natural gas found in the State of Alaska, United States of America to markets in others of the United States;

AND UPON; Foothills Pipe Lines Ltd., hereinafter referred to as "Foothills", having filed with the Board, an application for "a certificate of public convenience and necessity to construct and operate said natural gas pipeline and certain works and facilities connected therewith and incidental thereto" dated March, 1975, and in support of its application having filed supplementary material;

Westcoast Transmission Company Limited, hereinafter referred to as "Westcoast", having filed with the Board an application for "a certificiate of public convenience and necessity pursuant to Part III of the said statute" dated April 1, 1975;

The Alberta Gas Trunk Line (Canada) Limited, hereinafter referred to as "Trunk Line (Canada)", having filed with the Board an application for "a certificate of public convenience and necessity to construct and operate the said natural gas pipeline" dated May, 1975, and in support of its application having filed supplementary material;

The Alberta Gas Trunk Line Company Limited, hereinafter referred to as "Trunk Line", having filed a submission dated May, 1975, and in support of its submission having filed supplementary material;

The Board upon considering the applications and material just described and having issued deficiency letters (hereinafter more particularly dealt with) and subject to responses received and to be received thereto and to other deficiency letters which may hereinafter be issued, all of which, that is to say, the applications of Foothills, Westcoast and Trunk Line Canada and supplementary material, the submission of Trunk Line and material supplementing the submission, the deficiency letters, the responses thereto, and any additional information which may be received and any amendments to any of them, hereinafter shall be referred to collectively as the "Foothills Group application";

AND UPON IT APPEARING THAT Foothills, Westcoast, Trunk Line Canada, all of which hereinafter will be referred to collectively as the "Foothills Group" are applicants for certificates of public convenience and necessity to construct pipelines and works to move natural gas found in, inter alia, the Mackenzie River Delta and Beaufort Basin area of Canada's Northwest Territories to markets in Southern Canada;

AND UPON Alberta Natural Gas Company Ltd., hereinafter referred to as "Alberta Natural", having filed with the Board an application for "a certificate, or certificates, of public convenience in respect of the pipeline and facilities described in paragraph 6 thereof", and in support of its appplication having filed supplementary material and which said application was subsequently amended, and the Board, having considered the application, as amended, and the material just described and having issued deficiency letters (hereinafter more particularly dealt with) and subject to responses received and to be received thereto and to other deficiency letters which may hereinafter be issued, all of which, that is to say, the application, as amended, the deficiency letters and the responses thereto, and any additional information which may be received and any amendments to any of them, hereinafter shall be referred to collectively as the "Alberta Natural application";

AND UPON it appearing that Alberta Natural is an applicant for a certificate of public convenience and necessity to construct extensions to its pipeline and works to move natural gas found, *inter alia*, in the State of Alaska, in the United States of America, and in the Mackenzie River Delta and Beaufort Basin area of Canada's Northwest Territories and delivered to it at a point at or near the Town of Coleman, in the Province of Alberta, to interconnecting pipelines and works in the State of Washington, in the United States, for ultimate delivery to markets in the State of California, in the United States;

AND UPON it appearing to the Board that the issues to be determined in hearing the CAGPL application, the Foothills Group application and the Alberta Natural application are of great national importance, of great complexity and of great interest to all Canadians including bodies politic, communities, bodies corporate and associations;

Wherever in this Order, the terms Foothills, Foothills Group or Foothills Group application are used, they shall include and be deemed to include the submission of Trunk Line.

IT IS THEREFORE ORDERED THAT

1. This order may be cited as the Mackenzie Valley Pipeline Hearing Order.

2. The foregoing applications and submission shall be heard together in the Hearing Room of the National Energy Board, room 940, Trebla Building, 473 Albert Street, in the City of Ottawa, in the Province of Ontario, commencing on Monday, the 12th day of April 1976, at the hour of 9:00 a.m. local time and at such other locations in the Northwest Territories and such other places as the Board may direct on dates, at times and at locations to be announced by further Board Order.

3. CAGPL, Foothills, Trunk Line (Canada), Westcoast and Alberta Natural shall arrange among them to have the notice of hearing set forth in Appendix 3 published not later than the 30th day of March, 1976, or so soon thereafter as may be practicable in one issue each of the "Times" and the "Colonist" in the City of Victoria, the "Province" and the "Sun" in the City of Vancouver, all in the Province of British Columbia; the "Albertan" and the "Herald" in the City of Calgary, the "Journal" in the City of Edmonton, the "Herald" in the City of Lethbridge, all in the province of Alberta; the "Leader-Post" in the City of Regina, the "Star-Phoenix" in the City of Saskatoon, both in the Province of Saskatchewan; the "Free Press" and the "Tribune" in the City of Winnipeg, the "Sun" in the City of Brandon, all in the Province of Manitoba; "The Spectator" in the City of Hamilton, the "Miner and News" in the City of Kenora, the "Free Press" in the City of London, the "Nugget" in the City of North Bay, the "Citizen"", "Le Droit" and the "Journal"

in the City of Ottawa, the "Observer" in the City of Sarnia, the "Chronicle Journal" and the "Times News" in the City of Thunder Bay, the "Globe and Mail", the "Star" and the "Financial Post" in the City of Toronto, the "Star" in the City of Windsor, all in the Province of Ontario; "Le Devoir", the "Gazette", "La Presse" and the "Star" in the City of Montreal, "Le Soleil" and the "Chronicle-Telegraph" in the City of Québec, both in the Province of Québec; the "Telegraph Journal" in the City of Saint John, the "Gleaner" in the City of Fredericton and the "Transcript" in the City of Moncton, all in the Province of New Brunswick; the "Chronicle Herald" and the "Mail Star" in the City of Halifax, in the Province of Nova Scotia; the "Guardian" in the City of Charlottetown, in the Province of Prince Edward Island; the "Telegram" in the City of St. John's, in the Province of Newfoundland; the "News of the North" in the Town of Yellowknife, the "Drum" in the Town of Inuvik, the "Hub" in the Town of Hay River, all in the Northwest Territories; the "Star" and the "Yukon News" in the Town of Whitehorse, in the Yukon Territory; and as soon as possible in the Canada Gazette.

4. CAGPL, Foothills, Trunk Line (Canada), Westcoast and Alberta Natural shall arrange among them to forthwith give notice of the hearing by service of a true copy of this Order upon the Attorneys-General of the Provinces of British

Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland, the Commissioner of the Northwest Territories, the Commissioner of the Yukon Territory, the British Columbia Energy Commission, the Energy Resources Conservation Board of Alberta, the Oil and Gas Conservation Board of Saskatchewan, the Oil and Natural Gas Conservation Board of Manitoba, the Ontario Energy Board and Régie de l'Electricité et du Gaz du Québec.

5. CAGPL, Foothills, Trunk Line (Canada), Westcoast and Alberta Natural shall arrange among them to forthwith give notice of the hearing to those persons whose names appear in Appendix 2 of this Order, by service upon them of a true copy of the hearing notice which appears as Appendix 3 to this Order.

6. Any person in addition to those whose names appear in Appendix 2, who intends to oppose or intervene in the CAGPL application, the Foothills Group application or the Alberta Natural application or in any of the component applications to the Foothills Group application shall file with the Secretary on or before 30 April 1976, thirty copies of a written statement.

7. Every written statement of those hereafter intervening shall be signed by the person or his solicitor and in each case,

(a) shall contain a concise statement of the facts from which the nature of each such party's interest in the CAGPL application, the Foothills Group application or the Alberta Natural application may be determined,

(b) shall contain a concise statement of whether each such party supports or opposes either the CAGPL application, the Foothills Group application or the Alberta Natural application, or whether he supports or opposes any proposal to move natural gas found in the State of Alaska or in the Mackenzie River Delta and Beaufort Basin area to markets in Southern Canada, or in the United States of America, or of whether he takes any other position,

(c) may admit or deny any or all of the facts alleged in any of the material contained in the CAGPL application, the Foothills Group application or the Alberta Natural application.

8. Any objections to the form or content of this Order shall be made forthwith at the opening of this hearing.

9. The deficiency letters referred to in the form and on the dates set forth in Appendix 4 are issued and deemed to be issued in the same form pursuant to this Order and responses previously filed, unless amended, shall be deemed to have been received pursuant to this Order and served on all interested persons whose names appear in Appendix 2 and shall be served on all persons who shall hereafter be declared interested parties.

10. All direct evidence, to be prepared in written question and answer form, upon which CAGPL and Foothills will rely in phases 1A and 1B as set out in Appendix 1 shall be filed with the Board, in respect of phase 1A, on or before 7 April 1976, and in respect of phase 1B, on or before 7 May 1976.

11. Appendices 1, 2, 3 and 4 attached hereto form part of this Order.

12. The grouping of issues, procedures and rules to be followed in connection with the hearing shall, be in addition to any other relevant rule of law and subject to further amendment, be those set forth in Appendix 1.

13. Subject to a further Order of the Board, upon the receipt of further interventions pursuant to paragraph 6 of this Order or otherwise, the persons whose names appear on the order of appearances and sequence of cross-examination set forth in Appendix 2 shall be the persons who are interested persons for the purposes of section 45 of the Act.

14. In this Order

"Alaska gas" means gas from pools in the Prudhoe Bay area of the State of Alaska, United States of America;

"Alberta Natural" means Alberta Natural Gas Company Ltd.;

"Act" means the National Energy Board Act;

"Board" means the National Energy Board;

"CAGPL" means Canadian Arctic Gas Pipeline Limited;

"Foothills" means Foothills Pipe Lines Ltd.

"hearing" means the public hearing at which the applications of CAGPL, Foothills, Trunk Line (Canada), Westcoast and Alberta Natural will be heard together by the Board;

"Mackenzie Delta gas" means gas from pools in the Mackenzie River Delta and Beaufort Basin area of Canada's Northwest Territories;

"pre-hearing conference" means the conference held pursuant to Order GH-2-75, in the City of Ottawa on July 8th and 9th, 1975; presided over by Board Counsel as officers of the Board;

"policy witness" includes a witness presented by an applicant or other party to answer questions about the planning and management of its affairs as they relate to subject matter of the hearing;

"public documents" includes past reports, decisions and transcripts of hearings before the Board, the Energy Resources Conservation Board of Alberta, the Ontario Energy Board, the Québec Gas and Electricity Board, the British Columbia Energy Commission, independent inquiries and the United States Federal Power Commission and publications of the British Columbia Department of Mines and Petroleum Resources, the Saskatchewan Department of Energy and Natural Resources, the Manitoba Department of Mines, Resources and Environment Management, the Ontario Ministry of Energy and the Québec Ministry of Natural Resources;

"TransCanada" means TransCanada PipeLines Limited;

"Trunk Line" means the Alberta Gas Trunk Line Company Limited;

"Trunk Line (Canada)" means The Alberta Gas Trunk Line (Canada) Limited;

"Westcoast" means Westcoast Transmission Company Limited.

15. Any interested party may examine a copy of the applications and the submissions filed therewith at the office of the

National Energy Board
Trebla Building
473 Albert Street
OTTAWA, Ontario
K1A OE5

and

with respect to the CAGPL application at the following addresses:

Messrs. Russell & DuMoulin
Barristers and Solicitors
17th Floor, MacMillan Bloedel Bldg.
1075 West Georgia Street
VANCOUVER, British Columbia
V6E 3G2

or

Mr. H.A. Macdonell, Q.C.
Canadian Arctic Gas Pipeline Limited
P.O. Box 139
Commerce Court, Postal Code
TORONTO, Ontario
M5L 1E2

or

MacLeod Dixon
Barristers & Solicitors
555 Bentall Building
444 - 7th Avenue S.W.
CALGARY, Alberta
T2P OY1

or

Mr. D.G. Gibson
Canadian Arctic Gas Pipeline Limited
Suite 403
60 Queen Street
Ottawa, Ontario
K19 5Y7

and

with respect to the Foothills application at the following address:

Foothills Pipe Lines Ltd.
1600 Bow Valley Square 11
205 - 5th Avenue S.W.
CALGARY, Alberta
T2P 2W4

and

with respect to the Alberta Natural application at the following address:

Alberta Natural Gas Company Ltd.
Alberta and Southern Building
240 - 4th Avenue S.W.
CALGARY, Alberta
T2P OH5

and

with respect to the Trunk Line (Canada) application and Trunk Line submission at the following address:

The Alberta Gas Trunk Line (Canada) Limited
505 Second Street S.W.
CALGARY, Alberta
T2P 2N6

and

with respect to the Westcoast application at the following address:

Westcoast Transmission Company Limited
1333 West Georgia Street
VANCOUVER, British Columbia
V6E 3K9

Dated at the City of Ottawa, in the Province of Ontario, this 19th day of March, 1976.

NATIONAL ENERGY BOARD

B.H. Whittle

Brian H. Whittle
Acting Secretary

APPENDIX 1

RULES OF PROCEDURE
AND OTHER MATTERS
RELEVANT TO THE HEARING.

1. GROUPING OF ISSUES

Subject to further Order the hearing will be divided into four subject matter areas which are as follows and evidence with respect to them will be heard in the sequence set forth.

(1) FACILITIES

(1A) Alternate systems of transportation, design and capacity of facilities, construction plan and pipeline operations and maintenance.

(1B) Right-of-way, interconnecting pipeline facilities, and alternate routes.

(1C) Cost of facilities.

(1D) Agreements between Trunk Line and Trunk Line (Canada).

(2) CONTRACTS AND FINANCIAL MATTERS

(2A) Contracts, including the examination of supply, transportation, sales contracts, and in the case of the CAGPL and the Alberta Natural applications, contracts for sale of gas from Alaska in the United States.

(2B) Financial matters, including pro forma financial statements, cost of service and tariffs and financing plans.

(3) SOCIO-ECONOMIC, ENVIRONMENTAL AND OTHER PUBLIC INTEREST MATTERS

(3A) Impact on the Canadian economy.

(3B) Canadian content.

(3C) Socio-economic factors.

(3D) Environmental matters.

(3E) Other matters of public interest.

(4) SUPPLY AND REQUIREMENTS

(4A) Supply of gas which might be available to the pipeline from Canadian and Alaskan sources.

(4B) Supply of Canadian gas from all other sources.

(4C) Requirements for gas to satisfy the Canadian market.

This grouping of subject matter does not preclude the introduction of certain types of evidence from being heard under different subject matter areas ("phases"), if it is relevant.

2. ORDER OF APPEARANCES AND SEQUENCE OF CROSS-EXAMINATION

The order of appearances and sequence of cross-examination has placed persons into 19 groups. Any new interested parties will be placed in one of these groups. A person wishing any change in the order of appearance and sequence of cross-examination should request it by letter to the Secretary of the Board as soon as possible. Any request for a change in the order of appearances and sequence of cross-examination after the commencement of the hearing should be directed to Board Counsel.

3. GROUPING OF PARTIES

Interested persons with common interest are urged to form voluntary grouping or associations on particular issues and to arrange for a common presentation of evidence and cross-examination. All persons will be accorded an opportunity to present their case fully and to cross-examine on relevant issues. Whether there is grouping or not, if evidence has been placed on the record or if certain interests have been exhaustively explored in cross-examination, the Board and the Board Counsel will ensure that there is no duplication or repetition.

4. "POLICY WITNESSES" AND OPENING STATEMENT

Applicants and other parties are not required to open their cases by calling policy witnesses. However, the following rules will apply notwithstanding what has just been said.

(a) CAGPL, Foothills, Trunk Line (Canada), Trunk Line and Alberta Natural are required at some point in their presentations to call policy witnesses capable of outlining their applications and providing a balanced appraisal of the issues involved.

(b) TransCanada and Westcoast are required during the course of their presentations to provide witnesses qualified to answer questions regarding their proposed facilities programs assuming connection with either of the CAGPL or Foothills Projects. Specifically, TransCanada's and Westcoast's policy witnesses should be qualified to answer the question of whether Westcoast's and TransCanada's pipeline systems are equally capable of being connected with the Foothills Project as with the CAGPL Project.

(c) Other parties may call policy witnesses as part of their presentation and the Board may direct the calling of a policy witness by any party.

(d) All policy witnesses will be subject to cross-examination.

5. REBUTTAL EVIDENCE

In accordance with the principles applicable to rebuttal evidence, every applicant or other party who proposes to adduce rebuttal evidence to evidence in the application or otherwise on record should adduce such evidence as part of his presentation, even if such rebuttal evidence may not be required as part of his case. Unless the facts which a party wishes to contradict were uunknown and unforeseen by him when a party's case was put in, or unless otherwise ordered by the Board, rebuttal evidence must be put in as part of the main case. A party initially adducing evidence will have a right of reply subject to the principles applicable to rebuttal evidence.

6. THE MACKENZIE VALLEY REGISTRY

The Board has established a Mackenzie Valley Registry. The permanent location of the Mackenzie Valley Registry is on the Board's premises in Room 944, 9th Floor, Trebla Building, 473 Albert Street, Ottawa, Ontario. Temporary locations will be established at sites of the hearing. This registry is a branch of the National Energy Board's central registry of documents and has been set up to assist the applicants and other parties during the hearing. The purpose of the Registry, in so far as the applicants and interested parties are concerned, is to facilitate the service of documents.

It is recognized, however, that some of the parties wishing to participate in the hearing may not wish to utilize the Registry. Therefore, the rules regarding service of documents, the number of documents required and the use of the Mackenzie Valley Registry are as follows:

(1) Prior to the commencement of the hearing, thirty (30) copies shall be served on the Secretary of the Board and copies also shall be served on all other parties. Service on

the Board may be accomplished by mail addressed to the Secretary of the Board or by deposit at the Mackenzie Valley Registry. Service of copies on other parties shall be done by mail and an affidavit of service shall be filed.

(2) After commencement of the hearing, unless any person not wishing to be served through the Mackenzie Valley Registry otherwise indicates, all documents shall be served through the Registry. New intervenors not wishing to be served through the Mackenzie Valley Registry shall advise the Secretary of the Board. The Secretary of the Board will provide all persons with a listing which will show the names of those who wish to be served through the Mackenzie Valley Registry and the names of those who wish to be served direct by mail. Thereafter, 30 copies shall be served on the Board by mailing them to the Secretary of the Board or by deposit at the Mackenzie Valley Registry. Whatever number of copies those persons wishing to be served through the Mackenzie Valley Registry require, should

be sent to the Mackenzie Valley Registry by mailing them to the Secretary or by deposit in the Mackenzie Valley Registry. Service of whatever number of copies those persons not wishing to be served through the Mackenzie Valley Registry require shall be done by mail and an affidavit of service prepared. A clerk will be in attendance at the Mackenzie Valley Registry during business hours and all documents shall be signed for. Service will be deemed to have been made upon the person signing for the documents. A copying machine is available to make additional copies for any person wishing to make copies, at his expense.

7. The applicants shall provide copies of their applications to all persons who shall hereafter be declared interested persons by the 10th day of May 1976. For purposes of this paragraph "application" means the material included in the definitions of the applications set out in the recitals to Hearing Order GH-1-76. Applications shall be served in accordance with sub-paragraph (1) under the preceding heading "The Mackenzie Valley Registry".

8. WRITTEN DIRECT EVIDENCE

All direct evidence is to be prepared in written question and answer form and is to be filed in the Mackenzie Valley Registry and except where otherwise ordered by the Board shall be served on the other parties thirty days prior to commencement of each phase by the applicants and twenty days prior to commencement of that phase, by other parties.

The Board recognizes that some written direct evidence might require a response by the other parties beyond that contained in their own written direct evidence if it relates to matters which are not touched upon in the application or the other parties' submissions and which are unforeseen. If any party wishes to respond to evidence of this nature, further written direct evidence should be filed in the Mackenzie Valley Registry within a reasonable time before that evidence is to be presented.

The Board may order a date by which evidence on a particular subject matter area is to be filed and served. Such a date will be chosen so as to afford the applicants and other parties reasonable time to study and review the direct evidence. Unless circumstances otherwise prescribe, the hearing of evidence on a particular issue will not commence until the written evidence of applicants and other parties has been filed and served.

9. USE OF NON PUBLIC DOCUMENTS OTHER THAN MATERIAL COMPRISING APPLICATIONS

The applicants and other parties are required to list all the documents relevant to the issues of a given phase which are intended to be relied upon or referred to in direct evidence in that phase. The disclosure of documents by phase must be filed at the same time that written direct evidence on that subject area is required to be filed.

Copies of all documents listed shall be filed in the Mackenzie Valley Registry as discussed under the heading "The Mackenzie Valley Registry". However, other than material comprising applications, copies of large and voluminous documents such as published learned papers, textbooks, reports and studies other than public documents, and public documents need not be served on other parties. Instead, two copies of such material shall be deposited in the Mackenzie Valley Registry where they can be examined by those persons wishing to examine them.

A person proposing to cross-examine should provide a list of documents he intends to use in his cross-examination to the counsel for the witness being cross-examined as soon as it is possible and feasible to do so, so that as much notice as possible be given of documents to be used in cross-examination.

The Board also considers that in disclosing documents and using documents at the hearing the following rules should apply.

(i) In listing documents, references to specific pages should be made where possible.

(ii) Unless otherwise ordered, press clippings, learned articles, learned textboooks, reports and studies other than public documents and hearsay evidence generally will not be admissible unless the party wishing to enter the same into evidence produces a witness who is prepared to support such documents and the truth of the facts asserted therein and to be cross-examined on them.

10. PUBLIC DOCUMENTS

Public documents will be treated as evidence of the matters which they assert without being supported by a witness to prove their authenticity or reliability. For example, if the Alberta Energy Resources Conservation Board predicted in 1973 that Alberta requirements for natural gas in 1979 would be "x" Bcf, this will be taken as evidence only of the fact that the Alberta Board made that finding. It would not preclude the Board hearing other evidence as to Alberta requirements.

As in the case with non-public documents, public documents intended to be relied upon in evidence must be listed in the written statement listing documents. Public documents fall within the category of documents, copies of which, need not be served on other applicants and other parties but which may be inspected in the Mackenzie Valley Registry.

11. INTERVENTIONS

Every interested person other than those persons whose names are set forth in Appendix 2 of this Order who intends to oppose or intervene in any of the applications shall file with the Secretary, the written statement referred to in paragraph 6, of Order GH-1-76, on or before the 30th day of April, 1976, namely a written statement which may admit or deny any or all of the facts alleged in the applications and which shall be endorsed with the name and address of the interested person or his solicitor to whom communications may be sent. Each interested person shall serve a copy of such written statements on each applicant on or before the 30th of April, 1976, and an affidavit of service thereof shall be filed.

12. TRANSCRIPTS

The applicants and other parties who are companies or represent governments and associations representing corporations who wish transcripts may obtain transcripts by purchasing from the official Court Reporter. Group (17) and those persons who are not corporations or associations of corporations in Group (18) may make use of copies of the transcript held in the Mackenzie Valley Registry. These transcripts will be available on loan for periods of seventy-two (72) hours, in the National Capital Region. Transcripts are not to be removed from the National Capital Area.

13. MOTIONS

If any matters of law or any questions on which a decision of the Board may be required arise, a Notice of Motion with respect thereto should be filed with the Board and will be dealt with on a date to be fixed by the Board or at the opening of the hearing.

14. HEARING HOURS

The Board will sit from 9:00 a.m. to 1:00 p.m., with a mid-morning break, subject to the exigencies of the hearing.

APPENDIX 2

ORDER OF APPEARANCES AND SEQUENCE OF CROSS-EXAMINATION

Re: Hearing Order GH-1-76;
Applications of CAGPL, Foothills
Group and Alberta Natural, etc.

The Board has grouped applicants and interested persons as follows:

(1) CAGPL GROUP

Canadian Arctic Gas Pipeline Limited
Alaskan Arctic Gas Pipeline Company
Northern Border Pipeline Company
- Columbia Gas Transmission Corporation
- Michigan Wisconsin Pipe Line Company
- Natural Gas Pipe Line Company of America
- Northern Natural Gas Company and Consolidated Natural Gas Limited
- Texas Eastern Transmission Corporation

Pacific Lighting Gas Development Company

(2) FOOTHILLS GROUP

Foothills Pipe Lines Ltd.
The Alberta Gas Trunk Line (Canada) Ltd.
The Alberta Gas Trunk Line Company Limited

(3) WESTCOAST

Westcoast Transmission Company Limited

(4) ALBERTA NATURAL GROUP

Alberta Natural Gas Company Ltd.
Alberta and Southern Gas Co. Ltd.
Natural Gas Corporation of California

(5) TRANSCANADA

TransCanada PipeLines Limited

(6) EL PASO

El Paso Alaska Company

(7) EXPLORATION AND PRODUCTION COMPANIES WITH NO MACKENZIE-BEAUFORT HOLDINGS

Panarctic Oils Ltd.

(8) EXPLORATION AND PRODUCTION COMPANIES WITH MACKENZIE-BEAUFORT HOLDINGS

Dome Petroleum Limited
Gulf Oil Canada Limited
Imperial Oil Limited
Shell Oil Limited
SOQUIP

(9) TRANSMISSION COMPANIES SUPPORTING CAGPL GROUP

Canadian-Montana Pipe Line Company

(10) OTHER TRANSMISSION COMPANIES

Arctic Canada Gas Transmission Company
Great Lakes Gas Transmission Company

(11) DISTRIBUTION COMPANIES SUPPORTING CAGPL GROUP

Greater Winnipeg Gas Company
Inter-City Gas Limited
Northern and Central Gas Corporation Limited
The Consumers' Gas Company
Union Gas Limited

(12) DISTRIBUTION COMPANIES SUPPORTING FOOTHILLS GROUP

Inland Natural Gas Co. Ltd.

(13) OTHER DISTRIBUTION COMPANIES

British Columbia Hydro and Power Authority
Gaz Métropolitain, inc.

(14) INDUSTRIAL CUSTOMERS

Industrial Gas Users Association
Abitibi Paper Company Ltd.
Algoma Steel Corporation Limited, The
Canadian Industries Limited
Canadian Pittsburgh Industries
Canadian Titanium Pigments Limited
Consumers Glass Company, Limited
Dominion Glass Company Limited
Dominion Malting Limited
Dow Chemical of Canada, Limited
Du Pont of Canada Limited
Falconbridge

(14) INDUSTRIAL CUSTOMERS (cont'd)

Inland Cement Industries Limited and Ocean Cement Limited
Noranda Mines Limited
Pilkington Brothers (Canada) Limited
I-XL Industries Ltd.
SIDBEC
Steep Rock Iron Mines Limited
Stelco
Texasgulf Canada Ltd.

(15) EXPORT CUSTOMERS

Midwestern Gas Transmission Company
Northwest Pipeline Corporation
St. Lawrence Gas

(16) INDUSTRY ASSOCIATIONS

Canadian Gas Association
Motor Vehicle Manufacturers' Association

(17) INDIAN AND INUIT PEOPLES GROUPS

The Committee for Original Peoples Entitlement and Inuit Tapirisat
Indian Association of Alberta
Indian Brotherhood of the Northwest Territories
T.K. Smith and William Smith

(18) OTHER PERSONS, NOT INCLUDED IN ANY OF THE ABOVE (FURTHER SUBDIVIDED, IF NECESSARY)

PUBLIC INTEREST GROUPS

Canadian Arctic Resources Committee

PUBLIC INTEREST GROUPS (cont'd)

Canadian Wildlife Federation
Canadians for Responsible Northern Development
Committee for an Independent Canada
C.J.L. Foundation
Consumers' Association of Canada
Energy Probe
Workgroup on Canadian Energy Policy

COMPANIES

Interprovincial Steel and Pipe Corporation Ltd.
Liquefaction Limited

ASSOCIATIONS

Canadian Labour Congress
Polar Gas Project
Beaufort-Delta Oil Project Limited
Pipeline Contractors Association of Canada
Housing and Urban Development Association

INDIVIDUALS

R.A. Bradley, P. Eng.
John Helliwell
Ken Rubin

(19) GOVERNMENTS AND GOVERNMENT AGENCIES

Attorney General for British Columbia
Attorney General for Manitoba
Ontario Minister of Energy
Attorney General for Québec
Government of Saskatchewan

APPENDIX 3

NATIONAL ENERGY BOARD

NOTICE OF HEARING

MACKENZIE VALLEY GAS PIPELINE HEARING

A public hearing will be held before the National Energy Board, commencing on Monday, the 12th day of April, 1976, at 9:00 a.m., in the Hearing Room of the National Energy Board, room 940, Trebla Building, 473 Albert Street, in the City of Ottawa, in the Province of Ontario, to hear together the several applications of Canadian Arctic Gas Pipeline Limited, Foothills Pipe Lines Ltd., Westcoast Transmission Company Limited, The Alberta Gas Trunk Line (Canada) Limited, Alberta Natural Gas Company Ltd. for certificates to construct natural gas pipelines for the movement of gas from the State of Alaska and the Mackenzie River Delta and Beaufort Basin in Canada to markets in Southern Canada and the United States.

The public hearing will be held in Ottawa, the Northwest Territories and at such other places as the Board may direct, on dates, at times and at locations to be announced later.

Any person who intends to oppose or intervene and who has not already done so in the CAGPL application, the Foothills Group application or the Alberta Natural application or in any of the component applications to the Foothills Group application shall file with the Secretary on or before 30 April 1976 thirty copies of a written statement.

Every such written statement shall be signed by the person or his solicitor and in each case,

(a) shall contain a concise statement of the facts from which the nature of each such party's interest in the CAGPL application, the Foothills Group application or the Alberta Natural application may be determined,

(b) shall contain a concise statement of whether each such party supports or opposes either the CAGPL application, the Foothills Group application or the Alberta Natural application, or whether he supports or opposes any proposal to move natural gas found in the State of Alaska or in the Mackenzie River Delta and Beaufort Basin area to markets in Southern Canada, or in the United States of America, or of whether he takes any other position,

(c) may admit or deny any or all of the facts alleged in any of the material contained in the CAGPL application, the Foothills Group application or the Alberta Natural application.

APPENDIX 3

Anyone wishing further information about the public hearing should, as soon as possible, obtain a copy of Board Order No. GH-1-76 (Mackenzie Valley Pipeline Hearing Order), which Order sets out the rules of procedure and other information concerning the hearing, by writing or phoning the Secretary of the Board at the address below.

Mr. Brian H. Whittle
Acting Secretary
National Energy Board
473 Albert Street
OTTAWA, Ontario
K1A OE5

Telephone - Ask for Mr. R. Williamson

1-613-996-2781

Dated at the City of Ottawa, in the Province of Ontario, this 19th day of March, 1976.

NATIONAL ENERGY BOARD

"Brian H. Whittle"
Brian H. Whittle
Acting Secretary

APPENDIX 4

CAGPL DEFICIENCY LETTERS

LETTER NO.	DATE SENT	DATE OF REPLY
1	April 11, 1975	May 27, 1975
1A	June 16, 1975	September 29, 1975
1B	October 24, 1975	January 19, 1976
2	April 25, 1975	September 29, 1975
3	April 29, 1975	August 29, 1975
4	April 30, 1975	September 29, 1975
5	April 30, 1975	September 29, 1975
6	May 7, 1975	September 29, 1975
7	May 7, 1975	September 29, 1975
8	May 14, 1975	August 29, 1975
9	May 27, 1975	September 29, 1975
10	June 4, 1975	September 29, 1975
COST BENEFIT STUDY	May 16, 1975	December 31, 1975
SOCIO-ECONOMIC IMPACT	July 15, 1975	________
ALTERNATE ROUTE: SHALLOW BAY	September 29, 1975	________
11	October 14, 1975	January 19, 1976
12	December 8, 1975	
13	January 15, 1976	

FOOTHILLS DEFICIENCY LETTERS

LETTER NO.	DATE SENT	DATE OF REPLY
1	June 9, 1975	October 8, 1975
2	July 2, 1975	October 8, 1975
3	July 2, 1975	August 26, 1975
4	July 2, 1975	October 8, 1975
5	July 16, 1975	October 8, 1975
6	July 16, 1975	October 8, 1975
7	July 16, 1975	
8	December 8, 1975	
8(i)		February 16, 1976
8(ii)		February 16, 1976
8(iii)		February 16, 1976
8(iv)		
8(v)		
8(vi)		
8(vii)		March 5, 1976
SOCIO-ECONOMIC IMPACT	September 11, 1975	

APPENDIX 4

WESTCOAST DEFICIENCY LETTERS

LETTER NO.	DATE SENT	DATE OF REPLY
1	July 28, 1975	September 15, 1975
1A	November 6, 1975	February 2, 1976
2	December 8, 1975	February 2, 1976
Material Requested Pursuant to Order No. PO-2-GH-2-75	December 6, 1975	February 2, 1976

TRUNK LINE (CANADA) DEFICIENCY LETTERS

LETTER NO.	DATE SENT	DATE OF REPLY
1	July 28, 1975	October 23, 1975
Material Requested Pursuant to Order No. PO-2-GH-2-75	December 5, 1975	January 30, 1976

ALBERTA NATURAL DEFICIENCY LETTERS

LETTER NO.	DATE SENT	DATE OF REPLY
1	July 24, 1975	September 9, 1975
1A	November 6, 1975	December 5, 1975
2	December 8, 1975	January 30, 1976

NATIONAL ENERGY BOARD — OFFICE NATIONAL DE L'ÉNERGIE

CANADA

ORDER NO. AO-9-GH-1-76

IN THE MATTER OF The National Energy Board Act;

AND IN THE MATTER OF an application by Canadian Arctic Gas Pipeline Limited for a certificate of public convenience and necessity for the construction and operation of a natural gas pipeline, under File No. 1555-C46-1;

AND IN THE MATTER OF applications by Foothills Pipe Lines Ltd., Westcoast Transmission Company Limited and The Alberta Gas Trunk Line (Canada) Limited for certificates of public convenience and necessity for the construction and operation of certain natural gas pipelines, under File Nos. 1555-F2-3, 1555-W5-49 and 1555-A34-1;

AND IN THE MATTER OF an application by Alberta Natural Gas Company Ltd. for a certificate of public convenience and necessity for the construction and operation of certain extensions to its natural gas pipeline, under File No. 1555-A2-10;

AND IN THE MATTER OF a submission by The Alberta Gas Trunk Line Company Limited, under File No. 1555-A5-2;

AND THE MATTER OF applications by Foothills Pipe Lines (Yukon) Ltd., Westcoast Transmission Company Limited and the Alberta Gas Trunk Line (Canada) Limited for certificates of public convenience and necessity for the construction and operation of certain natural gas pipelines under File Nos. 1555-F6-1, 1555-W5-55 and 1555-A34-2;

AND IN THE MATTER OF a submission by The Alberta Gas Trunk Line Company Limited under File No. 1555-A5-3.

B E F O R E:

J.G. Stabback	)	on Friday, the 10th
C.G. Edge	)	day of September 1976.
R.F. Brooks	)	

UPON IT APPEARING THAT:

In Order GH-1-76, "The Mackenzie Valley Pipeline Hearing Order", dated the 19th day of March 1976, the Board, inter alia, ordered that the application of Canadian Arctic Gas Pipeline Limited, herein referred to as "CAPGL", applications of Foothills Pipe Lines Ltd., Westcoast Transmission Company Limited, and the Alberta Gas Trunk Line (Canada) Limited, application of Alberta Natural Gas Company Ltd., all for certificates of public convenience and necessity for the construction and operation of natural gas pipelines; and the submission of the Alberta Gas Trunk Line Company Limited be heard together,

AND UPON IT APPEARING THAT:

Applications for certificates of public convenience and necessity with supporting material have since been filed by Foothills Pipe Lines (Yukon) Ltd. herein referred to as "Foothills (Yukon)", dated August 30, 1976, Westcoast Transmission Company Limited, herein referred to as "Westcoast" dated August 30, 1976, The Alberta Gas Trunk Line (Canada) Limited, herein referred to as "Trunk Line (Canada)", dated August 26, 1976, and a submission has been filed by The Alberta Gas Trunk Line Company Limited, herein referred to as "Trunk Line", dated September 8, 1976.

The said applications are for the purpose of obtaining certificates of public convenience and necessity to construct pipelines and works to move natural gas found in the State of Alaska, United States of America, to markets in others of the United States.

The Board having considered the applications and material described above and subject to responses to be received to deficiency letters which may hereinafter be issued, all of which, that is to say, the applications of Foothills (Yukon), Westcoast, and Trunk Line (Canada), and supplementary material, the submission of Trunk Line and supplementary material, the deficiency letters which may be issued and responses hereto, and any additional information which may be received, any amendments to any of the above, hereinafter directed that they shall be referred to collectively as the "Foothills (Yukon) Group" application,

Wherever in this Order, the terms Foothills (YUkon) Group or Foothills (Yukon) Group application are used, the shall include and be deemed to include the submission of Trunk Line.

The Board is presently considering the CAGPL application as amended for the purpose, _inter alia_, of obtaining a certificate of public convenience and necessity to construct a pipeline and works to move natural gas found in the State of Alaska, United States of America to markets in others of the United States.

AND UPON IT APPEARING:

To the Board that the issues to be determined in hearing the CAGPL application and the Foothills (Yukon) Group application should due to their nature be properly heard together.

IT IS THEREFORE ORDERED THAT:

1. This order may be cited as the Mackenzie Valley-Yukon Pipeline Hearing Order.

2. Foothills (Yukon) Group application shall be heard together with the CAGPL application and the applications of Foothills, Trunk Line (Canada), Westcoast and Alberta Natural and the submission of Trunk Line presently before the National Energy Board pursuant to Order GH-1-76, as amended, and heard in the Hearing Room of the National Energy Board, room 940, Trebla Building, 473 Albert Street, in the City of Ottawa, in the Province of Ontario, commencing on Monday, the 18th day of October 1976 at the hour of 8:30 a.m. local time.

3. The members of the Foothills (Yukon) Group shall arrange among them to have the notice of hearing set forth in Appendix 3 published not later than the 17th day September, 1976 or so soon thereafter as may be practicable, in one issue each of the "Times" and the "Colonist" in the City of Victoria, the "Province" and the "Sun" in the City of Vancouver, all in the Province of British Columbia; the "Albertan" and the "Herald" in the City of Calgary, the "Journal" in the City of Edmonton, the "Herald" in the City of Lethbridge, all in the Province of Alberta; the "Leader-Post" in the City of Regina, the "Star-Phoenix" in the City ofSaskatoon, both in the Province of Saskatchewan; the "Free Press" and the "Tribune" in the City of Winnipeg, the "Sun" in the City of Brandon, all in the Province of Manitoba; "The Spectator" in the City of Hamilton, the "Miner" and News" in the City of Kenora, the

"Free Press" in the City of London, the "Nugget" in the City of North Bay, the "Citizen", "Le Droit" and the "Journal" in the City of Ottawa, the "Observer" in the City of Sarnia, the "Chronicle Journal" and the "Times News" in the City of Thunder Bay, the "Globe and Mail", the "star" and the "Financial Post" in the City of Toronto, the "Star" in the City of Windsor, all in the Province of Ontario; "Le Devoir", the "Gazette", "La Presse" and the "Star" in the City of Montreal, "Le Soleil" and the "Chronicle-Telegraph" in the City of Québec, both in the Province of Québec; the "Telegraph Journal" in the City of Saint John, the "Gleaner" in the City of Fredericton and the "Transcript" in the City of Moncton, all in the Province of New Brunswick; the "Chronicle Herald" and the "mail Star" in the City of Halifax, in the Province of Nova Scotia; the "Guardian" in the City of Charlottetwon, in the Province of Prince Edward Island; the "Telegram" in the City of St. John's, in the Province of Newfoundland; the "news of the North" in the City of Yellowknife, the "Drum" in the Town of Inuvik, the "Hub" in the Town of Hay River, all in the Northwest Territories; the "Star" and the Yukon News" in the City of Whitehorse, in the Yukon Territory; and as soon as possible in the Canada Gazette.

4. The members of the Foothills (Yukon) Group shall arrange among them to give notice of the hearing by service of a true copy of this Order upon the Attorneys-General of each of the Province of Canada, the Commissioner of the Northwest Territories, the commissioner of the Yukon Territory, the British Columbia Energy Commission, the Energy Resources Conservation Board of Alberta, the Oil

and Gas Conservation Board of Saskatchewan and the Oil and Natural Gas Conservation Board of Manitoba.

5. The members of the Foothills (Yukon) Group shall arrange among them for the service of a copy of the several applications and maps showing the general location of the proposed lines, the termini, and all cities, towns, villages, railways, and navigable waters, through, under or across which the proposed lines are to pass upon the Attorneys-General of British Columbia, Alberta and Saskatchewan and upon the Commissioners of the Northwest Territories and the Yukon Territory.

6. Any person in addition to these whose names appear in Appendix 2, who intend to oppose or intervene in the Foothillls (Yukon) Group application or in any of the component applications shall file with the Secretary on or before the 12th day of October 1976, thirty (30) copies of a written statement, signed by the person or his solicitor and in each case

a) shall contain a concise statement of the facts from which the nature of each such party's interest in the Foothills (Yukon) Group application may be determined,

b) shall contain a concise statement of whether each such party supports or opposes the Foothills (Yukon) Group application and whether he supports or opposes any proposal to move natural gas found in the State of Alaska to markets in others of the United States of America, or whether he takes any other position,

c) may admit or deny any or all of the facts alleged in any of the material contained in the Foothills (Yukon) Group application.

7. Any objection to the form or content of this Order shall be made on October 18, 1976.

8. All written direct evidence, to be prepared in question and answer form, upon which any applicant or interested person will rely shall be filed as set out in Appendix 4.

9. Appendices 1, 2, 3 and 4 attached hereto form part of this order.

10. The grouping of issues to be followed in connection with the hearing shall be that set forth in Appendix 1.

11. Subject to further Order of the Board, upon the receipt of further interventions pursuant to paragraph 6 of this Order or otherwise, the persons whose names appear on the order of appearances and sequence of cross-examination set forth in Appendix 2 shall be the persons who are interested persons for the purposes of section 45 of the Act.

12. The definition "hearing" in order GH-1-76 is hereby amended by adding Foothills (Yukon) Group. All other definitions as set out at paragraph 14 of Order GH-1-76 remain unchanged save as amended by this order.

13. Any interested party may examine a copy of the applications and supplementary material filed therewith and the submission of Trunk Line at the offices of the Board at the

Trebla Building
473 Albert Street
Ottawa, Ontario
K1A 0E5

and

with respect to the Foothills (Yukon) application, at the following address:

Foothills Pipe Line (Yukon) Ltd.
1600 Bow Valley Square II
205 - 5th Avenue S.W.
Calgary, Alberta
T2P 2W4

and

with respect to the Trunk Line (Canada) application and the Trunk Line submission at the following address

The Alberta Gas Trunk Line (Canada) Limited
505 Second Street S.W.
Calgary, Alberta
T2P 2N6

and

with respect to the Westcoast application at the following address

Westcoast Transmission Company Limited
1333 West Georgia Street
Vancouver, British Columbia
V6E 3K9

14. Save as specifically amended by this order the Rules of Procedure and Other Matters relevant to the hearing as set out at Appendix 1 of Order GH-1-76 remain in full force and effect and wherever the word applicant appears it shall be read to include the Foothills (Yukon) Group and members thereof.

15. Appendix 2 of Order GH-1-76 (Order of Appearances and Sequence of Cross-Examination) is hereby deleted and replaced by Appendix 2 of this Order.

16. The record, as it will stand immediately prior to the date fixed for the commencement of the hearing of the Foothills (Yukon) Group application, as set forth in paragraph 2 hereof, will extend to and be binding on all applicants added under this order.

17. Dated at the City of Ottawa, in the Province of Ontario, this 10th day of September, 1976.

NATIONAL ENERGY BOARD

B.H. Whittle

Brian H. Whittle

Secretary

APPENDIX 1

GROUPING OF ISSUES AND OTHER MATTERS RELEVANT TO THE HEARING

1. GROUPING OF ISSUES

Subject to further Order, four subject matter areas are herein listed and evidence with respect to them will be heard in the sequence set forth in Appendix 4.

(1) FACILITIES

(1A) Alternate systems of transportation, design and capacity of facilities, construction plan and pipeline operations and maintenance.

(1B) Right-of-way, interconnecting pipeline facilities and alternate routes.

(1C) Cost of facilities.

(2) CONTRACTS AND FINANCIAL MATTERS

(2A) Contracts, including the examination of supply, transportation, sales contracts, and in the case of CAGPL and the Alberta Natural applications, contracts for sale of gas from Alaska in the United States.

(2B) Financial matters, including pro forma financial statements, cost of service and tariffs and financing plans.

. . . 2

(2C) All matters relating to Trunk Line and Trunk Line (Canada), including agreements between Trunk Line and Trunk Line (Canada), relating to both Foothills and Foothills (Yukon) excepting those falling within subject matter areas (3) and (4) hereof.

(2D) All matters pertaining to Foothills (Yukon) application relating to Phases (1), (2A) and (2B).

(3) SOCIO-ECONOMIC, ENVIRONMENTAL AND OTHER PUBLIC INTEREST MATTERS

(3A) Impact on the Canadian economy.

(3B) Canadian content.

(3C) Socio-economic factors.

(3D) Environmental matters.

(3E) Other matters of public interest.

(4) SUPPLY AND REQUIREMENTS

(4A) Supply of gas which might be available to the pipeline from Canadian and Alaskan sources.

(4B) Supply of Canadian gas from all other sources.

(4C) Requirements for gas to satisfy the Canadian market.

