National Energy Board

REASONS FOR DECISION NORTHERN PIPELINES

VOLUME 2

National Energy Board

REASONS FOR DECISION
NORTHERN PIPELINES

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National Energy Board

REASONS FOR DECISION
NORTHERN PIPELINES

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ROUTE MAPS

CAGPL Project

Foothills Project

Foothills (Yukon) Project

CHAPTER 3

ENGINEERING DESIGN AND TECHNICAL FEASIBILITY

3.1 CAGPL GROUP PROJECT

3.1.1 Introduction

CAGPL

CAGPL's proposed pipeline was designed, for its Base Case, to transport a maximum of 2.25 Bcf/d of Mackenzie Delta gas to Canadian markets and 2.25 Bcf/d of Prudhoe Bay gas to United States markets in the lower 48 states. Under the No Expansion Case, where it was assumed there would be no increase in supply volumes after the second operating year, the Applicant's proposed pipeline would transport a maximum of 1.25 Bcf/d of Delta gas and 2.00 Bcf/d of Prudhoe Bay gas.

The pipeline systems in Alaska and the lower 48 states which would interconnect with the CAGPL project facilities would consist of the Alaskan Arctic, PGT and Northern Border pipelines. The proposed Alaskan Arctic facilities would consist of a 48-inch diameter pipeline from Prudhoe Bay, across the North Slope of Alaska, to the point of connection with the CAGPL pipeline at the Alaska-Yukon border; an application was filed before the FPC in respect to these facilities. The PGT pipeline system would connect near Kingsgate with the ANG pipeline in southern British Columbia. PGT has applied to the FPC to complete the looping of its existing system by the addition of 36-inch O.D. pipe. The proposed CAGPL pipeline would connect at Monchy, Saskatchewan with a 42-inch O.D. pipeline proposed by Northern Border to the FPC.

Mackenzie Delta gas would flow to Canadian markets through interconnections of the CAGPL system with Westcoast at the 60th parallel and with TransCanada at Empress.

CAGPL proposed to construct a 48-inch O.D. supply line from a point of interconnection with the proposed Alaskan Arctic pipeline on the Alaska-Yukon border (milepost 0*) running southeastward for a distance of approximately 178 miles along the Arctic coast of the Yukon and Northwest Territories, crossing Shallow Bay, to Tununuk Junction (milepost 178). A 19.3-mile, 48-inch diameter pipeline, known as the Richards Island supply lateral, would run south from the proposed Taglu gas plant and connect with the 48-inch diameter mainline at Tununuk Junction. A 24-inch O.D. line 10.75 miles in length would transport gas from the proposed Niglintgak processing plant to the north end of this supply lateral. The mainline would run south from Tununuk (milepost 0) to approximately milepost 36. A 12.5-mile, 30-inch diameter supply lateral running west from the proposed Parsons Lake processing plant would connect with the mainline at this point.

The 48-inch O.D. mainline would then continue in a southerly direction through the Northwest Territories, along the east side

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* Mileposts are approximate and do not correspond to those found in the application, where milepost numbering commences at Prudhoe