2. POLICY WITNESSES

Foothills (Yukon) is required at some point in the presentation to call policy witnesses capable of outlining the applications and producing a balanced appraisal of the issues involved, and Trunk Line (Canada), Trunk Line, Westcoast shall similarly call policy witnesses with respect to the Foothills (Yukon) Group application.

3. The applicants added by this order shall provide copies of their applications to all persons who are declared to be interested persons as set out at appendix 2 of this Order by the 12th day of October, 1976. For purposes of this paragraph 'application' means the application and supporting material and deficiency letters and responses thereto, any additional information which may be received and any amendments to any of them. Applications shall be served in accordance with sub paragraph (2) of paragraph 6 of appendix 1 of Order GH-1-76 (The Mackenzie Valley Registry).

4. INTERVENTIONS

Each interested person other than those persons whose names are set forth in Appendix 2 of this Order who intends to oppose or intervene shall file the submission required by paragraph 6 of this Order and serve a copy of such written statement on each applicant on or before the 12th day of October, 1976, and an affidavit of service thereof shall be filed.

APPENDIX 2

ORDER OF APPEARANCES AND SEQUENCE OF CROSS-EXAMINATION

Re: Hearing Order AO-9-GH-1-76

The Board has grouped applicants and interested persons as follows:

(1) CAGPL GROUP

Canadian Arctic Gas Pipeline Limited
Alaskan Arctic Gas Pipeline Company
Northern Border Pipeline Company
  Columbia Gas Transmission Corporation
  Michigan Wisconsin Pipe Line Company
  Natural Gas Pipe Line Company of America
  Northern Natural Gas Company and Consolidated Natural Gas Limited
  Texas Eastern Transmission Corporation
Pacific Lighting Gas Development Company

(2) FOOTHILLS GROUP AND FOOTHILLS (YUKON) GROUP

Foothills Pipe Lines Ltd.
Foothills Pipe Lines (Yukon) Ltd.
The Alberta Gas Trunk Line (Canada) Ltd.
The Alberta Gas Trunk Line Company Limited

APPENDIX 2

(3) WESTCOAST

Westcoast Transmission Company Limited

(4) ALBERTA NATURAL GROUP

Alberta Natural Gas Company Ltd.
Alberta and Southern Gas Co. Ltd.
Natural Gas Corporation of California

(5) TRANSCANADA

TransCanada PipeLines Limited

(6) EL PASO

El Paso Alaska Company

(7) EXPLORATION AND PRODUCTION COMPANIES WITH NO MACKENZIE-BEAUFORT HOLDINGS

Panarctic Oils Ltd.

(8) EXPLORATION AND PRODUCTION COMPANIES WITH MACKENZIE-BEAUFORT HOLDINGS

Dome Petroleum Limited
Gulf Oil Canada Limited
Imperial Oil Limited
Shell Canada Limited
SOQUIP
Sun Oil Company Limited
Chevron Standard Limited

(9) TRANSMISSION COMPANIES SUPPORTING CAGPL GROUP

Canadian-Montana Pipe Line Company

(10) OTHER TRANSMISSION COMPANIES

Arctic Canada Gas Transmission Company
Great Lakes Gas Transmission Company

(11) DISTRIBUTION COMPANIES

Gaz Métropolitain, inc.
Greater Winnipeg Gas Company
Inter-City Gas Limited
Northern and Central Gas Corporation Limited
The Consumers' Gas Company
Union Gas Limited
British Columbia Hydro and Power Authority
Inland Natural Gas Co. Ltd.

(12) Not allocated

(13) Not allocated

(14) INDUSTRIAL CUSTOMERS

Industrial Gas Users Association
Abitibi Paper Company Ltd.
Algoma Steel Corporation Limited, The
Canadian Industries Limited
Canadian Pittsburgh Industries
Canadian Titanium Pigments Limited
Consumers Glass Company, Limited
Dominion Glass Company Limited
Dominion Malting Limited
Dow Chemical of Canada, Limited
Du Pont of Canada Limited
Falconbridge

APPENDIX 2

(14) INDUSTRIAL CUSTOMERS (cont'd)

Inland Cement Industries Limited and
Ocean Cement Limited
Noranda Mines Limited
Pilkington Brothers (Canada) Limited
I-XL Industries Ltd.
SIDBEC
Steep Rock Iron Mines Limited
Stelco
Texasgulf Canada Ltd.

(15) EXPORT CUSTOMERS

Midwestern Gas Transmission Company
Northwest Pipeline Corporation
St. Lawrence Gas

(16) INDUSTRY ASSOCIATIONS

Canadian Gas Association
Motor Vehicle Manufacturers' Association

(17) NORTHERN RESIDENTS AND NATIVE PEOPLES GROUPS

NATIVE PEOPLES GROUPS

The Committee for Original Peoples Entitlement
and Inuit Tapirisat
Indian Association of Alberta
Indian Brotherhood of the Northwest Territories
Council for Yukon Indians
Native Working Men of the Northwest Territories

GOVERNMENTS AND MUNICIPALITIES OF THE NORTHERN TERRITORIES

Town of Inuvik
City of Yellowknife
Settlement Council of Norman Wells
Legislative Assembly of the Northwest Territories
Government of the Yukon Territory

APPENDIX 2

(17) NORTHERN RESIDENTS AND NATIVE PEOPLES GROUPS (cont'd)

OTHER NORTHERN RESIDENTS

Robert Sharp
Northwest Territories Chamber of Commerce
T. Butters, M.L.A.
Northwest Territories Association of Municipalities
Whitehorse Chamber of Commerce
White Pass and Yukon Corporation Ltd.
Pacific Western Airlines

(18) OTHER PERSONS, NOT INCLUDED IN ANY OF THE ABOVE (FURTHER SUBDIVIDED, IF NECESSARY)

PUBLIC INTEREST GROUPS

Canadian Arctic Resources Committee
Canadian Wildlife Federation
Canadians for Responsible Northern Development
Committee for an Independent Canada
C.J.L. Foundation
Consumers' Association of Canada
Energy Probe
Workgroup on Canadian Energy Policy

COMPANIES

Interprovincial Steel and Pipe Corporation Ltd.
Liquefaction Limited

ASSOCIATIONS

Canadian Labour Congress
Polar Gas Project
Beaufort-Delta Oil Project Limited
Pipeline Contractors Association of Canada
Housing and Urban Development Association
United Association of Journeymen and Apprentices
of the Plumbing and Pipe Fitting Industry
of the United States and Canada

(18) OTHER PERSONS, NOT INCLUDED IN ANY OF THE ABOVE (FURTHER SUBDIVIDED, IF NECESSARY) (cont'd)

INDIVIDUALS

R. A. Bradley, P. Eng.
John Helliwell
Ken Rubin

(19) OTHER GOVERNMENTS AND GOVERNMENT AGENCIES

Attorney General for British Columbia
Attorney General for Manitoba
Ontario Minister of Energy
Attorney General for Québec
Government of Saskatchewan

APPENDIX 3

NATIONAL ENERGY BOARD

NOTICE OF HEARING

MACKENZIE VALLEY-YUKON GAS PIPELINE HEARING

The applications of Foothills Pipe Lines (Yukon) Ltd., The Alberta Gas Trunk Line (Canada) Limited, and Westcoast Transmission Company Limited, hereinafter referred to collectively as the "Foothills (Yukon) Group", for certificates of public convenience and necessity to construct gas pipeline facilities to move gas from the State of Alaska to markets in others of the United States of America have been ordered to be heard together with the several applications of Canadian Arctic Gas Pipeline Limited, Foothills Pipe Lines Ltd., Westcoast Transmission Company Limited, The Alberta Gas Trunk Line (Canada) Limited, Alberta Natural Gas Company Ltd. for certificates to construct natural gas pipelines for the movement of gas from the State of Alaska and the Mackenzie River Delta and Beaufort Basin in Canada to markets in Southern Canada and the United States now being heard in public hearings at The Hearing Room of the National Energy Board, room 940, Trebla Building, 473 Albert Street, Ottawa, Ontario. The present hearings will incorporate the new applications commencing effective Monday October 18, 1976.

Any person who intends to appear or intervene in the Foothills (Yukon) Group application or in any component application shall file with the Secretary on or before October 12, 1976 thirty (30) copies of a written statement signed by the person or his solicitor and in each case

(a) shall contain a concise statement of the facts for which the nature of each such party's interest in the Foothills (Yukon) Group application may be determined

(b) shall contain a concise statement of whether each such party supports or opposes the Foothills (Yukon) Group application or whether he supports or opposes any proposal to move natural gas found in the State of Alaska to markets in others of the United States of America, or whether he takes any other position

(c) may admit or deny any or all of the facts alleged in any of the material considered in the Foothills (Yukon) Group application.

Anyone wishing further information about the public hearing should, as soon as possible, obtain a copy of Board Order No. AO-9-GH-1-76 (Mackenzie Valley-Yukon Pipeline Hearing Order), which Order sets out the rules of procedure and other information concerning the hearing, by writing or phoning the Sectretary of the Board at the address below.

Mr. Brian H. Whittle
Secretary
National Energy Board
473 Albert Street
OTTAWA, Ontario
K1A 0E5

Telephone - Ask for Mr. R. Williamson
1-613-996-2781

APPENDIX 3

Dated at the City of Ottawa, in the Province of Ontario, this 10th day of September, 1976.

NATIONAL ENERGY BOARD

"Brian H. Whittle"

Brian H. Whittle
Secretary

APPENDIX 4

Mackenzie Valley-Yukon Pipeline Hearing -
Order AO-9-GH-1-76

Summary of Filing Dates -
Written Direct Evidence and Supplementary Material

The filing dates set out below supersede any dates previously published.

	By Applicants	By Intervenors
1A	Filed	Filed
1B	Filed	Filed
1C	Filed	Filed
2A	Sep 27	Oct 6
2B	Oct 4	Oct 14
2D	Nov 1 & Nov 15 (1)	Nov 25
2C	Nov 22	Nov 30
3B	Filed (2)	Nov 15 (2)
3C	Filed (2)	Filed (2)
3D	Filed (2)	Filed (2)
3A	Nov 1 (3)	Nov 15 (3)
3E	Filed (3)	Filed (3)
4A		
4B	To be announced	
4C		

(1) with respect to evidence relating to phases 2A & 2B - Nov 1
with respect to evidence relating to phases 1A, 1B, 1C - Nov 15

(2) except evidence relating to Foothills (Yukon) Group for which the date is Nov 15 for applicants and Nov 25 for intervenors

(3) except evidence relating to Foothills (Yukon) Group for which the date is Nov 29 for applicants and Dec 9 for intervenors

CHAPTER 2

SUPPLY AND DEMAND

2.1 INTRODUCTION

This Chapter of the report is a summary of evidence and views on the supply of gas which might be available to the pipeline from Canadian and Alaskan sources, the supply of Canadian gas from all other sources, the requirements for gas to satisfy the Canadian market, and on Canadian gas supply-demand balance and related matters.

The main purpose of this Chapter is to outline the reasonably foreseeable demand for natural gas in Canada and to analyze the various supply alternatives that are available.

The key question that is addressed in this gas supply-demand balancing process is whether or not the gas that has been discovered in the Mackenzie Delta is needed to meet Canada's foreseeable requirements, and if so, when.

A subsidiary question is whether or not there are available markets in Canada and the United States and sufficient reserves and deliverability in Prudhoe Bay and the Mackenzie Delta to support the construction of one or more of the various pipelines for which applications for certificates of public convenience and necessity have been made.

2.2 DEMAND FORECASTS - DOMESTIC MARKETS

2.2.1 Introduction

Information was submitted regarding the Canadian markets which would be supplied by either the CAGPL or Foothills systems, the two pipeline projects proposed for transporting Mackenzie Delta/Beaufort Sea gas. Certain industrial users of natural gas presented evidence on their current and future needs for natural gas in their operations. Three producers, several transmission and distribution companies, and some public interest groups commented on the market demand aspects or provided evidence on conservation, alternative renewable energy sources, and changes in lifestyles.

Detailed market projections for each province of Canada and each market sector were submitted by CAGPL, Trunk Line and Gulf. Foothills adopted the forecast submitted by Trunk Line. Forecasts for total Canadian demand with less detail as to region and/or market sector were submitted by Imperial, Shell, TransCanada, CJL and Helliwell. Westcoast, and B.C. Hydro submitted forecasts for British Columbia and Gaz Métropolitain submitted a forecast for Quebec.

2.2.2 Overview of Applicants' and Intervenors' Forecasts

The forecasts of natural gas sales submitted by Applicants and intervenors are summarized for total Canada in Table 2-1.

Table 2-1

NET SALES OF NATURAL GAS

Canada

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	Imperial	Gulf Case 2	Shell Case 1	Shell Case 2	Helliwell[1] Base Case	CJL[1]	NEB
1975	1,495	1,369	1,339	1,324	1,329	1,329	1,495	1,450	1,337
1977	1,702	1,595	1,436	1,426	1,405	1,394	1,579	1,508	1,456
1980	2,031	1,888	1,766	1,732	1,614	1,583	1,732	1,601	1,754
1985	2,550	2,319	2,356	2,307	1,936	1,830	2,114	1,768	2,110
1990	3,078	2,614	2,814	2,600	2,229	2,062	2,611	1,952	2,473
1995	3,599	2,892	3,297	2,977	2,552	2,305	3,204	2,155	2,864

(1) Pipeline fuel and losses included.

As may be noted from the table the range of variation of submitted forecasts was considerable. By 1995, the highest forecast (CAGPL) was some 50 per cent higher than the lowest forecasts (Shell Case 2 and CJL).

The CAGPL forecast of net sales of 3,599 Bcf (including 104 Bcf for an extended Quebec franchise area) in 1995 represented an average annual rate of growth between 1977 and 1995 of 4.3 per cent. In comparison, Trunk Line forecast net sales of 2,892 Bcf in 1995 which represented a growth rate of 3.4 per cent over the period.

Westcoast provided estimates of sales by type of end-use for British Columbia only. It estimated that sales would grow from 161 Bcf in 1977 to 375 Bcf in 1995. This represents an average rate of increase of 4.8 per cent per annum.

A number of industrial users of natural gas intervened in the hearing and/or submitted evidence on their current and future demand for natural gas. Most of the industrial customers stressed the importance of a secure and continuing source of natural gas in their operations. Many companies noted that their manufacturing operations had been specifically designed to use natural gas and that conversion to alternative fuels would be difficult and expensive. The industrial users who submitted evidence in this regard are included in the list in Chapter 1.

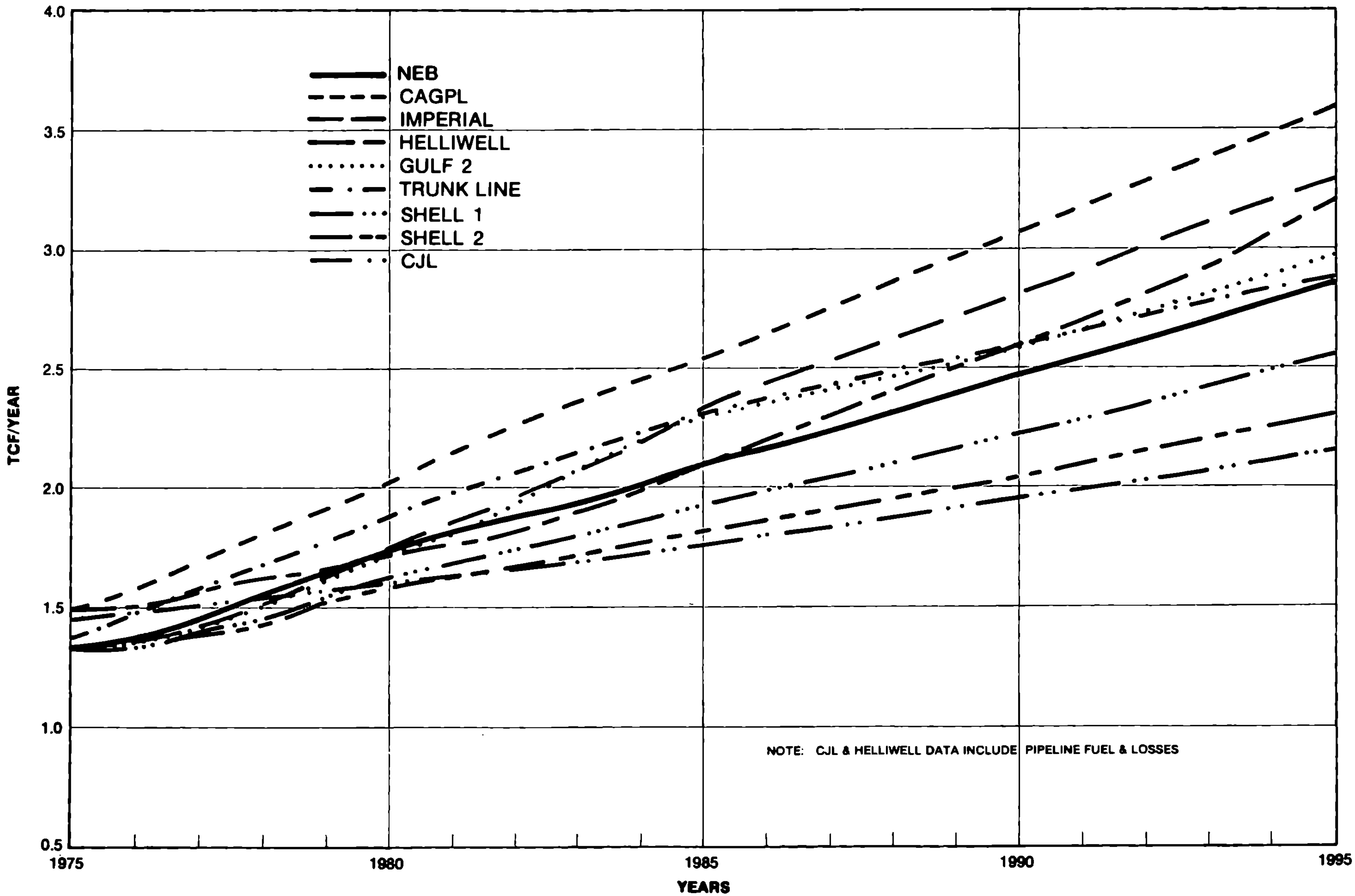
2.2.3 Overview of the Board Forecast

The Board forecasts that natural gas net sales will grow from 1,456 Bcf in 1977 to 2,864 Bcf in 1995 for an average annual rate of increase of 3.8 per cent. A summary of the forecast of net sales of natural gas is included in the comparison presented in Table 2-1. In Figure 2-1 the Board forecast is compared with those of Applicants and intervenors.

The sections which follow review the methodology and assumptions used by Applicants, intervenors and the Board. The Board forecast of total energy and natural gas demand is then presented in Section 2.2.5 while details of its forecast of net sales of natural gas are presented by province and by sector in Appendix 2-1. The presentation of the Board's forecast is followed by a comparison with the forecasts of Applicants and intervenors which is supported by Appendix 2-2 containing detailed data by sector of consumption and by province.

FIGURE 2-1

NET SALES OF NATURAL GAS COMPARISON OF FORECASTS



2.2.4 Methodology and Assumptions

2.2.4.1 Methodology

Evidence

CAGPL forecast natural gas demand by estimating total energy demand for Canada as a whole, then dividing the total energy demand among the sectors and provinces, and finally assuming a market share for natural gas. The total energy demand was forecast by assuming a constant ratio of 80,000 Btu's per dollar of real GNP. Multiplying the values of GNP by the energy/GNP ratio provided the energy demand forecast. This was allocated among the sectors and provinces judgmentally taking into account the historical experience and expected trends in economic and demographic growth. The allocation among fuel types was based on an analysis of historical trends in market shares and expectations regarding future trends.

Trunk Line did not use a total energy demand forecasting approach but did incorporate the relative gas/oil prices. It used an econometric model to forecast residential/commercial gas demand in Ontario and British Columbia to the early 1980's. For the residential/commercial sectors for Alberta, Manitoba, and Saskatchewan and for Ontario and British Columbia after the early 1980's, Trunk Line projections were based on overall relationships between residential and commercial gas consumption and households, and the expected penetration of gas. For the Quebec residential/commercial forecast, its forecast was prepared by ascertaining the proportion of new households available for gas service, recent price relationships and the indicated objectives of the Quebec Government with respect to energy.

For the industrial sectors from 1976 to 1981 for Ontario, Quebec and British Columbia, Trunk Line used an econometric model which related industrial gas consumption to the relative prices of natural gas and heavy fuel oil and the level of real manufacturing value added. For Manitoba and Saskatchewan, and after 1981 for Ontario, Quebec and British Columbia, gas demand was assumed to grow at rates equal to or slightly below the rates of growth in real manufacturing value added. In Alberta, industrial gas demand was assumed to grow at five per cent to 1985 and at three per cent thereafter. The reduced rates of growth in Alberta after 1985 reflected an assumption of a greater use of coal.

The methodology utilized by Imperial assumed a continuing linkage between energy use and economic activity. Imperial started with a national economic forecast which was used to develop regional energy demand projections for each of the three major end-use sectors - residential/commercial, industrial and transportation. These projections reflected Imperial's estimates of improvements in end-use efficiency arising from higher real energy prices and from demand-reducing initiatives. The energy demand in each end-use sector was divided among fuels on the basis of historical trends and its assumptions about future competitive relationships.

Gulf projected total primary energy demand by energy source and end-use sector. The forecast was based on historical consumption trends, along with population and housing projections and relevant economic indicators.

Shell forecast natural gas requirements by estimating total energy requirements for the various end-use sectors and then determining the likely market share for natural gas over the forecast period.

The methodology used by Dr. Helliwell was as follows: total primary energy demand (coal, electricity, crude oil, and natural gas) was estimated by region; this was then allocated among fuels through a market share mechanism based on relative prices. Finally, the fuels used to generate thermal electricity were estimated by a share mechanism also based on relative prices. The regional estimates of these items were added together to obtain the total demand for each fuel.

Views of the Board

In developing its estimates of the demand for natural gas in Canada, the Board adopted a total energy approach for those sectors of demand where a variety of fuels are used. In the Board method, forecasting of the demand for energy in these particular sectors was considered prior to and separately from the selection of fuel type.

The major end-use sectors which were considered by the Board in forecasting energy requirements were the residential, commercial, industrial, petrochemical and transportation sectors. In the residential, commercial and industrial sectors, demand for individual fuels was forecast by first determining energy demand in each sector using equations linking energy demand to forecasts of economic activity, population and energy prices. Then a set of market share estimates was applied to yield demands for individual fuels, including natural gas, in each sector.

The Board forecast of demand for natural gas feedstock for petrochemicals was based on an assessment of announced company plans and expected trends in the demand for petrochemicals.

In the transportation sector, energy demand was estimated separately for each of its various main segments, namely road, rail, air and marine. In each of these segments a model was developed incorporating the prime variables affecting demand. For example, automotive gasoline demand is forecast by estimating the stock of cars by age and weight class, and then applying estimated average miles driven and fuel economies per car according to type of car.

The Board forecast assumes no constraints on the supply of natural gas, that is, adequate supplies are assumed whether they come from conventional or frontier areas.

Given the uncertainties in predicting economic growth and future price levels of energy, three scenarios were evaluated. One scenario combined a high economic growth forecast with declining real energy prices to produce the high natural gas demand case. Another scenario combined lower than historic levels of economic growth with increasing real energy prices. This scenario results in the lowest natural gas demand. The third scenario and the one which was selected as the Board forecast is a combination of the lower economic growth and constant real international oil prices.

2.2.4.2 Demography and Economic Growth

Evidence

CAGPL's forecast assumed a decline in Canada's potential for future growth. This would be caused by slower growth in the working age population which would reduce the rate of growth of the labour force. A slowing trend in productivity gains associated with the move of activity towards the service industries was expected. The combination of these factors was estimated to reduce growth in real GNP to about four per cent per annum in the 1985-1995 period compared with an average of five to 5.5 per cent during the 1960's and early 1970's.

The rate of growth in GNP forecast by Trunk Line declined from five per cent in the 1975-1980 period to 3.4 per cent in the 1985-1995 period.

Imperial stated that natural gas demand projections must recognize that the low rate of growth in the 1974 to 1976 period was due to reduced rates of growth in the economy and that this in turn reduced total energy use. Imperial expected that these growth rates would recover from their below-trend performance by the mid 1980's.

Shell considered two economic growth rates, both feasible depending on the success with which the Canadian economy was managed and conditions in the world economy. However, it recommended the higher gas demand of Case 1 as the most appropriate for planning purposes to ensure gas availability would not restrict the economic growth rate.

CJL challenged the assumptions on economic growth used by CAGPL and Trunk Line stating that they did not take account of structural changes in the economy and consequently were overly optimistic as to the rate of growth.

Table 2-2 compares the growth rates for Gross National Product expected by Applicants and intervenors with those used in the Board forecast.

Views of the Board

The Board forecast employs a projection of economic growth arrived at by utilizing the CANDIDE econometric model of the Canadian economy. The forecast of economic activity is below rates experienced in the historical period 1960 to 1974, with real GNP growth moderating from the 5.3 per cent rate experienced in that period to an average of 4.6 per cent between 1977 and 1990. The real GNP for 1977 is assumed to rise by only 3.1 per cent. The real GNP growth is progressively reduced from 4.2 per cent in 1990 to 3.7 per cent by 1995.

The rate of increase in population is predicted to slow from an average 1.7 per cent over the historical period 1960 to 1974 to between 1.2 per cent and 1.1 per cent per annum over the forecast period. The resultant population in 1995 is 28.5 million. Other features characterizing the projection of the economy used by the Board are summarized in Table 2-3.

For the high economic growth scenario described previously, the Board employs the 1960 to 1974 historical growth rates for the economic and demographic variables for the 1980 to 1995 period.

Table 2-2

REAL GROSS NATIONAL PRODUCT - GROWTH RATES

Comparison of Forecasts

(per cent per annum)

Period	CAGPL	Trunk Line	Imperial	Gulf	Shell Case 1	Shell Case 2	NEB
1975-80	4.3 (1)	5.0	4.5	4.6	5.2	4.4	4.9
1980-85		3.6	5.2	4.8	4.8	3.5	4.3
1985-90	4.0	3.4	4.0	4.3	3.9	3.2	4.1

(1) Average for ten-year period.

Table 2-3

DEMOGRAPHIC AND ECONOMIC GROWTH

NEB Forecast

	1975 Level	Historical (per cent per annum) 1960-74	Forecast (per cent per annum) 1976-80	Forecast 1980-85	Forecast 1985-95	1995 Level
Gross National Product ($1961 billions)	79.0	5.3	4.9	4.3	4.1	185.2
Population (millions)	22.8	1.7	1.2	1.1	1.1	28.5
Households (millions)	6.9	2.9	2.7	2.4	2.4	11.3
Ratio of multiple (1) dwellings to total housing stock	0.42	0.42	0.44	0.46	0.49	0.49
Employment (millions)	9.3	3.1	2.4	2.5	2.5	15.2
Unemployment rate (2) (per cent)	7.0	5.3	7.5	5.7	4.6	4.6
Consumer price index (1) (1961 = 1)	1.85	1.67	2.56	3.34	5.71	5.71
Personal disposable income ($1961 billions)	55.8	5.1	3.6	4.1	3.6	116.4
Retail trade ($1961 billions)	27.8	4.8	4.0	3.6	3.4	56.0
Real domestic product in the industrial sector ($1961 billions)	26.5	5.5	5.9	4.1	3.9	63.0

(1) Annual level at period end shown, rather than growth rate.
(2) Period average shown, rather than growth rate.

2.2.4.3 International and Domestic Crude Oil Pricing

Evidence

The world or international price of crude oil is an important determinant of domestic crude oil prices and, in turn, domestic crude oil prices influence the price at which natural gas is sold in Canadian markets.

The Board heard evidence relative to the future world price of crude oil. All witnesses agreed that the future course of world oil prices was most uncertain, and that there were many difficulties in forecasting these prices. Future trends in supply and demand, and expected world-wide rates of inflation were the determining variables in the projections submitted. There were wide differences in the prices forecast. Projected international prices for crude oil landed in Toronto were based on the price of marker crude fob Persian Gulf, forecast tanker rates, and estimated pipeline tariffs.

CAGPL projected as a "conservative estimate", nominal annual increases in world crude oil prices of five per cent until 1982 and seven per cent thereafter. CAGPL forecast that until 1982, there would be surplus productive capacity available within OPEC, and, furthermore, that a large portion of expected market expansion would be supplied by non-OPEC sources.

In these cicumstances, CAGPL predicted that OPEC price increases would just keep pace with the rate of inflation in the western world, averaging five per cent annually. After 1982, CAGPL predicted that because of a tightening of world crude oil supply, OPEC could obtain price increases exceeding the rate of inflation. To estimate international crude oil prices in

Toronto, CAGPL assumed transport costs from the Persian Gulf to remain at a nominal $2.00/bbl. CAGPL's forecast was based on a report prepared by W.J. Levy Consultants Corp. of New York submitted as an exhibit to the hearing. No representatives of W.J. Levy testified before the Board but the report was adopted as the views of CAGPL.

Foothills held that world crude oil prices would increase slightly in real terms to the early 1980's relative to the Canadian rate of inflation. Assuming additional production from non-OPEC sources, and increased conservation, Foothills predicted that the world price would decline in real terms in the mid-1980's. Beyond 1990, Foothills forecast that increasing pressure on OPEC sources of supply would result in world prices increasing in real terms. Foothills predicted that tanker rates would decline in real terms to 1980 and remain constant in real terms thereafter.

Imperial estimated that nominal prices would escalate from 1976 levels at five per cent annually until 1982 and at seven per cent annually thereafter.

Shell forecast a nominal price of $15.00/bbl. fob Middle East in 1980, and estimated that it would increase at an average rate of seven per cent annually.

Applicants and intervenors expected domestic crude oil price would reach world levels between 1980 and 1982.

Views of the Board

There are a large number of unknowns, both political and economic, which make future levels of world or international oil prices very uncertain. Because such a wide range of future prices is possible, as previously mentioned, the Board has examined possible natural gas demand under three different price assumptions as to world oil prices. The assumptions considered were constant real prices, then real prices rising at about five per cent per year and finally real prices falling at a rate equivalent to approximately five per cent per year. For its forecast, the Board assumed that the world price of crude oil will remain constant in real terms at its 1975 level.

The domestic price of crude oil is assumed to rise towards the world price of oil, approaching it in 1980.

2.2.4.4 Natural Gas Pricing and Interfuel Competition

Evidence

Applicants and most intervenors appearing before the Board assumed that natural gas at the city-gate in Toronto would be priced at the Btu commodity value of crude oil at the refinery gate by the early 1980's (see Table 2-4). However, some intervenors felt that natural gas should instead be priced at a premium while others felt that gas should be priced below its full commodity value to encourage the substitution of domestic natural gas for imported crude oil.

Table 2-4

NATURAL GAS VS CRUDE OIL PRICES

Applicant or Intervenor	Expected Year of Btu Equivalence
CAGPL	Early 1980's
Trunk Line	By 1980
TCPL	By 1981
Imperial	By 1982
Gulf	Early 1980's
Shell	By 1981
Saskatchewan	Early 1980's
Helliwell	By 1980

Although CAGPL testified that it expected price equivalence between crude oil and natural gas at the city-gate would not occur until the early 1980's, its forecast, which had been prepared in 1974, was based on the assumption that the equivalence would occur in 1977 or 1978.

CAGPL, TransCanada, Union and Consumers' all discussed the present price competitiveness of natural gas and oil in the Ontario market. It was acknowledged that natural gas was at a slight disadvantage compared to heavy fuel oil in the industrial sector and at an advantage, sometimes significant, when compared to light fuel oil in the commercial and residential sectors.

CAGPL stated that it was necessary to hold natural gas prices at 85 per cent of commodity value of crude oil in order to maintain the competitive position of natural gas. Furthermore, it argued that significant economic incentives would be required to encourage any substitution. CAGPL expressed the view that a

75 per cent commodity value equivalence pricing for natural gas would encourage substitution of domestic gas for foreign oil. Similarly, TransCanada maintained that the present Toronto city-gate price would have to be decreased by at least 10 per cent to secure a significant degree of conversion by industrial customers using heavy fuel oil.

Union stated that natural gas had a competitive advantage over light fuel oils but that it was having difficulty remaining competitive with residual fuel oil in the large industrial market. Therefore, it recommended that there should be no upward change in the relative price of gas as compared with crude oil. It stated that, in the residential market, natural gas had a price advantage of approximately 10 per cent over light fuel oil, and a greater advantage over electricity. Specifically it stated that at the burner tip, in the residential market, gas had an advantage of from 20 to 25¢/MMBtu over light fuel oil. However, this advantage could be eliminated by the need to adjust residential rates because of the higher cost of its incremental supplies such as synthetic natural gas from Petrosar. Union concluded that if the wholesale price of gas, at the city-gate, reached 100 per cent of the commodity value of crude oil "not only could it not be marketed, but Union would lose a very large proportion of its present sales".

Consumers' testified that if city-gate gas prices increased to a price equivalence with crude oil, gas could lose some markets. It stated that in late 1976, Consumers' was selling natural gas in competition with heavy fuel oil at close to a 25 per cent competitive disadvantage. If gas prices increased from the present 85 per cent of crude oil equivalent pricing to 100 per cent, then Consumers' could lose a significant portion of its market to heavy fuel oil suppliers. According to Consumers' one of the reasons that it would lose customers if natural gas and crude oil were priced similarly was that it costs more to get gas from the city-gate to the burner tip than it does to get oil from the refinery gate to the burner tip. Another reason was that refiners might not allocate crude oil price increases evenly among the various grades of fuel they manufacture, thus undercutting natural gas prices in certain markets.

Dr. Helliwell concluded that gas from the Mackenzie Delta would have to be sold at much less than the commodity equivalence price if it were to displace imported oil. Specifically, he maintained that even with natural gas priced at 85 per cent of commodity value at the Toronto city-gate, a market would not be created for volumes such as those anticipated from the Mackenzie Delta. Any further price reduction would, in his view, be impossible because then the Delta gas would be uneconomic to produce.

The Industrial Gas Users Association concluded that there would be little or no chance of natural gas penetrating any further into the industrial market if it were priced at or above parity with heavy fuel oil. Furthermore it concluded, based on the likelihood of heavy fuel oil surpluses which will tend to hold prices below the crude oil Btu equivalent, that heavy fuel oils will remain competitive with natural gas. Therefore, it recommended that for the next few years, at least, the price of natural gas should stay at approximately the 85 per cent level of indexing.

Notwithstanding the evidence as to the price incentives required to induce the substitution of natural gas for oil, CAGPL and some intervenors provided estimates of the substitution potential or included such potential in their submitted forecasts.

CAGPL stated that during the next ten years there would be considerable opportunities and potential for substitution of natural gas for fuel oils. It estimated that if 15 per cent of the base light fuel oil and heavy fuel oil market in Ontario and Quebec and 50 per cent of the growth in the oil market from 1975 were to be taken over by gas, then the 1995 demand could be increased to 3,856 Bcf from 3,495 Bcf (excluding any expansion of the Quebec franchise area). It stated that, in the short run, interfuel substitution would involve primarily oil and gas since coal and electricity were not readily capable of capturing much of the space-heating market irrespective of comparative prices. CAGPL maintained that the replacement of imported oil by domestic natural gas in certain markets could be the rationale of federal policies for reasons of security of supply and balance of payments.

TCPL's forecast was predicted on the assumption that Canada would strive for self-reliance in energy. Beginning in 1981, the share of incremental energy demand captured by natural gas was increased in all provinces, and in Quebec, expansion of the service area was also assumed.

Gulf stated that approval of a frontier pipeline system would alleviate the fear of shortages and allow distributors and users of natural gas to plan future consumption based on increased security of supply. It predicted that the share of energy provided by natural gas would increase from 22 per cent in 1975 to 28 per cent in 1995.

Imperial noted that the range of variability in the Canadian natural gas demand outlook was significant. Factors that could result in a lower rate of growth include lower than assumed economic growth or no increase in the share of the energy market supplied by natural gas. A higher growth rate could result from greater substitution of natural gas for other fuels leading to a higher market share for natural gas. Any slippage in achieving the assumed hydro, nuclear or coal supply programs could also lead to a higher growth rate for natural gas. Imperial stated that a reasonable estimate of the variability in Canadian demand for gas could be as much as ± 300 Bcf in 1985 and ± 600 Bcf in 1995 (above or below Imperial's base case).

Imperial stated that reduced gas demand in 1975 and 1976 was partly caused by a perception of supply constraint. Its forecast assumed a reversal of this trend, contingent in large measure on early approval of a Mackenzie Valley pipeline. Imperial forecast a rate of increase in hydro and nuclear generation substantially in excess of the growth rate for total energy. It noted that its assumed nuclear generation development pace implied the completion of a major plant (Pickering size or larger) each year between 1985 and 1995. Imperial expected the share of total energy supplied by oil and gas to decline from 65 per cent in 1975 to 54 per cent in 1995.

For purposes of demand forecasting, Shell assumed adequate supplies of all conventional fuels. A physical shortage of any of these fuels would introduce revisions to the forecast. It would be important to the growth of natural gas sales to convince industrial customers, particularly, that there would continue to be a supply of natural gas available to them. Shell stated that there were several markets which would be candidates for substitution of natural gas for oil products if transportation/distribution costs could be overcome. These markets were held to be uneconomic under its present assumptions. The potential gas consumption in these new markets or through substitution was estimated as follows (Bcf per annum):

	1985	1995
New Markets		
Vancouver Island	21	56
Quebec	35	200
Maritimes	170	190
Displacement of oil in present gas service areas	230	540
Total potential additional gas consumption	456	986

Shell stated that relative pricing with respect to competing fuels would be important in determining the share of energy requirements to be supplied by natural gas. It observed that the availability of fuels, or perhaps more important, the customer's perception of the continuity of fuel supplies was also important in determining the market shares captured by different fuels. Shell expected customers to recognize a competitive advantage for natural gas relative to oil products even at a price equivalence on a Btu basis in each market. This advantage was attributed to lower capital costs for new installations and to lower operating and maintenance costs for existing installations.

Views of the Board

The Board forecast assumes that the city-gate price of natural gas in Toronto will increase to parity with the price of crude oil at the refinery gate on a Btu equivalent basis in 1980. In developing the market share estimates for oil and gas, this parity was assumed to result in approximate price equivalence on a Btu basis at the burner tip for industrial customers in Southern Ontario and British Columbia.

The Board accepts that there is a considerable potential for interfuel substitution among all energy forms. However, it believes that the substitution of frontier gas for imported oil would not come about in markets now served with imported oil without certain policies or conditions coming into existence. Examples of such conditions would be a world wide shortage of oil, government intervention to require certain current users of oil to switch to natural gas, or government intervention to price natural gas significantly lower than competing oil products. In the absence of positive incentives as described above there would be few economic reasons to switch to gas.

2.2.4.5 Expanded Service Areas

There was considerable difference of views as to the likelihood of expansion of gas franchise areas. The three regions where an expanded natural gas network is possible are Vancouver Island, the Province of Quebec and the Atlantic Provinces.

Evidence

Vancouver Island

With regard to the extension of service to Vancouver Island, varying views were expressed as to whether or not such an extension would take place.

CAGPL's, Trunk Line's and Imperial's forecasts included natural gas demand on Vancouver Island while Shell and Gulf did not expect gas service to be extended to this market.

Westcoast did not include service to the Island in its requirements forecast. It noted that the economic viability of this service would depend upon the immediate conversion of many of the large industrial plants from fuel oil to natural gas. Westcoast stated that with price parity at the burner tip, large industrial users on Vancouver Island would find conversion to gas too expensive while the Island's residential/commercial market by itself would not be economically viable.

B.C. Hydro submitted a forecast of potential natural gas demand on Vancouver Island increasing from 3 Bcf in 1981 to 31 Bcf in 1995. B.C. Hydro stated that there were no firm plans at this time to provide gas service to Vancouver Island. B.C. Hydro noted that gas costs would be higher on the Island than on the Lower Mainland.

None of the Applicants or intervenors presented studies which would have enabled the Board to assess the economic viability of a pipeline extension to Vancouver Island.

Quebec Service Area

There were conflicting views as to whether the natural gas service area in Quebec would be expanded. CAGPL, Trunk Line, TransCanada and Imperial included additional volumes in their forecasts for an expanded franchise area, although they adduced no evidence to show that an expansion would be economically feasible. According to Imperial, extension of the current franchise area would require removal of the eight per cent provincial sales tax on natural gas and very aggressive marketing.

Neither Gulf nor Shell included an expanded market area in its forecast. Shell estimated the potential demand but stated that such service would be uneconomic under its forecast assumptions because of the high transmission and distribution costs involved.

Gaz Métropolitain provided estimates of potential demand in an expanded service area, including markets which could be served by liquefied natural gas. It submitted the following timetable for expansion relative to its high natural gas demand forecast: in 1978, service would be extended to Bécancour, Ste-Hyacinthe and Drummondville; in 1979 to Trois-Rivières, Cap-de-la-Madeleine, Shawinigan, Grand-Mère, Grandby and St-Jean; in 1980 to Sherbrooke; in 1981 to Québec; in 1982 to Lévis, Lauzon, and Joliette. It stated that expansion would not take place unless natural gas were priced 15 to 20 per cent lower than competing oil products. No studies were submitted by Gaz Métropolitain on the economics of extending gas service in the Province of Quebec.

Atlantic Region

Only one intervenor, Gulf, forecast significant increases in natural gas demand in the Atlantic Provinces. Gulf expected natural gas markets would be developed as East Coast offshore production commenced. This was shown as beginning after 1990 with the net sales reaching 66 Bcf in 1995. Shell provided estimates of a potential market of 190 Bcf in 1995 but did not include these volumes in its submitted forecasts.

Views of the Board

Vancouver Island

No evidence was adduced to demonstrate the feasibility of a pipeline to Vancouver Island and therefore the Board has not made any provision in its forecast for such service. However, if service were extended, the Board estimates that the potential demand would be in the order of 50 Bcf in 1995.

Quebec Service Area

None of the Applicants or intervenors presented studies to demonstrate that servicing an expanded Quebec franchise area would be economically viable. Nevertheless, the Board believes that, under certain conditions, there would be a considerable potential for market expansion. Examples of conditions which would encourage the expansion of the natural gas use in Quebec would be a reduction of the price of natural gas relative to competing oil products, the elimination of the sales tax on natural gas, or a world shortage of oil.

At the present time, relative prices of natural gas and refined petroleum products do not particularly favour the expansion of the franchise area in Quebec. The Board does, however, believe that the growth in natural gas demand will be strong in that province. The predicted growth rate in net sales of natural gas in Quebec is expected to be 5.8 per cent over the 1977 to 1995 period, significantly higher than the 3.3 per cent growth predicted in the adjacent Ontario market and the 3.8 per cent growth in the total Canadian market. The growth in Quebec implies that the market share for natural gas in Quebec will increase from 6.7 per cent in 1977 to 11.0 per cent in 1995. Some expansion in the present distribution network might be necessary to achieve these levels of natural gas demand, although the Board believes that the expansion would take place more slowly than the timetable contained in the Gaz Métropolitain evidence.

Atlantic Region

The Board believes that while there is a potential for natural gas in the markets of the Atlantic region, such markets are not likely to be served by conventional Alberta sources or by Mackenzie Delta gas. Accordingly the Board has not included any gas demand for this region in its forecast.

2.2.4.6 Effect of Conservation

Evidence

CAGPL stated that to allow for the likely future effect of price and conservation, growth in total energy demand by 1995 was reduced by about 20 per cent from the business-as-usual trend. The rate of economic growth was also reduced over the forecast period. A further 10 per cent reduction in gas demand could be brought about by greater conservation efforts which would reduce its forecast by 350 Bcf in 1995. CAGPL divided conservation into two categories according to motivation, that is, a) economic or price motivated and b) ethical. CAGPL stated that ethical conservation, being emotional, was less likely to be permanent. Conservation motivated by higher prices was difficult to measure. It would be unwise to assume that the total potential for energy conservation would be achieved. It was possible to estimate the potential for conservation but it was not possible to predict accurately the degree to which the potential would be realized and over what length of time. There would, no doubt, be further gains in the efficiency of energy utilization but CAGPL stressed the need to recognize that the scope for further progress is limited by the large efficiency gains already achieved.

Trunk Line estimated that conservation would reduce residential/commercial gas demand by eight per cent by 1995. The effect of conservation on industrial gas demand was incorporated by reducing the industrial gas requirements/manufacturing value added ratio for the period 1986-1995.

Shell estimated that conservation would reduce natural gas demand in 1990 by six per cent in the industrial sector, nine per cent in the commercial sector and 15 per cent in the residential sector.

Gulf expected that various conservation policies would result in energy savings of up to 20 per cent of the non-conservation amount in 1995.

TCPL submitted two forecasts, one based on historical consumption factors and the other based on making allowances for conservation. In 1995, the conservation allowance was estimated to reduce residential/commercial energy demand by 26 per cent and industrial energy demand by 15 per cent.

Westcoast's forecast assumed a constant natural gas use per residential customer throughout the forecast period, contrary to the historical experience of growing consumption. It believed that this adequately provided for the effect of conservation in this sector. In the industrial sector, Westcoast reduced its forecast of gas demand to reflect the tendency to utilize energy sources such as "hog fuel" (mainly fuel from wood waste).

B.C. Hydro expected improved insulation standards would reduce natural gas demand for residential space-heating by 15 per cent in 1986. However, the possible reduction in use resulting from voluntary conservation, elimination of pilot lights, etc. would be outweighed by swimming pool additions, and the increasing use of dryers and fireplaces.

Pilkington stated that it was continuing the modifications of its glass furnaces and had already achieved reduction of nine per cent in the amount of natural gas consumed per ton of glass manufactured.

The Motor Vehicle Manufacturers' Association stated that the industry was vigorously undertaking energy conservation activities in its manufacturing processes. Its goal was to reduce the amount of energy used per unit of value added by 15 per cent between 1972 and 1980. The Motor Vehicle Manufacturers' Association testified that the industry was on track for the 1980 target of 24 miles per gallon for new cars. It stated that a large part of the fuel economy would be achieved by reducing the mass of vehicles by means of more precise engineering of the body structure. In turn the reduction of mass results in savings in the manufacturing process as there is less metal to heat up during various production steps.

CIC stated its belief that a halt should be called to what appeared to it to be a mindless expansion of energy delivery systems and that Canada should move away from promoting exponential growth in energy demands by instituting sound conservation programs.

The Workgroup on Canadian Energy Policy and Energy Probe provided witnesses who testified as to the potential reductions in demand because of conservation measures. These witnesses also testified that there was a possibility of a change in lifestyles which would lead to a society less oriented to energy consumption. They noted government announcements on minimum standards for automobiles and furnaces, reduced taxes on insulating material, accelerated capital cost allowances on energy saving equipment and higher insulation standards (through Central Mortgage and Housing Corporation). A new national standard for insulation of new buildings was expected to be adopted by several provinces by the end of 1978.

Evidence was submitted by the Workgroup on Canadian Energy Policy and Energy Probe as to measures which would reduce energy consumption in the transportation sector, particularly motor gasoline. It was stated that savings of 30 per cent were probable in the commercial sector by 1980 or 1981. They testified that a conservative estimate of savings in the industrial sector would be 12 per cent by 1980 and 25 per cent by 1990 using 1972 as a base. Their witnesses testified that conservation was the cheapest, quickest, and most certain approach to solving the energy supply/demand problems. They testified that total energy demand growth of 2.1 per cent had a high probability and that demand growth could be even less with a "conserver society" approach.

Dr. David Barry Brooks, testifying for the Workgroup on Canadian Energy Policy and Energy Probe, suggested that the "technical fix" approach to conservation was the easiest and most painless conservation policy. The "technical fix" approach was defined as an approach in which government action is taken to obtain greater economic efficiency than could be achieved by the market mechanism alone. This approach would seek to meet demand in the most efficient manner possible without seriously altering lifestyles.

Archbishop Edward Walter Scott, testifying for CJL, maintained that a moratorium on northern pipeline construction was feasible because of various supply and demand alternatives available. He stated that the major demand alternative would be the adoption of a conservation program which would move in a determined fashion toward stable per capita energy consumption.

Dr. Frederick Michael Bradfield, testifying for CJL, stated that the Board should encourage conservation by denying additional supply from the Mackenzie Delta. He also stated that a significant portion of the population had become more sensitive to questions of economic growth and that people would move towards lifestyles which emphasize quality of life rather than economic growth. Dr. Bradfield believed that CAGPL had underestimated the effect of conservation by not giving sufficient weight to the effect of technological change in reducing energy demand.

Mr. Gerald Vandezande testified for CJL that there should be a substantial reduction in the annual increase in per capita energy consumption through the elimination of energy waste and through demand-reduction programs. CJL believed that the question of the need for frontier gas should be decided on the basis of an energy policy which expressed "conserver" rather than "consumption" values.

Views of the Board

The Board expects that significant and increasing conservation of all energy types will take place over the forecast period as consumers respond to higher energy prices combined with supporting government-sponsored conservation initiatives. In developing its forecast of energy demand, with the exception of requirements for road transportation, the Board has assumed that price will be the main driving force which will result in energy conservation, and that substantial conservation will not arise simply from appeals urging adoption of conservation measures unless the economic considerations involved are favourable to such conservation.

Some of the price-driven response expected by the Board will presumably be brought about by relying solely on market forces to produce an adaptation of demand to higher energy prices. To some extent these forces may have to be supplemented by suitable public information programs so that people will have access to the knowledge required to make intelligent economic choices. In other areas of the market, legislative changes may well be required to reinforce the price effect in order to overcome the market resistance and/or imperfections which might delay response to higher energy prices. In such an event, the Board has assumed that all such legislation would be based on economic considerations. An example of legislative changes of this nature is the revision of building codes requiring increased insulation for new construction. The Board assumes that these insulation standards will not be improved beyond levels which will be economic for the owners of new buildings. Notwithstanding any such facilitating measures, the method adopted by the Board to estimate conservation effects assumes that there will be a substantial time-lag before the market responds fully to higher energy prices.

The conservation effect on electricity demand is expected to be less than that for other fuels. For electrically-heated homes higher insulation standards than those generally applicable have already been in effect in some provinces. Accordingly, the Board has assumed that, by retrofitting to higher insulation standards, there is more scope for energy savings in dwellings heated by fossil fuels than in those which are heated electrically.

Regarding natural gas, the Board estimates that compared with a "no conservation" situation, demand in the combined residential, commercial, and industrial sectors will be reduced by approximately seven per cent in 1980, increasing to 12 per cent in 1985 and 17 per cent in 1995. It is in these three sectors that most of the gas is consumed and most of the savings are expected to occur. The impact of conservation is expected to be largest in the industrial sector. In contrast to these estimates for conservation of natural gas, the corresponding figures for the effect of conservation on the demand for all forms of energy in these sectors combined with the transportation sector are estimated to be eight per cent in 1980, increasing to 15 per cent in 1985 and 20 per cent in 1995. Examples of the types of anticipated consumer actions range from lower settings of thermostats to improved insulation in buildings and investment in more energy-efficient facilities.

The Board recognizes that there exists a potential for larger savings but believes it is prudent to take a middle course in estimating these effects until there is more evidence to show that the full potential for conservation savings will actually be achieved.

2.2.4.7 Alternative Energy Sources

Evidence

CAGPL maintained that the pattern of energy consumption was set for the ten years ahead because of the long lead times required to develop and implement new technology. For this reason, CAGPL concluded that by the late 1980's, oil and gas would still supply the bulk of energy demand, estimated at about 77 per cent in 1975. CAGPL expected that alternative renewable energy sources such as wind, solar, geothermal or biomass would contribute little to Canada's overall energy supply before 1995.

Shell did not consider solar energy and other renewable resources to be competitive enough to warrant consideration in estimating demand for natural gas in Canada.

Energy Probe and the Workgroup on Canadian Energy Policy referred to various estimates prepared by others of the potential for alternative energy sources (such as solar, wind, biomass) in meeting energy deficiencies in Canada. These estimates ranged from two to four per cent in 1990. It was the view of these two intervenors that these figures underestimated the contribution that could be made by such sources. Principal contributions to energy supply mentioned were active and passive solar space-heating and water-heating in residential and commercial buildings, the use of biomass, specifically wood, in the industrial sector and the use of methanol from wood in a motor gasoline blend. The latter could reduce gasoline consumption by 15 to 20 per cent. The Workgroup on Canadian Energy Policy and Energy Probe argued that the approval of a Mackenzie Valley pipeline could have a restraining effect on the development of alternative energy sources.

Views of the Board

The Board recognizes that alternative renewable energy sources could contribute significantly to Canada's energy supply over the long run. Because of the inherent uncertainties involved in developing new technologies, the Board has opted for a conservative approach to estimating the probable market share for such energy sources. The Board sees a potential for solar heating in the residential and commercial sectors and for the use of biomass in the industrial sector. The share of the market is assumed to vary among regions. At the output or useful Btu level, the market share of solar energy assumed for the residential/commercial sectors varies from three per cent in Ontario to 4.5 per cent in the Atlantic region in 1995. In the industrial sector renewable energies are assumed to contribute up to 2.5 per cent in 1995 in some regions. Reductions in energy demand because of passive solar heating is shown as conservation. Biomass (as methanol) is not expected to become economical in the transportation sector until the 1990's.

The overall share of Canada's primary energy demand which the Board estimates will be met by renewable energy sources (other than hydro) is 1.4 per cent in 1995. This share is somewhat less than that predicted by the studies referred to by the Workgroup on Canadian Energy Policy. The Board believes that for these renewable resources to achieve a market share of two per cent of total primary energy by 1990 would require the construction of 8,000 solar housing units in 1978, 20,000 in 1980, rising to 60,000 in 1990. The Board does not believe such a rapid movement towards solar-heated houses will take place. The two per cent contribution of renewable energy predicted by Middleton Associates in their report "Canada's Renewable Energy Resources: An Assessment of Potential" would also require the construction of 30 windmills each generating 400,000 KWH/year each year between now and 1990. The Board does not see such contributions taking place this rapidly.

2.2.5 Views of the Board on Natural Gas Demand

2.2.5.1 Board Forecast

In the preceding sections the Board's methodology and assumptions have been outlined. This section presents the Board forecast of total primary energy demand and natural gas demand.

As shown in Table 2-5, the Board expects total primary energy demand to grow from 8,482 trillion Btu's in 1977 to 16,008 trillion Btu's in 1995. Domestic natural gas demand (net sales plus pipe line fuel and losses) is expected to increase from 1,594 trillion Btu's in 1977 to 3,058 trillion Btu's in 1995. In terms of percentage of total primary energy, the natural gas share remains at about 19 to 20 per cent throughout the forecast period.

Table 2-5

PRIMARY ENERGY DEMAND

NEB Forecast

(10^{12} Btu's)

	Natural Gas[1]	Oil	Coal	Solar	Hydro & Nuclear Electricity	Total[2] Primary Energy
1960	345	1,784	557	0	1,015	3,700
1977	1,594	3,907	755	0	2,227	8,482
1980	1,909	4,227	919	0	2,615	9,671
1985	2,283	4,633	1,118	0	3,361	11,394
1990	2,649	5,062	1,341	94	4,386	13,533
1995	3,058	5,597	1,630	217	5,504	16,008

1 Natural gas demand is defined in this table as net sales plus pipeline fuel and losses. Reprocessing shrinkage and field plant uses and losses are not included.

2 Totals may not correspond exactly to detailed figures due to rounding.

Table 2-6 illustrates the historical rates of growth in demand for natural gas (net sales plus pipeline fuel and losses) and total primary energy and compares these growth rates to the rates implicit in the Board's forecast. As can be seen from the table, the Board is predicting that the rates of growth in primary energy and natural gas demand will fall from historical levels. This occurs in response to expected higher energy prices and lower economic growth than was experienced in the 1960 to 1975 period.

Table 2-6

PRIMARY ENERGY DEMAND

GROWTH RATES

NEB Forecast

(per cent per annum)

Period	**Natural Gas**	**Total Primary Energy**
1960-1975	10.1	5.1
1975-1980	5.4	4.5
1980-1985	3.6	3.3
1985-1990	3.0	3.5
1990-1995	2.9	3.4
1977-1995	3.7	3.6

Details of the Board forecast by end-use sector and by province are presented in Appendix 2-1. Demand for natural gas in Canada and for export is shown in Table 2-8.

As discussed in Section 2.2.4.1 the Board prepared three demand scenarios which combine three different world crude oil price assumptions with two economic growth scenarios. These assumptions are summarized as follows:

Table 2-7

NEB ENERGY DEMAND SCENARIOS

Basic Assumptions

Scenario	Economic Growth	World Crude Oil Prices	
High	High	Low:	Constant in Nominal Terms
Most Likely	Medium	Medium:	Constant in Real Terms
Low	Medium	High:	Rising in Real Terms at 5 per cent per annum

The Board estimates of natural gas net sales under the three economic growth/price scenarios are illustrated in Figure 2-2. The scenario designated as the "most likely" is the one which has been adopted as the Board forecast.

The current Board forecast of natural gas demand is considerably lower than the forecast published by the Board in April 1975 as part of the report "Canadian Natural Gas: Supply & Requirements". There are a variety of reasons which have tended to move the forecast in a downward direction. In the short-term period 1975 to 1977 the growth in the economy was considerably less than predicted by the Board in its April 1975 report. This factor, combined with strikes in some energy-intensive industries during the same period, tended to decrease the industrial demand for natural gas to lower levels than predicted. As well, the

Table 2-8

NATURAL GAS DEMAND

NEB Forecast

(Bcf/Year)

	Total Net Sales	Pipeline Fuel & Losses	Domestic Demand	Reprocessing Shrinkage	Exports	Total Demand At Plant Gate
1977	1456	138	1594	101	1045	2740
1978	1560	144	1703	104	1044	2851
1979	1649	149	1798	134	1040	2972
1980	1754	155	1909	164	999	3072
1981	1830	159	1989	157	967	3113
1982	1893	159	2052	164	911	3128
1983	1954	163	2117	164	911	3193
1984	2018	168	2186	168	911	3265
1985	2110	173	2283	153	896	3332
1986	2168	175	2343	144	803	3290
1987	2247	176	2423	136	660	3219
1988	2326	181	2506	134	657	3297
1989	2404	186	2591	133	539	3264
1990	2473	176	2649	132	215	2996
1991	2545	174	2719	127	124	2970
1992	2619	180	2799	125	55	2980
1993	2703	184	2887	128	46	3061
1994	2786	188	2974	128	8	3110
1995	2864	194	3058	128	6	3192

Note: Totals may not add due to rounding.

NET SALES OF NATURAL GAS
NEB SCENARIOS

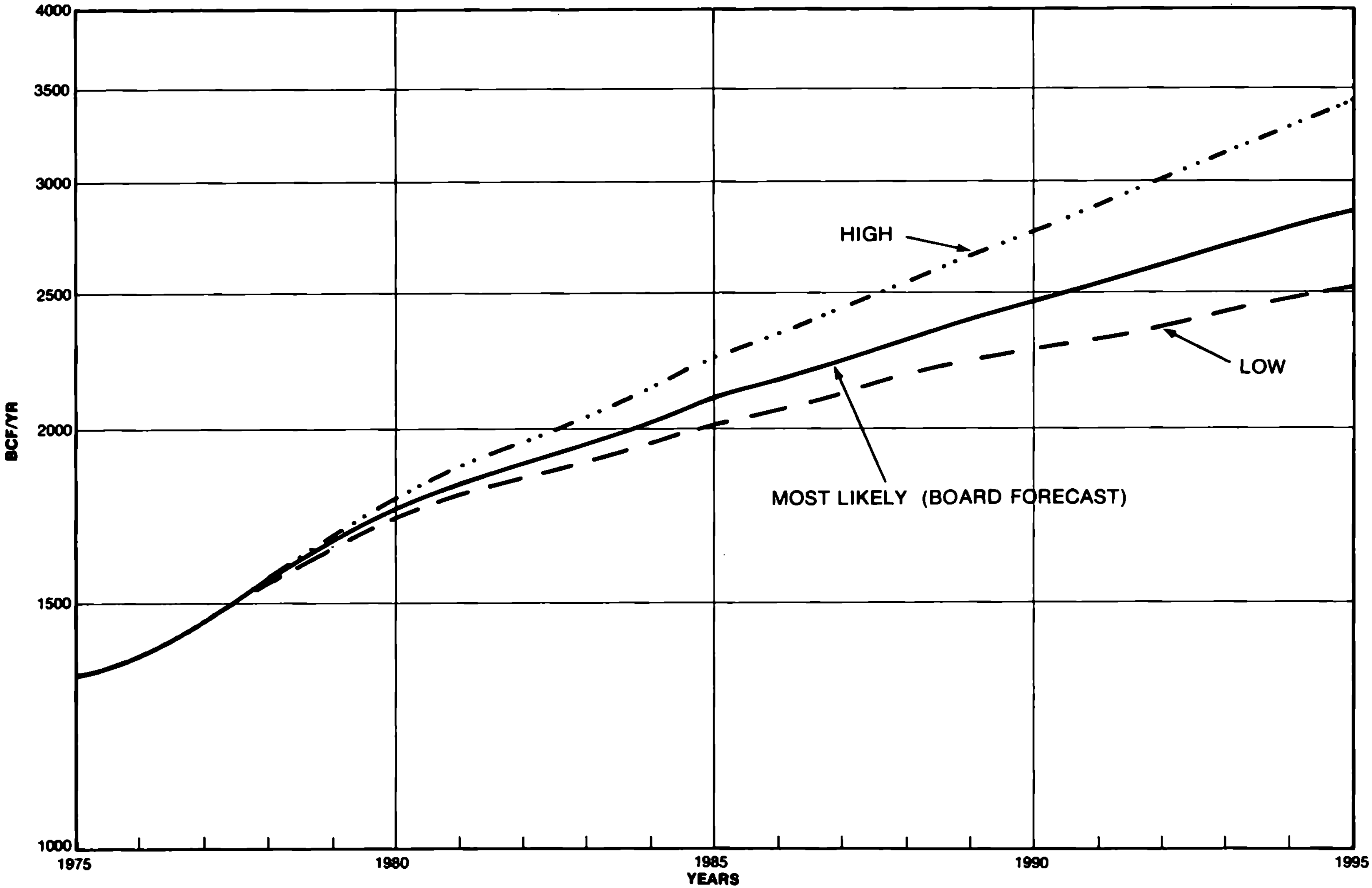


FIGURE 2-2

price of heavy fuel oil in some Eastern Canadian markets was below the price of natural gas to the industrial sector. This price relationship was the opposite to the relative price assumption underlying the 1975 forecast. As noted in the 1975 Report, the 1975 forecast was a demand forecast unconstrained by supply and did not take into account the reduction in growth rates which would be brought about by actual or perceived shortages of supply. The Board believes that some potential natural gas sales have been lost because some gas distributors have been unable to sign long term supply contracts. All these items serve to lower the base from which the long-term gas projection is made. Over the longer term, the present forecast is lower than the 1975 forecast because of a somewhat lower expected rate of economic growth and an assumption that increased energy prices will result in considerably more conservation than was foreseen when the Board forecast was completed in 1975.

The current Board forecast of oil demand is essentially the same as the forecast (Scenario I) presented in the Board report "Canadian Oil: Supply and Requirements" dated February 1977, with primary oil demand differing by only some two per cent in 1995. The natural gas demand forecast in the present report is also very similar to the forecast prepared for, although not published in, the oil report. Specifically, the Board's present natural gas forecast is approximately four per cent higher throughout the mid 1980's and somewhat less than seven per cent higher in 1995 than the gas forecast made for the oil report.

While the natural gas and oil demand forecasts have changed insignificantly from the oil report, the Board's present forecast of total primary energy demand is somewhat higher than the "expected case" presented in the oil report. This comment is particularly applicable in the later years of the forecast period, although the new forecast remains within the range of forecasts presented in the oil report.

There are two main reasons for the present forecast of total primary energy demand differing from the forecast in the oil report. The evidence of the present hearing and further work by the Board have resulted in the adoption of a somewhat higher economic growth scenario for the later years of the forecast period. This approach was considered by the Board to be more appropriate although the higher growth rates in the later years have little impact upon the current decisions before the Board. The other main factor leading to an increase in the forecast of primary energy demand has been a recent re-examination of expected electricity demand in Canada by the Board. The electricity demand in this report is significantly higher than the demand incorporated but not published in the oil report. It may be noted that an increase in electricity demand induces an even larger increase in the Board forecast of primary energy demand. The Board procedure assumes that all electrical generation requires roughly three units of primary energy to produce one unit of electricity.

2.2.5.2 Comparison of Forecasts

In this section forecasts of natural gas demand presented by Applicants and intervenors are discussed in relation to the Board forecast. In Appendix 2-2 the same forecasts are compared in tables providing details by province and by sector of consumption. The forecasts are compared at the net sales level to eliminate differences among the forecasts in the treatment of pipeline fuel and reprocessing shrinkage.

As described in the preceding sections, the various forecasts are based on different assumptions as to the expected rates of economic growth, the effect of higher prices on reducing demand, the possibility for expanded service areas for natural gas and the market shares for gas in existing service areas.

CAGPL's forecast is considerably higher than the Board forecast throughout the forecast period with the difference in total net sales widening from 277 Bcf in 1980 to 735 Bcf in 1995. There are several reasons for the difference; among these are the Board's lower estimate of total energy demand, a higher share of electricity demand in the end-use markets, and a lower petrochemical demand. In testimony CAGPL stated that its petrochemical forecast was on the high side, that its electricity forecast was too low, and that its estimate of total energy consumption of 522 MMBtu per capita was also on the high side. CAGPL conceded that its forecasts for 1974, 1975 and 1976 overestimated the actual sales for those years. However, it believed that the growth rate from 1977 to 1980 would be such that the actual levels of sales in 1980 would correspond to its original forecast. The Board believes that the growth rates in demand necessary to regain the 1980 level forecast by CAGPL are not realistic. Indeed, for purposes of its deliverability studies presented elsewhere in this report, CAGPL reduced its demand forecast between 1976 and 1980.

The Board forecast of net sales is lower than that of Trunk Line throughout the forecast period. The difference is 134 Bcf in 1980 and 28 Bcf in 1995. The Board has assumed that increased energy prices will reduce demand to a greater extent than did the Trunk Line forecast. In testimony, Trunk Line's witnesses stated that it believed that its forecast was on the high side.

The reasons for the differences between the Board forecast and the intervenors' forecasts have been presented in the preceding sections on methodology and assumptions.

2.3 CANADIAN CONVENTIONAL PRODUCING AREAS

2.3.1 Reserves of Gas

2.3.1.1 Established Reserves

Estimates of reserves in the conventional producing areas as of 31 December 1975 were submitted by CAGPL, Trunk Line, Westcoast and Gulf. Westcoast also provided an estimate up-dated to 31 December 1976. These estimates are discussed in this section and are compared with the Board estimate in Table 2-13.

CAGPL

CAGPL submitted estimates of remaining reserves at a pressure base of 14.65 psia and estimates of both initial and remaining reserves at 1,000 Btu/cf. The data, compiled for CAGPL by John R. Lacey International Consultants Ltd., were generally published estimates of the respective regulatory agencies. It was stated under cross-examination that regulatory agency data were used for purposes of consistency, even though there were concerns regarding estimates for certain fields, particularly in British Columbia.

Table 2-9

RESERVES OF CONVENTIONAL PRODUCING AREAS

CAGPL Estimate

Marketable Natural Gas
at 31 December 1975

(Tcf)

	Initial Reserves	Remaining Reserves	
	1,000 Btu/cf	14.65 psia	1,000 Btu/cf
British Columbia	10.9	6.9	7.2
Alberta	75.3	51.5	53.7
Saskatchewan	1.6	0.8	0.8
Southern Territories	0.6	0.5	0.5
Total Western Canada	88.4	59.7	62.2
Ontario	1.0	0.2	0.2
Total Conventional Producing Areas	89.4	59.9	62.4

Trunk Line

Trunk Line, in support of the Foothills group, submitted estimates of initial reserves only, at both a pressure base of 14.73 psia and at 1,000 Btu/cf. These estimates, set out in Table 2-10, were based on data published by the AERCB, as well as an analysis of certain pools by Grant Trimble Engineering Ltd., Foothills staff and JLJ Exploration Consultants, Ltd.

Table 2-10

RESERVES OF CONVENTIONAL PRODUCING AREAS

Trunk Line Estimate

Marketable Natural Gas
at 31 December 1975

(Tcf)

	Initial Reserves	
	14.73 psia	1,000 Btu/cf
British Columbia[1]	11.191	11.661
Alberta	71.842	75.288
Saskatchewan	1.619	1.628
Total Western Canada	84.652	88.577
Ontario	1.026	1.026
Total Conventional Producing Areas	85.678	89.603

1 Southern portion of Northwest and Yukon Territories included with British Columbia.

Westcoast

Westcoast submitted reserves data as of both 31 December 1975 and 31 December 1976 for its own supply area, namely, British Columbia, the southern Territories, and fields for which it holds provincial removal permits in northwestern Alberta. These were the company's own estimates. The 31 December 1976 data reflected substantial downward revisions to the estimated reserves of the Clarke Lake field in British Columbia and the Pointed Mountain field in the Northwest Territories. Estimates of both initial and remaining reserves of raw gas were provided, but estimates of marketable volumes were for remaining reserves only. All estimates were at 14.73 psia, with a total of the company's supply area at 1,000 Btu/cf.

Table 2-11

RESERVES OF CONVENTIONAL PRODUCING AREAS

Westcoast Estimate

Marketable Natural Gas

(Tcf)

	Remaining Reserves			
	14.73 psia		1,000 Btu/cf	
	31-12-75	31-12-76	31-12-75	31-12-76
British Columbia	7.2057	6.7871		
Alberta (fields under permit to Westcoast only)	0.3067	0.3260		
Southern Territories	0.5729	0.2001		
Total Westcoast Supply Area	8.0853	7.3132	8.2917	7.5698

Gulf

Gulf submitted an estimate of initial reserves only, at a pressure base of 14.65 psia. These were estimates of proved reserves compiled by the CPA, except for British Columbia where Gulf believed the CPA estimate was high. As a result of using CPA's estimates of proved reserves, Gulf's overall assessment of the conventional producing areas is below others received in evidence and also that of the Board, since no reserves which might be categorized as probable are included.

Table 2-12

RESERVES OF CONVENTIONAL PRODUCING AREAS

Gulf Estimate

Marketable Natural Gas

at 31 December 1975

(Tcf)

	Initial Reserves
	14.65 psia
British Columbia	10.062
Alberta	65.834
Saskatchewan	1.707
Southern Territories	0.580
Total Western Canada	78.183
Ontario	0.916
Total Conventional Producing Areas	79.099

Table 2-13

RESERVES OF CONVENTIONAL PRODUCING AREAS

Comparison of Estimates
Remaining Marketable Natural Gas at 31 December 1975

(Tcf at 1,000 Btu/cf)

	CAGPL	FOOTHILLS[1]	WCTL[2] 31-12-75	WCTL[2] 31-12-76	GULF[3]	NEB Established 31-12-75	NEB Established 31-12-76
British Columbia	7.2	7.6	7.5	7.0	6.5	5.6	6.2
Alberta	53.7	53.6	*	*	46.8	51.3	53.4
Saskatchewan	0.8	0.8	*	*	0.9	1.1	1.0
Southern Territories	0.5	Incl. with B.C.	0.6	0.2	0.5	0.7	0.5
Total Western Canada	62.2	62.0	N/A	N/A	54.7	58.7	61.1
Ontario	0.2	0.2	*	*	0.2	0.3	0.3
Total Conventional Producing Areas	62.4	62.2	N/A	N/A	54.9	59.0	61.4

(1) Calculated by subtracting cumulative production from estimates of initial marketable reserves as submitted

(2) Converted to 1,000 Btu/cf base from estimates of remaining reserves at 14.73 psia as submitted

(3) Calculated as for(1) and converted to 1,000 Btu/cf

* No estimate

Views of the Board

It appears that the majority of the evidence was based upon published estimates of reserves prepared by provincial regulatory bodies or the CPA, and as a result there was generally good agreement among the estimates. As noted earlier, Gulf's lower estimate resulted from its use of CPA's estimate of proved reserves only, which is significantly lower than the Association's estimate of probable reserves. Historically CPA's probable reserves estimates generally have been more closely relatable to reserves estimates of others. The estimates are shown on Table 2-13, together with those of the Board.

The Board's estimates as of 31 December 1975 are the result of individual pool studies by the Board using basic reservoir data from drilled wells. These estimates were updated to 31 December 1976 to reflect the reserves additions which have taken place in 1976 as well as reductions due to production and reassessments during the year.

The conventional producing areas are now sufficiently mature that there should be no major disagreement as to the total quantity of reserves that have been found. On an individual pool basis, however, estimates of reserves often vary considerably due to numerous judgmental elements involved.

It will be noted that the Board estimate for British Columbia at year-end 1975 was lower than the others shown on Table 2-13. This reflects concern that the reserves of a number of fields, in particular Clarke Lake, were not as high as generally accepted.

Exploration and development activity during 1976 resulted in a very significant increase in the established reserves of both

Alberta and British Columbia, as evident from a comparison of the Board estimates for year-end 1975 and 1976.

2.3.1.2 Reserves Additions

Forecasts of future additions to reserves in the conventional producing areas were submitted by CAGPL, Trunk Line, Westcoast, TCPL and Gulf. These forecasts and the resulting growth in initial marketable reserves over the forecast period 1976-1995 are compared with the Board estimates on Table 2-14 and Figure 2-3. In addition, Imperial and Shell provided data with respect only to new discoveries in the conventional producing areas.

CAGPL

CAGPL provided forecasts for British Columbia and Alberta only. For purposes of study, CAGPL's consultant, John R. Lacey, subdivided these provinces into areas based on geology, geography, level of activity or a combination of these factors. Forecasts were made for each area and then added to yield provincial totals. CAGPL stated that the forecast for Alberta, 29.6 Tcf to 1995, was unchanged from that submitted to the Board's 1974-1975 hearing on natural gas supply and requirements. The British Columbia forecast, 6.7 Tcf to 1995, was slightly lower, reflecting less activity in the early years of the forecast period than previously anticipated.

Trunk Line

Trunk Line, in support of Foothills, submitted estimates of reserves additions for British Columbia and the southern

Territories, and for Alberta and Saskatchewan. These estimates were prepared for Trunk Line by JLJ Exploration Consultants Ltd (JLJ). JLJ employed a methodology similar to that of CAGPL's consultant, that is, geological assessment of prospects for future production; however, JLJ subdivided only Alberta into areas for individual evaluation. The Alberta forecast, 21.0 Tcf (20.9 Tcf when constrained by Alberta's 30 year protection policy and the impact of frontier supply) for the period 1976-1995, was practically the same as that prepared by JLJ for the Foothills Submission to the Board's 1974-1975 Gas Hearing. The British Columbia and southern Territories forecast, 4.6 Tcf, was lower by some 3 Tcf. Trunk Line's forecast of additions to reserves for Saskatchewan was 1.6 Tcf, increased from its previous forecast of 0.7 Tcf to reflect increased confidence in the development of shallow reservoirs in the southwestern part of the Province within the forecast period.

Westcoast

Westcoast developed a forecast of reserves additions for British Columbia based on projection of historical additions rates. The company believed that if exploratory and development activity were maintained at past levels, future average annual additions of 451 Bcf could be achieved.

TCPL

TCPL's submission considered Alberta only, where a reserves additions rate of 2.6 Tcf a year was assumed until 1980 following which additions were assumed to decline at 10 per cent annually.

Gulf

Gulf submitted reserves additions forecasts for British Columbia, Alberta and Saskatchewan. (The Territories were treated as an entity and reserves additions tabulated under frontier areas.) Additions of 6.7 Tcf in British Columbia, 28 Tcf in Alberta, and 0.5 Tcf in Saskatchewan were forecast for the period 1976-1995. Gulf evidenced slightly more optimism with respect to British Columbia and slightly less with respect to Alberta than it did in its forecast submitted to the Board for its 1974-1975 Gas Hearing.

Imperial and Shell

Imperial and Shell provided estimates of reserves of gas which would be discovered during the 1976-1995 forecast period. These estimates, which did not consider additions to fields discovered before 1976, were 19 Tcf for Imperial and 20 Tcf for Shell. Shell noted that it expected this gas to be discovered over the next 15 years at initial rates of about 2.4 Tcf, declining over time. Imperial did not indicate the rate of reserves additions expected from the new discoveries.

Views of the Board

The estimates of reserves additions submitted by the various parties were based to a considerable extent on assessment of the prospectiveness of individual areas. The Board found this material most useful for its deliberations.

GROWTH OF INITIAL RESERVES IN CONVENTIONAL PRODUCING AREAS
COMPARISON OF FORECASTS

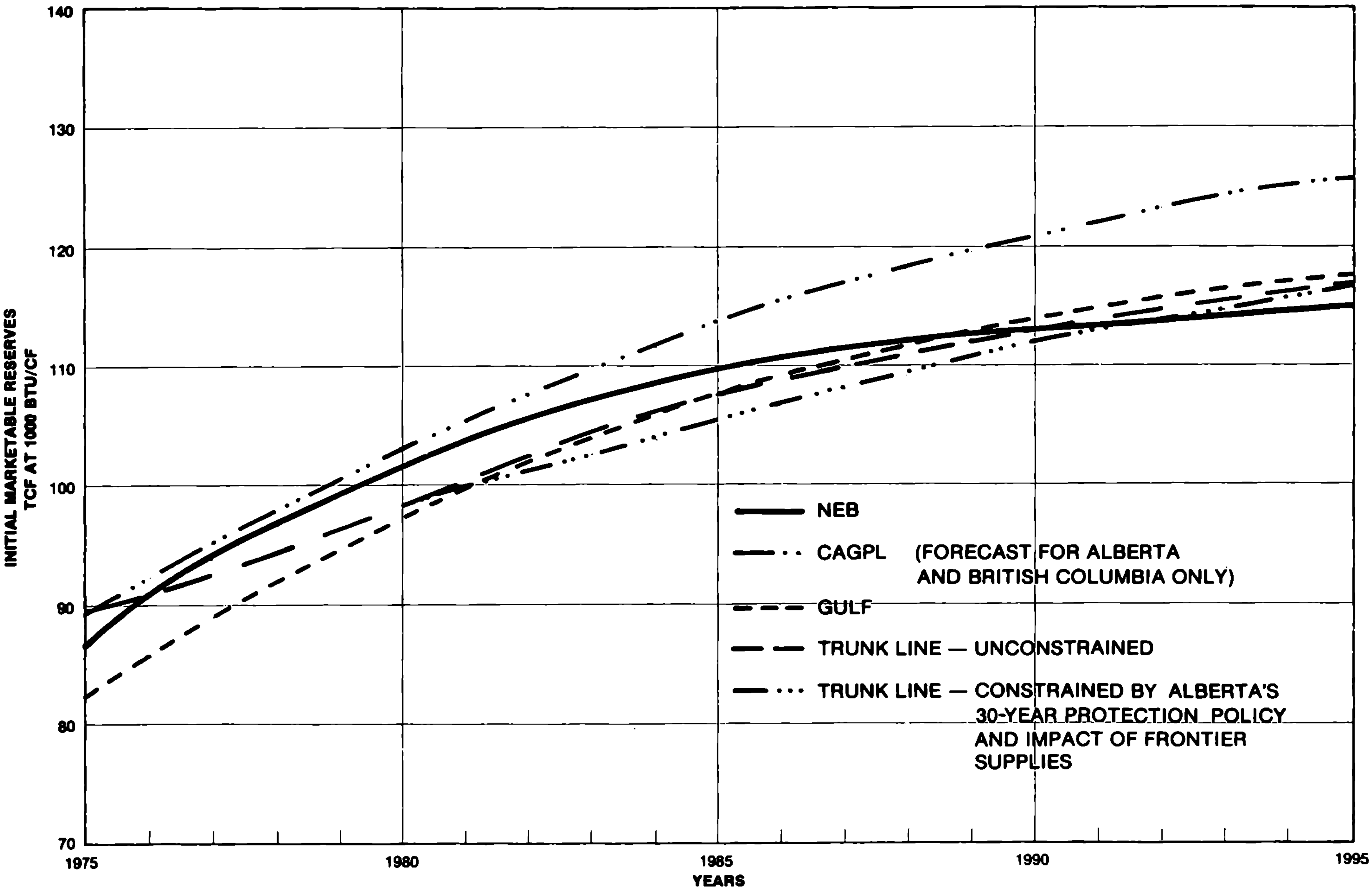


FIGURE 2-3

Table 2-14

RESERVES ADDITIONS FOR CONVENTIONAL PRODUCING AREAS

Comparison of Forecasts

Marketable Natural Gas Reserves

1976-1995

(Tcf at 1,000 Btu/cf)

	CAGPL	Trunk Line	Westcoast	Gulf (1)	NEB
British Columbia	6.7	4.6	9.0	6.7	5
Alberta	29.6	21.0	*	28.0	23
Saskatchewan	*	1.6	*	0.5	1
Southern Territories	*	(4)	(4)	(2)	(4)
Total Western Canada	N/A	27.2	N/A	35.2	29
Ontario	*	*	*	0.1	(3)
Total Conventional Producing Areas	N/A	27.2	N/A	35.3	29

(1) Volumes at 14.65 psia

(2) Gulf did not forecast separately reserves additions for that region of the Northwest and Yukon Territories adjacent to the territorial-provincial boundary. The Company estimated reserves additions of 6.5 Tcf for the Territories as a whole, excepting the Mackenzie Delta area and the Beaufort Sea.

(3) Less than 0.5 Tcf

(4) Included with British Columbia

* No Estimate

The essence of the evidence submitted is that, to the year 1995, reserves additions in the conventional producing areas are expected to be between about 20 and 30 Tcf in Alberta, between 5 and 9 Tcf in British Columbia, and between 0.5 and 1.5 Tcf in Saskatchewan. Using the extremes of the forecast gives a range from some 25 to 40 Tcf for the three provinces.

Nothing, either from the data submitted to this hearing or from its general knowledge, suggests to the Board that there has been any major change in thinking with respect to reserves additions in the conventional producing areas since the Gas Hearing in 1974-1975. Accelerated exploratory and development activity due to higher field prices produced a substantial increase in reserves additions, in both Alberta and British Columbia in 1976. Should comparable or even higher levels of activity continue, additions rates over the next several years may well prove higher than anticipated. It should be emphasized, however, that this would not necessarily imply higher additions in total for the forecast period.

Forecasts of reserves additions using geological and engineering assessment of prospective areas have not been undertaken by the Board. The Board's estimates published in the 1975 Gas Report, based on evidence at that hearing and on its own interpretations of reserves additions trends in previous years, are in reasonable agreement with those submitted to the current hearing. For this current supply forecast the Board has estimated reserves additions of 29 Tcf for the Western Provinces and southern Territories during the forecast period, 1976-1995.

This estimate is slightly higher than the Board's 1975 forecast of 25 Tcf for the period 1974-1995, reflecting in part a higher pricing structure. Actual reserves additions of 4.9 Tcf for 1976 were incorporated.

2.3.1.3 Ultimate Potential

Estimates of ultimate potential relating to the conventional producing areas were submitted by Trunk Line, TCPL and Gulf. These are compared with the Board estimate in Table 2-15.

Trunk Line

The Trunk Line estimate of 122 Tcf made by JLJ, was somewhat lower than JLJ's estimate of 130 Tcf included in the Foothills submission to the 1974-1975 Gas Hearing. Most of the difference concerned the southern Territories and was a matter of definition. The southern Territories for purposes of the current submission were defined as a limited area immediately adjacent to the British Columbia boundary; for the Gas Hearing all the regions south of the 68th parallel were included. Trunk Line stated that the British Columbia volume had been reduced slightly to reflect lower estimates of gas reserves in certain producing fields.

TCPL

TCPL provided an ultimate potential estimate of 115 Tcf for Alberta only. The Company stated this was the average of its own estimate of about 120 Tcf and that of the AERCB of 110 Tcf.

Gulf

Gulf's estimate of 138 Tcf was essentially unchanged from that of 135 Tcf submitted to the Board's Gas Hearing; it increased its estimate for British Columbia by some 10 Tcf while reducing its Alberta estimate by approximately the same amount. Gulf was more optimistic than Trunk Line with respect to the future prospects of British Columbia, although under cross-examination the company stated that its estimate for that Province could be high.

Views of the Board

As is to be expected because of the substantial element of judgment involved in the forecasting of ultimate potential, submitted estimates show considerable variation. The range, from 122 to 138 Tcf for the conventional producing areas in total is not unreasonable, although the Board believes the probability is very low that quantities toward the higher end of the range can be realized.

The Board deemed it appropriate, based on evidence presented, to increase its Alberta estimate from 92 to 100 Tcf. The region of the Yukon and Northwest Teritories considered to be within the conventional producing areas is now redefined and limited to being only that immediately adjacent to the territorial-provincial boundary lines, to conform with what appears to be general practice[1]. The ultimate potential estimate has been reduced accordingly from 4 to 1 Tcf. The Alberta increase, offset by a reduction of 3 Tcf in the Yukon and Northwest Territories, results in an overall increase in the Board estimate of the ultimate potential of the conventional producing areas from 115 to 120 Tcf. It should be possible to attach a high degree of confidence to the development of quantities of this order; however, the reader is reminded of the uncertainties inherent in forecasting ultimate potential. Hydrocarbons can not properly be termed reserves nor counted upon with certainty, until their presence has been established through drilling.

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(1)Prospects elsewhere in the Yukon and Northwest Territories, excluding the Mackenzie Delta Beaufort Sea, are not discussed separately in this report. Very limited relevant data were submitted to the hearing and the potential of the region, in the opinion of the Board is modest.

Table 2-15

ULTIMATE POTENTIAL OF CONVENTIONAL PRODUCING AREAS

Comparison of Estimates

(Tcf)

	Trunk Line (1)	TCPL (2)	Gulf (2)	NEB (1)
British Columbia	16.8	*	30	15
Alberta	101.1	115	100	100
Saskatchewan	3.3	*	3	3
Southern Territories	Incl. with B.C.	*	(3)	1
Total Western Canada	121.2	N/A	133	119
Ontario	1.0	*	5	1
Total Conventional Producing Areas	122.2	N/A	138	120

(1) Volumes at 1,000 Btu/cf

(2) Volumes at 14.65 psia

(3) Gulf did not make a separate estimate of the ultimate potential of that region of the Northwest and Yukon Territories adjacent to the territorial-provincial boundary. The Company estimated the ultimate potential of the Territories as a whole, excepting the Mackenzie Delta area and Beaufort Sea, to be 9.0 Tcf.

* No Estimate

2.3.2 Available Deliverability

Evidence

Forecasts of total Canadian gas deliverability from the conventional areas were submitted by CAGPL, Trunk Line, Gulf, Imperial, Shell and Professor J. Helliwell. TransCanada submitted a forecast of total Alberta deliverability; A&S and Westcoast each submitted forecasts of deliverability of its system based only on controlled reserves. The total Canada forecasts of expected deliverability are illustrated in Figure 2-4 (Table 2-16). These deliverability forecasts except for those of Shell and Professor Helliwell were based on detailed pool-by-pool analyses ranging in number from as few as 125 large pools by Imperial to some 2,200 pools by CAGPL. Shell used the NEB forecast of deliverability from the conventional established reserves contained in the NEB April 1975 Natural Gas Supply and Requirements report, and added its own estimate of deliverability from reserves appreciation and trend gas.

CAGPL used two approaches to its natural gas deliverability forecast - a "Field Gate" analysis and a "System Supply" case. Its study represented an analysis of the reserves from the conventional producing areas of Canada and an in-depth analysis of unconnected reserves. A forecast of trend gas was made with an analysis of finding rates by areas throughout the provinces and with a forecast of attachment rates for new gas by each particular area. CAGPL also reviewed, at the pool and well level, the well productivity in the pools and the effects of adding compression where economical to do so. Further, the impact on deliverability generated by connecting unconnected wells and pools and by undertaking infill drilling in each pool was studied. From this pool analysis a field-by-field forecast was carried out, integrating contract data, plant restrictions and the heating value of the gas for each field.

The supply from all the individual pools and fields in each province in the conventional producing areas was integrated into a provincial supply picture to yield CAGPL's "Field Gate" supply for the various provinces to equate against provincial requirements. The Total Canada "Field Gate" analysis indicated a current surplus of supply changing to a deficiency beginning in 1979 and increasing thereafter. Its "Field Gate" forecast of production peaked at a level of 3,257 Bcf in 1981. CAGPL emphasized that it had made certain assumptions concerning connection of non-producing gas pools, the addition of compression, the infill drilling of wells, the continued development of shallow gas and continuing success of exploration efforts in the conventional areas. It stated that if any of these assumed activities failed to take place, supply would fall short of its projections.

CAGPL also undertook a complete "System Supply" analysis to trace the flow of gas from the field to the market place. To accomplish this, it projected production from the fields into the gathering and transmission systems, where offline sales, exchanges, storage, fuel usage and shrinkage in each section of the various transmission systems were simulated. Alberta's needs were satisfied first and exchanges were then made between the systems to meet total demand as long as possible. (CAGPL's system analysis indicated production peaking at a level of 3,247

Bcf in 1981 including fuel and losses.) This system analysis showed a total current deficiency in Canada growing with time. CAGPL stated that this deficiency occurred in the Westcoast British Columbia system in spite of current contracts with Pan Alberta and the addition of significant volumes of unconnected and trend gas. CAGPL indicated that a deficiency would occur in the East of Alberta market by 1981 even with the connection of trend gas, unconnected gas and transfers from other systems.

AGTL, on behalf of the Foothills group, presented a study on the supply of natural gas to meet Canadian demand including exports. Two forecasts of Alberta natural gas production were prepared. The first forecast, called "unconstrained", was taken from a study undertaken by Grant Trimble Engineering Ltd. (GTEL) for AGTL. One hundred large connected pools each with remaining reserves greater than 50 Bcf were studied in detail with production forecasts based on material balance and empirical well deliverability relationships. Marketable production from these pools represented 75 per cent of the 1975 Alberta production. Each year compression was added to the pools where necessary, up to the maximum selected, to maintain the pool production at the daily contract quantity. After maximum compression was reached, additional wells were added if necessary to maintain the daily contract quantity. The operator's proposed well addition schedule was used when available.

The marketable gas production forecasts for the shallow southeast Alberta gas were based on historical production performance. For presently developed shallow reserves, AGTL assumed a 17 per cent decline in 1976 followed by harmonic decline. For new connections, AGTL assumed that initial producing rates would decline 40 per cent in the first year, 20 per cent in the second year, and harmonically thereafter.

AGTL prepared production forecasts for some 426 small connected pools, each with remaining reserves less than 50 Bcf, based on decline criteria. It assumed that the 1976 production rate would be the average annual rate for the period 1 January 1969 to 31 December 1975. Production was held constant until 50 per cent of the reserves had been produced, declined exponentially thereafter, and abandoned at a rate which was 20 per cent of the 1976 rate.

AGTL incorporated GTEL's forecasts of production for 18 large unconnected pools into its total Alberta supply picture. These forecasts were based on material balance and empirical well deliverability relationships as was the case for the large connected pools.

AGTL studied nine distinct areas of Alberta for the classification of the balance of the unconnected reserves including its estimate of appreciation of existing reserves. This complete category included some 14.6 Tcf of gas reserves. AGTL assumed that all contracted gas would be connected over the six-year period 1976-1981 and that the volumes connected would coincide with each company's supply-requirements balance. With the exception of two areas, AGTL showed all this gas coming onstream at a rate of 1:7,300. Decline was forecast at six per cent per year after 50 per cent of initial reserves had been produced. In northwestern Alberta (Area 6), AGTL showed production of the unconnected reserves at a rate of 1:5,475 with decline after seven years at eight per cent per year. In central eastern Alberta (Area 3) the reserves were assumed to be produced at a rate of 1:5,000 with a decline of 14 per cent per year after 62.5 per cent of the initial reserves had been produced.

AGTL used a forecast of new reserves discoveries prepared on its behalf by JLJ and scheduled connection of these reserves three to five years after discovery depending upon location. Production was assumed to be at a rate of 1:7,300 until 50 per cent of the ultimate reserves had been produced followed by a six per cent per year decline.

AGTL's second forecast of production from Alberta was called a "constrained" forecast because it took into account the need to balance overall market demand with available supply (including Beaufort Basin volumes) and the need to protect Alberta markets for thirty years. There was no change from the unconstrained case for production from large pools connected, small pools connected and large pools unconnected. AGTL placed the total burden of the constraint upon production from southeastern shallow, other pools unconnected and new reserves discoveries. It accomplished the constraint on southeastern shallow supply by altering the schedule of drilling. The constrained volumes of production were the same as the unconstrained through 1978, lower from 1979 to 1987 and higher thereafter. Constrained production from other pools unconnected was the same as the unconstrained through 1981, but because of lower reserves connections in the constrained case, production was lower than the unconstrained after 1981. The forecast of supply from new discoveries was the same for both cases in 1979, 1980 and 1981; however, the delay of connections after 1981 resulted in a lower production forecast in the constrained case.

AGTL projected the transfer of gas to British Columbia in order to fully meet exports under Licence GL-41 as long as possible. By permitting Alberta gas to be made available to the British Columbia market in this way and by showing removal of the balance of gas surplus to Alberta's requirements to markets East of Alberta, AGTL was able to show Total Canadian demand including exports being met until 1977. The unconstrained case showed volumes capable of meeting total demand until 1983.

For production from conventional reserves in Saskatchewan, AGTL used the forecast of the Saskatchewan Power Corporation. AGTL developed its own forecast of additions and production from the shallow southwestern reserves based upon Saskatchewan's policy to delay development of this area until there is a need in Saskatchewan for the gas.

For British Columbia and the southern portion of the Territories, AGTL used Westcoast's forecast of production from existing reserves for the first five years. Production thereafter was derived using a fixed ratio between available reserves and annual production. New reserves discoveries were connected allowing for adequate lead time and were produced at a rate of 1:7,300. Decline was started after 50 per cent of the reserves were depleted.

AGTL used historical production volumes for Eastern Canada and maintained them essentially constant throughout the forecast period.

Imperial's forecast of natural gas production assumed a business environment that would encourage exploration and development. Imperial did not restrict supply by either demand or by government regulations. Imperial provided a "Base Case" production forecast with a range above and below it that could reasonably occur. Its forecast included a specific analysis of some 125 major pools with marketable reserves greater than 50 Bcf representing some 75 per cent of the Southern Basin reserves along with a general analysis of the minor pools grouped by area. Imperial's forecast for currently producing fields was comprised of all pools supplying marketable gas at the beginning of 1976 including non-associated gas pools, gas cycling condensate reservoirs and solution gas production from oil pools.

Imperial's best estimate of future gas production from currently producing fields showed supply declining from the current 2.6 Tcf/year to 1.9 Tcf/year by 1985 and 0.9 Tcf/year by 1995. It assumed that industry would continue to make economic investments in infill drilling and compression necessary either to increase production rates or to reduce the rate of decline in individual pools.

In the undeveloped fields, Imperial assumed that the major non-associated pools with reserves greater than 50 Bcf would be producing by 1980 at rates of 1:7,300. Production from the small scattered pools was not necessarily commenced at a rate of 1:7,300. For example, Imperial stated that production forecasts for the shallow gas pools of southern Alberta were built up to a rate of take of approximately 1:10,000 over the next ten years. Imperial forecasted that production from associated gas caps would commence when oil production from such pools reaches the economic limit.

Imperial's forecast of the gas supply from new discoveries in the Southern Basin was developed from an assessment of the reserves potential of each significant geological play. Its Base Case forecast assumed production from these reserves would be developed within three to four years from initial discovery date at a rate of take of 1:7,300.

Imperial's forecast of total production from the Southern Basin peaked at about 3,050 Bcf/year in 1984.

Gulf Oil Canada Limited looked at the supply from conventional areas on a provincial basis. Its analyses of British Columbia, the southern portion of the Territories, Saskatchewan and Eastern Canada were quite general. Gulf stated that according to CPA statistics, annual production from the southern portion of the Territories increased until 1974 and remained steady in 1975, while in British Columbia the yearly production peaked in 1973 and had declined thereafter. Approximately 85 per cent of the established reserves in British Columbia were producing at the end of 1975. For reserves additions in British Columbia, Gulf assumed that five per cent of the total addition would be connected in year one, 10 per cent in year two, 15 per cent in years three to six, 10 per cent in year seven and five per cent in each of years eight to 10. It assumed that the established non-producing reserves would be connected at a similar rate starting in 1976.

Gulf indicated that according to CPA statistics, sales of Saskatchewan gas production had declined only slightly during the past five years. Gulf noted that development of Saskatchewan gas was not being encouraged at this time.

Gulf stated that the forecast of gas supply from Eastern Canada was relatively small and was not expected to increase substantially.

In Alberta, Gulf reviewed production forecasts for 157 large pools submitted in AERCB Proceeding No. 8666 representing 65 to 70 per cent of total Alberta supply capability in 1976. Gulf made small adjustments to these forecasts to account for possible acceleration of the installation of compression, drilling of infill wells, etc. Gulf's forecast of production from the southern Alberta shallow gas pools represented slightly more than 10 per cent of the total Alberta supply capability in 1976, with increasing volumes during the next few years. Gulf assumed a rate of take of 1:4,380 for this shallow gas to approximate the deliverability-type contracts being made for this gas. Gulf's forecast of supply from small non-producing pools represented 20 per cent of the 1976 Alberta capability and was handled in a manner similar to the reserves additions with the first year of production occurring in 1976. Gulf connected new reserves additions in Alberta at the same rate as it did for British Columbia. Variable rates of take were used to reflect the probability that relatively more shallow gas would be connected during the first three years while more sour and rich gas would be connected during the fourth to seventh years. Gulf's assumed rates of take varied between 1:4,745 and 1:6,570 (initial rate) with an average of 1:5,840.

Gulf's forecast of total supply from conventional reserves peaked at a level of 3,176 Bcf/year in 1981.

Shell adopted the forecast of production from established reserves as at 31 December 1973 prepared by the NEB and presented in Table 20 on page 60 of the Board's report "Canadian Natural Gas Supply and Requirements, April 1975". Shell then appreciated the reserves used for this forecast using CPA statistics to the December 1975 level. Shell converted the annual reserve increments to a production schedule by assuming the annual imcrements would begin producing, one year after being recognized, at the same life index as in the Board's forecast of production from established reserves. Shell's estimate of new reserves discoveries was converted to a production schedule by commencing production at a rate of 1:7,300 with a commencement date 3 1/2 years after discovery. An eight-year flat life period was assumed followed by decline based on a composite decline curve made by combining standard production profiles of three basic reserve types.

Shell's forecast of supply peaked at a level of 3,190 Bcf/year in 1979, declined to 2,925 in 1985 and to 1,892 in 1995.

A&S submitted its estimate of its own gas supply from its reserves under contract in some 300 pools in Alberta. It assumed that deliverability from a given gas field would decline as the reserves were produced unless additional facilities were added. These additions would only occur if the producer felt the capital expenditures were warranted.

A&S noted that it did not expect its supply would follow its firm requirements as they would fall abruptly due to the expiry of its export licences. It believed that the more likely situation would be that the gas then would flow to as yet undefined markets.

A&S suggested that there was a definite upper limit to the total amount of gas that could be produced from its contracted fields. It noted that virtually all its contracted gas required processing to remove liquids and/or acid gases and thus existing plant capacity is a limiting factor. A&S said that although some additional gas could be supplied to Canadian markets in the next ten years from its contracted reserves, the actual amount would be relatively minor and at the expense of production in later years.

TransCanada showed the total Alberta gas supply under contract to various purchasers and included all "Field Gate" volumes delivered for use within Alberta and for removal from the Province. TCPL's estimate of the Alberta contracted supply was obtained from a detailed study of deliverability of reserves under contract to be delivered at the "Field Gate". TCPL obtained all other purchasers' projections of contractual supply volumes from their most recent available submission to the AERCB or from direct contact with the particular purchasers.

TCPL had made an effort to keep well informed on the ongoing drilling activity in Alberta. It estimated that as of 31 December 1976 there were approximately 7.0 Tcf of uncommitted reserves in Alberta of which 5.3 Tcf could be purchased and made available to market and 1.7 Tcf would be unavailable. It estimated that the contracted minimum rate of take for these reserves - both sweet and sour - would be 1:7,300. TCPL included uncontracted Suffield reserves in this uncommitted category. TCPL estimated that it would be able to achieve a deliverability flat life of only three to four years assuming that it utilized its existing contracted gas supply at minimum rates and that it was successful in purchasing new gas supplies at a minimum rate of take of 1:7,300 so that TransCanada would be, in total, fully bought up to a take or pay level.

TCPL assumed that the long-term Alberta trend of 2.6 Tcf/year of reserves additions would be maintained until 75 per cent of Alberta's ultimate potential of 115 Tcf had been developed followed by a decline in the growth rate of 10 per cent per year. TCPL estimated that after development of the trend gas 15 per cent would become available in the first contract year, 40 per cent by the second, 45 per cent by the third, 50 per cent by the fourth, 75 per cent by the fifth and the remaining 25 per cent after the fifth year. It assumed an average rate of take of 1:7,300 for these trend reserves reduced by some six per cent for operating unreliability, plant turnarounds and AGTL outages.

Westcoast's July 1976 study of its own supply area illustrated a current deficiency growing with time until its export requirement expired in 1989. Its gas supply consisted of connected gas, non-connected gas, Aitken Creek storage, Pan Alberta gas and trend gas. Westcoast also included volumes of gas supply from the Delta starting in 1982 at 500 MMcf/d. Westcoast showed the use of the Aitken Creek reservoir to store gas for peaking purposes in the winter heating season. Westcoast assumed trend gas reserves to become available in the year 1980. For both the non-connected reserves and the British Columbia trend reserves, it assumed a rate of take of 1:5,750. Production declines were determined by analogy with similar producing reservoirs.

Westcoast's updated study showed that only with new connections, trend gas, and increased Pan Alberta purchases, could it meet its projected demand including exports at Huntingdon until 1981.

Professor Helliwell produced a Canadian gas supply forecast for use in his cost-benefit submission to the Hearing. In projecting supply, Professor Helliwell utilized a numerical analysis approach using various sources of published material with certain judgments applied in the use of this material in a computer model.

One of the problems that Professor Helliwell faced was to determine an estimate of the reserves necessary to support a deliverability schedule. To do this Professor Helliwell used historical CPA statistics and deliverability rates of 1:7,300 with an assumed 15-year constant rate of take on initial reserves, declining 15 per cent annually thereafter to calculate the reserves which would be necessary to maintain this deliverability schedule from 1947 until 1973. Under cross-examination, Professor Helliwell stated that his assumed deliverability rates were higher than the actual deliverability rates and hence he had underestimated the reserves that should have been used to support his schedules. Thus, he had over-estimated the quantity of unconnected reserves available for future deliverability.

Professor Helliwell also used the NEB 1975 Gas Report schedule of deliverability to estimate the reserves underlying his schedule. To do this he extended the NEB deliverability forecast, from producing reserves only, beyond 1995 at a 10 per cent rate of decline and then terminated the schedule in the year 2001. Professor Helliwell truncated the series at this point because, after 28 years of extended production, he assumed the producibility would be finished in terms of marketable reserves. Using this technique, Professor Helliwell calculated the reserves necessary to support the NEB deliverability schedule as 42.9 Tcf. Professor Helliwell also allowed for 2.6 Tcf of deferred reserves. Starting with the NEB estimate of remaining reserves of 60.3 Tcf as of 31 December 1973 and subtracting the above 42.9 Tcf and 2.6 Tcf, Professor Helliwell calculated remaining non-producing reserves of 14.8 Tcf.

Professor Helliwell assumed this quantity of 14.8 Tcf would be available along with all reserves additions as and when required at a rate of take of 1:7,300 with a 15-year constant rate of take on initial reserves and a 15 per cent decline thereafter for 13 years with all the reserves being completely produced by the 29th year.

Professor Helliwell stated that although he did not allow for any time lag in hooking up reserves, actual lag would depend upon the location and type of reserve additions. Professor Helliwell stated that there need be almost no time lag between the actual drilling and the establishment of flow rates and subsequent delivery to market since he assumed that there would be no new discoveries in Alberta and British Columbia in the 1990's not close to an existing facility.

CAGPL prepared an estimate of supply with the removal of certain limitations in order to simulate, on a pool-by-pool basis, the supply theory Professor Helliwell was proposing. It concluded that supply under "wide open" conditions might meet its requirements East of Alberta until 1984-85.

Views of the Board

The Board has studied the evidence and firmly believes that the only reliable forecasts of deliverability were those based on deliverability which was studied on a pool-by-pool basis. Figure 2-4 illustrates that the variation in forecasts of this nature is relatively small and in most cases, in the early years at least, is the result of the differences in the demand projections which were filed.

The Board has reviewed in detail the supply model used by Professor Helliwell and has recalculated some of the key variables that Professor Helliwell has used in his model. The reserves underlying the NEB deliverability schedule shown on page 61 of the Board's 1975 Canadian Natural Gas Supply and Requirements report were 48.3 Tcf @ 1000 Btu/cf compared to Professor Helliwell's estimate of 42.9 Tcf. The Board also finds that the deferred reserves are 4.2 Tcf compared to 2.6 Tcf used by Professor Helliwell. This gives a net result of 7.8 Tcf when these two figures are subtracted from the 31 December 1973

FIGURE 2-4

DELIVERABILITY FROM CONVENTIONAL PRODUCING AREAS COMPARISON OF FORECASTS

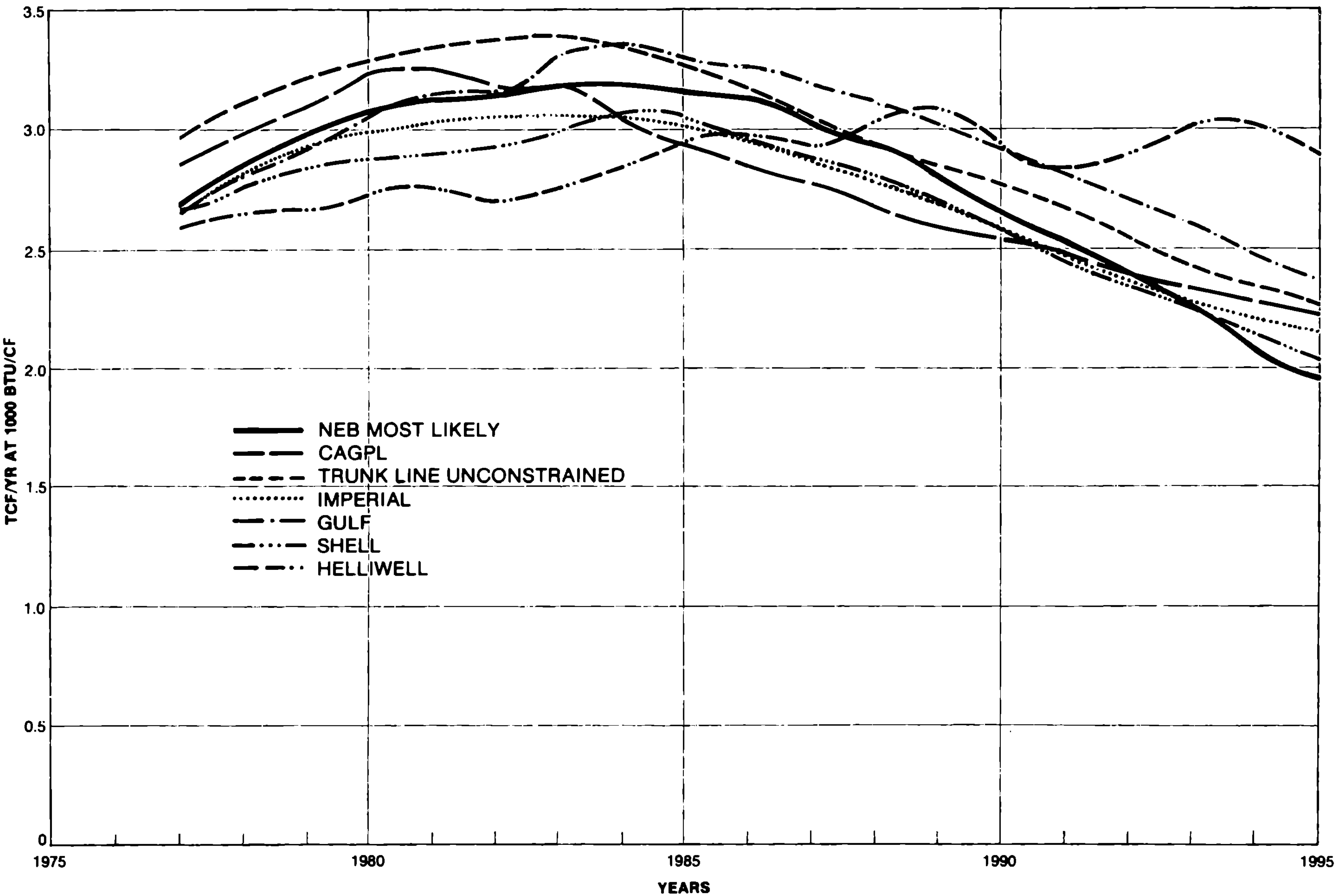

Table 2-16

DELIVERABILITY FROM CONVENTIONAL PRODUCING AREAS:

Comparison of Forecasts

(Bcf/Yr @ 1000 Btu/cf)

Year	CAGPL System	AGTL Unconstrained	Gulf Case 1	Imperial	Shell	Helliwell	NEB Most Likely
1977	2852	2968	2648	2660	2670	2590	2675
78	2967	3102	2812	2820	2760	2635	2851
79	3081	3210	2934	2920	2830	2656	2970
1980	3230	3297	3054	2990	2870	2728	3069
81	3247	3342	3149	3030	2900	2749	3112
82	3159	3363	3139	3040	2940	2679	3131
83	3178	3392	3298	3040	3000	2755	3180
84	3037	3338	3349	3050	3070	2845	3175
1985	2936	3269	3308	3010	3050	2949	3149
86	2846	3164	3251	2950	2960	2972	3127
87	2774	3031	3181	2870	2870	2929	3023
88	2672	2936	3105	2780	2800	3030	2939
89	2596	2847	3017	2670	2700	3072	2800
1990	2544	2758	2922	2580	2570	2924	2651
91	2479	2664	2815	2470	2460	2837	2527
92	2404	2546	2705	2370	2350	2891	2399
93	2337	2436	2592	2280	2240	3007	2261
94	2270	2345	2471	2210	2140	3010	2086
1995	2219	2268	2357	2160	2030	2899	1951

Notes: -These forecasts are those which are projected to meet the filed demand forecasts as long as possible.

-CAGPL includes fuel and loses.

-Gulf converted to 1000 Bcf/cf.

estimate of remaining marketable reserves of 60.3 Tcf compared to 14.8 Tcf used by Professor Helliwell.

The Board also differs with Professor Helliwell's method of connecting new reserves as outlined earlier in this section and discusses later in this section the detailed method used by it to connect these new additions.

The Board is in agreement with Professor Helliwell that a rate of take on initial reserves of 1:7,300 is reasonable. The Board does not share Professor Helliwell's optimism that these reserves will be produced at a constant rate of take for 15 years and that they will be completely produced in the 29th year.

The Board has studied in depth the availability of gas from presently established reserves to supply current and forecast market demands. In excess of 1,200 pools representing some 85 per cent of the controlled gas reserves in Canada were studied in detail. Producer forecasts for solution and associated gas production representing seven per cent of the controlled reserves were adopted by the Board as production from these fields is related to oil production. Deliverability forecasts for the remaining eight per cent of controlled reserves were based on information from other sources.

The Board employed its gas deliverability computer model to forecast the deliverability of gas to meet the projected requirements of each of the major gas transmission systems - TransCanada, A&S, Westcoast, Canadian-Montana and Pan Alberta. The model performs a pool-by-pool analysis of gas deliverability as characterized by average well flow characteristics, basic reservoir parameters, and daily contract rates. The model utilizes drilling and compression cost data to determine the degree to which it would be economic to maintain deliverability from a pool at the contract rate by drilling infill wells and/or adding field compression. The computer model incorporates the producer forecasts for the solution and associated gas production available to the appropriate gas transmission system to meet its requirements.

The remaining components of the gas supply forecast, covering the remaining eight per cent of the controlled reserves, were derived from the following sources. Forecasts of supply for the major Alberta utilities, Canadian Western Natural Gas Limited and Northwestern Utilities Limited, were taken from their submissions to the AERCB in August 1975. CAGPL's forecast of supply for the small Alberta utilities was considered reasonable and was adopted by the Board. The Many Islands Pipelines' forecast of supply from Alberta was taken from the Saskatchewan Power Corporation's recent submission to the AERCB for a removal permit, adjusted to reflect the decision of the Alberta Board contained in its report ERCB 77-B and extrapolated beyond 1986 to 1995. The forecast of production East of Alberta included a forecast of Saskatchewan production taken from the aforementioned submission and a Board estimate of supply from Ontario based on production history. The Board estimated production of supply to meet Westcoast's Licence GL-4 to be at the annual permit level until the total permit volumes had been produced. The estimated two remaining years of production from this supply source was assumed available for Albert use.

A summary of the above-described forecasts is presented on page 3 of Appendix 2-3. In total they represent a forecast of supply from controlled reserves. In the case of British Columbia, all non-contracted gas is considered in the system analysis to be controlled by Westcoast.

The Board estimates that there are some 3.2 Tcf of established uncommitted shallow gas reserves in southeast Alberta as of 31 December 1976. It is estimated that 80 per cent of these gas reserves will be connected by the end of 1984 and a deliverability forecast for this shallow gas was prepared following a typical deliverability profile as predicted by the deliverability model. This rate of attachment is largely related to the anticipated rate of development of the Suffield Military Block.

The Board estimates that as of 31 December 1976 there is some 4.4 Tcf of uncommitted non-associated gas in Alberta other than the southeast Alberta shallow reserves. It has been estimated that 75 per cent of these presently uncommitted reserves will be connected by the end of 1979. It has been assumed that they would be contracted at a rate of take of 1 MMcf/d per 7,300 MMcf of reserves, consistent with current contracting practice, and that the average pool characteristics would be such as to allow the contract rate to be maintained for about nine years and the deliverability to decline at 10 per cent annually thereafter. The Board adopted the supply forecasts for the estimated 4.2 Tcf of Alberta deferred gas from those shown in the recently published Alberta ERCB Report No. 75-F.

The Board estimated supply from trend additions in the same manner as did CAGPL. The Board's forecast of additions for Alberta was prorated amongst the areas described in the CAGPL submission and the rates of connection for these areas as determined by CAGPL were judged to be reasonable and were employed. The gas thus connected would be delivered at a rate of take of 1:7,300 with a nine-year flat life followed by a 10 per cent decline as in the case of the presently uncommitted non-associated gas. A similar analysis was performed for British Columbia and Saskatchewan. The Board recognizes that the forecast of supply from Saskatchewan trend gas is dependent upon the institution of a policy in Saskatchewan which would encourage the development of the marginally economic shallow gas reserves in southwest Saskatchewan.

In matching the total forecast of supply described above with the projected demand for Canadian gas, the Board estimates that there is a potential surplus supply of gas for the next few years. In developing this total supply forecast, the Board did not impose any limitations on the supply which could result from the implementation of the Alberta protection policy. The Board judged that the projected oversupply would be removed from the forecasts of production from Alberta trend gas and the Alberta uncommitted non-associated gas. The volumes not produced would contribute to deliverability in later years when the need arises. This is illustrated on page 7 of Appendix 2-3 where some 420 Bcf of reserves which could be produced during the years 1977 to 1982 as shown in column 9, but which in fact would not be produced because of market limitations, would be available to provide additional deliveries where required commencing in 1983 as shown in column 2. The production profile assumed was similar to that described for the uncommitted non-associated gas.

Figure 2-5 represents the Board's forecast of "Most Likely" gas deliverability. The major components of this supply forecast are indicated by the different shaded areas. Future development of existing controlled reserves plays a very important role in this deliverability projection. The influence of infill drilling and additional compression on total supply is illustrated in Figure 2-6. The Board assumes the continuation of the present economic climate for the producers to continue to develop deliverability from existing reserves to maintain contract rates as long as possible.

The Board has given consideration to the degree of uncertainty in its "Most Likely" forecast of supply. It has studied the sensitivity of deliverability from presently connected reserves to changes in well-head prices and has concluded that the deliverability projections would be relatively insensitive to further increases in price. The greatest level of uncertainty in the forecast is in the projection of supply from presently established but uncommitted reserves and from trend gas reserves. An upper limit in the range of uncertainty in the supply forecast was established by developing a trend additions projection with higher initial discovery rates and assuming a more rapid rate of connection of reserves additions than in the "Most Likely" case. In addition, the connection of a larger percentage of the presently uncommitted gas reserves was considered than in the "Most Likely" case. A similar exercise was carried out to establish a lower range of supply using lower trend additions rates and a smaller percentage connection of the uncommitted gas. The length of time between the discovery of gas and the availability of a market for the gas, as perceived by producers will be a major factor in trend additions rates and rates of connection. The band of possible variation in the Board's supply forecast is shown in Figure 2-7.

It should be emphasized that the Board's estimate of "Most Likely" supply discussed here has not taken into account any constraint which might be imposed by the AERCB surplus protection policy. A discussion of the implications of this policy is found in a subsequent section.

DELIVERABILITY FROM CONVENTIONAL PRODUCING AREAS
NEB MOST LIKELY FORECAST

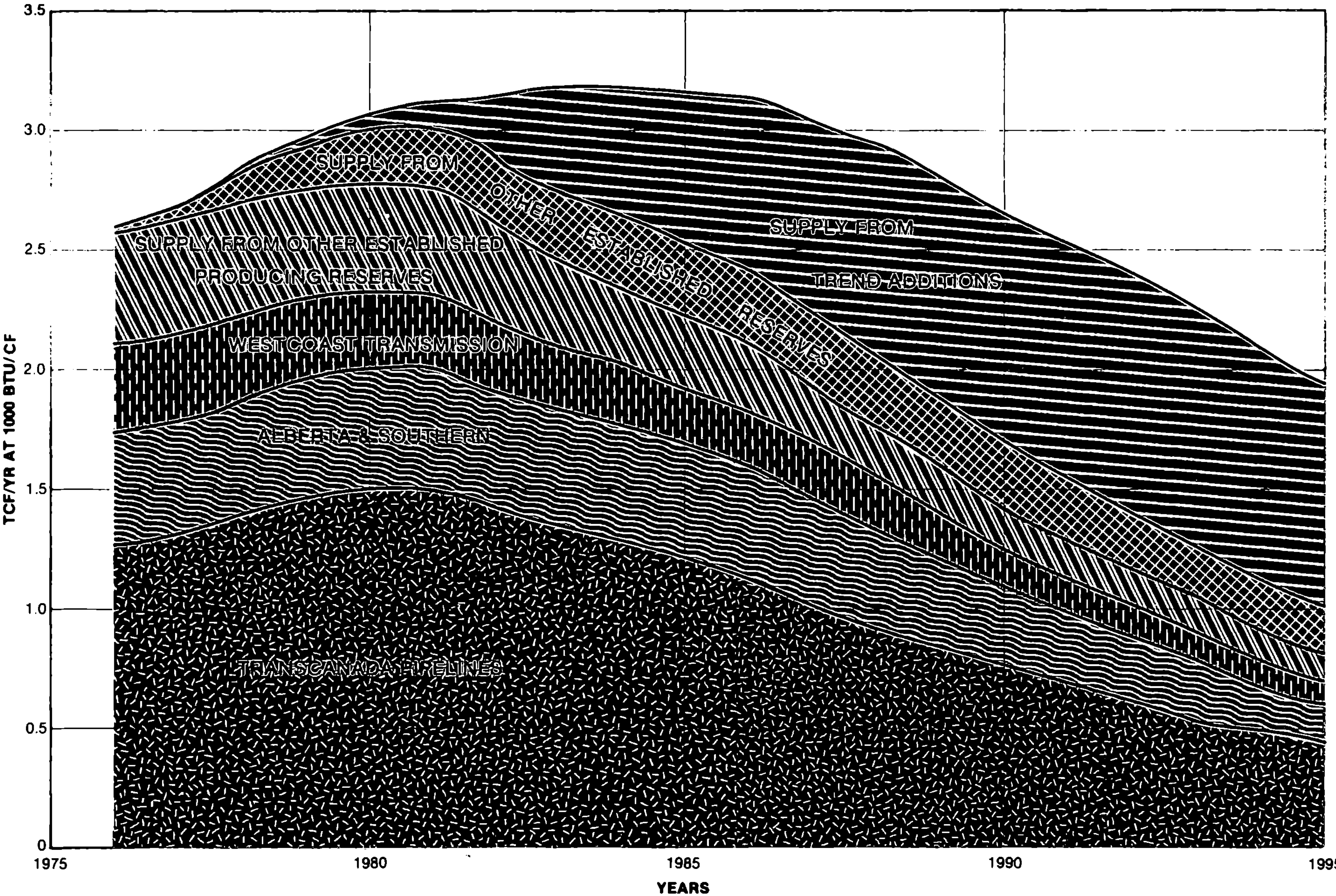

FIGURE 2-5

DELIVERABILITY FROM CONVENTIONAL PRODUCING AREAS SIGNIFICANCE OF DEVELOPMENT IN NEB FORECAST

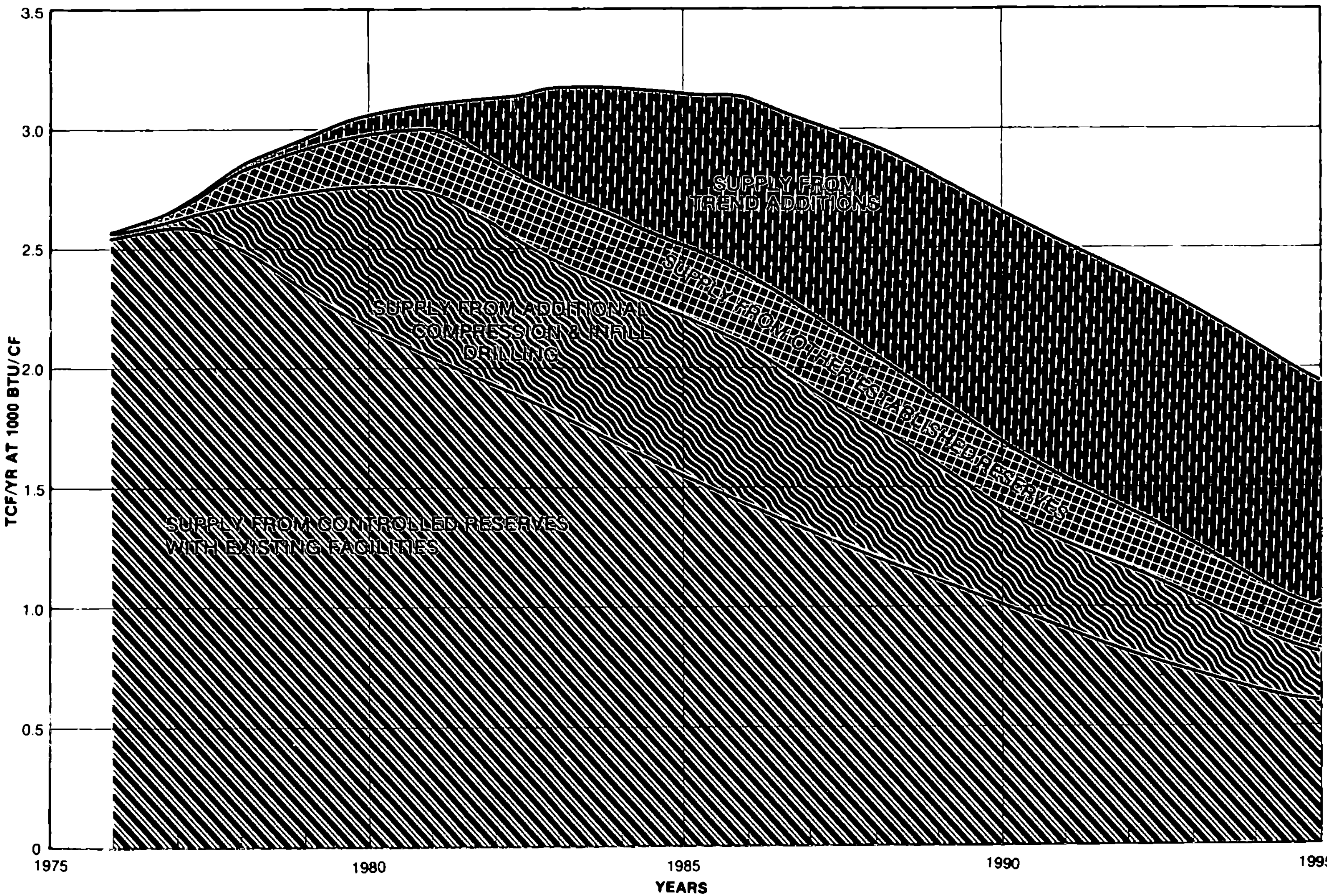

FIGURE 2-6

DELIVERABILITY FROM CONVENTIONAL PRODUCING AREAS
RANGE OF UNCERTAINTY IN NEB FORECAST

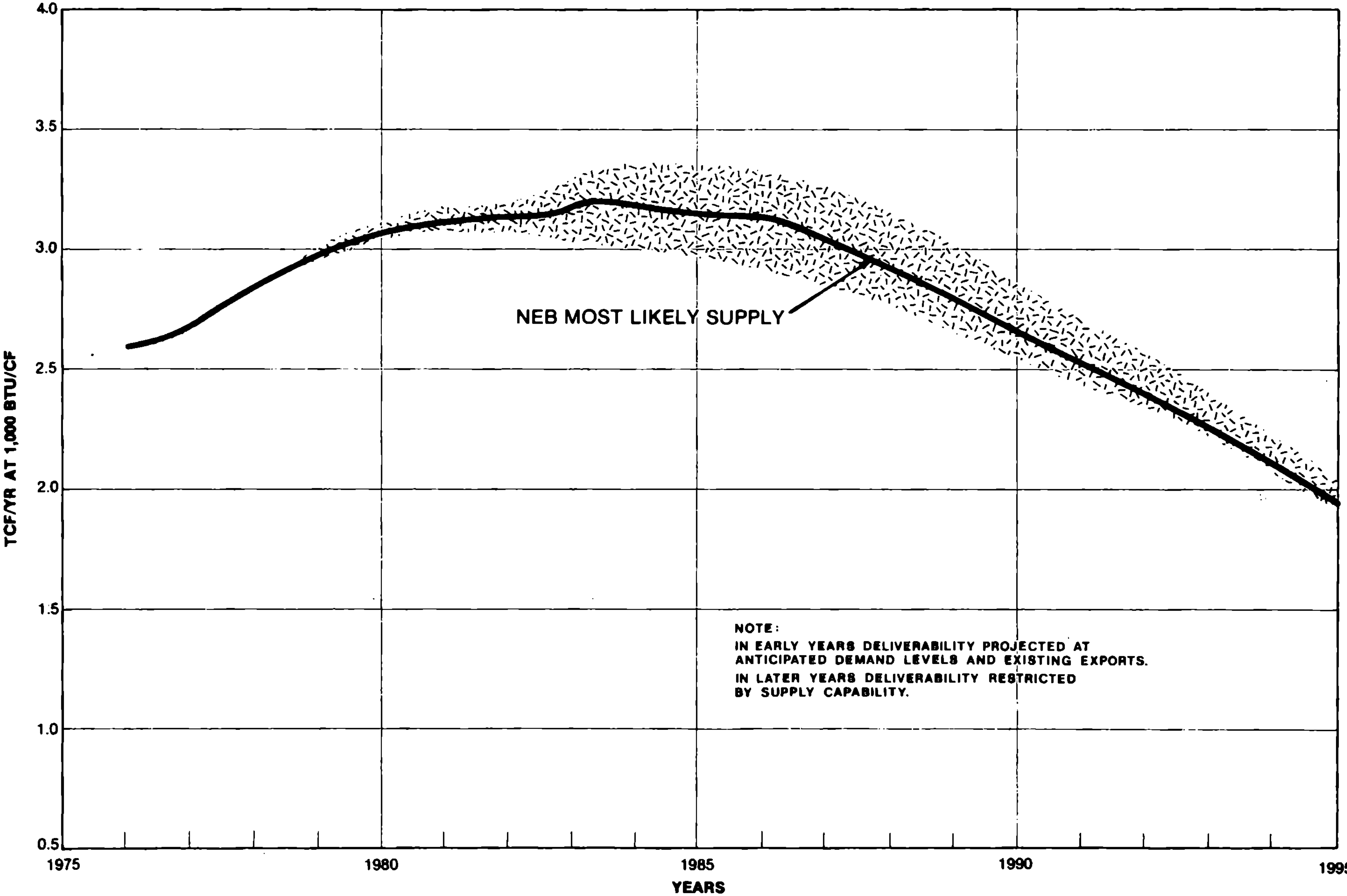

FIGURE 2-7

2.4 GAS SUPPLY/DEMAND BALANCE IN THE CONVENTIONAL AREAS

2.4.1 Evidence

2.4.1.1 Supply/Demand

CAGPL submitted a total Canada supply/demand balance produced on a system by system basis. This analysis showed that there was a growing deficiency in the supply of natural gas from the conventional areas in Canada to meet Canadian demand and licenced exports. The current small deficiency was forecasted to increase with time to 1,498 Bcf per year in 1995.

The Westcoast-British Columbia system on which the current deficiency exists was projected by CAGPL to have a 253 Bcf deficiency by 1995. Alberta requirements were shown to be fully met over the forecast period with excess gas being shown as available to meet demands east of Alberta. CAGPL forecasted a small deficiency in meeting these demands in 1981 growing to a deficiency of 1,246 Bcf in 1995.

Trunk Line on behalf of the Foothills Group provided extensive data on the supply/demand balance for unconstrained (Alberta protection formula not considered) supply from conventional producing areas compared to total Canadian demand. It showed the first significant deficit in supply in 1984, some 163 Bcf, rising to 300 Bcf in 1985 and to 918 Bcf in 1995. In the constrained (includes effects of restrictions by Alberta on removal of gas from the Province) supply case, there were small deficiencies beginning in 1978 rising to 78 Bcf in 1982, 587 Bcf in 1985 and 1210 Bcf in 1995.

Mr. Blair, President of Foothills, stated that he believed the supply/demand intersection in the unconstrained case would occur in 1986 or 1987, rather than the dates contained in the Trunk Line filed evidence. His latest assessment was that the supply forecasts submitted earlier by technical and policy witnesses for Trunk Line were too low and demand forecasts were too high, but he did not file any supporting evidence.

Shell submitted evidence which showed a deficit in gas supply from non-frontier areas beginning in 1984. Shell also submitted an oil supply/demand forecast which showed Canada as a net importer of oil in 1975 with dependence on imported oil increasing rapidly in subsequent years. Shell recommended that Mackenzie Valley gas be used to displace imported oil in Canadian markets when it was economic to do so, with short-term gas exports being made to the United States while Canadian markets were being developed. Such exports would help to offset the deficit in the balance of payments of Canada's oil account.

Gulf submitted two demand forecasts, Case 1 based on non-frontier gas only and Case 2 based on frontier gas being available in 1982. The supply/demand balance for Case 1 indicated a shortage in total domestic demand plus licensed exports beginning in 1983 (excluding the current British Columbia export deficiency which was forecast to continue). Gulf indicated that there would be problems in meeting peak daily winter demands as early as 1980.

Gulf's Case 2 supply/demand balance assumed frontier supply from the Mackenzie Delta, Beaufort Sea, Arctic Islands and East Coast offshore sources. In this case, there was a higher demand growth. This indicated that there would be a surplus of gas from 1982 to 1984 as a result of the availability of Mackenzie Delta gas. A deficit would occur in 1985 which would be offset in 1986 and future years by production from the Beaufort Sea and by declining export commitments.

Gulf noted that its domestic demand forecasts did not include any major shift from existing use of oil to natural gas. Gulf suggested that it would be prudent to move towards natural gas from oil to offset the rising volume of oil imports.

Imperial provided estimates of total Canadian energy demand, as well as the supply and demand for oil and natural gas. Imperial maintained that in 1985 the supply of natural gas available from only the existing Southern Basin fields would fall one Tcf per year short of meeting total requirements including authorized exports. The supply would fall short of Canadian demand beyond 1985. The deficit could be met by the discovery and development of additional gas in the Southern Basin and the development of existing gas reserves in the Beaufort/Mackenzie Delta area. Including new discoveries and development in the Southern Basin, supply would fall short of total requirements including authorized exports by 1981. By about 1987, total Southern Basin sources would not satisfy Canadian gas demand.

Imperial compared the total oil and gas supply from conventional areas with the expected Canadian demand for oil and gas. In the absence of further oil sands production over and above Great Canadian Oil Sands and Syncrude and of frontier supply development, Canada's net dependence on foreign energy supplies would increase rapidly.

The Workgroup on Canadian Energy Policy and Energy Probe stated that the energy supply deficit could be met through measures other than increasing supply from frontier sources. It was suggested that a vigorous conservation policy combined with initiatives in the area of alternative renewable energy sources stimulated by a negative decision by the Board on a northern pipeline could substantially reduce or eliminate the energy deficit.

Professor Helliwell developed a computer model which provided as one of its outputs a natural gas supply/demand balance. As discussed in Section 2.3.2 of the report, he developed a "standard" case employing supply statistics from various sources. He used his own model to develop a demand forecast and matching supply and demand concluded that there would be no deficiency in meeting Canadian gas demands from conventional sources of supply until 1994. Professor Helliwell presented a second case based upon his assessment of the NEB estimates of supply contained in the Board's 1975 Gas Supply and Requirements report and the same demand forecast used in the base case. The second case depicted supply deficiencies commencing in 1989.

Under cross-examination Professor Helliwell agreed that a forecast of deliverability from existing reserves calculated on a pool-by-pool basis would be superior to the method employed by him.

A number of industrial customers submitted evidence on their requirements and expressed their view of the necessity for a secure and continuing supply of natural gas to meet growing industrial needs.

Archbishop Scott, on behalf of CJL, believed that it was not unreasonable to rely on some level of imported oil.

CJL further stated that the supply/demand balances presented by the various Applicants were based on erroneous assumptions about the level of economic recovery and the ineffectiveness of conservation policies. By overestimating the level of economic activity and underestimating conservation, the Applicant's forecasts were said to overestimate the demand for natural gas. The consequent predictions of shortages were said to be ten years in advance of the date by which they would likely occur.

In support of these allegations, Dr. Bradfield, on behalf of CJL, submitted a series of 18 combinations of conventional supply and demand forecasts from various sources with a view to showing a significantly later year of first shortfall and why this was more likely to develop than the forecasts of the Applicants.

The data bases for these scenarios were indicated to be Energy, Mines and Resources and Helliwell demand forecasts, at 2 per cent, 3.5 per cent and 4.5 per cent growth rates, respectively, and deliverability estimates of NEB, CAGPL and Helliwell.

Some of the basic supply assumptions underlying Dr. Bradfield's work were that

(a) deliverability is independent of demand;
(b) surplus deliverability can be accumulated or banked for future use at whatever level required; and
(c) producers would be willing to adjust activities to accommodate depressed levels of demand.

During cross-examination, Dr. Bradfield affirmed that his procedure for determining the date of first shortfall consisted of accumulating any so-called "deliverability surplus", that is the area between the curves to the left of the intersection point or cross-over of each combination of supply and demand curves, and applying it, as required, to fill the gap to the right of the point of intersection for as long as possible.

By this method, depending upon the combination of curves used, the year of first shortfall could be deferred to as late as 2012.

Dr. Bradfield stated his own belief that the most likely combinations would be those using the EMR 2 per cent demand growth rate case and 50 per cent of export commitments in conjunction with the NEB and CAGPL deliverability forecasts. The shortfall dates for these two scenarios were shown to be 2005 and 2012, respectively.

Dr. Bradfield admitted to having made no study of the deliverability characteristics or behaviour of actual gas pools, to being unfamiliar with relevant evidence in the public record such as that relating to the conclusions respecting the McDaniel study. Perhaps more importantly, Dr. Bradfield acknowledged having no expertise in the field of reservoir engineering.

In this regard, it was shown in evidence that Dr. Bradfield was unable to clearly distinguish the difference between annual reserves additions and deliverability from such additions; as evidenced by the manner in which he made use of his so-called "rediscoveries".

The Government of Saskatchewan stated that Canadian domestic consumers would not require access to frontier sources until about 1987, if present export commitments were gradually phased out. It was the view of the Saskatchewan Government that construction of the pipeline should be deferred to a date later than proposed by the Applicants.

GAS SUPPLY/DEMAND BALANCES FOR CONVENTIONAL PRODUCING AREAS
SUBMITTORS' FORECASTS

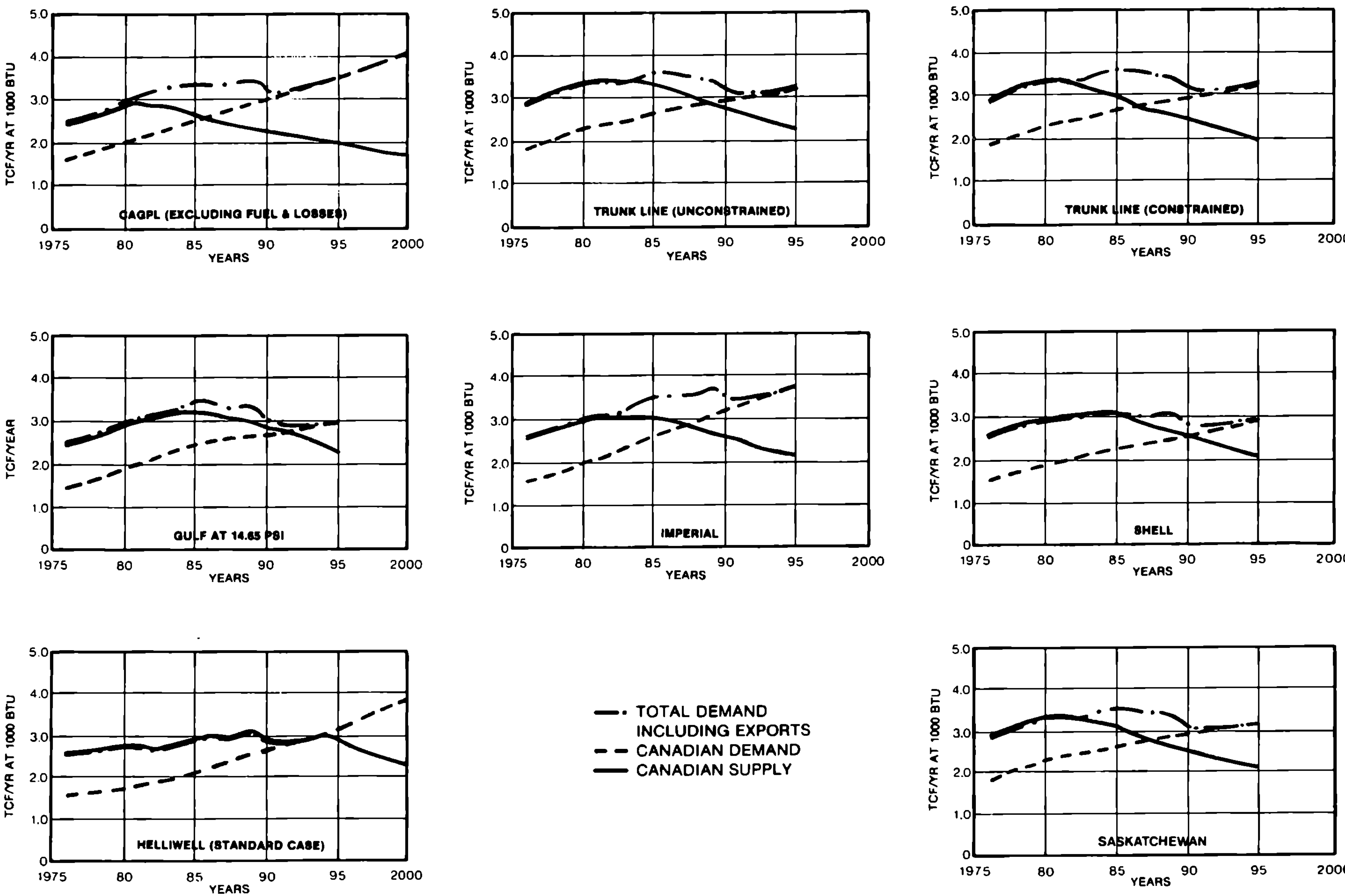

FIGURE 2-8

Figure 2-8 graphically displays the relationships between supply and demand as submitted by the Applicants and some intervenors as discussed above.

2.4.1.2 Alberta Protection Formula

Introduction

Under the Alberta Gas Resources Preservation Act the AERCB is required to enquire into applications made by qualified persons for permits authorizing the removal of gas from the Province. The legislation states that before a permit may be issued, the AERCB must satisfy itself that it is in the public interest, having regard for the present and future needs of persons within Alberta and having regard for the established reserves and the trends in growth and discovery of reserves of gas in Alberta.

In making its gas surplus determination, the AERCB considers the present and future needs of Alberta over a 30-year period and determines the gas which is surplus to those needs. Before the AERCB will issue a permit for removal of gas from Alberta, there must be positive contractable and overall surpluses.

The contractable surplus test was introduced in 1966 to focus on the established gas available for immediate contracting to meet Alberta requirements and to some extent to afford a greater degree of protection to local consumers of gas.

In July 1976 the AERCB held a public hearing to review the above procedures and accepted the Alberta Utilities' contention that it was becoming increasingly difficult to place volumes of gas under direct contract from producers. As a result of that review, the AERCB now uses a two-stage process for determining whether there are gas reserves surplus to Alberta's requirements.

The first stage determines the current, future and overall surpluses. The current surplus is determined by balancing the reserves which are currently available with the current requirements for export permits, plus Alberta's general requirements which are usually taken as thirty times the requirements of the first forecast year. The future surplus is calculated by comparing the remaining and future reserves with the future requirements in Alberta. The overall surplus is the sum of the current and future surpluses.

The second stage is a new test, called the "availability for contracting test" which determines, on the basis of contract information filed with the AERCB, if there are sufficient reserves actually available for contracting by Alberta users. In order for new permits to be granted, there must not be a significant deficit in either the current, overall or available for contracting categories.

Evidence

CAGPL submitted in evidence a detailed current surplus calculation for Alberta as of the beginning of 1976 and projected current surplus calculations for the years 1975 to 1990. These calculations showed a current surplus of 9.38 Tcf for 31 December 1975 and a maximum current surplus occurring in 1986 when 14.85 Tcf was projected to be available. In these calculations no allowance was made for any removal of gas from Alberta.

AGTL submitted a detailed Alberta surplus forecast for the years from 1975 to 1984 showing both the current surplus calculation and the future surplus calculation which were combined to give a resulting overall surplus. The AGTL results projected an overall surplus of 4.0 Tcf for 1975 which became negative in 1977 at -1.5 Tcf and remained negative through 1984.

AGTL also tabulated an "AERCB Surplus" case which showed similar results for the current surplus calculation but projected an overall surplus of 9.9 Tcf for 1975 which steadily decreased to 0.8 Tcf in 1983 becoming negative at -0.2 Tcf in 1984.

The estimate of ultimate potential upon which the AGTL forecast is based on JLJ's estimate of 101 Tcf @ 1,000 Btu while the AERCB assumes 110 Tcf @ 1,000 Btu. Foothills' forecast of Alberta requirements was used in the AGTL forecast while the AERCB forecast of Alberta requirements shown in AERCB Report 74-W was used in the "AERCB Surplus" case.

2.4.2 Views of the Board

2.4.2.1 Total Canada

The Board considers the supply/demand balance evidence of CAGPL, Trunk Line and most submittors realistic in the presentation of their cases. The Applicants provided the most detail and the other submittors varying degrees of depth of consideration of this subject. The final result of each comparison of supply and demand, however, depended on the many assumptions which must be made in relating the forecasts of gas supply to demands in the different provinces.

The Board has performed simulations using Professor Helliwell's approach to determine the gas supply/demand balance. As discussed in section 2.3.2 of the report, using the NEB 1975 estimates, the Board has determined a surplus of 7.8 Tcf as of 31 December 1973. In these simulations, the Board used two different connection rates for new reserves, namely a 10 per cent per year for ten years which approximates the more detailed forecast of connections used by the Board in its "Most Likely" forecast as explained in section 2.3.2; and a 20 per cent per year rate of connection for five years which would indicate a more optimistic forecast in the simulation. The Board also used the planned rates of take for deferred reserves as discussed in section 2.3.2. Using these assumptions and the approach of taking reserves at a rate of take of 1:7,300 on initial reserves, the Board has calculated a supply deficiency based on the Board's "Most Likely" demand given in this report in section 2.2.5. Using the average rate of connection of new reserves, the simulation showed that a deficiency would occur in 1983 and using an accelerated rate of connection of new reserves a deficiency would occur two years later, in 1985. This compares to Helliwell's estimates discussed in section 2.4.1.1.

In the case of Dr. Bradfield who appeared on behalf of CJL, it is apparent from the evidence adduced in cross-examination that he has given little, if any, consideration to either the technical or economic feasibility of developing deliverability in the purely numerical exercise that he undertook for presentation at the hearing. In the view of the Board, Dr. Bradfield's unfamiliarity with basic gas supply concepts and supply/demand interactions, has led him to faulty assumptions and erroneous conclusions; making his assessment of the possible range of shortfall dates inaccurate.

The Board's "Most Likely" forecast of gas supply from the conventional areas is compared with the Board's "Most Likely" forecast of Canadian demand plus remaining authorized export volumes as shown in Figure 2-9. In preparing this supply/demand balance, the Board studied the availability of gas supplies to meet total demand by considering three segments of the total Canadian and export market - Alberta including exports south from Alberta, British Columbia including exports at Huntingdon and East of Alberta including all other exports.

The demand for gas in the above mentioned market areas is summarized on page 1 of Appendix 2-3. The domestic demand for gas in Alberta including fuel for its distribution is shown separately from the AGTL requirement for fuel to transport gas to other markets in the Canadian and export markets.

The forecast of net reprocessing shown as an Alberta demand is derived on page 2 of Appendix 2-3. The forecast of total reprocessing shrinkage includes a projection of the historical shrinkages at the existing plants at Cochrane, Empress and Edmonton plus the projected shrinkages due to ethane extraction at new plant facilities currently under construction at Cochrane, Empress and Edmonton. Since the demand for ethane for ethylene production is included as part of the forecast of domestic demand for Alberta, the shrinkage due to ethane extraction must be deducted from the total reprocessing shrinkage to avoid double counting. The balance becomes the net reprocessing shrinkages in Alberta.

The forecasts of deliverability from controlled reserves are summarized by system on page 3 of Appendix 2-3 as discussed in section 2.3.2. The volumes shown in each column supply specific markets to be discussed in the following paragraphs.

Deliverability forecasts for the various sources of supply available to satisfy Alberta demand are summarized on page 4 of

Appendix 2-3 and can be described as follows: deliverability from the controlled reserves of the Alberta utilities as discussed in section 2.3.2; forecasts of sales by TCPL and A&S to the Alberta utilities, according to their own estimates; a forecast of deliverability from deferred reserves taken from the Alberta ERCB Report No.75-F; the Board's forecasts of deliverability from the shallow uncommitted, non-associated uncommitted and Alberta trend reserves discussed in section 2.3.2; and a forecast of the volumes of gas supply available in fields allocated to export and which are in excess of the licensed exports of A&S, Canadian-Montana, and Westcoast (Licence GL-4). The early years of this excess supply represent additional deliverability in fields supplying Canadian-Montana's combined Cardston and Aden licences whereas the later years represent the A&S supply capability as its export licences expire. The sum of these forecasts of supply for Alberta exceeds the domestic demand in Alberta as shown in Column 10 on page 4 of Appendix 2-3 and the excess volumes of supply are assumed to be available to supply British Columbia and East of Alberta when these regions require the gas.

To determine the need for this additional Alberta gas in British Columbia, the Board examined the fixed supply sources for British Columbia. Summarized on page 5 of Appendix 2-3, these forecasts of supply include the Board's forecast of Westcoast's deliverability from its total supply area including all established reserves in British Columbia, the Southern Territories and its Alberta supply area; the Board's forecast of deliverability available from Pan Alberta's reserves after making allowance for Pan Alberta's sales to Gaz Métropolitain; A&S's estimate of its sales to Columbia Gas; and the Board's forecast of deliverability from British Columbia trend additions. Comparing this total forecast of deliverability with the total British Columbia demand including the authorized exports at Huntingdon, the Board concluded that there is a current deficiency in British Columbia and there will continue to be a deficiency except during the years 1990-1992 after the export licence expires when there is a slight surplus of deliverability. This deficiency in British Columbia is treated as a demand for the surplus Alberta deliverability.

Before allocating any of the surplus Alberta deliverability to British Columbia, the Board also determined the need for surplus deliverability East of Alberta. The forecasts of deliverability from sources that supply markets East of Alberta are summarized on page 6 of Appendix 2-3. These forecasts include the Board's forecast of deliverability from TransCanada's controlled reserves less TCPL's estimate of its Alberta sales, the Board's forecast of the AGTL fuel requirement to transport TCPL's gas, and the Board's forecast of total reprocessing at Empress based on the forecast of TCPL throughput; Saskatchewan Power Corporation's forecast of Many Islands Pipelines' deliverability; the Board's forecast of Pan Alberta sales to Gaz Métropolitain; production East of Alberta as discussed in section 2.3.2; and the Board's forecast of deliverability from Saskatchewan trend additions. This total forecast of supply is capable of satisfying total demand East of Alberta including authorized exports shown on page 1 of Appendix 2-3 until 1982 when a deficiency first occurs. This deficiency continues to grow throughout the forecast period and can be partially satisfied by the surplus Alberta deliverability determined earlier.

The Board then allocated the gas deliverability surplus to Alberta demand as shown on page 7 of Appendix 2-3 to requirements (including exports) in British Columbia and East of Alberta. Additional gas was assumed to flow to meet British Columbia deficiencies commencing in 1978. The Board assumed that the necessary additional capacity in available pipelines connecting British Columbia with Alberta reserves would be constructed when required. It can be seen from page 7 of Appendix 2-3, that after satisfying British Columbia and East of Alberta demands from 1978 to 1982, there would remain volumes of gas, shown in Column 9, which provide a temporary overall surplus to Canadian demand. These are indicative of the "gas supply bubble" in Alberta, of which more will be said later. In this schedule these volumes are assumed not to be produced between 1978 and 1982 and are converted to a forecast of deliverability starting in 1983. The total surplus supply shown on page 7 of Appendix 2-3 is then allocated to British Columbia and East of Alberta based upon the proportion of the unsatisfied demand which is attributable to each of these regions. The requirement for AGTL fuel and reprocessing shrinkage at Empress associated with the surplus supplies flowing East of Alberta is also supplied from the surplus Alberta deliverability.

Since the Board deferred deliverability from the temporary overall surplus supplies from 1977 to 1982 until 1983 and later, adjustments had to be made to the Board's forecasts of deliverability from uncommitted and trend reserves in Alberta. The Board judged that, except for the year 1977, the total adjustment would be made to the trend additions forecast. The total effect of the adjustments to these forecasts is detailed on page 8 of Appendix 2-3.

The Board's Total Canadian Supply/Demand Balance is shown on page 11 of Appendix 2-3 and is illustrated in Figure 2-9. There is presently a supply deficiency in meeting total requirements. The deficiency exists only on the Westcoast system as indicated on page 5 of Appendix 2-3 and, assuming the necessary additional capacity in available pipelines connecting that system with Alberta reserves, it could be eliminated in 1978. Thus, total Canadian supply can theoretically meet total Canadian demand plus authorized exports until a deficiency appears in 1983. In that year, Canadian conventional gas supply would have reached its approximate maximum annual production potential and thereafter the annual deficiency in meeting total projected demand from supplies in conventional producing areas increases until it amounts to 1,241 Bcf in 1995 as indicated on page 11 of Appendix 2-3. It should be noted that this Board forecast of "Most Likely" supply to meet "Most Likely" total demand does not contain any limitations which could result from the implementaion of the Alberta protection policy. The effect of that policy on the results depicted in the Board's schedules is discussed later in this section.

Figure 2-10 shows the Board's total Canada supply/demand balance illustrating the projected variations in supply and demand as shaded areas. It indicates that even with the most optimistic forecast of production and the lowest forecast of demand, a deficiency in meeting total demand for Canadian gas from supplies in conventional producing areas would occur about 1989.

Recently there has been much discussion in the media and also at this hearing about a current gas deliverability excess supply or "gas supply bubble" in Alberta. To illustrate this "gas supply bubble" the Board prepared an estimate of the maximum production capability from reserves in the conventional producing areas. This forecast is illustrated in Figure 2-11 along with the "Most Likely" total demand forecast. The forecast includes an estimate of the maximum deliverability capability of the contracted reserves of TCPL, A&S, Westcoast and Pan Alberta. It assumes deliverability from a higher percentage of the uncommitted reserves in Alberta than in the "Most Likely" case. Finally, higher initial discovery rates and faster rates of connection are assumed for the trend additions than in the "Most Likely" case. (Column 9 on page 7 of Appendix 2-3 showing Temporary Alberta Surplus depicts a "bubble" of small dimensions because of its use of the deliverability assumptions of the "Most Likely" supply case.)

The Board, in its 1975 report on Gas Supply and Requirements, predicted that productive capacity would reach 2,788 Bcf for the year 1976. Natural gas sales including pipeline fuel and reprocessing shrinkage in 1976 amounted to approximately 2,560 Bcf - somewhat lower than anticipated.

The reduced market realization has resulted in pressure by producers to obtain additional markets for non-producing gas reserves. The situation has been exacerbated by the recent practice of purchasers entering into "deliverability-type" contracts with producers instead of the traditional type of contract under which the purchasers contract for a specified daily quantity of gas for each specified volume of reserve, most frequently 1 MMcf/d per 7,300 MMcf of reserves.

Under a "deliverability" contract, the purchaser undertakes to take delivery of or to pay for the volumes of gas tendered by the producer. In the early life of a pool, it is usually possible to deliver a greater quantity of gas than would be contracted for under the traditional type contract, and conversely usually less in the later years. If a gas purchaser has a significant volume of gas under contract in the form of deliverabiltty contracts, its flexibility to adjust supply to fluctuating market demand is reduced. If demand flattens out, as it has over the last two or three years, the purchaser is placed in a take-or-pay position and is unable to enter into contracts for newly developed sources of gas. It is this phenomenon which has contributed to the so-called "gas supply bubble" in Alberta. The effect of creating an over-supply situation is expected to be temporary as initial flush production in low permeability fields declines rapidly and as producers adjust development programs to the realties of demand.

It is the Board's view that while there may be some limited need for deliverability-type contracts, particularly in the Southeastern Alberta shallow gas pools, it would generally be in the best interests of purchasers and producers if the normal rate of take type of contracts were negotiated.

Figure 2-11 indicates that if markets were available for the "gas supply bubble" volumes and without giving consideration to the effect of the AERCB Alberta protection formula, the increased demands could be met until 1984 and significant deficiencies would only occur in 1987. The Board views this projection as optimistic.

2.4.2.2 Alberta

Having in mind the location of the greatest portion of the gas reserves from the conventional producing areas and the AERCB protection formula, it is perhaps stating the obvious to say that the requirements of that province will be fully met over the period of the forecast. This has been shown on page 4 of Appendix 2-3.

2.4.2.3 British Columbia

The supply-demand relationship for the Province of British Columbia is presented on page 9 of Appendix 2-3 and is displayed in Figure 2-12. The total forecast of supply as previously discussed includes those supplies from British Columbia, the Southern Territories and Alberta destined to satisfy the total British Columbia demand as shown on page 5 of Appendix 2-3 and those additional supplies of Alberta gas calculated on page 7 of Appendix 2-3.

The total demand, under the assumptions employed, can be met from 1978 until a deficiency re-appears in 1983. The deficiency grows until Westcoast's export licence GL-41 terminates in 1989 and a slight excess capacity would exist for the years 1990 to 1992 inclusive as shown in Column 5 on page 9 of Appendix 2-3. Deficiencies appear in 1993 and amount to 47 Bcf in 1995.

2.4.2.4 East of Alberta

The Board's assessment of the "Most Likely" gas supply which may be available to meet requirements East of Alberta is presented on page 10 of Appendix 2-3 and illustrated in Figure 2-13. The gas considered available for this projection includes the supplies, previously discussed, from page 6 of Appendix 2-3 and the additional gas from Alberta calculated on page 7 of Appendix 2-3.

As may be seen from page 10 of Appendix 2-3 and Figure 2-13, total demand East of Alberta including authorized exports can be met until 1983 when a small deficiency of nine Bcf occurs. This deficiency continues to grow and becomes 1,107 Bcf by 1995.

2.4.2.5 Effect of Eliminating Exports in 1978

The Board stated in its 1975 Canadian Natural Gas Supply and Requirements report that there was a high degree of probability that Canadian natural gas supply from the conventional areas would not be able to meet Canadian demand beyond 1984. In an earlier part of this section the Board is projecting that supply will not be able to meet total demand, including exports, in 1983

GAS SUPPLY/DEMAND BALANCE FOR CONVENTIONAL PRODUCING AREAS
NEB MOST LIKELY FORECAST

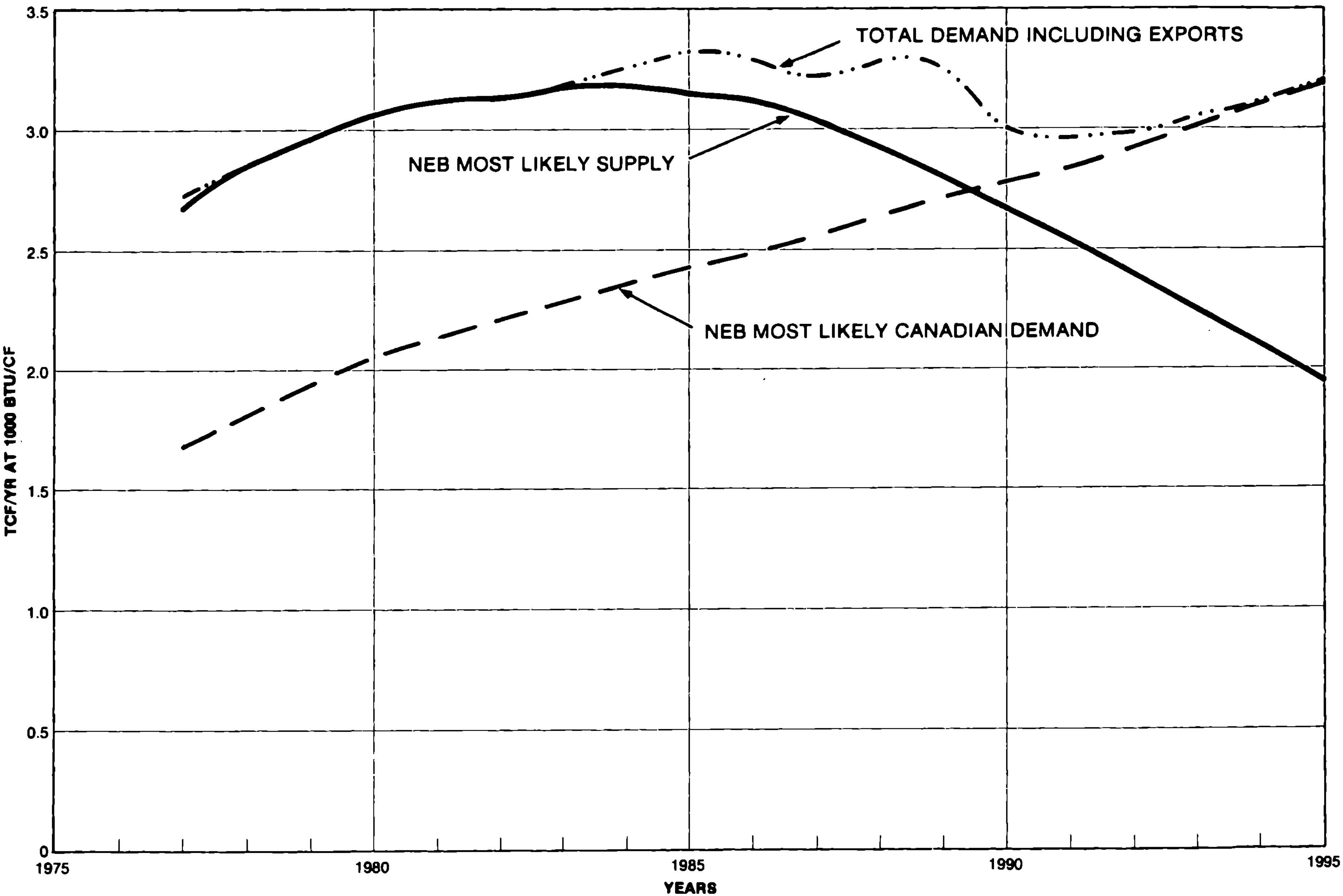

FIGURE 2-9

GAS SUPPLY/DEMAND BALANCE FOR CONVENTIONAL PRODUCING AREAS
RANGE OF UNCERTAINTY IN NEB FORECASTS

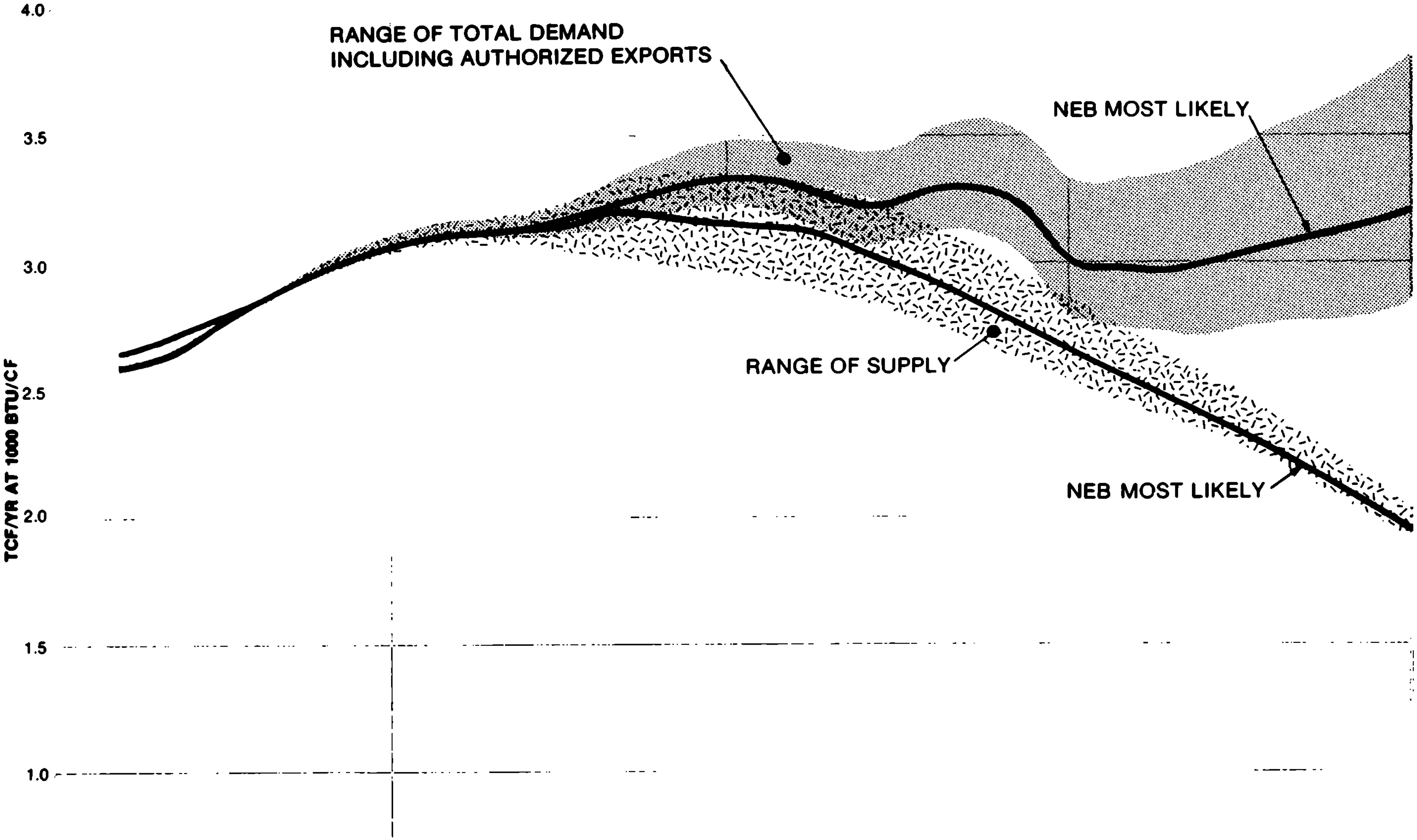

FIGURE 2-10

GAS SUPPLY/DEMAND BALANCE FOR CONVENTIONAL PRODUCING AREAS
NEB MAXIMUM CAPABILITY FORECAST

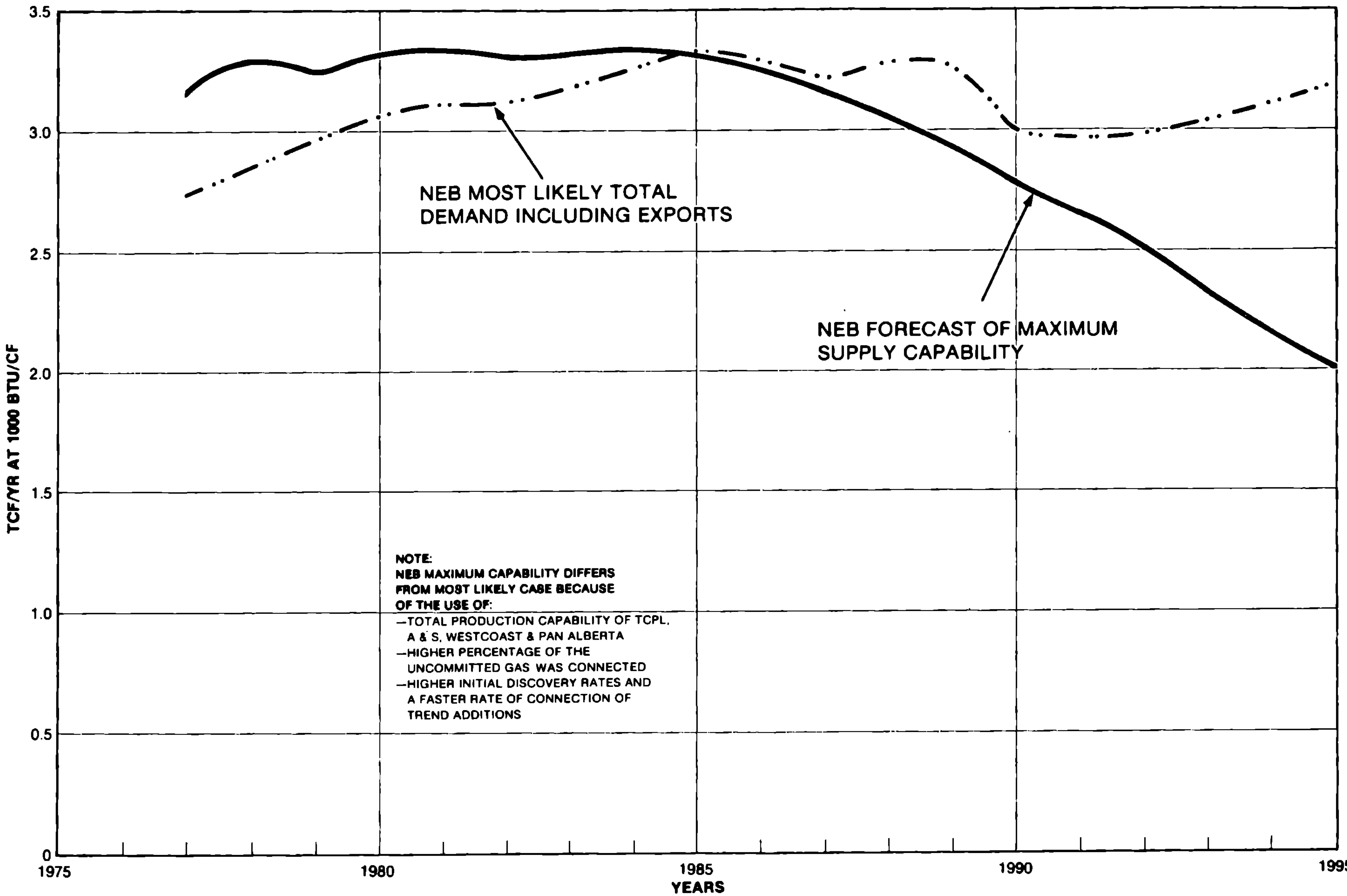

FIGURE 2-11

GAS SUPPLY/DEMAND BALANCE FOR BRITISH COLUMBIA
NEB MOST LIKELY FORECAST

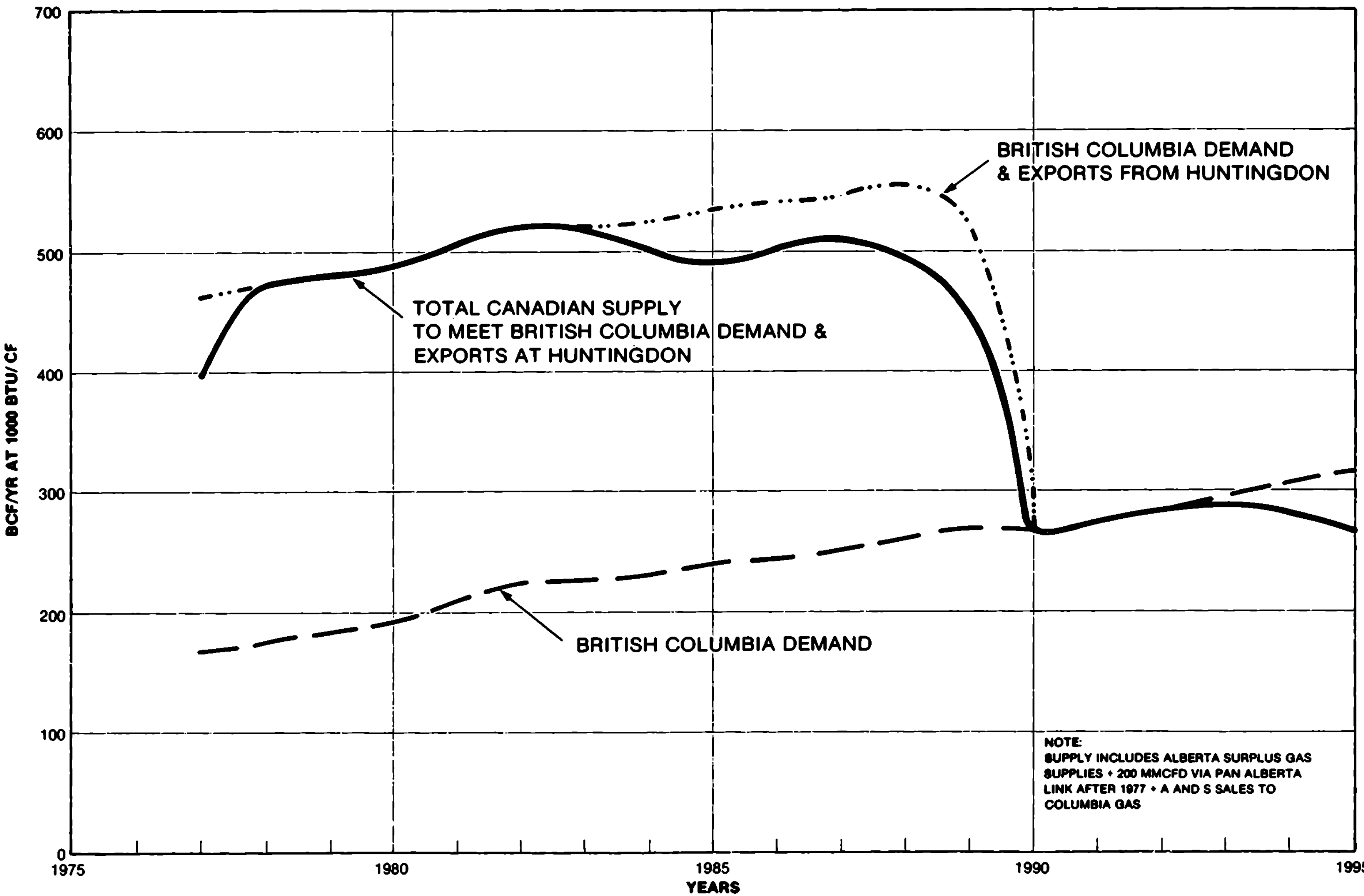

FIGURE 2-12

GAS SUPPLY/DEMAND BALANCE FOR EAST OF ALBERTA
NEB MOST LIKELY FORECAST

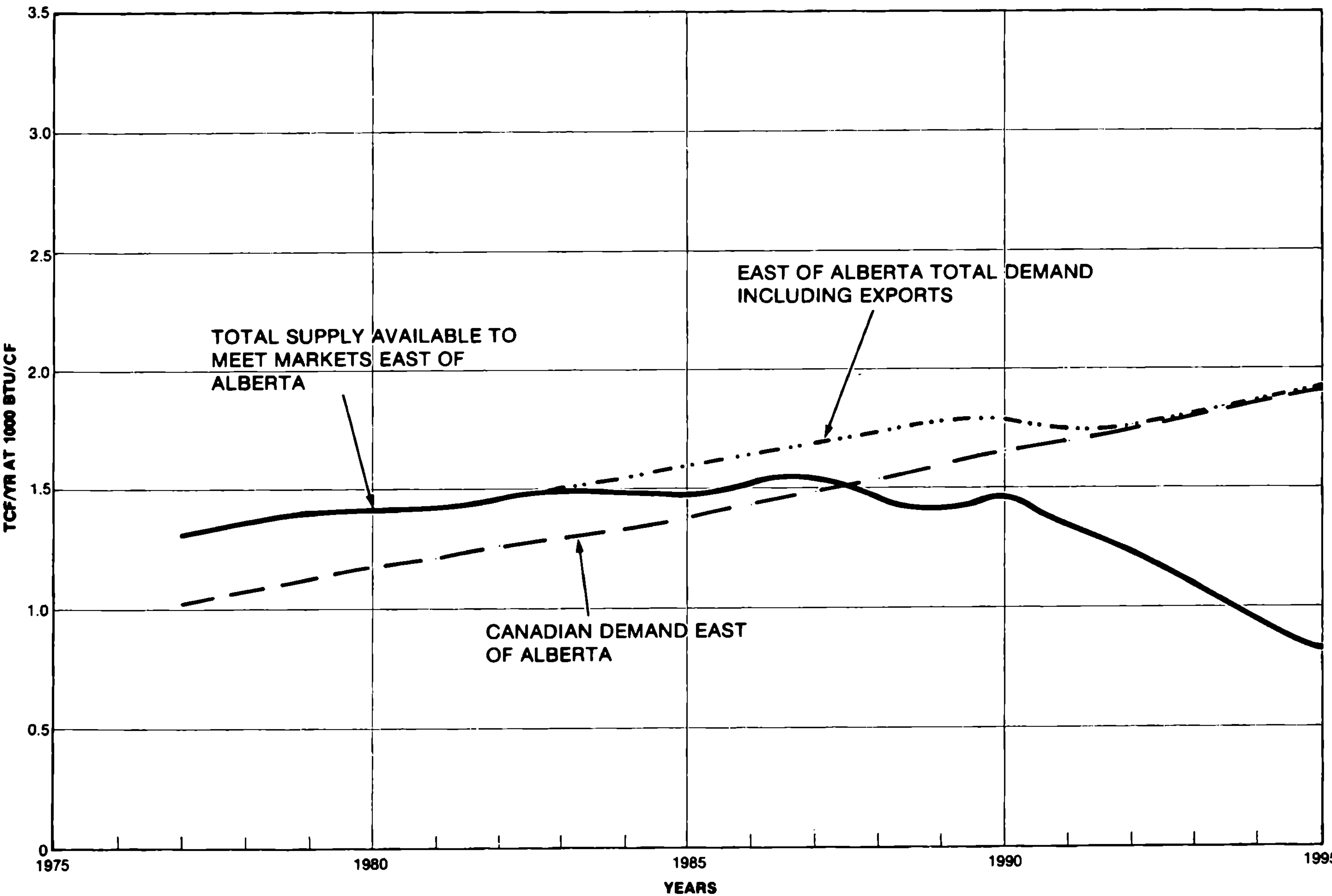

FIGURE 2-13

and will not be able to meet Canadian demand after 1989. In view of these circumstances, a study was made of the effect on deliverability of eliminating exports in 1978 and the results are shown graphically in Figure 2-14.

In projecting the levels of supply in circumstances of not permitting exports after 1977, the normal field development that is forecast for the late 1970's and early 1980's in the "Most Likely" case would not be expected to take place, as there would be an oversupply during this period. Later, when there was a requirement for additional deliverability, many of the fields would be depleted to an extent that it would no longer be economic to provide such deliverability through infill drilling or addition of compression.

The Board reduced the trend additions forecast for the years 1978 to 1986 in order to reflect the expected industry reaction to the reduced market opportunity resulting from the elimination of exports. By the middle 1980's the need for additional reserves would be within the foreseeable future and exploration activity was then forecast to increase. The total trend additions for the forecast period remain the same as those associated with the lower level of the supply forecast shown in Figure 2-7.

With the combined effect of lower rates of deliverability from existing reserves and a slower rate of reserve additions the point at which the supply projection declines from the domestic demand projection has been extended by less than one year compared to the time that supply would have been insufficient to meet Canadian demands; this assumes that exports would have been continued only to the extent that deliverability was available in excess of Canadian demands.

The Board concludes from this study that eliminating exports in 1978 would have very little effect on extending the period during which Canadian gas demands could be met from conventional gas producing areas. The reserves, otherwise produced for export during the period 1978 to 1989, however, would be available beyond that date. In such circumstances, the deferred deliverability would be at lower rates over an extended period and would increase the supply in the period 1990 to 1995 as shown in Figure 2-14.

2.4.2.6 Effect of Alberta Protection Formula

The Board has reviewed the calculations of current surplus submitted by CAGPL and has concluded that they are not an accurate calculation of the AERCB surplus formula for current surplus. No consideration was given to deferred reserves, to permit-related fuel and shrinkage or to permit requirements. Also, the failure to subtract each year the amount of gas removed from the Province gives a misrepresentation of the current surplus calculation.

The Board also reviewed the current surplus calculations presented by AGTL for the "AGTL" case and the "AERCB Surplus"

GAS SUPPLY/DEMAND BALANCE FOR CONVENTIONAL PRODUCING AREAS EFFECT OF ELIMINATING EXPORTS IN NEB MOST LIKELY FORECAST

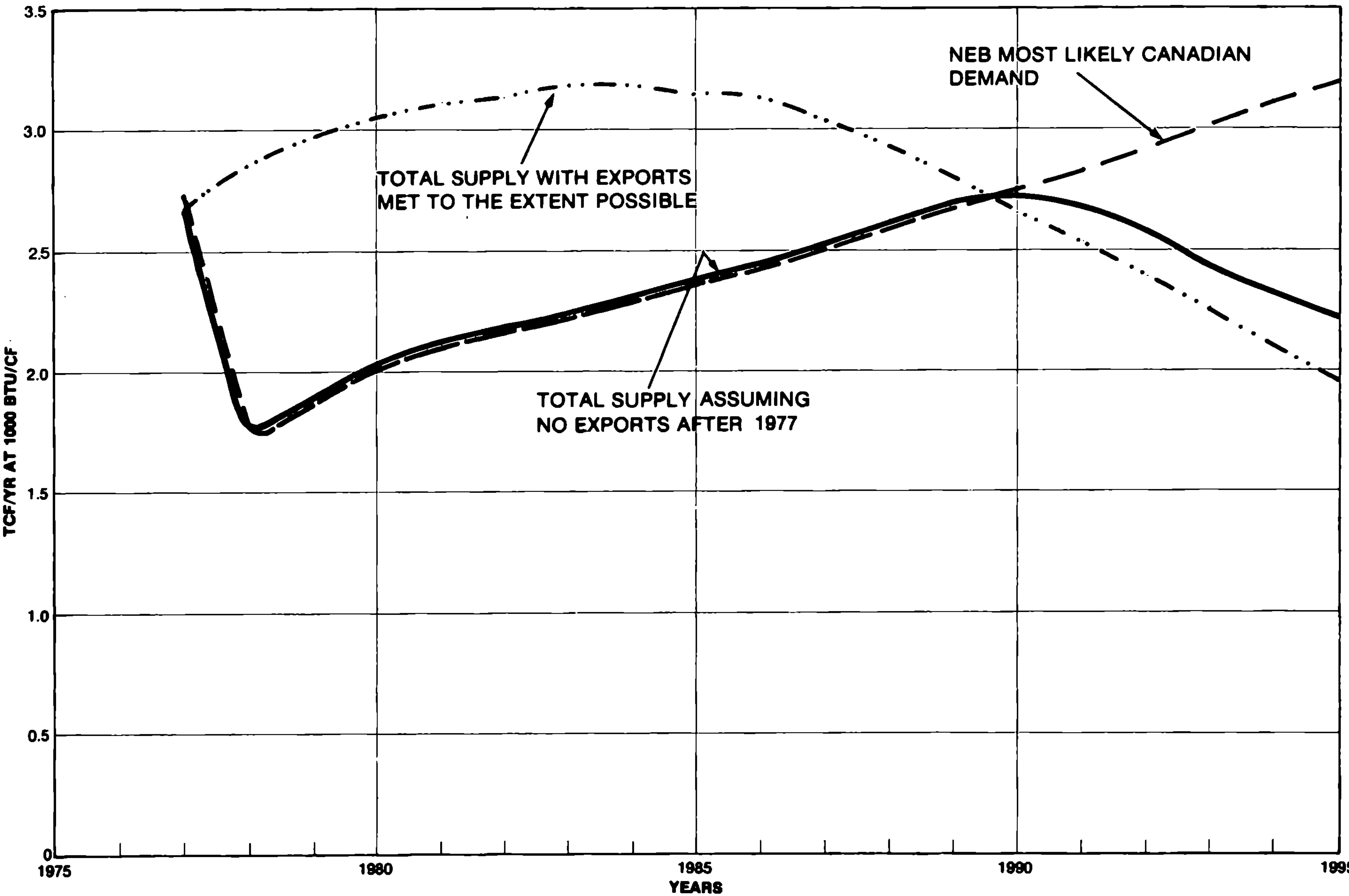

FIGURE 2-14

case and finds that these cases are representative of the range of uncertainty which is involved in the calculation of current surplus of Alberta.

The Board also reviewed the future surplus calculations and has similar comments to those expressed regarding the current surplus calculations. The Board feels that the two cases presented by AGTL represent the range of possible future surplus from Alberta and finds its own estimates would lie between Trunk Line's "AGTL" case and its "AERCB Surplus" case.

With respect to the question of overall surplus, the Board finds that its own estimate of the time that the overall surplus would become negative lies between the estimates of AGTL for its AGTL case (1977) and its "AERCB Surplus" case (1984). The Board finds that the overall surplus test would indicate a negative value in the early 1980's, perhaps as early as 1981.

Neither CAGPL nor Trunk Line (on behalf of the Foothills Group) presented evidence with respect to the most recent AERCB test, - "the availability for contracting" test. This test makes use of supply contract data details which are filed with the Alberta Board on a regular basis. In the Board's view it is the most restricting of any of the surplus tests. Without access to all of the contractual information, it would be difficult for anyone other than the Alberta Board to make an accurate calculation of the test and it would be difficult in any circumstance to project the likely results of the test into the future.

The recently published data with respect to the "availability for contracting" test is contained in the Alberta ERCB Report 77-A dated January 1977 in which the Alberta Board estimated the surplus reserves available for contracting as of 31 December 1976 to be 2.6 Tcf.

The Board in reviewing the available data and in making certain assumptions as to dispositions of supplies now under contract to exporting companies, concludes that the reserves available for contracting would become negative no later than 1982.

2.5 GAS SUPPLY - FRONTIER AREAS

2.5.1 Mackenzie Delta - Beaufort Sea

Estimates of reserves in the Mackenzie Delta Beaufort Sea were submitted by two Applicants, CAGPL and Foothills. Gulf, Imperial, Shell and Sun submitted estimates of reserves for their own fields only, while Alberta and Southern submitted estimates of reserves underlying the areas controlled by Gulf and Shell. These estimates are discussed in the text that follows and Table 2-17 compares the estimates with those of the Board.

2.5.1.1 Established Reserves

CAGPL

CAGPL's estimate of proved, probable and possible natural gas reserves in the Mackenzie Delta - Beaufort Sea as of January, 1977 was prepared by Sproule Associates Limited, Geological and Engineering Consultants. The estimate of reserves of marketable gas[1] were 5,059.8 Bcf proved, 736.9 Bcf probable, and 944.2 Bcf possible, for a total of 6,740.9 Bcf. Of this total, 5,034.6 Bcf were attributed to the Tertiary sandstones of the Adgo, Garry, Kumak, Mallik, Netserk, Niglintgak, Taglu, Titalik and Ya Ya areas with the remaining 1,706.3 Bcf in the Lower Cretaceous sandstones of the Parsons Lake area.

Sproule Associates, the consultants for CAGPL, had not re-assessed Parsons Lake, Taglu and other areas in the light of the new well completions during the 1976-1977 drilling season.

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(1) All estimates with respect to the Mackenzie Delta-Beaufort Sea are at 14.73 psia and 60°F.

Foothills

Foothills' estimates of proved, probable, and possible natural gas reserves in the Mackenzie Delta-Beaufort Sea were updated to include the results of the 1976-1977 drilling season. They were prepared by Grant Trimble Engineering Limited, and JLJ Exploration Consultants Limited. The estimates of discovered natural gas, classified as proved, probable, and possible totalled 6,150.3 Bcf of which 5,086.7 Bcf were proved, 508.9 Bcf probable, and 554.7 Bcf possible. The Tertiary sandstone fields were stated to contain 4,306.6 Bcf in all categories while the Cretaceous sandstones of the Parsons Lake area were said to contain the remaining 1,843.7 Bcf.

Producers

The Mackenzie Delta area producers, Gulf, Imperial, Shell and Sun, submitted estimates of gas reserves under their control.

Gulf's estimates for Parsons Lake, Ya Ya North, Ya Ya South, Reindeer and Titalik were 1,627.3 Bcf proven, 387.6 Bcf probable and 298.8 Bcf possible for a total of 2,313.7 Bcf. Gulf excluded the Reindeer and Titalik fields from the proven and probable category, considering them to be of low deliverability and containing low reserves, thus rendering them beyond economic reach.

Shell's estimates of the Niglintgak area were 607 Bcf proven, 366 Bcf probable and 39 Bcf possible for a total of 1,012 Bcf. Under cross-examination Shell stated that a recent drilling step-out, Shell Kumak E-58, had tentatively increased the proven reserves by 300 Bcf basically by confirming the probable as proven reserves. The estimates shown on Table 2-17 do not reflect these changes.

Imperial submitted its estimates on the basis of "minimum", "likely" and "maximum" related to probability factors. Its estimates for Adgo, Mallik, Netserk, and Taglu were 2,200 Bcf "minimum", 3,440 Bcf "likely", and 4,650 Bcf "maximum".

Sun's estimates for the Garry area, including both associated and non-associated gas, were 253.8 Bcf "likely" and 269.2 Bcf "maximum".

Others

Alberta and Southern submitted estimates of reserves controlled by Gulf and Shell. Only proved and probable reserves were considered. For the Gulf-controlled fields of Parsons Lake, Reindeer, Titalik, Ya Ya North and Ya Ya South, Alberta and Southern estimated the reserves to be 1,445.3 Bcf proven and 186.9 Bcf probable for a total of 1,632.2 Bcf. For Shell's Niglintgak area, it estimated 455.1 Bcf as proven and 344.5 Bcf as probable for a total of 799.6 Bcf. Alberta and Southern had not included the latest Shell gas well Shell Kumak E-58 in its estimates.

Views of the Board

In its assessment of the reserves contained in the fields discovered to date, the Board is satisfied that sufficient delineation drilling has been carried out in the Taglu, Parsons and Niglintgak fields to allow for a reasonable assessment of the established reserves. In pools such as Adgo, Garry, Mallik, Netserk and others, more interpretative data are required to fully determine the reserves. In the absence of adequate delineation drilling, however, preliminary indications are that these fields will be of limited size compared with major accumulations at Taglu, Parsons and Niglintgak, the three proposed start-up fields.

Despite the variance in the reservoir parameters amongst the Applicants, producers and others, particularly in the areas of water saturation, porosities, and productive areas, there was close agreement as to the total proven reserves in the Mackenzie Delta. Estimates of other categories of reserves varied to some degree, reflecting differences in technical interpretations. These variances do not raise particular concern, since new data and technology will result in more accurate re-determinations.

The Board has independently assessed the reserves in the Mackenzie Delta - Beaufort Sea and finds that the current established reserves contained in all the fields are 5,280 Bcf. As in the past, the Board, although recognizing the existence of possible reserves, does not consider any part of these for its established reserves estimates.

The Board acknowledges that differences in the interpretation of data as well as variations in definitions of reserves do occur. In noting these differences in the various submissions, the Board also recognizes that there are difficulties in assessing net pay values and water saturations in the Mackenzie Delta-Beaufort Sea. In its own assessment of the reserves, the Board has, in some cases, been less optimistic than the producers in its appraisal of reservoir parameters, particularly net pay values and water saturations. While this may have resulted in the exclusion of sections which may be gas bearing, it nevertheless was deemed prudent until more is known about the reservoirs.

2.5.1.2 Reserves Additions and Ultimate Potential

Estimates of reserves additions and ultimate potential were either submitted or supplied under cross-examination by various parties during the course of the hearing.

CAGPL

CAGPL believed that based on the limitations of the presently available data and on the methods used in its assessment, the most reasonable prediction it could make of ultimate potential, including reserves discovered to date, was between 40 Tcf and 60 Tcf for both the Mackenzie Delta and the Beaufort Sea to a water depth of 600 feet. Estimates of volumes attributable to either onshore or offshore were not made. CAGPL made no attempt to assess the rate of reserves additions, suggesting that projections would be speculative, not solely controlled by the market, but affected by pending political and regulatory decisions on land tenure and ownership as well as the disposition of the applications being considered by the Board.

It was the view of Sproule, on behalf on CAGPL, that the fields which had been discovered to date in the Mackenzie Delta area demonstrated that substantial reserves were yet to be found. The discoveries to date indicated that the thicker volume of sediments and the numerous structures present in the Beaufort Sea, coupled with a recent gas show at an offshore location

(Tingmiark) suggested that gas would also be found in the deeper offshore areas.

Foothills

In its assessment of ultimate potential of the Mackenzie Delta-Beaufort Sea and the mainland Northwest Territories, JLJ Exploration Consultants, on behalf of Foothills, indicated that its current estimate would not vary significantly from the 37.41 Tcf used in the original Foothills application in 1975 or the 38 Tcf of ultimate potential in Foothills' submission to the Board's 1974-1975 Gas Hearing. Foothills estimated that a volume of 30 Tcf from onland Mackenzie Delta, offshore shallow (man-made island zone) and offshore deep Beaufort Sea, with an additional 4.4 Tcf from the mainland Northwest Territories would be available to supply Foothills within a time frame of 1982 to 2012. The availability of these volumes was based on the assumption that exploration and development would proceed vigorously throughout the period.

It was stated in evidence that by the year 1982, 5.5 Tcf could be connected. It was further stated that a volume of gas would be discovered by 1980 that, when fully appreciated, would amount to 18 Tcf.

Producers

Gulf estimated that proved reserves in the Mackenzie Delta would increase during the next few years as a result of drilling within and beyond existing pool areas, contingent only upon the start-up of a pipeline and the construction of processing facilities. Gulf's estimate of ultimate potential for the Mackenzie Delta-Beaufort Sea was 50 Tcf with 25 per cent being onshore and 75 per cent offshore. This was 15 Tcf less than the estimate in its submission to the Board's 1974-1975 Gas Hearing. Gulf stated that the deep water portion of the Beaufort Basin, because of thicker sediments and larger structures, appeared to have a higher potential. It also stated that in the deep Beaufort Sea there are over 20 structures in the 20,000 acre size, each with a potential of 3 to 4 Tcf. Assuming a success ratio of one in three, the ultimate potential would be 30 to 35 Tcf. Cumulative reserves for the Mackenzie Delta as of 31 December 1995, were estimated to be 10.04 Tcf (including discoveries to date) while reserves additions for the Beaufort Sea were estimated at 22.4 Tcf for the same period. This total of 32.44 Tcf was substantially lower than the 54.5 Tcf contained in Gulf's submission to the 1974-75 Gas Hearing.

Imperial estimated the ultimate potential of the Mackenzie Delta onshore to be 4 to 5 Tcf, offshore to a water depth of 60 feet to be 12 Tcf, and offshore to a water depth of between 60 and 600 feet to be 22 Tcf. For depths beyond 600 feet, it estimated 6 to 7 Tcf for a total in the order of 46 Tcf. Imperial stated that there was a reasonable chance that 16 Tcf could be discovered by 1980, 20 Tcf by 1985, 26 Tcf by 1990 and 30 Tcf by the year 1995. These additions were predicated on the current rate of exploration with some acceleration if the CAGPL pipeline were approved.

Shell estimated an ultimate potential for the Mackenzie Delta-Beaufort Sea of 47 Tcf. This comprised 12 Tcf onshore, 10 Tcf offshore to a 60-foot water depth, and 25 Tcf beyond 60 feet. Shell estimated that 15 Tcf could be discovered by 1980 and about

30 Tcf by 1995, most of which are likely to be found in the Beaufort Sea. This estimate was considerably less optimistic than the 68.5 Tcf Shell anticipated would be discovered by 1991 in its submission to the Board's 1974-1975 Gas Hearing. Although Shell holds no offshore acreage, it nevertheless expected that several wells would be drilled in the Beaufort Sea in each of the next three or four years, and that there would be one success every two years which could have an average size of 3 Tcf.

Views of the Board

Estimates of reserves additions and ultimate potential represent the levels of anticipated reserves accumulations which may be found and developed by some future date. These anticipated accumulations cannot be considered as reserves now nor should they be confused with reserves that have already been discovered. Estimates of potential and additions, particularly in relatively unexplored basins, are extremely speculative and no technique exists, nor can be expected to exist for accurately predicting the magnitude of these hydrocarbon resources. It should be realized that estimates which show the probability that a certain level of reserves may exist are subjective, made by experts, but nevertheless, often based on quite limited data. Potential reserves, to which high probabilities of their existence had been assigned, have in many cases been radically reduced in recent years as more information became available. The use of potential reserves estimates may be relevant for broad policy considerations but have little relevance to specific pipeline applications where decisions must be based on solid facts of what actually exists.

Table 2-17

Comparison of Estimates

Reserves of Marketable Natural Gas at May 1977

Mackenzie Delta-Beaufort Sea
(Bcf at 14.73 psia & 60°F)

Field	CAGPL				Foothills				Operators and Others					NEB
	Proved	Probable	Possible	Total	Proved	Probable	Possible	Total	Proved	Probable	Possible	Total	Source	Estab.
Adgo	43.7	107.3	141.5	292.5	88.7	20.5	57.9	167.1	80(1)	185(2)	310(3)		(Imp.)	100
Garry	103.1	172.9	29.7	305.7	172.3	*	*	172.3	*	253.8(2)	269.2(3)		(Sun)	200
Kumak	15.1	2.8	*	17.9	*	*	*							15
Mallik	21.1	61.0	136.4	218.5	19.4	13.2	46.3	78.9	50(1)	100(2)	160(3)		(Imp.)	90
Netserk	19.1	26.8	*	45.9	80.6	*	4.6	85.2	50(1)	115(2)	200(3)		(Imp.)	60
Niglintgak	409.1	63.3	235.6	708.0	487.7	65.9	199.0	752.6	607	366	39	1012	(Shell)	650
									455.1	344.5	*	799.6	(A&S)	
Parsons Lake	1558.0	94.4	53.9	1706.3	1423.9	309.5	110.3	1843.7	1452.3	375.1	202.6	2030.0	(Gulf)	1500
									1292.9	118.6	*	1411.5	(A&S)	
Reindeer	3.4	10.7	23.8	37.9	1.1	2.4	7.5	11.0	*	*	11.1	11.1	(Gulf)	5
									*	3.7	*	3.7	(A&S)	
Taglu	2689.4	133.0	*	2822.4	2679.4	24.7	8.1	2712.2	2020(1)	3040(2)	3980(3)		(Imp.)	2500
Titalik	32.0	23.7	95.3	151.0	*	18.1	114.5	132.6	*	*	85.1	85.1	(Gulf)	10
									10.7	5.3	*	16.0	(A&S)	
Ya Ya North	31.4	17.7	110.7	159.8	64.0	10.1	*	74.1	68.2	*	*	68.2	(Gulf)	50
									76.5	23.4	*	99.9	(A&S)	
Ya Ya South	134.4	23.3	117.3	275.0	69.6	44.5	6.5	120.6	106.8	12.5	*	119.3	(Gulf)	100
									65.2	35.5	*	100.7	(A&S)	
TOTAL	5059.8	736.9	944.2	6740.9	5086.7	508.9	554.7	6150.3						5280

(1) Minimum (2) Likely (3) Maximum

* No Estimate

2.5.1.3 Deliverability - Mackenzie Delta - Beaufort Sea

Evidence

The total deliverability projections of CAGPL and Foothills, as submitted, are shown in Table 2-18 and Figure 2-15. As these forecasts use different reserves bases and were generated to meet differing pipeline throughputs, direct comparison is not possible.

CAGPL

The CAGPL forecasts of average and maximum daily capability were predicated on total reserves - proven, probable and possible - in all presently known fields in the Mackenzie Delta-Beaufort area. CAGPL maintained that if a pipeline was built all of these reserves would eventually be within economic reach at the time they were required.

CAGPL's contractual rate of take of 1:7,300 would provide a constant average day pipeline throughput of 925 MMcf/d for some 12 years commencing in 1982, followed by decline to a rate of 582 MMcf/d by the year 2000.

The corresponding year-end maximum capability projections demonstrated an initial overall ability to produce at a rate some 2.5 times the contractual rate. No firm minimum nor optimum pipeline throughput was indicated or specified by CAGPL. Testimony was given, however, that a total combined minimum throughput of some 2.75 Bcf/d of Mackenzie Delta and Alaska gas would yield a viable project; only 500 to 700 MMcf/d of which need come from the Delta depending upon the Alaska volumes available.

No specific trend gas connection schedule or deliverability forecasts including trend gas were presented and CAGPL did not rely directly on such forecasts of gas in presenting its case. It was the view of CAGPL that any projection of reserves additions, and, therefore, of deliverability therefrom, would be speculative and subject to considerable error and disagreement. However, an estimate of potential reserves was submitted with the inference that additional supplies would eventually be made available to the pipeline.

Foothills

Foothills relied solely on a "maximum capability" approach to provide a very rapid four-year build-up from 800 MMcf/d in 1982 toward a constant pipeline demand of 2,400 MMcf/d commencing in the fifth year.

To achieve this forecast, deliverability from the start-up fields would be progressively increased up to the limits of the assigned well or field capabilities. This would occur in the fifth year with production peaking at 2,117 MMcf/d followed by very rapid decline and the maximum pipeline demand would never be attained from these fields.

While no deliverability schedule from trend gas was submitted, Foothills provided an estimate of "connectable" reserves that would be available within a specified time frame such that the pipeline requirements could be met from onshore and shallow offshore reserves additions for an extended period depending upon the rate of take employed. Trend gas from the deep water portions of the Beaufort Sea was shown as being developed by 1987 and, therefore, available in time to sustain pipeline throughput.

It was the view of Foothills that, of necessity, production practice would be different in the Beaufort Basin than that in established areas. Discovery and development patterns would have to accommodate or adapt to the realities of northern operations. In particular, the concept of sequential production from the larger, high productivity pools would permit the maximum or optimal use of gas plants, equipment and personnel at the lowest cost.

Producers

Individual deliverability estimates for the start-up fields, as submitted by the respective operators, each using a reserves base and rate of take considered appropriate to its own particular circumstances, are shown on an average day basis in Table 2-19. Imperial and Gulf indicated initial production rates of 410 and 250 MMcf/d for Taglu and Parsons Lake, respectively, at a 1:7,300 rate of take. Shell's estimate of production for Niglintgak was 126 MMcf/d based on a rate of take of 1:8,000. An average day CAGPL forecast, adjusted to the same start-up field basis, together with the maximum capability Foothills forecast, are also shown in Table 2-19 for comparison.

Imperial indicated that recoverable reserves of 3.2 Tcf, comprising the proven reserves and some measure of the probable reserves in the Adgo, Mallik, Netserk North and Taglu fields, had been agreed to for contractual purposes. Contractual pooling of these fields at a 1:7,300 rate of take would result in an average daily rate of 438 MMcf/d. Initially, all production would be taken from the Taglu field.

Although a capability forecast for Taglu was not provided, Imperial did state that it would have no concern about the physical capability of the field to produce at two to three times its normal contract rate of 1:7,300, that is, some 800 to 1,200 MMcf/d based on "likely" reserves.

Similarly, Gulf's maximum capability forecast for Parsons Lake showed the field's ability to meet requirements at twice the projected 1:7,300 rate of take level based on proven plus probable reserves.

In contrast, Shell did not provide any assessment as to maximum capability at Niglintgak, submitting only a forecast based on a slower contractual rate of take of 1:8,000 using total (proven, probable, possible) reserves. Under the proposed development plan the field was stated to be capable of meeting a peak day requirement approximating 110 per cent of average day. In testimony Shell indicated that with the unconsolidated nature of the producing formation, production rates might be reduced somewhat by well bore sand consolidation procedures, but was optimistic, on the basis of similar work done in other areas, that flow restriction would be negligible.

Regardless of capability, however, Imperial and Gulf stated that they would not be prepared to meet the increasing forecast requirements of Foothills. They acknowledged the physical possibility of faster rates of take at Parsons Lake and Taglu, and perhaps the necessity or desirability of some acceleration for contractual pooling purposes and maximization of recovery in the event of water influx. Commitment to fixed plant sizes and economics were cited as reasons for not projecting production at higher rates. Shell indicated that accelerated production from Niglintgak was not possible.

It was stated by CAGPL and Foothills and confirmed by the producers that formation damage had occurred in most, if not all, wells drilled to date in the Delta area. Incomplete or inadequate well test data resulted from this and other problems and consequently flow potentials could not be calculated for all of the pools. Gulf and Imperial stated that if pool deliverability turned out to be less than originally anticipated, further development drilling or addition of compression would be undertaken, within reason, to maintain a flat deliverability life of some 13 to 15 years.

Views of the Board

On the basis of the evidence adduced and of its own knowledge, it is the view of the Board that the initial supply from the Delta could be based on total established reserves of 5,090 Bcf in the following fields - Garry, Mallik, Niglintgak, Parsons Lake, Taglu and Ya Ya - as shown in Table 2-17.

It has been assumed that the three gas processing plants at Taglu, Parsons and Niglintgak would be built and sized as given in evidence but that initial throughput would be related to contracts for the sale of gas based on total established reserves

DELIVERABILITY FROM MACKENZIE DELTA-BEAUFORT SEA APPLICANTS' FORECASTS

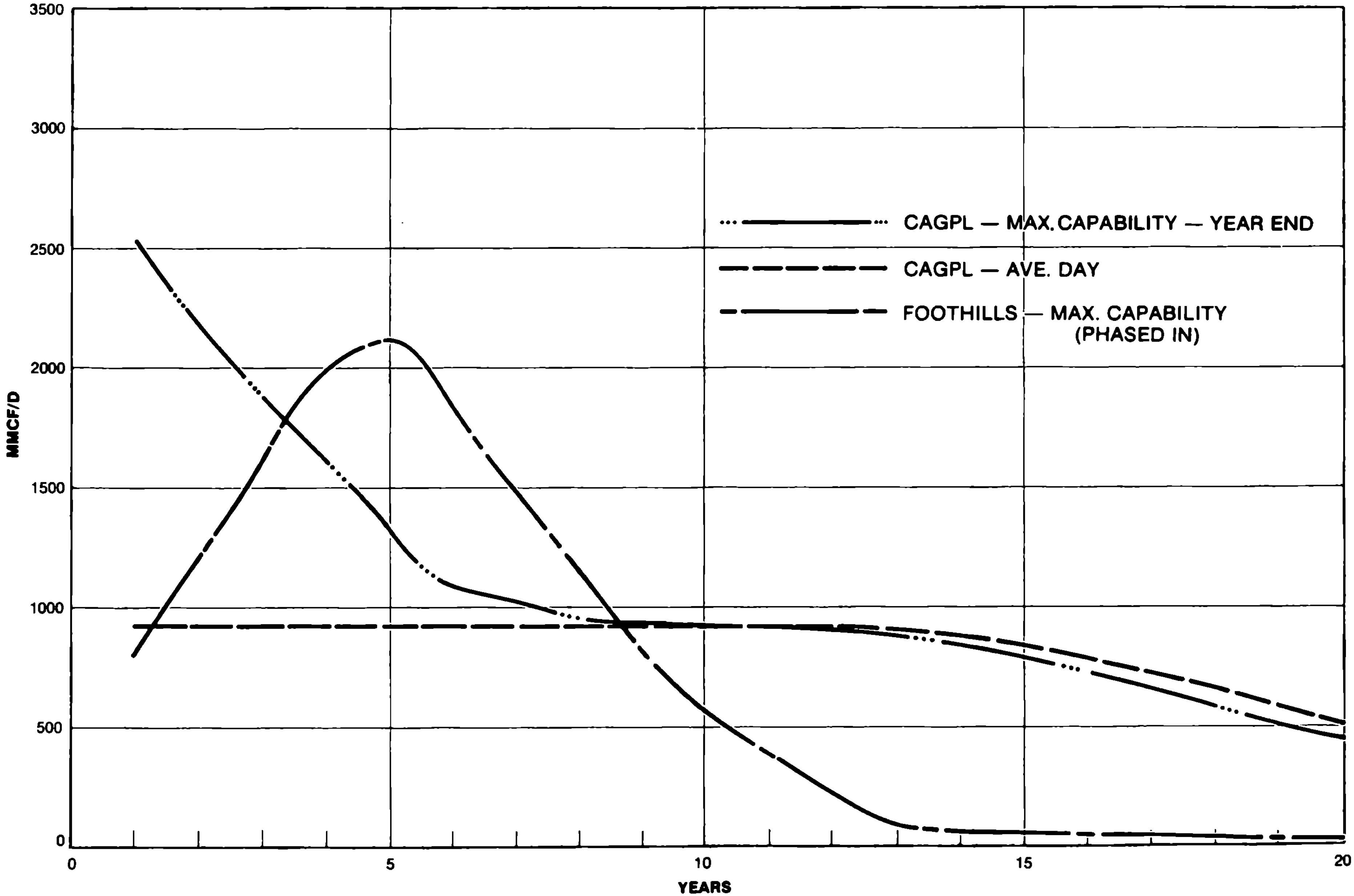

FIGURE 2-15

TABLE 2-18

DELIVERABILITY FROM MACKENZIE DELTA-BEAUFORT SEA:

Applicants' Forecasts (1) (2)

YEAR	APPLICANT			
	CAGPL		FOOTHILLS	
Commencing Nov. 1 - Foothills July 1 - CAGPL	Ave. Day (MMcf/d)	Max. Cap'y (MMcf/d) (Year End)	Ave. Day (3) (MMcf/d)	Max. Cap'y (MMcf/d)
1982	925	2535		800
83	925	2195		1200
84	925	1878		1600
1985	925	1591		2000
86	925	1329		2117
87	925	1086		1817
88	925	1025		1485
89	925	939		1155
1990	925	943		806
91	925	925		574
92	925	925		386
93	925	908		218
94	908	880		77
1995	880	834		68
96	834	788		60
97	788	722		53
98	722	664		47
99	644	582		42
2000	582	513		37
01	513	454		3
02	454	276		-
03	276	242		-
04	242	138		-
2005	138	124		-
06	124	108		-

(1) CAGPL - Total proven, probable and possible reserves
- All fields; average daily rate at 1:7,300

(2) Foothills - Total proved, probable, and possible reserves
Start-up fields only - Niglintgak, Parsons, Taglu

(3) Not provided

Table 2-19

DELIVERABILITY FROM MACKENZIE DELTA-BEAUFORT SEA:

Submittors' Forecasts

(Start-Up Fields - Average Day Basis)[1]

(MMcf/d)

Estimator:	CAGPL	Foothills	Imperial[2]	Gulf	Shell	Producer Total
Field:			Taglu	Parsons	Niglintgak	
Reserve Base:	Total	Total	Likely	Prov. & Prob.	Total	
Rate of Take:	1:7,300		1:7,300	1:7,300	1:8,000	
Year						
1	718	800	410	250	126	786
2	718	1200	410	250	126	786
3	718	1600	410	250	126	786
4	718	2000	410	250	126	786
5	718	2117	410	250	126	786
6	718	1817	410	250	126	786
7	718	1485	410	250	126	786
8	718	1155	410	250	126	786
9	718	806	410	250	126	786
10	718	574	410	250	126	786
11	718	386	410	250	126	786
12	718	218	410	250	126	786
13	712	77	410	250	126	786
14	703	68	410	231	120	761
15	675	60	410	206	109	725
16	645	53	369	187	100	656
17	593	47	295	170	90	555
18	549	42	236	156	82	474
19	479	37	189	143	75	407
20	419	3	151	133	69	353

(1) Except Foothills - maximum capability - as submitted
(2) Imperial decline not specified - assumed 20% exponential - mid-year average

for the above fields. Assuming sale on the basis of 1:7,300, the average daily and annual production projections, based on the Board's independent reservoir simulations, indicate a deliverability of 697 MMcf/d for a period of 11 years, declining to 266 MMcf/d by the 20th year, as shown in Table 2-20. Although no direct comparison with those of CAGPL, Foothills or the producers is presented, the differences between the Board's production forecasts and those of submittors obviously result from the Board's more conservative estimate of reserves in the indicated initial supply fields.

While the Board concurs with the industry views as to the high potential production capacities of the Delta fields, it considers as academic the "maximum capability" concept implicit in the Foothills forecast. All of the evidence given was contrary to the assumption that acceleration of production would be agreed to by the producers, for reasons of fixed plant sizes and, perhaps, marginal economics as was indicated by Shell. It is recognized, however, that contractual pooling and sequential production could occur within the capacity limitations of the presently proposed gas plants and the Board's deliverability forecasts have been prepared on the basis of that concept with respect to the pools listed above.

It is further assumed that Mobil's share of the reserves will be dedicated from the start.

Table 2-20

DELIVERABILITY FROM MACKENZIE DELTA-BEAUFORT SEA:

NEB Forecast

Year	Start-Up Fields[1] Niglintgak Daily MMcf/d	Niglintgak Annual Bcf/Yr	Parsons Daily MMcf/d	Parsons Annual Bcf/Yr	Taglu Daily MMcf/d	Taglu Annual Bcf/Yr	Other[2] Fields Daily MMcf/d	Other Fields Annual Bcf/Yr	Total Supply Daily MMcf/d	Total Supply Annual Bcf/Yr
1	116	42.5	226	82.5	355	129.5	-	-	697	254.5
2	116	42.5	226	82.5	355	129.5	-	-	697	254.5
3	116	42.5	226	82.5	355	129.5	-	-	697	254.5
4	116	42.5	226	82.5	355	129.5	-	-	697	254.5
5	116	42.5	226	82.5	355	129.5	-	-	697	254.5
6	116	42.5	226	82.5	355	129.5	-	-	697	254.5
7	116	42.5	226	82.5	355	129.5	-	-	697	254.5
8	108	39.6	226	82.5	355	129.5	8	2.9	697	254.5
9	93	34.1	226	82.5	355	129.5	23	8.4	697	254.5
10	80	29.4	226	82.5	355	129.5	36	13.1	697	254.5
11	69	25.4	226	82.5	355	129.5	47	17.1	697	254.5
12	60	21.9	226	82.5	351	128.3	58	21.1	695	253.8
13	52	19.0	226	82.5	327	119.3	57	20.9	662	241.7
14	45	16.4	226	82.5	314	114.8	57	20.7	642	234.4
15	39	14.3	226	82.5	262	95.5	56	20.5	583	212.8
16	34	12.4	203	74.0	225	82.2	54	19.7	516	188.3
17	30	10.8	141	51.6	194	70.9	52	19.1	417	152.4
18	26	9.5	113	41.1	168	61.4	51	18.6	358	130.6
19	23	8.3	90	32.8	146	53.4	49	18.1	308	112.6
20	20	7.3	71	26.1	127	46.5	48	17.4	266	97.3
Cumulative		545.9		1463.1		2196.8		217.6		4423.4
Remaining		104.1		36.9		303.2		222.4		666.6

(1) Production at 1:7,300 - based on reserves combined as follows:
Niglintgak-Garry; Parsons-YaYa N., S.; Taglu-Mallik.

(2) Production from Garry, Mallik, YaYa N., S., as and when required.

2.5.2 Arctic Islands

2.5.2.1 Reserves Discovered

Panarctic submitted estimates of the reserves of natural gas discovered to date in the Arctic Islands, calculated by JLJ Exploration Ltd. and D & S Petroleum Consultants (1974) Ltd. The estimates as originally submitted were revised to reflect the results of recent drilling in the Drake Point field and these revised volumes are used herein.

Panarctic estimated proven and probable marketable reserves of 11.287 Tcf and "highly possible" reserves of 1.560 Tcf, for a total of 12.847 Tcf described as "most likely". Of this volume, 9.265 Tcf were attributed to the Drake Point and Hecla fields on Melville Island, and the balance of 3.582 Tcf to five fields on and adjacent to the southwestern coast of Ellef Ringnes Island.

Panarctic stated that its definition of proved and probable reserves was the same as that of the Board. The Company's highly possible reserves were defined as those which have a slightly lower confidence level than probable reserves due to distance from well control and/or inadequacies in seismic definition, but with a relatively high probability of being present. Panarctic's most likely reserves comprise the proved, probable and highly possible reserves.

2.5.2.2 Reserves Additions and Ultimate Potential

Gulf was the sole submittor of an estimate of reserves additions for the Arctic Islands, 37.2 Tcf for the period 1976-1995, essentially unchanged from its estimate to the Board's 1974-1975 Gas Hearing. In making this forecast, the company assumed that government policies and regulations would be such as to not discourage exploration and development, and exploration would be sufficiently successful in the next few years to encourage continued drilling and the necessary research and planning for production development.

Gulf also included in its submission an estimate of the ultimate potential of the Arctic Islands of 115 Tcf.

Imperial forecast levels of future production from the Arctic Islands of 1 Tcf per year by the late 1980's and 1.5 Tcf per year by the mid 1990's. The company commented that technological developments were required in order to make drilling and production possible, and that if exploration success or development economics fell short of required levels, there would be no production from the Arctic Islands by 1995, the end of the forecast period.

Shell estimated the ultimate potential of the Arctic Islands at 75 Tcf. The company emphasized strongly in its submission the speculative nature of this estimate, noting that the actual quantity of undiscovered gas might be considerably more or less. Shell considered it very uncertain when this undiscovered gas would become available for production, if at all.

2.5.2.3 Views of the Board

The Board has independently estimated the established reserves of fields in the Arctic Islands at 7.3 Tcf, from basic reservoir data. Estimates by field are compared with those of Panarctic in Table 2-21. Reserves in the Arctic Islands must be considered beyond economic reach at this time.

The Board concludes that the estimates submitted by Panarctic are not unreasonable, considering that limited well control is available. However, it has concern regarding the extent to which geophysical data were used to postulate field limits beyond the control provided by drilled wells. The need for caution in this regard is exemplified by the effect on Panarctic's reserves estimates as first submitted to this hearing, of an unsuccessful well recently drilled in anticipation of extending the Drake Point field. It was necessary to reduce the most likely marketable gas reserves of this field from 8.6 to 5.4 Tcf. Almost all of the reduction involved reserves in the highly possible category. The Board estimates placed less reliance on geophysical evidence, and its reserves estimates are accordingly lower. It should be noted that since the Board's established reserves comprise its proved reserves together with only part of its probable reserves, there is no direct comparison between its estimates and those of Panarctic.

It is evident there is a high degree of uncertainty attached to the volumes of natural gas that may become available in future from the Arctic Islands. Certainly a vigorous program of exploration must continue and prove successful if quantities of gas comparable to those envisaged by Gulf, and Imperial and Shell are to be realized.

Discoveries of natural gas in the Arctic Islands have been encouraging. In particular, the Drake Point and Hecla fields are large by Canadian standards. However, reserves thus far found are still well below the economic level required for pipeline connection, and clearly there are difficult technological problems related to drilling and production which must be solved before commercial development can take place. At the present time, there are no firm criteria on which to base a judgement as to when production might commence.

2.5.3 East Coast Offshore

2.5.3.1 Reserves Discovered

Only Gulf provided an estimate of the quantity of gas found to date in the offshore areas of the east coast. The company's witness stated under cross-examination that this estimate, 2.85 Tcf for both the Scotian Shelf and the Labrador Shelf, was very approximate.

2.5.3.2 Reserves Additions and Ultimate Potential

Gulf also included in its submission a reserves additions forecast to 1995 of 40 Tcf and an ultimate potential estimate of 80 Tcf. These volumes were somewhat different from those given to the Board's 1974-1975 Gas Hearing, namely 25 and 130 Tcf respectively.

Imperial noted that there had been discoveries in the Scotian Shelf area, but overall results had been disappointing. It suggested some production might be achieved from this area in the 1980's. With respect to the Labrador Coast and Davis Strait, Imperial did not expect production before 1995.

Shell estimated the east coast offshore potential at about 70 Tcf, but stressed that the estimate was speculative and the actual amount could be considerably higher or lower. The company referred in its submission to factors and concerns which combined to leave the timing and quantity of production totally uncertain.

2.5.3.3 Views of the Board

The Board has studied basic well data from both the Scotian Shelf and Labrador Shelf areas. Reserves discovered to date in the former region are relatively insignificant, and there is little likelihood additional reserves can be developed in this region in quantities sufficient to have a major impact on Canadian supply.

Discoveries to date off the Labrador Shelf have been encouraging, but exploration here is in the very early stages so it is really not possible to do more than speculate on the amount of gas that may be present and the rate at which it might be developed. With the current tempo of exploration, it is difficult to envisage sufficient reserves to support production before at least 10 to 15 years, although this outlook could change dramatically with the early discovery of very large pools.

Table 2-21

Comparison of Estimates

Reserves of Marketable Natural Gas at May 1977

Arctic Islands

(Tcf at 14.73 psia & 60^{o}F)

	Panarctic			NEB
	Proven and Probable	Highly Possible	Most Likely	Established
Drake Point	4.664	.728	5.392	3.40
Hecla	3.526	.347	3.873	2.40
Kristoffer Bay	.653	.454	1.107	.25
King Christian	.557	.031	.588	.35
Jackson Bay	1.074	Nil	1.074	.50
Thor	.715	Nil	.715	.35
Wallis	.098	Nil	.098	.05
Total	11.287	1.560	12.847	7.30

2.6 ENERGY SUPPLY ALTERNATIVES

Evidence

CAGPL submitted that supplies of crude oil from conventional Canadian sources were steadily declining, based on the NEB September, 1975 report, Canadian Oil Supply and Requirements. CAGPL submitted that alternative domestic sources of oil included the development of tar sands and heavy oil deposits, from which total production could be as high as one million barrels per day. CAGPL further submitted that crude oil from tar sands or heavy oil development in Alberta was likely to cost some $3.25 to $5.00 per Mcf equivalent ($1976) in the market-place based on a plant designed to produce 125 Mb/d of synthetic crude oil.

CAGPL also indicated that its forecast of Canadian requirements for coal was based on information contained in the EMR document, An Energy Strategy for Canada. CAGPL forecast that Canadian coal supply at the source would be equivalent to domestic requirements for primary energy in the form of coal at the source.

CAGPL submitted comparisons of capital requirements per unit of energy produced which indicated that unit capital costs of developing electrical energy sources would be from two to eight times as high as the unit capital costs associated with the development of alternative hydrocarbon energy sources. CAGPL indicated that electrical energy generated by western mine mouth coal-fired plants would range from $5.00 to $6.50 per Mcf equivalent ($1976) when provision was made for scrubbing the flue gases to eliminate sulphur components.

Electrical energy generated by nuclear stations was estimated to range from \$7.00 (based on Ontario Hydro data) to \$10.50 (based on Quebec data) per Mcf equivalent (\$1976). Electrical energy from hydraulic sources was estimated to range from about \$3.50 to \$8.00 per Mcf equivalent (\$1976).

CAGPL submitted that the bulk of Canada's energy requirements would continue to be met by hydrocarbon supply, therefore Canada must consider the development of all new domestic sources of supply, including the gasification of coal. Capital costs for a plant capable of producing 250 MMcf/d of synthetic gas were estimated at 1.0 to 1.3 billion dollars. The cost of this gas in the market place was expected to be \$4.45 to \$5.15 per Mcf (\$1976) including operating costs and gas transmission charges. CAGPL indicated that two plants of this size could be in operation by 1995.

CAGPL submitted that the pattern of energy consumption changes very slowly due to the long lead times required to develop and implement new technology. It expected that alternative renewable energy sources such as solar, wind, geothermal or biomass would contribute little to Canada's overall energy supply before 1995.

Energy Probe and the Workgroup on Canadian Energy Policy estimated that alternative energy sources could supply two to four per cent of Canada's energy needs by 1990 and 20 per cent or more by the year 2020. It was also submitted that up to five billion gallons of methanol could be produced annually from Canada's surplus forest biomass and that methanol could be produced profitably for about 55 cents per gallon. Implementation of this technology could occur within 10 to 15 years if substantial financial, developmental and market incentives were provided.

Costs for installation of solar space heating to supply 60 to 70 per cent of the heat for a well-insulated average-sized home in the Toronto region were estimated to be $10,000 to $15,000 in 1977 declining to $5,000 within two years.

Views of the Board

The Board has reviewed the total energy supply-demand balance for Canada and is in general agreement with the approach used by Energy, Mines and Resources in its report "An Energy Strategy for Canada". The Board is in agreement with the EMR view that based on assured supply of oil, gas, coal and electricity, Canada now has a small net energy gap until 1979 or 1980 when the gap is projected to be in the order of one quadrillion Btu's, thereafter increasing to perhaps two quadrillion Btu's by 1985.

This conclusion was reinforced in the Board's February, 1977 report entitled Canadian Oil Supply and Requirements where the Board forecast, even in the case of low requirements and high supply of indigenous oil, a projected shortfall of approximately 250 Mb/d in 1985; with the shortfall decreasing slowly thereafter. In addition, the Board has found that Canadian production of liquefied petroleum gases from non-refinery sources will decline from about 166 Mb/d in 1976 to some 64 Mb/d in 1995.

The Board concurs with the estimated coal supply projections given in the EMR document, An Energy Strategy for Canada. The cost of electricity using coal has already been reviewed and there are only limited applications of coal likely for other energy uses in the forecast period. No reliable estimate of cost for these purposes is available.

The Board has reviewed the production of synthetic gas from coal by in-situ gasification or by mining the coal and processing it through a plant. The development of in-situ gasification technology is still in the experimental stage. The technology for the gasification of mined coal exists; however, there are only a limited number of potential sites where economically sized plants designed to produce 250 MMcf/d of synthetic gas, could be located due to the large amounts of coal and water that are required. For these reasons the Board has concluded that no significant quantities of synthetic gas from coal will be produced in the time period considered by this report.

The Board has reviewed CAGPL's calculations of unit capital costs of electrical generation and, in general, agrees with them. The Board does not, however, consider unit capital costs to be a reasonable basis for comparing energy costs from different sources; unit energy costs, which include the cost of fuelling are more appropriate.

The Board also reviewed CAGPL's calculations of unit energy costs in the market and generally agrees with CAGPL's calculations. The Board notes that CAGPL's figure of $10.50 per Mcf equivalent ($1976) for nuclear electrical generation was based on a source for which the assumptions used are not available and hence could not be verified by the Board.

The Board also notes that end-use utilization efficiencies are considerably different for the two broad categories of heating and mechanical end-use and these efficiencies can drastically alter the end-use comparisons. For mechanical drive uses only, modifying CAGPL's proposed costs to take into account motor efficiency, the relative costs to the user of electrical energy would be about the same.

The Board recognizes that there exists a significant potential for the implementation of alternative renewable technologies. This observation is particularly applicable to the areas of solar heating in the residential and commercial sector and in the use of biomass in the industrial sector.

Although recognizing this potential, it is the opinion of the Board that approximately 1.4 per cent of Canada's total primary energy demand will be supplied by alternative energy forms by the year 1995 but no reliable cost for this energy is available at this time. However, it is important to stress two important facts. Firstly, the estimate of supply does not include passive solar energy collection through improved building design and orientation of buildings to maximize solar energy collection; this is considered under the effects of conservation in reducing energy demand. Secondly, any major shift in government policy which is directed towards the stimulation of construction of dwellings using solar energy as the principal source of space-heating could make this forecast supply level somewhat low.

Another alternative is the reserves of gas discovered in the Arctic Islands. These are still well below threshold level for a pipeline and the technical feasibility of a transportation system to bring them to market has not yet been demonstrated. However, the Board believes that there is a good possibility that such a system can be available for use after 1985 in the form of either a liquefied natural gas tanker system or a pipeline.

Table 2-22 summarizes the range of estimated costs of some of the energy alternatives which could be developed over the forecast period. It is obvious from this table that currently imported oil and Mackenzie Delta gas are the least expensive energy alternatives available to Canada. In order to minimize Canada's dependence on world oil, it is essential that Canada develop a number of the available energy options. Mackenzie Delta gas is at present the lowest cost source of supply and from this point of view should be developed.

Table 2-22

COST OF ENERGY ALTERNATIVES

Energy Type	Order of Magnitude Cost of New Supply in Market Place ($ 1976) (per Mcf equivalent) (1), (2)
Electrical Energy	
- coal-fired plants	$5.00 to $6.50
- nuclear plants	$7.00 to $8.00
- hydro plants	$3.50 to $8.00
Synthetic Gas	$4.00 to $5.00
Imported Oil	$2.35 (4)
Oil Sands and Heavy Oil	$2.25 to $3.25 (4)
Arctic Island Gas	(3)
Mackenzie Delta Gas (on-shore)	$2.00 to $2.35

(1) If prospects were to be compared on a "real" cost basis, and taxes and royalties were to be excluded, then indigenous hydrocarbon developments would show a greater advantage relative to electrical energy and to imported oil.

(2) Direct comparison of costs must also be adjusted for different end-use efficiencies.

(3) No direct evidence was introduced on this cost. Because of the location and geological structures involved and the formidable transportation problems to be overcome, the Board expects these costs will be higher than those for on-shore Mackenzie Delta gas.

(4) Plus refinery margin.

2.7 UNITED STATES MARKET AND ALASKA SUPPLY

2.7.1 United States Market Requirements

2.7.1.1 Introduction

The Board heard evidence from CAGPL and Foothills (Yukon) with respect to the marketability of Alaska gas in regional market areas in the lower 48 states. The evidence included estimates of gas supply and demand in those regional markets.

2.7.1.2 CAGPL Analysis

CAGPL submitted evidence concerning the marketability of Alaska gas in those regional markets proposed to be served by the nine interstate pipeline companies which would transport gas via the Alaskan Arctic Gas Pipeline Company. The regional markets included the areas to be served by the Northern Border Pipeline Company, a group consisting of six interstate natural gas pipeline companies; namely, Michigan Wisconsin Pipeline Company, Natural Gas Pipeline Company of America, Texas Eastern Transmission Corporation, Columbia Gas Transmission Company, Northern Natural Gas Company and Panhandle Eastern Pipeline Company; as well as the market areas to be served by Pacific Gas and Electric Company, Transwestern Pipeline Company and Pacific Interstate Transmission Company.

The Northern Border pipeline would connect with CAGPL at a point on the international boundary near Monchy, Saskatchewan and would serve the following geographic areas: Missouri Basin, consisting of Montana, North Dakota and South Dakota; Upper Mississippi Basin, consisting of Minnesota, Iowa and Illinois; and, Ohio River Basin, consisting of Indiana, Ohio, West Virginia and Pennsylvania. The remaining three pipeline companies would receive gas at Kingsgate, British Columbia and would serve the northwestern states as well as California.

In its analysis, CAGPL outlined natural gas demand and supplies for the nine Alaskan Arctic companies. These are summarized graphically in Figure 2-16. Demand is set out by Federal Power Commission priority categories[1] for the years 1975, 1980 and 1985. CAGPL argued that both Alaska gas and other gas supplies would be needed in 1985 to replace declining lower 48 states' supplies in order to meet demand in Priorities 1 and 2.

It was shown that in 1975 annual supply for the nine companies amounted to 6.9 Tcf while annual demand was 8.7 Tcf. Thus, curtailments extended into Priorities 3 to 9.

By 1980 annual supplies were projected to decline to 6.8 Tcf, the same level as the sum of Priorities 1 and 2. On this basis, all of Priorities 3 to 9 were projected to be curtailed in 1980.

From 1980 to 1985 annual supplies were projected to increase to 7.3 Tcf, in part because Alaska gas was assumed to be on stream. However, demand in Priorities 1 and 2 was projected to be 7.6 Tcf in 1985. On this basis, curtailments by the nine companies were projected to extend into Priority 2.

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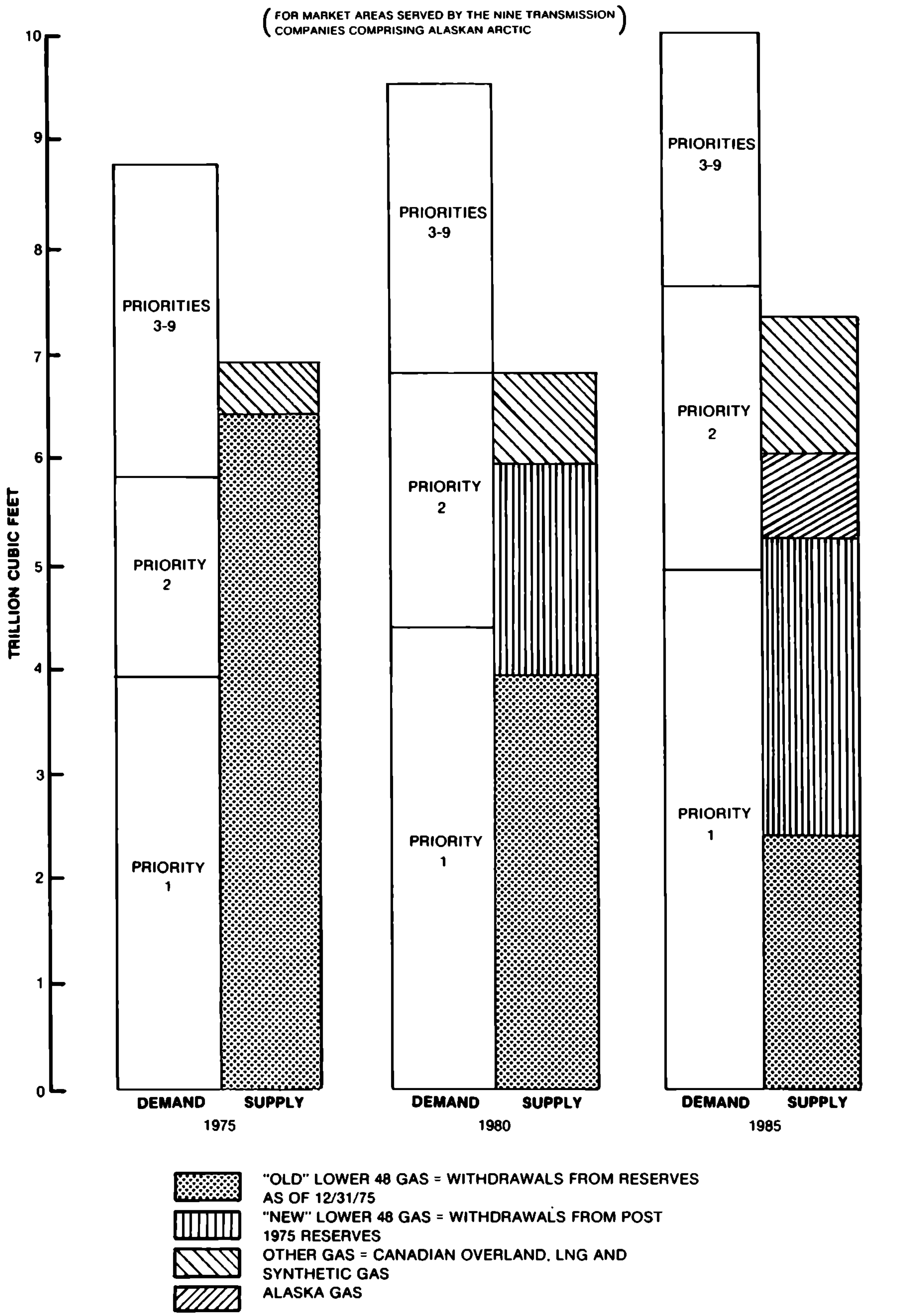
(1) Priority 1 includes residential and small commercial users. Priority 2 includes large commercial users; industrial users with firm contracts that use gas for feedstocks, processing or plant protection; and distribution companies that store gas for peak season use. Priorities 3 to 9 include other industrial users.

FIGURE 2-16

GAS SUPPLY/DEMAND IN THE UNITED STATES CAGPL SUBMISSION



CAGPL estimated that the 1985 annual supply for the nine Alaskan Arctic companies would consist of 2.4 Tcf of lower 48 gas produced from reserves proven as of 31 December 1975, 2.8 Tcf of lower 48 gas produced from reserves to be discovered from 1976 to 1985, 0.8 Tcf of Alaska gas and 1.3 Tcf of Canadian gas, synthetic gas and LNG, for a total of 7.3 Tcf.

Concerning the marketability of Alaska gas in each of the areas to be served by the nine Alaskan Arctic companies, CAGPL noted that Alaska gas must enter the market in competition with other energy for Priorities 1 and 2 customers. Gas, fuel oil and electricity compete for Priorities 1 and 2 markets in the Northern Border market and gas and electricity compete in California.

CAGPL noted that price was only one of the competitive factors affecting the utilization of gas, fuel oil and electricity in the high priority market areas to be served. Non-price factors included the cost of installation, operating and maintenance costs, clean burning qualities, heat control capability, versatility, and convenience. CAGPL referred to a United States Department of the Interior report in which the non-price premium for gas over fuel oil was estimated at 46 cents to 63 cents per MMBtu, when oil was priced at about $12 per barrel.

CAGPL submitted price analyses to demonstrate the marketability of Alaska gas. Prices of competitive energy were compared at the city gate of eight key metropolitan areas which represented the larger markets to be served by the nine Alaskan Arctic companies. In the Northern Border market area the metropolitan areas included Minneapolis, Peoria, Chicago, Detroit, Columbus and New York City. For the west coast market, the metropolitan areas included San Francisco and Los Angeles. Prices were shown on both a rolled-in and incremental basis in 1975 dollars per million Btu.

Table 2-23 sets out CAGPL's analysis of the comparative rolled-in prices of energy at the city gate. CAGPL concluded that Alaska gas, when rolled-in with other gas supplies, was competitive and marketable. Focusing on the individual key metropolitan areas, CAGPL noted that gas was priced appreciably below oil and electricity in all cities.

Table 2-24 summarizes CAGPL's analysis of the projected cost of Alaska gas compared incrementally with fuel oil and electricity at the city gate of each key metropolitan area. The city-gate price of Alaska gas was shown at two assumed field prices.

CAGPL concluded that Alaska gas was competitive and was marketable vis-a-vis substitutable energy forms on an incremental basis. Turning to the individual key metropolitan areas, CAGPL estimated that, at the lower assumed field price (95¢/MMBtu), Alaska gas was priced below electricity and fuel oil in all areas.

At the higher assumed field price (146¢/MMBtu), Alaska gas was priced below electricity in all areas and below fuel oil in most areas. Only in the eastern portion of the United States (Detroit, Columbus, New York City) was the price of Alaska gas, at the higher assumed field price, at or slightly above the price of fuel oil. CAGPL contended that the non-price premiums favoured gas over oil, especially heavy fuel oils and that these premiums would more than offset the price differential.

In calculating the cost of Alaska gas in the market place, CAGPL utilized its Base Case transportation costs. CAGPL noted that depending on the market area, the fifth year transportation costs were higher by 6.3 to 6.5 cents per million Btu (in 1975 dollars) for the CAGPL No Expansion Case as compared with the Base Case.

Concerning the No Expansion Case, CAGPL concluded that Alaska gas would still be easily competitive on the rolled-in basis. On an incremental cost basis, Alaska gas would remain competitive in most of the key metropolitan areas and would command a premium over oil.

During cross-examination, Mr. R.L. Schantz, the witness for CAGPL, stated that President Carter's energy policy proposal of 20 April 1977, "will certainly have, in some manner yet to be decided by the Congress and the Administration, a substantial impact on the types of evidence that we are looking at here today". In this context, Mr. Schantz put forward three points from President Carter's energy message which he felt would affect gas supply, demand and marketability in the United States: (1) a general recognition of the international oil pricing structure; (2) a major emphasis on conservation of energy; and (3) a new pricing structure for "new" gas produced in the lower 48 states to be oriented towards parity with the cost of acquisition of crude oil for refiners in the United States of domestically produced oil.

With respect to energy conservation, Mr. Schantz was doubtful that President Carter's goal of reducing the growth rate of energy consumption to two per cent per year by the 1980's would be achieved but he felt that something in the order of three per cent might be more likely. Mr. Schantz suggested that switching thermal plants from natural gas to coal, as proposed by President Carter, would not have a significant effect on United States demand for gas.

Mr. Schantz noted that President Carter had proposed that a price of $1.75/Mcf be established for "new" gas at the wellhead in the lower 48 states but that this proposal specifically excluded Prudhoe Bay gas. Mr. Schantz suggested that there should be some melding of the distillate fuel oil prices and electricity prices in determining United States natural gas prices. Such a scheme would suggest a city gate average price for the Prudhoe Bay supply in the 1980's, expressed in 1975 dollars, somewhere in the order of $4.00 - $4.50/Mcf.

If the Prudhoe Bay gas was priced in this range, the witness could see no problems with it being marketed in the United States either on an incremental basis or on a rolled-in basis with the lower priced gas in the lower 48 states. Mr. Schantz was not aware of anything in the President's proposal which would disallow the rolling-in of prices of Alaska gas with gas produced in the lower 48 states. The witness concluded that even a substantial cost overrun in the transportation networks necessary to bring the gas to the United States markets would not affect the marketability of Prudhoe Bay gas in the lower 48 states.

Table 2-23

ROLLED-IN ENERGY PRICES IN THE UNITED STATES: CAGPL Submission

At the City Gate of Key Metropolitan Areas to be Served by the Nine Transmission Companies Comprising Alaskan Arctic

(¢ /MMBtu)

(1975 Dollars)

Key Metropolitan Area	Gas (1)	Fuel Oil (2)	Electricity (3)
Northern Border Market			
Minneapolis	147	230	393
Peoria	179	227	522
Chicago	149	223	520
Detroit	183	215	586
Columbus	180	221	533
New York City	163	228	923
Simple Average for Six Cities	166.8	224	579.5
West Coast Market			
San Francisco	207	234	595
Los Angeles	202	234	630
Simple Average for Two Cities	204.5	234	612.5
Simple Average for Eight Cities	176.3	226.5	587.8

(1) Rolled-in price of gas produced in lower 48 states and Alaska, plus LNG and synthetic gas, where relevant; 1985 volumes; field price is for "new" gas in accordance with FPC Opinion No. 770-A issued 11 November 1976, deflated to 1975 dollars. A field price of 146 cents per MMBtu is used for Alaska gas.

(2) Fuel oil prices are November 1976 terminal postings, adjusted upward for an assumed 10 per cent foreign crude oil price increase as of 1 January 1977, and then deflated to express the price in 1975 dollars. The prices are a blend of "old" and "new" domestic oil, and imported foreign oil. The fuel oil price is a weighted average of the price of distillate fuel oil and residual fuel oil, weighted by reference to the 1974 consumption of energy by stationary users in key states served by Alaskan Arctic companies.

(3) 1975 average sales for resale prices. Price for Los Angeles is average for 1975 industrial customers.

Source: Exhibit No. N-AG-3-170, Schedule 9.

Table 2-24

INCREMENTAL ENERGY PRICES IN THE UNITED STATES: CAGPL Submission

At the City Gate of Key Metropolitan Areas to be Served by the Nine Transmission Companies Comprising Alaskan Arctic

(¢/MMBtu)

(1975 Dollars)

Key Metropolitan Area	Alaska Gas[1] 95¢ Field Price	Alaska Gas[1] 146¢ Field Price	Fuel Oil[2]	Electricity[3]
Northern Border Market				
Minneapolis	224	275	296	393
Peoria	243	294	295	522
Chicago	237	288	293	520
Detroit	235	286	286	586
Columbus	249	300	290	533
New York City	255	306	287	923
Simple Average for Six Cities	240.5	291.5	291.2	579.5
West Coast Market				
San Francisco	221	272	307	595
Los Angeles	225	276	307	630
Simple Average for Two Cities	223	274	307	612.5
Simple Average for Eight Cities	236.1	287.1	295.1	587.8

(1) 1985 transportation cost, estimated in 1975 dollars, provided by Alaskan Arctic. Field price is for "new" gas in accordance with FPC Opinion No. 770-A issued 11 November 1976, deflated to express the price in 1975 dollars.

(2) The fuel oil price is based on the cost of delivered foreign crude oil, plus refiners' margin and transportation cost to city gate where relevant. It was assumed foreign oil prices will increase an average of 10 per cent as of 1 January 1977, then deflated to express the price in 1975 dollars. The fuel oil price is a weighted average of the price of distillate fuel oil and residual fuel oil, weighted by reference to the 1974 consumption of energy by stationary users in key states served by Alaskan Arctic companies.

(3) 1975 average sales for resale prices. Price for Los Angeles is average for 1975 industrial customers.

Source: Exhibit No. N-AG-3-170, Schedule 10.

2.7.1.3 Foothills (Yukon) Analysis

Foothills (Yukon) submitted evidence to the Board with respect to the ability of United States markets to absorb Alaska gas in specific market areas in the lower 48 states. The evidence focussed on regional markets proposed to be served by the United States companies participating in the competing Alaskan Arctic projects. The proposed Foothills (Yukon) pipeline system would deliver Prudhoe Bay gas to United States shippers at two points on the international boundary; at Monchy, Saskatchewan and at Kingsgate, British Columbia.

In its analysis, Foothills (Yukon) utilized data that had been presented by the participants in Alaskan Arctic in various filings before the Federal Power Commission. The analysis showed the estimated demand, by FPC priority classification, for the years 1977 through 1983. Also shown were available supplies which were currently certified by the Federal Power Commission excluding any projected supplies either planned or pending before the Federal Power Commission. The deficiency was arrived at by subtracting the available supplies from the total demand.

Table 2-25 summarizes the evidence prepared by Foothills (Yukon) and submitted to the Board.

Foothills (Yukon) noted that the primary increase in demand for the period 1977 through 1983 was in Priorities 1 and 2 with only a slight increase occurring in some of the lower priorities. The Northern Border Pipeline Company would not be able to serve its Priorities 1 and 2 customers for the period shown. Northwest and Pacific Gas and Electric would be able to serve all of their Priorities 1 and 2 requirements during the period. Pacific

Table 2-25

GAS SUPPLY/DEMAND IN THE UNITED STATES: Foothills (Yukon) Submission

For Market Areas to be Served by the
Nine Transmission Companies Comprising Alaskan Arctic

(MMcf @ 14.73 psia)

	1977	1980	1983
Northern Border Pipeline Companies			
Demand (1)			
Priority 1	3,610,000	3,960,000	4,310,000
2	1,930,000	2,250,000	2,540,000
3 to 9	1,280,000	1,320,000	1,350,000
Total	6,820,000	7,530,000	8,200,000
Supplies	5,180,000	4,420,000	3,630,000
Deficiency	1,640,000	3,110,000	4,570,000
Northwest Pipeline Corporation			
Demand (1)			
Priority 1	185,341	206,809	228,335
2	114,833	121,365	126,186
3 to 9	247,262	258,137	268,771
Total	547,436	586,311	623,292
Supplies	462,760	449,656	410,021
Deficiency	84,676	136,655	213,271
Pacific Gas and Electric Company			
Demand (2)			
Priority 1	350,835	369,188	386,657
2	160,237	173,558	186,710
3 to 5	486,205	555,671	581,918
Total	997,277	1,098,417	1,155,285
Supplies	781,422	696,171	597,338
Deficiency	215,855	402,246	557,947
Pacific Lighting Service Company			
Demand (2)			
Priority 1	478,000	528,000	574,000
2	208,000	174,000	145,000
3 to 5	875,000	991,000	909,000
Total	1,561,000	1,693,000	1,628,000
Supplies	784,000	575,000	418,000
Deficiency	777,000	1,118,000	1,210,000
State of Arizona			
Demand (2)			
Priority 1	66,201	75,388	85,877
2	37,591	38,409	39,120
3 to 5	108,877	104,486	104,810
Total	212,669	218,658	229,807
Supplies	112,332	92,565	58,022
Deficiency	100,337	126,093	171,785
Summary All Areas			
Total Demand	10,138,382	11,126,386	11,836,384
Total Supplies	7,320,514	6,233,392	5,113,381
Total Deficiency	2,817,868	4,892,994	6,723,003
Per cent of Market Served	72%	56%	43%

(1) Priority classification based on FPC Order 467-B.
(2) Priority classification based on FPC Opinion 697 and 697-A.

Source: Exhibit No. FH(Y)-114-23, P. 18

Lighting Service Company and the State of Arizona would be curtailing Priorities 1 and 2 customers beginning in 1979.

Foothills (Yukon) noted in summary that there was an increase in annual demand in 1983 over 1977 of approximately 17 per cent with a decrease in annual supply availability of approximately 30 per cent. As a result of the divergence between demand and supplies, the percentage of the market being served would decrease from a high of 72 per cent in 1977 to a low of 43 per cent in 1983.

The Board was advised that Foothills (Yukon) accepted the direct testimony submitted by CAGPL with respect to the marketability of Alaska gas in the lower 48 states. Foothills (Yukon) concluded that the testimony was completely valid and the conclusions accurate.

2.7.1.4 Views of the Board

The Board notes that fully executed gas supply contracts between shippers and producers, transportation contracts between the Applicants and shippers, and gas sales contracts between shippers and purchasers would have contributed substantially to the Board's assessment of the marketability of natural gas in the proposed market areas.

During the course of this hearing, several reasons were brought forward with respect to the absence of these contracts. This aspect is outlined in the section of the report dealing with contracts.

In the absence of gas sales contracts, the specific markets for Alaska gas have not been identified and the market studies submitted by the Applicants might not be representative of the actual situation should either of the proposed projects be built.

In addition, the allocation of Alaska gas volumes among the markets to be served, the total volumes of Alaska gas to be marketed and the date of first flow have not been explicitly determined. This determination cannot occur prior to (1) the execution and publication of definitive gas supply and gas sales contracts; (2) the determination by the State of Alaska of its royalty provisions; and, (3) the publication of a final Prudhoe Bay Field unitization and operating agreement approved by the State of Alaska, upon which the terms of the contracts in part depend.

The Board also notes that the field price for Prudhoe Bay gas has not yet been determined and as a result the price to the ultimate consumer has not been established. However, the CAGPL witness pointed out that, within the probable range of field prices, there was absolutely no doubt that the Alaska gas could be sold on a rolled-in basis and virtually no doubt that it could be sold on an incremental basis. The Federal Power Commission in its "Recommendation to the President" was quite clear on this point.

> "Since incremental pricing does provide a market test of the economic attractiveness of Alaskan gas, its use should only be ruled out where proof of such economic viability is unnecessary. It is our judgment, based on the record, that Alaskan gas most likely could be sold competitively on an incremental pricing basis. However, the net national economic benefit of the project is positive and large. Since Alaskan

natural gas will be a major contribution to domestic energy supplies, and since obtaining the critical financing for the project is more likely by utilizing rolled-in pricing, we believe it is in the public interest and recommend that rolled-in pricing be adopted".[1]

The Board is therefore confident that all of the Alaska gas forecast to be carried by the CAGPL or the Foothills (Yukon) pipeline can be sold in United States markets; however, knowledge of the geographic distribution will have to await the signing of gas sales contracts.

2.7.2 Alaska Reserves

2.7.2.1 Natural Gas Reserves - Prudhoe Bay

The natural gas reserves of the Prudhoe Bay field were estimated independently by DeGolyer and MacNaughton for CAGPL and by Core Laboratories, Inc., for Foothills (Yukon).

CAGPL

The DeGolyer and MacNaughton study, submitted in evidence by CAGPL, determined volumetrically the quantity of natural gas-in-place in the Sadlerochit formation, the main reservoir in the Prudhoe Bay field, as 38.1 Tcf. A further 3.5 Tcf was attributed to the overlying Sag River and Shublik reservoirs for a total field gas-in-place of 41.6 Tcf. Coresponding marketable gas reserves were determined to be 22.2 Tcf. These are shown in Table 2-26.

(1) "Recommendation to the President", Federal Power Commission, Page XII-31, dated 1 May 1977.

Table 2-26

RESERVES OF PRUDHOE BAY

CAGPL Estimate

(Tcf at 14.73 psia)

	Sag River Sandstone and Shublik Formation	Sadlerochit Formation		
	Associated	Associated	Solution	Total
Gas-in-place	3.5	21.4	16.7	41.6
Marketable gas	2.1	12.7	7.4	22.2

CAGPL submitted evidence, reproduced as Table 2-27, which compares the DeGolyer and MacNaughton estimate of associated gas-in-place in the Prudhoe Bay field with that of the consulting firm of H.K. van Poollen and Associates, Inc. The estimates submitted by Foothills (Yukon) were based on van Poollen's work. The table was prepared to explain the difference between the evidence of CAGPL and that of Foothills (Yukon) with respect to associated gas-in-place in the Sadlerochit formation.

Table 2-27

ASSOCIATED GAS-IN-PLACE

Prudhoe Bay Field, Alaska

CAGPL Comparison

(Tcf at 14.73 psia)

	Sag River Sandstone and Shublik Formation	Sadlerochit Formation	Total
van Poollen (6-1974)	No estimate made	21.2	21.2
D & M (12-1974)	3.1	20.1	23.2
van Poollen (1-1976)	*	*	26.5
D & M (12-1976)	3.5	21.4	24.9

* Gas-in-place by formation not reported by van Poollen

CAGPL stated that van Poollen explained the increase in his December 1976 estimate over his earlier estimate as due to additional well control, and inclusion of gas in the Shublik formation which overlies the Sadlerochit reservoir. CAGPL pointed out that when its estimate of 3.5 Tcf for the Shublik formation and Sag River sandstone (immediately overlying the Shublik formation) is included, the difference between the two 1976 estimates of total associated gas-in-place is 1.6 Tcf or 6.2 per cent.

Foothills (Yukon)

Estimates of the volumes of natural gas in the Prudhoe Bay field were determined for Foothills (Yukon) by Core Laboratories, Inc., based on the results of 21 operating plans that were simulated and analysed. Most of the geological interpretation, volumetric data, fluid distribution, and reservoir rock and fluid properties were obtained from prior work by H.K. van Poollen and Associates, Inc., for the State of Alaska. Table 2-28 shows the reserves estimates.

Table 2-28

RESERVES OF PRUDHOE BAY FIELD, ALASKA

Foothills (Yukon) Estimate

(Tcf at 14.73 psia)

	Sadlerochit Formation		
	Associated	Solution	Total
Gas-in-place	26.58	15.28	41.86
Marketable gas			
- at 2.0 Bcf/d,			22.28
- at 2.4 Bcf/d,			26.01

Under cross-examination, Foothills (Yukon) stated that its higher estimate of gas-in-place in the Sadlerochit formation, as compared with that of CAGPL, reflected van Poollen's revised estimates based on additional well control, and the possibility of communication between the Sadlerochit and Shublik formations.

2.7.2.2 Reserves Additions

No evidence was submitted with respect to anticipated rates of reserves additions in those areas of Alaska that might in future become tributary to a pipeline from Prudhoe Bay.

2.7.2.3 Ultimate Potential

CAGPL

CAGPL quoted a 1974 estimate of "speculative recoverable resource" by the Division of Geological and Geophysical Surveys (DGGS) of the State of Alaska of 41.8 Tcf for the onshore area of the Alaska North Slope.[1] To this was added the American Petroleum Institute's estimate of proved reserves to give an ultimate potential of 67.8 Tcf. CAGPL stated that it believed this estimate to be "reasonable if not conservative". By adding a further 46.5 Tcf for the DGGS estimate of offshore resource, CAGPL calculated an ultimate potential for the entire North Slope of 114.3 Tcf. CAGPL also testified that Atlantic Richfield Corporation estimated 135 Tcf for the area of the North Slope from the Brooks Range to the 300 foot water depth offshore, and Mobil Oil estimated 104 Tcf for the onshore area only of the North Slope.

Foothills (Yukon)

Foothills (Yukon) submitted that 25 Tcf remained to be discovered in the onshore areas of the Alaska North Slope, and 2

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1) CAGPL defined the Alaska North Slope as an area of approximately 80,000 square miles bounded on the north and west by the Beaufort and Chukchi Seas of the Arctic Ocean, on the south by the Brooks mountain range, and on the east by Canada.

Tcf in other interior basins of the State. No estimate was provided for the offshore areas of the North Slope.

2.7.2.4 Views of the Board

The Prudhoe Bay field appears to be well delineated and this is reflected in the closeness of the reserves estimates submitted. The larger Foothills (Yukon) estimate with respect to the volume of associated gas-in-place in the Sadlerochit formation appears to have been satisfactorily explained as due largely to inclusion by Foothills (Yukon) of reserves in the overlying Shublik formation.

It is reasonable to conclude from evidence submitted that in the Prudhoe Bay field the Sadlerochit formation, the Shublik formation and the Sag River sandstone likely comprise a common reservoir.

The Board has examined basic well data from the Prudhoe Bay field, and is satisfied that the range of estimates presented by CAGPL and Foothills (Yukon) does in fact represent a valid assessment of the reserves of this field.

The wide variance in estimates of ultimate potential emphasizes the highly speculative nature of ultimate potential forecasts, particularly in regions such as the Alaska North Slope where exploratory drilling is limited. The Board has simply no evidence on which to base independent conclusions. The potential of the North Slope may indeed be far in excess of the Prudhoe Bay reserves, but this can only be established by further exploration.

2.7.3 Deliverability - Prudhoe Bay

Evidence

It was the opinion of both CAGPL and Foothills (Yukon) that marketable gas volumes in the range of 2.0 to 2.5 Bcf/d would be available from Prudhoe Bay. This range was established by various independent studies carried out on behalf of CAGPL, Foothills (Yukon), the Alaska producers and also the State of Alaska.

CAGPL

CAGPL introduced evidence showing that agreement with respect to unitized operation of the Prudhoe Bay field had been reached by the producers and the State. The Unit Agreement, reflecting a development plan for initial rates of 1.5 million barrels of oil per day and 2.0 Bcf/d of gas, had been given tentative approval by the Director, Division of Minerals and Energy Management, Alaska, as being "consistent with sound conservation practices and protective of the correlative rights of all parties, including the State", according to CAGPL.

Public hearings on the application for approval of the proposed unit agreement and operating plan were held on 3 and 5 May 1977. In the absence of unforeseen information being received at that hearing, CAGPL expected the application to be approved by the Alaska Oil and Gas Conservation Committee.

The deliverability schedule presented by DeGolyer and MacNaughton on behalf of CAGPL showed initial sales gas deliveries of 2.0 Bcf/d commencing in mid 1982, building up to 2.25 Bcf/d by 1985 and constant thereafter to the end of the forecast period in 1995. Evidence given at the hearing revised this schedule to an initial start-up date of 1 July 1983.

Foothills (Yukon)

The evidence of Foothills (Yukon), based on a review of the van Poollen report and supported by an independent reservoir study by Core Laboratories Inc., was that a sales gas rate in the range of 1.2 to 2.0 Bcf/d would maximize oil recovery and that, generally, 2.0 Bcf/d would be available for the pipeline.

The original Foothills (Yukon) deliverability schedule was based on a phased build-up in gas sales levels of 1.2, 1.6 and 2.4 Bcf/d. This was revised to accommodate recent pipeline design changes and the revised forecast was for 1.6 Bcf/d starting 1 October 1981 building up to 2.4 Bcf/d by 1 January 1983.

An Alcan witness stated that it was his belief, from discussions with some producers, that Prudhoe Bay gas plant facilities could be completed by 1 October 1981; conforming to Alcan's initial delivery date. This was contrary to the previously stated evidence of CAGPL, based on producer submissions to the Federal Power Commission, indicating about a five-year construction interval following execution of the gas sales contracts.

Both CAGPL and Foothills (Yukon) accepted the initial findings of the Director, Division of Minerals and Management, Alaska, as being supportive of their respective cases.

While the schedules of both CAGPL and Foothills (Yukon) anticipated throughputs in excess of the initial 2.0 Bcf/d, both Applicants indicated that increased rates would depend upon actual reservoir performance and the discretion of the Alaska Oil and Gas Conservation Committee.

The deliverability forecasts of both CAGPL and Foothills (Yukon) are shown in Table 2-29.

Views of the Board

Given the size of the reserves in the Prudhoe Bay field and the known and expected producing characteristics of the reservoir at this time and having due regard for the preliminary findings of the Director, Division of Minerals and Energy Management, of the State of Alaska, it is the judgement of the Board that the initial sales gas volumes stated by CAGPL and Foothills (Yukon) to be available to meet pipeline demand are achievable.

Whether or not they are, in fact, sustainable, or even subject to increase or decrease, will not be determinable until the actual reservoir performance can be evaluated after several years of oil production.

Reservoir performance notwithstanding, it is further recognized that field production and removals from the State will be subject, at all times, to regulation by the appropriate authorities and State agencies.

Although Alaska's royalty gas, amounting to 12.5 per cent, has been contracted to Tenneco (50 per cent), El Paso (25 per cent) and Southern Natural (25 per cent), such disposition presupposes the success of the El Paso LNG proposal to move Prudhoe Bay gas.

Even so, Alaska has reserved the right to reduce daily deliveries by up to 25 per cent at any time during the first five years, 50 per cent during the next five years, 75 per cent during the third five-year period and 100 per cent after 15 years, for in-state use.

Failing approval of the El Paso Project, the royalty gas reverts to the State under the terms of the contracts. In that event, however, the Board has assumed that absent the development of a market within the state, royalty gas would be available for sale in the lower 48 states.

With regard to gas plant construction, the Board is unable to comment as to the adequacy of a three-year lead time as proposed by Alcan except to say that it is reasonable, given no delays in regulatory approvals.

Table 2-29

DELIVERABILITY FROM PRUDHOE BAY:

Applicants' Forecast

YEAR	APPLICANT	
	CAGPL	FOOTHILLS (YUKON)
	Ave. Day (MMcf/d)	- (MMcf/d)
1981	-	1600 (1)
82	-	*
83	2000 (2)	2400 (3)
84	2000	*
1985	2040	*
86	2250	*
87	2250	*
88	2250	*
89	2250	*
1990	2250	*
91	2250	*
92	2250	*
93	2250	*
94	2250	*
1995	2250	*

(1) 1 October 1981

(2) 1 July 1983

(3) 1 January 1983

* Not specified

2.8 OVERVIEW OF THE BOARD REGARDING THE NEED FOR MACKENZIE DELTA GAS AND THE RESERVES AND DELIVERABILITY OF NORTHERN GAS TO SUPPORT A PIPELINE

The Board's perception of the situation is as follows:

1. Excluding the effect of restrictions on removal of gas from Alberta, the year of first shortage, if domestic demand and export commitments are met, is expected to be 1983 but, because of the lack of precision in forecasting, this could be as early as 1982 or as late as 1985.
2. If Alberta applied rigidly its rules on removal of gas from the province, the year of first shortage could possibly be as early as 1981.
3. If exports were cut off immediately, the year of first shortage for Canadian demand would be 1990. Likewise, if exports were phased down and gas from new sources of supply were not available, the year of first shortage in respect to Canadian demand would also be about 1990.
4. Canada is likely to be deficient in the supply of energy from indigenous sources even with new sources of supply such as oil from tar sands or heavy oil; oil and gas from traditional sources will soon begin to decline rapidly and new sources of supply will be urgently needed.
5. Of the new sources of energy available, Delta gas while small as a new block of energy supply, is nevertheless attractive economically compared to other new sources. Other major new sources of gas present problems - gas

discovered from the Arctic Islands is still well below threshold levels and there are formidable problems to be overcome in bringing it to market by pipeline; LNG shipment from the Arctic is being tested but the volumes are likely to be small and the costs high. However, LNG from the Arctic Islands might provide a cushion, although at some cost penalty, if delays occurred in connecting Delta gas. Potential east coast reserves are likely to take too long to find and connect to be relevant to today's decision, and coal gasification is high cost and there are environmental concerns. Therefore the Delta appears to be the promising source of new gas at relatively attractive economic cost and with manageable technological problems in bringing it to market.

The question then appears to be, how does Delta gas relate to the pipeline projects being examined by the Board. These will be examined in more detail later but, in summary:

CAGPL offers early and economic connection of Delta gas, but with major environmental and socio-economic implications.

Foothills is probably not economic on the basis of reserves already discovered and probably requires major new finds of gas in the Beaufort Sea to make it viable.

Foothills (Yukon) offers the prospect of connecting Alaska gas to United States markets earlier than under the CAGPL proposal and at the same time appears to offer the prospect of connecting Delta reserves by about 1984 or 1985 at a cost not very different from the CAGPL proposal.

In the face of the situation, the fundamental question would appear to be, what policy considerations are important in shedding light on the flexibility Canada has in the timing of the connection of Delta gas. In the Board's view, these policy considerations include the following:

1. In relation to exports, it would be unacceptable in the Board's view to cut off all exports immediately with surplus gas available in Canada and a shortage of gas occurring in the United States.
2. Phasing down exports, or stretching out existing export licences, becomes a more tolerable policy once Alaska gas is connected to market - whether by the Foothills (Yukon) or the El Paso Project. In the case of CAGPL, a phasing down of exports would not be necessary.
3. Excess producibility in Alberta is now about 400 Bcf in 1977 and will likely decline progressively and disappear by about 1985. If this gas could be exported it would stimulate exploration and development and improve the total deliverability of Alberta gas in the 1980's. If it were to be exported it would have to be offset by a reduction of exports later in the 1980's, or be replaced by Alaska gas. Pipeline capacity would have to be built to move the gas. This policy would appear to the Board to have possibilities and it merits further analysis.
4. The earliest possible connection of Delta gas may not appeal to Alberta because of the fear of shutting in Alberta gas due to the need for a high level of throughput in a pipeline from the Delta. However, the

surge of Delta gas is not likely to be as great as originally contemplated because the reserves discovered are less than previously anticipated. If so, short-term exports could relieve the fears of Alberta gas being shut in. Furthermore, once there is a firm commitment to the connection of Alaska and/or Delta gas, Alberta may be willing to enter into exchange arrangements to release more Alberta gas early in exchange for Delta or Alaska gas later to protect the needs of Alberta consumers. For these reasons, the Board believes that Alberta would be less rigid in the application of its formula for restricting the removal of gas from the province.

5. The Board firmly believes that conservation offers, in the short and medium term, the lowest cost investment in closing the energy gap. The Board has projected substantial reductions in demand due to conservation in its most likely forecast of demand. If a faster rate of conservation is desired, the Board believes that both Federal and Provincial governments will have to provide greater incentives and impose measures to restrict demand. If the growth in natural gas demand could be reduced to two per cent per year by 1985, then Delta gas might not be needed until the late 1980's.

This is an appropriate point at which to enunciate the major policy thrust advocated by several intervenors and then to provide the Board's observations on it.

These intervenors postulated that the growth rate in the demand for energy should be restricted to two per cent per year and that the Board should encourage this by denying a pipeline to connect new sources of gas to market.

If the growth rate in the demand for natural gas were to immediately decline to two per cent per year and remain constant thereafter, a pipeline to connect frontier gas to market could be deferred until about 1990.

The Board's observations are:

1. No rationale has been established that a two per cent growth rate in the demand for energy should translate into a two per cent growth rate in the demand for natural gas. It surely should reflect availability and economics of supply and a matching of fuels with new patterns of consumption by end-use.

2. There is as yet no commitment by the Canadian people as a whole to adapt rapidly to the lifestyles that a two per cent growth rate would require. Rather, there are expressions of opinion by growing segments of the population that it would be a desirable course to follow. This is a far cry from already having federal, provincial and municipal commitments to this common goal, from having all the necessary legislation enacted and from each individual having changed his lifestyle and dispensed with his former ingrained wasteful habits. In the Board's view, society does not change that quickly.

3. Even supposing this low growth rate could be achieved more gradually by say 1985, and there is no certainty now that even that target could be met, should we forego

the possibilities of connecting Delta gas by one or the other of the large diameter pipelines - options which may only be open to Canada for a short time?

It has already been indicated that several different new major sources of energy will be needed by the mid-1980's even in the presence of vigorous conservation programs. It has further been stated that Delta gas would likely cost less than OPEC oil and that, security considerations aside, OPEC oil is usually considered to be a readily available source of supply but, by the mid-1980's, supply could start to become difficult and a sharp rise in price is not out of the question. Furthermore, other new sources of energy such as tar sands, heavy oil, nuclear and hydro generated electricity, and coal gasification are likely to be at least as costly as world oil and many of them more so, and finally, new forms of renewable energy supplies are expected to be insignificant before 1990 and increase only gradually after that time. In any realistic scenario, surely it would appear prudent to connect Delta gas by the mid-1980's.

The Board's assessment is that the policy advocated by several intervenors, while superficially attractive, and enabling the difficult and emotional socio-economic and environmental problems of the north to be avoided or postponed, could be dangerous and deluding. Undue dependence on new gas supplies from Alberta, based on overly optimistic forecasts, would be most unwise. Because long lead times in connecting new sources of supply are needed, and because of the cold Canadian climate, it is simply not prudent to risk being without energy in winter nor is it tolerable to force a shortage on our neighbours to the south by cutting off exports before Prudhoe Bay gas is connected, when supplies are or could be available in Canada. After weighing all aspects, the Board, while strongly endorsing a vigorous conservation program, equally strongly advocates the connection of economic new sources of supply such as Delta gas.

This chapter started by the question - do we need to connect Delta gas to markets and are there enough reserves in Alaska to make a pipeline carrying Delta or Alaska gas, or both, feasible? It concludes by the Board's finding, first, that we need a pipeline from the Delta by no later than 1985, that there is some flexibility between 1982 and 1985, and that the precise timing can be influenced by a number of policy options; and, secondly, Alaska reserves are adequate to justify a pipeline. The need for the pipeline has been identified, but whether it is economic to construct it, whether it can be financed, what route it should take, and whether it could be constructed on acceptable socio-economic and environmental grounds is the subject matter of the remaining chapters.

NET SALES OF NATURAL GAS

Canada

NEB Forecast

(Bcf/Year)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation(1)	Total Net Sales(2)
1975	298	295	85	485	175	1,337
1977	314	325	127	529	161	1,456
1980	339	377	189	646	204	1,754
1985	389	455	247	788	230	2,110
1990	460	542	290	937	244	2,473
1995	522	628	307	1,147	260	2,864

(1) Includes generation of electricity by industry as well as utilities.

(2) Totals may not add due to rounding.

NET SALES OF NATURAL GAS

British Columbia

NEB Forecast

(Bcf/Year)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation(1)	Total Net Sales(2)
1975	38.7	33.5	4.5	47.3	23.3	147.3
1976	39.5	34.7	4.5	51.9	5.8	136.4
1977	39.6	36.6	4.5	56.0	5.5	142.2
1978	40.8	38.8	4.5	60.7	5.5	150.3
1979	41.6	40.7	4.5	65.3	5.5	157.6
1980	42.6	42.5	4.5	70.4	5.5	165.5
1985	48.6	51.1	4.5	87.4	18.5	210.1
1990	57.9	62.2	4.5	106.9	17.5	249.0
1995	66.5	77.3	4.5	131.2	17.5	297.0

(1) Includes generation of electricity by industry as well as utilities.

(2) Totals may not add due to rounding.

NET SALES OF NATURAL GAS

Alberta

NEB Forecast

(Bcf/Year)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation[1]	Total Net Sales[2]
1975	71.7	74.5	49.7	54.9	63.5	314.3
1976	70.0	69.5	61.8	59.8	59.9	321.0
1977	74.8	78.5	89.9	64.0	65.3	372.5
1978	76.7	80.7	112.5	69.4	78.5	417.8
1979	77.8	82.3	134.6	81.5	78.7	454.9
1980	79.3	83.8	148.6	93.1	101.1	505.9
1985	88.4	93.0	207.2	125.1	102.4	616.1
1990	104.4	105.0	249.2	138.9	101.9	699.4
1995	118.5	120.6	266.2	179.2	101.7	786.2

(1) Includes generation of electricity by industry as well as utilities.

(2) Totals may not add due to rounding.

NET SALES OF NATURAL GAS

Saskatchewan

NEB Forecast

(Bcf/Year)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation (1)	Total Net Sales (2)
1975	26.7	12.9	-	41.9	10.0	91.5
1976	25.6	13.2	-	44.1	12.7	95.6
1977	27.4	13.4	-	46.0	13.1	99.9
1978	28.1	13.7	-	48.5	13.6	103.9
1979	28.4	13.9	-	50.9	14.0	107.2
1980	29.0	14.1	-	53.4	14.4	110.9
1985	31.7	15.0	-	65.8	17.2	129.7
1990	36.3	16.0	-	82.0	20.0	154.3
1995	40.0	17.4	-	102.9	22.7	183.0

(1) Includes generation of electricity by industry as well as utilities.

(2) Totals may not add due to rounding.

NET SALES OF NATURAL GAS

Manitoba

NEB Forecast

(Bcf/Year)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation (1)	Total Net Sales (2)
1975	23.9	20.2	3.5	15.6	.1	63.3
1976	23.1	21.0	3.5	16.9	-	64.5
1977	24.8	21.6	3.5	18.0	.2	68.1
1978	25.5	22.4	3.5	19.4	.5	71.3
1979	26.0	23.0	3.5	20.7	.8	74.0
1980	26.6	23.6	3.5	22.2	1.1	77.0
1985	29.5	26.5	3.5	27.5	1.1	88.1
1990	34.3	30.1	3.5	34.0	1.1	103.0
1995	38.4	34.8	3.5	42.2	1.1	120.0

(1) Includes generation of electricity by industry as well as utilities.

(2) Totals may not add due to rounding.

NET SALES OF NATURAL GAS

Ontario

NEB Forecast

(Bcf/Year)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation[1]	Total Net Sales[2]
1975	120.4	141.5	27.0	271.4	78.5	638.8
1976	133.6	155.7	29.0	280.0	77.2	675.5
1977	129.4	161.0	29.0	287.3	76.7	683.4
1978	133.3	173.7	29.0	298.2	78.9	713.1
1979	136.1	184.8	32.0	308.0	80.3	741.2
1980	139.7	196.3	32.0	319.8	81.9	769.7
1985	163.9	246.8	32.0	371.3	91.0	905.0
1990	191.6	299.7	33.0	438.2	103.0	1065.5
1995	215.2	342.4	33.0	522.0	117.1	1229.7

(1) Includes generation of electricity by industry as well as utilities.

(2) Totals may not add due to rounding.

NET SALES OF NATURAL GAS

Quebec

NEB Forecast

(Bcf/Year)

Year	Residential	Commercial	Petrochemical	Other Industrial	Thermal Electric Generation(1)	Total Net Sales(2)
1975	16.2	12.2	-	53.8	-	82.2
1976	18.6	14.1	-	49.6	-	82.3
1977	18.0	14.0	-	57.4	-	89.4
1978	19.3	15.1	-	68.8	-	103.2
1979	20.4	16.0	-	77.6	-	114.0
1980	21.7	17.0	-	86.7	-	125.4
1985	27.2	22.7	-	111.1	-	161.0
1990	35.0	29.2	-	137.1	-	201.3
1995	42.8	35.5	-	169.5	-	247.8

(1) Includes generation of electricity by industry as well as utilities.

(2) Totals may not add due to rounding.

NET SALES OF NATURAL GAS

Canada

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	Imperial	Gulf Case 2	Shell Case 1	Shell Case 2	Helliwell[1] Base Case	CJL[1]	NEB
1975	1,495	1,369	1,339	1,324	1,329	1,329	1,495	1,450	1,337
1977	1,702	1,595	1,436	1,426	1,405	1,394	1,579	1,508	1,456
1980	2,031	1,888	1,766	1,732	1,614	1,583	1,732	1,601	1,754
1985	2,550	2,319	2,356	2,307	1,936	1,830	2,114	1,768	2,110
1990	3,078	2,614	2,814	2,600	2,229	2,062	2,611	1,952	2,473
1995	3,599	2,892	3,297	2,977	2,552	2,305	3,204	2,155	2,864

(1) Pipeline fuel and losses included.

NET SALES OF NATURAL GAS: RESIDENTIAL/COMMERCIAL

Canada

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	Imperial	Gulf Case 2	NEB
1975	601	602	592	585	592
1977	662	658	638	630	639
1980	752	728	733	745	716
1985	933	882	1,011	972	845
1990	1,106	1,033	1,221	1,101	1,002
1995	1,278	1,133	1,455	1,278	1,150

NET SALES OF NATURAL GAS: INDUSTRIAL & PETROCHEMICAL

Canada

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	Imperial	Gulf Case 2	NEB
1975	733	628	602	596	570
1977	876	778	673	664	656
1980	1,099	981	890	855	834
1985	1,433	1,240	1,195	1,203	1,035
1990	1,784	1,398	1,428	1,377	1,227
1995	2,128	1,573	1,692	1,592	1,454

Note: Natural gas used by industry for thermal generation of electricity is not included in the NEB column. These amounts are shown as thermal electric generation.

NET SALES OF NATURAL GAS: THERMAL ELECTRIC GENERATION

Canada

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	Imperial	Gulf Case 2	NEB
1975	162	140	145	142	175
1977	164	148	125	132	161
1980	180	151	143	132	204
1985	184	146	150	132	230
1990	187	120	165	122	244
1995	193	120	150	107	260

Note: The NEB column includes the total natural gas used for the generation of electricity. This is the sum of demand by electric utilities and by industry. Other columns show the natural gas demand by electric utilities only. The amount of gas demand for electric generation by industry is forecast by NEB to be 33 Bcf in 1975, 49 Bcf in 1977, 86 Bcf in 1980, 98 Bcf in 1985, 112 Bcf in 1990 and 131 Bcf in 1995.

NET SALES OF NATURAL GAS

British Columbia

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	Westcoast	Gulf Case 2	Shell Case 1	B.C. Hydro*	NEB
1975	190	150	153	145	145	99	147
1977	210	161	161	156	146	87	142
1980	256	197	211	185	163	112	166
1985	376	239	249	254	202	170	210
1990	484	278	323	307	246	225	249
1995	581	317	375	372	287	295	297

* Lower Mainland of B.C., excluding Powell River.

NET SALES OF NATURAL GAS

Alberta

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	Gulf Case 2	Shell Case 1	NEB
1975	354	337	308	312	314
1977	434	441	340	348	373
1980	538	555	456	430	506
1985	649	693	574	504	616
1990	752	709	631	562	699
1995	873	750	665	602	786

NET SALES OF NATURAL GAS

Saskatchewan

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	TCPL	Gulf Case 2	NEB
1975	100	89	N.A.	92	92
1977	108	108	107	94	100
1980	121	116	116	105	111
1985	131	131	137	128	130
1990	143	142	159	136	154
1995	150	153	188	146	183

NET SALES OF NATURAL GAS

Manitoba

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	TCPL	Gulf Case 2	NEB
1975	71	61		60	63
1977	76	71	65	62	68
1980	86	79	72	73	77
1985	101	90	82	92	88
1990	114	99	90	105	103
1995	126	107	102	115	120

NET SALES OF NATURAL GAS

Ontario

Comparison of Forecasts

(Bcf/Year)

Year	CAGPL	Trunk Line	TCPL	Imperial	Gulf Case 2	NEB
1975	694	650		640	638	639
1977	766	712	679	671	689	683
1980	867	809	779	775	811	770
1985	1,062	972	993	989	1,111	905
1990	1,279	1,141	1,175	1,167	1,242	1,066
1995	1,484	1,286	1,413	1,389	1,395	1,230

NET SALES OF NATURAL GAS

Quebec

Comparison of Forecasts

(Bcf/Year)

			Gaz Metro				Gulf	
Year	CAGPL	Trunk Line	Low	High	TCPL	Imperial	Case 2	NEB
1975	87	82	83			83	82	82
1977	108	102	91	102	95	95	85	89
1980	164	133	106	148	114	129	102	125
1985	230	195	146	283	240	211	147	161
1990	306	244	178	362	330	317	178	201
1995	386	279	217	420	436	396	218	248

DEMAND FOR CANADIAN GAS BY AREAS

(Bcf/yr @ 1000 Btu/cf)

	ALBERTA				BRITISH COLUMBIA		EAST OF ALBERTA		TOTAL CANADA		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Year	Domestic	Export	AGTL Fuel	Net Reprocessing	Domestic	Export	Domestic	Export	Domestic (1+3+4+5+7)	Export (2+6+8)	Total (9+10)
1977	377	473	23	101	169	295	1025	277	1695	1045	2740
78	423	473	23	104	178	295	1079	276	1807	1044	2851
79	459	468	25	134	185	295	1128	277	1932	1040	2972
1980	512	468	25	164	194	295	1179	236	2073	999	3072
81	535	468	25	157	211	295	1218	204	2146	967	3113
82	545	412	24	164	226	295	1258	204	2217	911	3128
83	566	412	25	164	227	295	1299	204	2282	911	3193
84	584	412	26	168	231	295	1345	204	2354	911	3265
1985	623	397	26	153	241	295	1393	204	2436	896	3332
86	630	304	25	144	246	295	1440	204	2487	803	3290
87	654	164	24	136	252	295	1493	201	2559	660	3219
88	675	164	25	134	261	295	1546	198	2640	657	3297
89	695	106	25	133	270	246	1601	187	2725	539	3264
1990	707	81	24	132	267	-	1652	134	2781	215	2996
91	722	75	23	127	276	-	1700	49	2846	124	2970
92	736	47	23	125	286	-	1753	8	2925	55	2980
93	760	38	24	128	296	-	1807	8	3015	46	3061
94	781	-	23	128	306	-	1864	8	3102	8	3110
1995	796	-	23	128	317	-	1922	6	3186	6	3192
TOTAL	11,780	4962	461	2624	4639	3786	27,702	3089	47,208	11,837	59,045

- Figures may not add due to rounding.
- Columns 1 plus 3 represent the total domestic demand for gas in Alberta. Column 1 includes the fuel and losses for distribution of Alberta's net sales of gas. It also includes the ethane requirement for ethylene, (Column 9, page 2). Column 3 is the fuel requirements of AGTL for all gas transported in its system leaving the province.
- Column 2 is the exports south from Alberta - Alberta and Southern and Westcoast via Kingsgate, British Columbia, and Canadian-Montana via Cardston and Aden, Alberta.
- Column 4 is the net reprocessing shrinkage detailed in Column 10, page 2.
- Columns 5 and 7 are the Canadian requirements excluding Alberta. They include fuel and losses associated with transmission and distribution outside Alberta.
- Column 6 is the Westcoast GL-41 licensed volumes.
- Column 8 is the TCPL, ICG Transmission Limited and Niagara Gas licensed export volumes.
- Columns 2, 6 and 8, the export requirements, have been adjusted to reflect make-up provisions in the licences.

REPROCESSING SHRINKAGES

(Bcf/yr @ 1000 Btu/cf)

	REPROCESSING AT EXISTING PLANTS				REPROCESSING AT FUTURE PLANTS				ETHYLENE DEMAND	NET REPROCESSING
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Cochrane	Empress	Edmonton	Total (1+2+3)	Cochrane	Empress	Edmonton	Total (5+6+7)	Total	Total (4+8-9)
1977	26	73	2	101	-	-	-	-	-	101
78	26	76	2	104	-	-	-	-	-	104
79	26	79	2	107	12	20	12	44	17	134
1980	25	77	2	104	24	40	24	88	28	164
81	25	77	2	104	24	40	24	88	35	157
82	26	83	2	111	24	40	24	88	35	164
83	26	83	2	111	24	40	24	88	35	164
84	26	87	2	115	24	40	24	88	35	168
1985	26	89	2	117	24	40	24	88	52	153
86	24	94	2	120	23	40	24	87	63	144
87	22	96	2	120	22	40	24	86	70	136
88	20	99	2	121	19	40	24	83	70	134
89	18	102	2	122	17	40	24	81	70	133
1990	16	104	2	122	16	40	24	80	70	132
91	15	102	2	119	14	40	24	78	70	127
92	13	103	2	118	13	40	24	77	70	125
93	13	107	2	122	12	40	24	76	70	128
94	10	112	2	124	10	40	24	74	70	128
1995	8	116	2	126	8	40	24	72	70	128
TOTAL	391	1759	38	2188	310	660	396	1366	930	2624

- Columns 1, 2 and 3 are the projected reprocessing shrinkages at existing plants based on historical data.
- Columns 5, 6 and 7 are the projected shrinkages at new plants based upon the proposed capacities of the new facilities.
- Column 9 is the requirement of ethane for ethylene which is included in Alberta requirements (Column 1, page 1).
- The net reprocessing requirement, Column 10, includes all reprocessing shrinkage except that required for ethylene production.

CANADIAN GAS DELIVERABILITY FROM CONTROLLED RESERVES

(Bcf/yr @ 1000 Btu/cf)

Year	(1) TCPL	(2) A&S	(3) Westcoast	(4) Westcoast GL-4	(5) Pan Alberta	(6) Alberta Utilities Major	(7) Alberta Utilities Minor	(8) Canadian Montana	(9) Many Islands Pipelines	(10) Production East of Alberta	(11) Total
Remaining Reserves at 31 Dec. 1976	24,466	8936	6392	323	916	2686	570	268	500	1238	46,295
1977	1304	476	365	51	45	247	36	20	27	56	2627
78	1393	481	350	51	64	231	35	20	29	51	2705
79	1468	496	323	51	63	211	35	20	29	49	2745
1980	1487	509	318	51	61	199	35	20	32	51	2763
81	1490	510	304	51	60	183	36	19	37	53	2743
82	1422	483	272	51	58	177	33	17	34	53	2600
83	1346	483	265	17	55	154	32	16	32	50	2450
84	1264	503	258	-	52	141	32	14	31	46	2341
1985	1192	484	242	-	47	131	32	13	29	43	2213
86	1130	464	232	-	39	126	32	12	27	40	2102
87	1004	445	221	-	29	116	29	11	26	36	1917
88	919	417	208	-	20	107	27	10	23	33	1764
89	847	357	187	-	15	101	24	9	21	29	1590
1990	769	327	142	-	13	92	22	8	20	26	1419
91	688	295	135	-	12	88	21	7	18	24	1288
92	623	264	126	-	10	82	19	6	17	21	1168
93	555	244	116	-	9	75	18	5	15	19	1056
94	493	184	107	-	9	70	16	5	14	17	915
1995	444	161	96	-	8	64	15	4	13	16	821
TOTAL	19,838	7583	4267	323	669	2595	529	236	474	713	37,227
Total Remaining Reserves 31 Dec. 1995	4628	1353	2125	0	247	91	41	32	26	525	9068

- NEB forecasts of production from contracted reserves for TCPL, A&S, Westcoast, Pan Alberta and Canadian-Montana are in Columns 1, 2, 3, 5 and 8 respectively.
- The Westcoast forecast includes all gas in the Westcoast supply area (excepting supply for Licence GL-4).
- Westcoast GL-4 is at the annual authorized level until total licensed volumes have been produced.
- Major Alberta utilities supply forecast was taken from CWNG and NUL forecasts submitted to the AERCB in August 1975.
- Minor utilities supply forecast was adopted from CAGPL submission.
- Many Islands forecast was taken from the submission of Saskatchewan Power Corporation to the AERCB for a removal permit and adjusted to reflect the decision of the Alberta Board in its report AERCB 77-B.
- Production East of Alberta includes the forecast of Saskatchewan production from the above-noted submission of Saskatchewan Power Corporation and the Board's estimate of supply from Ontario based on historical production.
- Remaining reserves as at 31 December 1976 have been allocated on the basis of available information regarding controlled supplies, except for Alberta utilities and Many Islands Pipelines which have been estimated by the Board.

GAS SUPPLY AVAILABLE TO MEET ALBERTA DEMAND

(Bcf/yr @ 1000 Btu/cf)

Year	(1) Total Demand	(2) Alberta Utilities Supply	(3) TCPL, A&S Sales	(4) Deferred Supply	(5) Shallow Uncommitted Supply	(6) Non-Associated Uncommitted Supply	(7) Surplus of Exporters	(8) Alberta Trend Supply	(9) Total (2+3+4+5 +6+7+8)	(10) Surplus (9-1)
1977	377	283	32	-	22	66	15	13	431	54
78	423	266	69	-	34	100	15	38	522	99
79	459	246	76	-	45	133	20	84	604	145
1980	512	234	77	-	56	166	20	144	697	185
81	535	219	84	26	67	166	19	207	788	253
82	545	210	86	26	78	166	39	282	887	342
83	566	186	87	26	90	166	4	354	913	347
84	584	173	89	26	101	166	4	428	987	403
1985	623	163	107	28	112	166	(2)	499	1073	450
86	630	158	115	28	112	166	70	571	1220	590
87	654	145	122	28	112	166	204	638	1415	761
88	675	134	122	28	110	166	179	695	1434	759
89	695	125	122	28	108	149	180	739	1451	756
1990	707	114	122	28	106	134	183	770	1457	750
91	722	109	122	28	102	121	159	790	1431	709
92	736	101	122	28	101	109	160	796	1417	681
93	760	93	122	26	92	98	150	796	1377	617
94	781	86	122	25	85	88	134	787	1327	546
1995	796	79	122	23	78	79	115	772	1268	472
TOTAL	11,780	3124	1920	402	1611	2571	1668	9403	20,699	8919

- Column 1 is taken from Column 1, page 1.
- Column 2 is the sum of the major and minor Alberta utilities forecast, Columns 6 and 7 of page 3.
- Column 3 is the sum of the A&S and TCPL estimates of their sales to Alberta utilities.
- Column 4 is taken from the AERCB Report No. 75-F.
- Column 5 is the Board's estimate of production from 80 per cent of the uncommitted shallow gas reserves in southeastern Alberta.
- Column 6 is the Board's estimate of production from 75 per cent of the remaining uncommitted non-associated gas reserves in Alberta.
- Column 7 is the volume of gas supply in excess of the licensed exports of A&S, Canadian-Montana and Westcoast GL-4. In the early years there is an oversupply of Canadian-Montana's combined Cardston and Aden volumes while in the later years there is surplus A&S supply capability as its export licences expire.
- Column 8 is the NEB forecast of deliverability from Alberta trend gas additions.
- Column 10 is the volume of gas supply in excess of Alberta's total requirements.

ADDITIONAL GAS SUPPLY NECESSARY TO MEET BRITISH COLUMBIA TOTAL DEMAND

(Bcf/yr @ 1000 Btu/cf)

Year	(1) Total Demand	(2) Westcoast Supply	(3) Pan Alberta Supply	(4) A&S (Columbia) Sales	(5) B.C. Trend Supply	(6) Net B.C. Supply (2+3+4+5)	(7) Demand For Alberta Gas (1-6)
1977	464	365	27	5	1	398	66
78	473	350	46	5	4	405	68
79	480	323	45	5	9	382	98
1980	489	318	43	5	19	385	104
81	506	304	42	8	32	386	120
82	521	272	40	8	47	367	154
83	522	265	37	8	64	374	148
84	526	258	34	8	81	381	145
1985	536	242	29	8	97	376	160
86	541	232	21	8	112	373	168
87	547	221	11	9	125	366	181
88	556	208	2	9	137	356	200
89	516	187	-	9	146	342	174
1990	267	142	-	9	153	304	(37)
91	276	135	-	9	158	302	(26)
92	286	126	-	9	159	294	(8)
93	296	116	-	9	158	283	13
94	306	107	-	9	154	270	36
1995	317	96	-	8	148	252	65
TOTAL	8425	4267	377	148	1804	6596	1829

- Column 1 is the total British Columbia demand obtained by adding the total domestic and export demands, Columns 5 and 6 from page 1.
- Column 2 is the NEB forecast of Westcoast gas supply from Column 3, page 3.
- Column 3 is the NEB forecast of gas supply Pan Alberta can make available to British Columbia after deducting its Gaz Métropolitain requirement (Column 5, page 3 less Column 6, page 6).
- Column 4 is A&S's estimate of its sales to Columbia Natural Gas in British Columbia.
- Column 5 is the NEB forecast of supply from trend additions in British Columbia.
- Column 7 is the additional gas supply necessary to meet British Columbia total demand.

ADDITIONAL GAS SUPPLY NECESSARY TO MEET TOTAL DEMAND EAST OF ALBERTA

(Bcf/yr @ 1000 Btu/cf)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total Demand	TCPL Supply	TCPL Alberta Sales	AGTL Fuel and Reprocessing	Many Islands Pipelines Supply	Pan Alberta Supply	Production East of Alberta	Saskatchewan Trend Supply	Net East of Alberta Supply (2-3-4+5+6+7+8)	Demand For Alberta Gas (1-9)
1977	1302	1304	14	89	27	18	56	-	1302	-
78	1355	1393	46	91	29	18	51	1	1355	-
79	1405	1468	46	114	29	18	49	1	1405	-
1980	1415	1487	46	129	32	18	51	2	1415	-
81	1422	1490	46	134	37	18	53	4	1422	-
82	1462	1422	46	132	34	18	53	6	1355	107
83	1503	1346	46	127	32	18	50	8	1281	222
84	1549	1264	46	121	31	18	46	10	1202	347
1985	1597	1192	46	117	29	18	43	12	1131	466
86	1644	1130	46	112	27	18	40	14	1071	573
87	1694	1004	46	105	26	18	36	15	948	746
88	1744	919	46	100	23	18	33	17	864	880
89	1788	847	46	94	21	15	29	18	790	998
1990	1786	769	46	90	20	13	26	19	711	1075
91	1749	688	46	84	18	12	24	18	630	1119
92	1761	623	46	80	17	10	21	18	563	1198
93	1815	555	46	76	15	9	19	17	493	1322
94	1872	493	46	72	14	9	17	16	431	1441
1995	1928	444	46	69	13	8	16	15	381	1547
TOTAL	30,791	19,838	842	1936	474	292	713	211	18,750	12,041

- Column 1 is the total demand for gas East of Alberta from Columns 7 and 8, page 1.
- Column 2 is the NEB forecast of supply from TCPL's contracted gas volumes (Column 1, page 3).
- Column 3 is TCPL's estimate of sales of gas to Alberta utilities taken from material filed at its facilities hearing in 1976. An update of these figures was filed in this hearing in May 1977. Use of these new figures would not significantly change the total supply projections.
- Column 4 is the NEB estimate of total Empress shrinkage with both existing and new facilities and the AGTL fuel required to transport gas for East of Alberta use. The volumes are based on TCPL throughput.
- Column 5 is the Many Islands forecast of production from Column 9, page 3.
- Column 6 is the projected supply of Pan Alberta to meet its Gaz Métropolitain contract.
- Column 7 is the forecast of production East of Alberta (Column 10, page 3).
- Column 8 is the NEB forecast of supply from trend additions in Saskatchewan.
- Column 10 is the additional gas supply necessary to meet total demand east of Alberta.

ALLOCATION OF GAS SURPLUS TO ALBERTA DEMAND

(Bcf/yr @ 1000 Btu/cf)

	SURPLUS SUPPLIES			DEMAND FOR ALBERTA SURPLUS		ALLOCATION OF SURPLUS			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Alberta Surplus	Supply From Temporary Surplus	Total (6+7+8+9)	East of Alberta	British Columbia	East of Alberta	Empress Reprocess. and AGTL Fuel	British Columbia	Temporary Surplus Available for later use
1977	54	-	54	-	66	-	-	-	54
78	99	-	99	-	68	-	-	68	31
79	145	-	145	-	98	-	-	98	47
1980	185	-	185	-	104	-	-	104	81
81	253	-	253	-	120	-	-	120	133
82	342	-	342	107	154	107	7	154	74
83	347	22	369	222	148	213	14	142	-
84	403	22	425	347	145	286	19	120	-
1985	450	22	472	466	160	335	22	115	-
86	590	22	612	573	168	451	29	132	-
87	761	22	783	746	181	599	39	145	-
88	759	22	781	880	200	604	40	137	-
89	756	22	778	998	174	628	41	109	-
1990	750	59	809	1075	(37)	760	49	-	-
91	709	48	757	1119	(26)	711	46	-	-
92	681	28	709	1198	(8)	666	43	-	-
93	617	18	635	1322	13	591	38	6	-
94	546	16	562	1441	36	515	34	13	-
1995	472	15	487	1547	65	440	29	18	-
TOTAL	8919	338	9257	12,041	1829	6906	450	1481	420

- Column 1 is the total projected supply of gas surplus to Alberta requirements from Column 10, page 4.
- Additional gas was assumed to flow to meet British Columbia deficiencies commencing 1978.
- After supplying British Columbia and East of Alberta as shown in Columns 6, 7 and 8, there remain volumes of gas which provide a temporary overall surplus to Canadian Demand. These volumes, shown in Column 9, are assumed not to be produced and are converted to a forecast of deliverability starting in 1983 as shown in Column 2. The temporary surplus in British Columbia in the years 1990-1992 are also included in Column 2.
- The total surplus supply, Column 3, is allocated between British Columbia and East of Alberta based upon the proportion of the unsatisfied demand which is attributable to each of these regions.
- Column 7 is AGTL fuel and reprocessing shrinkage at Empress for all surplus supplies flowing East from Alberta.

ADJUSTMENTS TO ALBERTA UNCOMMITTED AND TREND SUPPLIES

(Bcf/yr @ 1000 Bcf/cf)

			UNADJUSTED		ADJUSTED	
	(1)	(2)	(3)	(4)	(5)	(6)
Year	Temporary Surplus Supply	Deferred Deliverability	Alberta Uncommitted	Alberta Trend	Alberta Uncommitted	Alberta Trend
1977	54	-	88	13	47	-
78	31	-	134	38	134	7
79	47	-	178	84	178	37
1980	81	-	222	144	222	63
81	133	-	233	207	233	74
82	74	-	244	282	244	208
83	-	22	256	354	256	376
84	-	22	267	428	267	450
1985	-	22	278	499	278	521
86	-	22	278	571	278	593
87	-	22	278	638	278	660
88	-	22	276	695	276	717
89	-	22	257	739	257	761
1990	-	22	240	770	240	792
91	-	22	223	790	223	812
92	-	20	210	796	210	816
93	-	18	190	796	190	814
94	-	16	173	787	173	803
1995	-	15	157	772	157	787
TOTAL	420	267	4182	9403	4141	9291

- Column 1 is the temporary surplus Alberta supply taken from Column 9, page 7.
- Column 2 is the deliverability, commencing in 1983, attributable to the volumes indicated to be surplus in Column 1 and assumed not to be produced in the period indicated in Column 1.
- The figures in Columns 1 and 2 were used to adjust the NEB forecasts of supply from uncommitted and trend gas in Alberta.
- The Board judged that the bulk of the adjustments necessary would be made to the trend gas forecast, Column 4 which is taken from Column 8, page 4. In 1977 a balancing adjustment was made to the uncommitted supply forecast, Column 3, which is the sum of Columns 5 and 6 from page 4.
- The adjusted forecasts to be used in the total supply-demand balance are in Columns 5 and 6.

BRITISH COLUMBIA SUPPLY/DEMAND BALANCE

(Bcf/yr @ 1000 Btu/cf)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	British Columbia Demand	Huntingdon Export	Total (1+2)	British Columbia Net Supply	Alberta Surplus to British Columbia	Total (4+5)	Deficiency (3-6)
1977	169	295	464	398	-	398	66
78	178	295	473	405	68	473	-
79	185	295	480	382	98	480	-
1980	194	295	489	385	104	489	-
81	211	295	506	386	120	506	-
82	226	295	521	367	154	521	-
83	227	295	522	374	142	516	6
84	231	295	526	381	120	501	25
1985	241	295	536	376	115	491	45
86	246	295	541	373	132	505	36
87	252	295	547	366	145	511	36
88	261	295	556	356	137	493	63
89	270	246	516	342	109	451	65
1990	267	-	267	304	(37)	267	-
91	276	-	276	302	(26)	276	-
92	286	-	286	294	(8)	286	-
93	296	-	296	283	6	289	7
94	306	-	306	270	13	283	23
1995	317	-	317	252	18	270	47
TOTAL	4639	3786	8425	6596	1410	8006	419

- Column 1 is taken from Column 5, page 1.
- Column 2 is taken from Column 6, page 1.
- Column 4 is taken from Column 6, page 5.
- Column 5 is taken from Column 8, page 7.

EAST OF ALBERTA SUPPLY/DEMAND BALANCE

(Bcf/yr @ 1000 Btu/cf)

	DEMAND			SUPPLY			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	Canadian	Export	Total (1+2)	Net Supply East of Alberta	Alberta Surplus to East of Alberta	Total (4+5)	Deficiency (3-6)
1977	1025	277	1302	1302	-	1302	-
78	1079	276	1355	1355	-	1355	-
79	1128	277	1405	1405	-	1405	-
1980	1179	236	1415	1415	-	1415	-
81	1218	204	1422	1422	-	1422	-
82	1258	204	1462	1355	107	1462	-
83	1299	204	1503	1281	213	1494	9
84	1345	204	1549	1202	286	1488	61
1985	1393	204	1597	1131	335	1466	131
86	1440	204	1644	1071	451	1522	122
87	1493	201	1694	948	599	1547	147
88	1546	198	1744	864	604	1468	276
89	1601	187	1788	790	628	1418	370
1990	1652	134	1786	711	760	1471	315
91	1700	49	1749	630	711	1341	408
92	1753	8	1761	563	666	1229	532
93	1807	8	1815	493	591	1084	731
94	1864	8	1872	431	515	946	926
1995	1922	6	1928	381	440	821	1107
TOTAL	27,702	3089	30,791	18,750	6906	25,656	5135

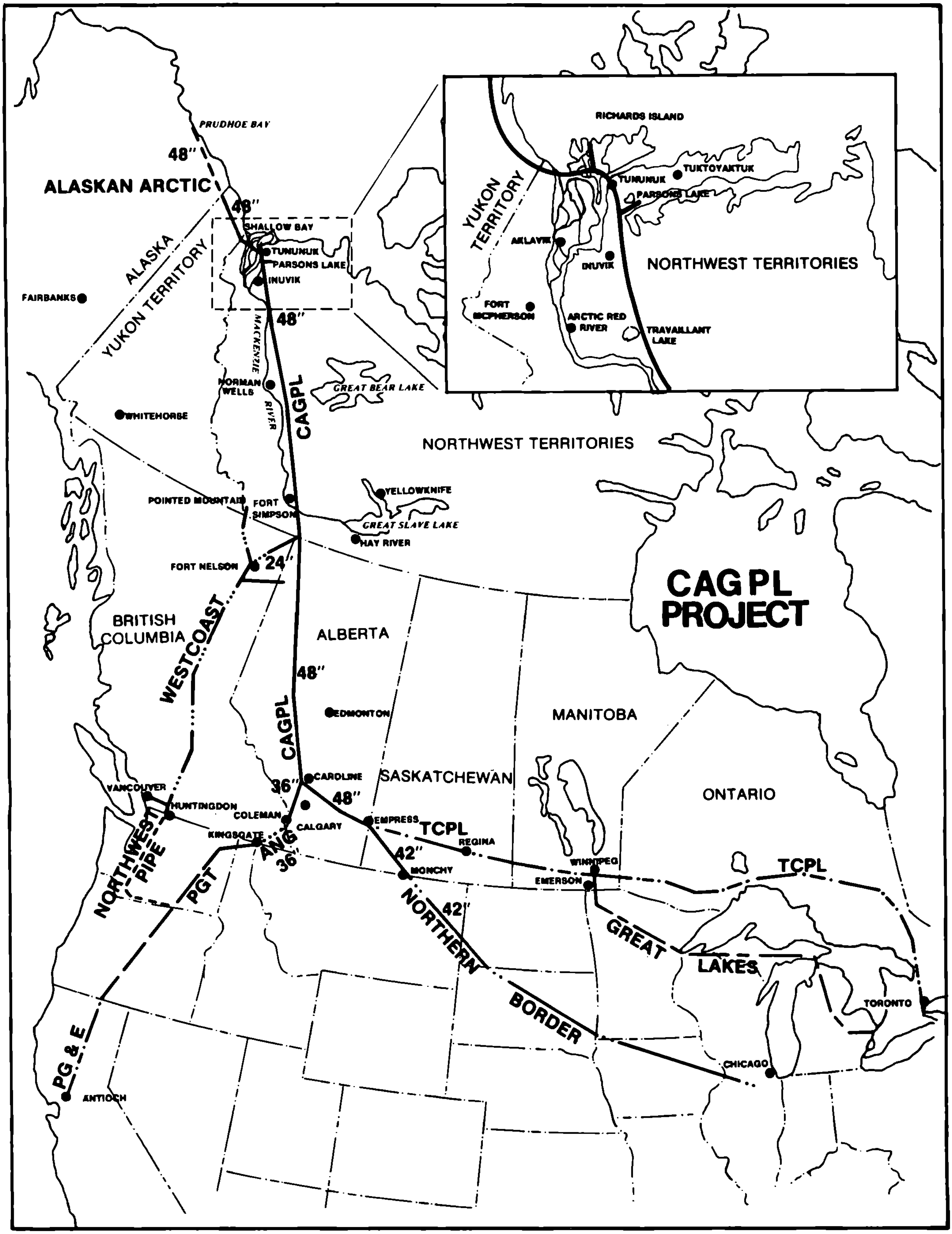
- Column 1 is taken from Column 7, page 1.
- Column 2 is taken from Column 8, page 1.
- Column 4 is taken from Column 9, page 6.
- Column 5 is taken from Column 6, page 7.

TOTAL CANADIAN SUPPLY/DEMAND BALANCE

(Bcf/yr @ 1000 Btu/cf)

	DEMAND			SUPPLY					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Domestic	Export	Total (1+2)	Total Controlled	Alberta Uncommitted	Alberta Deferred	Trend Supply	Total (4+5+6+7)	Deficiency (3-8)
Remaining Reserves at 31 December 1976				46,295	7659	4200	2800	60,954	
Total Including Trend to 31 December 1995							26,800	84,954	
1977	1695	1045	2740	2627	47	-	1	2675	66
78	1807	1044	2851	2705	134	-	12	2851	-
79	1932	1040	2972	2745	178	-	47	2970	-
1980	2073	999	3072	2763	222	-	84	3069	-
81	2146	967	3113	2743	233	26	110	3112	-
82	2217	911	3128	2600	244	26	261	3131	-
83	2282	911	3193	2450	256	26	448	3180	13
84	2354	911	3265	2341	267	26	541	3175	90
1985	2436	896	3332	2213	278	28	630	3149	183
86	2487	803	3290	2102	278	28	719	3127	163
87	2559	660	3219	1917	278	28	800	3023	196
88	2640	657	3297	1764	276	28	871	2939	358
89	2725	539	3264	1590	257	28	925	2800	464
1990	2781	215	2996	1419	240	28	964	2651	345
91	2846	124	2970	1288	223	28	988	2527	443
92	2925	55	2980	1168	210	28	993	2399	581
93	3015	46	3061	1056	190	26	989	2261	800
94	3102	8	3110	915	173	25	973	2086	1024
1995	3186	6	3192	821	157	23	950	1951	1241
TOTAL	47,208	11,837	59,045	37,227	4141	402	11,306	53,076	5967
Remaining Reserves at 31 December 1995				9068	3518	3798	15,494	31,878	

- Figures may not balance due to rounding.
- Board estimates of the remaining marketable gas reserves at 31 December 1976 which support the NEB forecasts of supply are shown at the top of Columns 4 to 8.
- The total trend additions from 1 January 1976 to 31 December 1995 are 26.8 Tcf and support the total deliverability from trend gas in Column 7. The remaining 2 of the 4.8 Tcf of trend additions in 1976 are treated as an appreciation to existing reserves and are included in the reserves base for controlled, uncommitted and deferred reserves in Columns 4, 5 and 6.
- Columns 1 to 6 inclusive are taken from Columns 9, 10 and 11, page 1; Column 11, page 3; Column 5, page 8 and Column 4, page 4 respectively.
- Column 7 is the sum of Columns 5, page 5; Column 8, page 6 and Column 6, page 8.
- The total deficiency in Column 9 includes deficiencies in British Columbia, East of Alberta and in the AGTL fuel and reprocessing requirements in Alberta to move supplies of gas east, south and west from Alberta.


CAGPL
PROJECT
PRUDHOE BAY
48"
ALASKAN ARCTIC
48"
SHALLOW BAY
TUNUNUK
PARSONS LAKE
INUVIK
ALASKA
YUKON TERRITORY
FAIRBANKS
48"
MACKENZIE
RIVER
NORMAN WELLS
GREAT BEAR LAKE
CAGPL
WHITEHORSE
NORTHWEST TERRITORIES
POINTED MOUNTAIN
FORT SIMPSON
YELLOWKNIFE
GREAT SLAVE LAKE
HAY RIVER
FORT NELSON
24"
BRITISH COLUMBIA
WESTCOAST
ALBERTA
48"
EDMONTON
CAGPL
MANITOBA
CAROLINE
SASKATCHEWAN
ONTARIO
36"
48"
VANCOUVER
HUNTINGDON
COLEMAN
CALGARY
EMPRESS
TCPL
REGINA
KINGSGATE
ANG
36"
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MONCHY
WINNIPEG
EMERSON
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NORTHWEST PIPE
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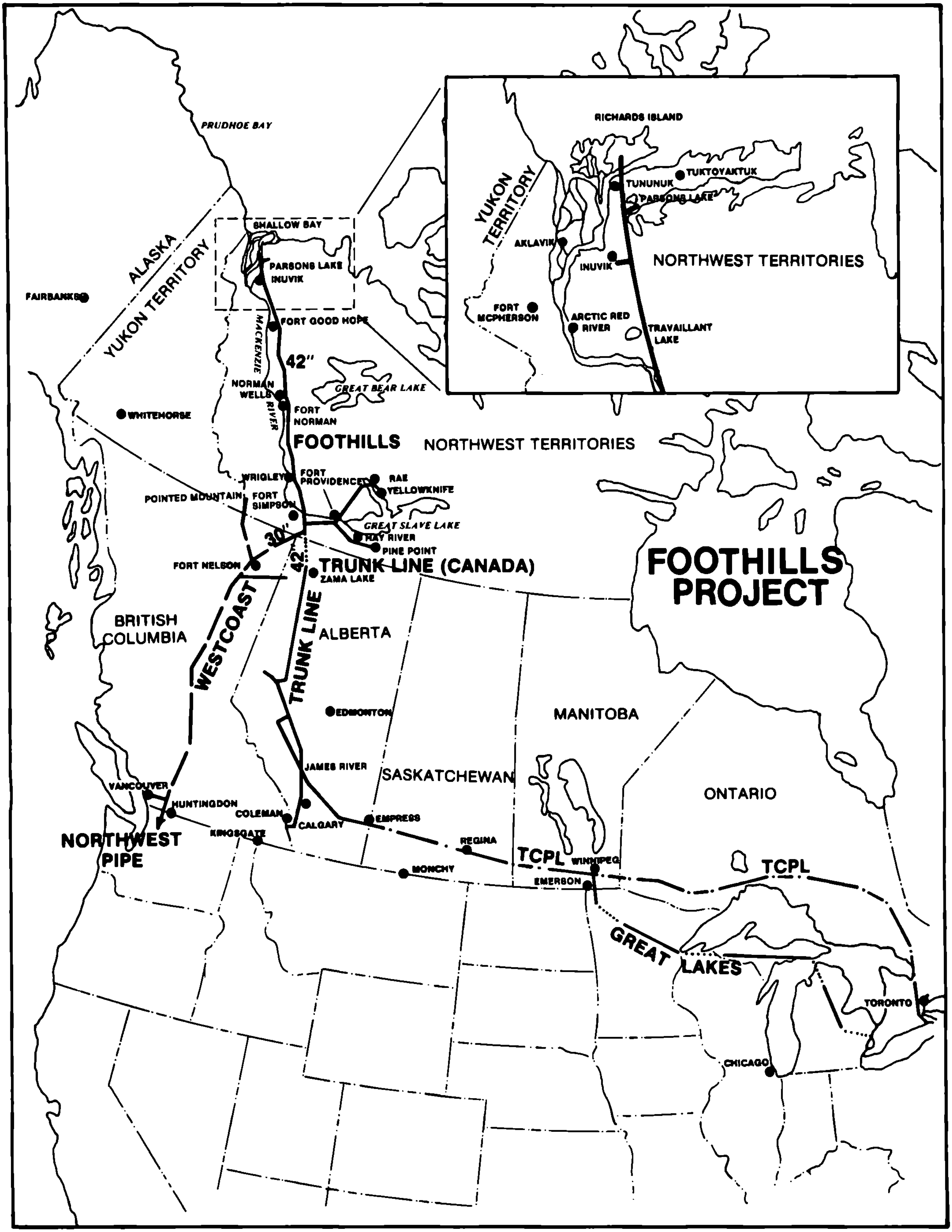
42"
GREAT
LAKES
BORDER
TORONTO
CHICAGO
PG & E
ANTIOCH
RICHARDS ISLAND
TUKTOYAKTUK
YUKON TERRITORY
TUNUNUK
PARSONS LAKE
AKLAVIK
INUVIK
NORTHWEST TERRITORIES
FORT MCPHERSON
ARCTIC RED RIVER
TRAVAILLANT LAKE


FOOTHILLS
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PRUDHOE BAY
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INUVIK
FORT GOOD HOPE
MACKENZIE RIVER
42"
GREAT BEAR LAKE
NORMAN WELLS
FORT NORMAN
WHITEHORSE
FOOTHILLS
NORTHWEST TERRITORIES
WRIGLEY
FORT PROVIDENCE
RAE
YELLOWKNIFE
POINTED MOUNTAIN
FORT SIMPSON
GREAT SLAVE LAKE
HAY RIVER
PINE POINT
30"
42"
TRUNK LINE (CANADA)
FORT NELSON
ZAMA LAKE
BRITISH COLUMBIA
WESTCOAST
ALBERTA
TRUNK LINE
EDMONTON
MANITOBA
ONTARIO
JAMES RIVER
SASKATCHEWAN
VANCOUVER
HUNTINGDON
COLEMAN
CALGARY
EMPRESS
NORTHWEST PIPE
KINGSGATE
REGINA
TCPL
WINNIPEG
MONCHY
EMERSON
TCPL
GREAT LAKES
TORONTO
CHICAGO
RICHARDS ISLAND
TUKTOYAKTUK
TUNUNUK
PARSONS LAKE
YUKON TERRITORY
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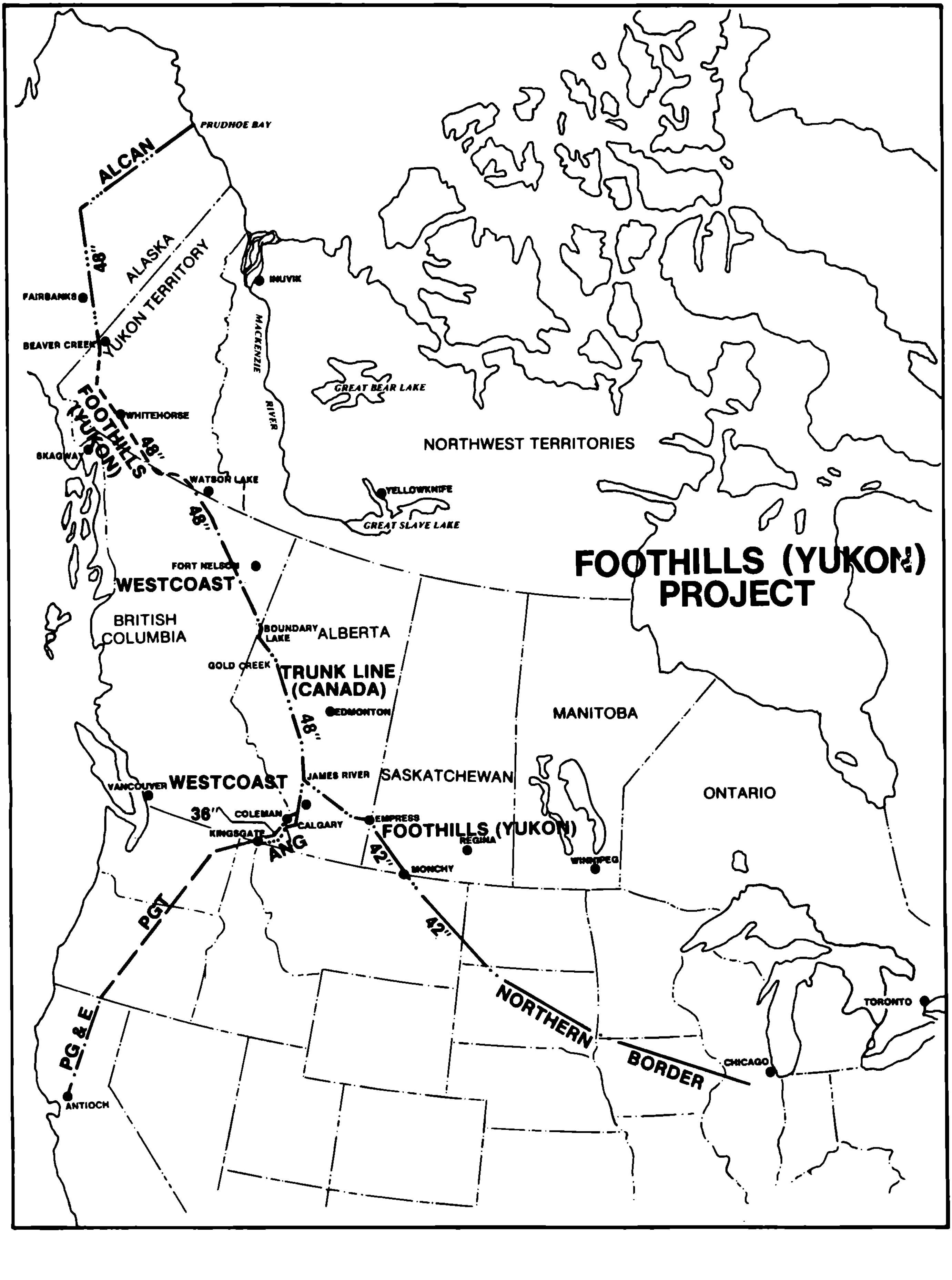
NORTHWEST TERRITORIES
FORT MCPHERSON
ARCTIC RED RIVER
TRAVAILLANT LAKE


FOOTHILLS (YUKON)
PROJECT
PRUDHOE BAY
ALCAN
48"
ALASKA
YUKON TERRITORY
FAIRBANKS
BEAVER CREEK
INUVIK
MACKENZIE
RIVER
GREAT BEAR LAKE
NORTHWEST TERRITORIES
FOOTHILLS (YUKON)
WHITEHORSE
SKAGWAY
48"
WATSON LAKE
YELLOWKNIFE
GREAT SLAVE LAKE
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FORT NELSON
WESTCOAST
BRITISH
COLUMBIA
BOUNDARY
LAKE
ALBERTA
GOLD CREEK
TRUNK LINE
(CANADA)
EDMONTON
48"
MANITOBA
JAMES RIVER
SASKATCHEWAN
ONTARIO
VANCOUVER
WESTCOAST
36"
COLEMAN
CALGARY
EMPRESS
FOOTHILLS (YUKON)
KINGSGATE
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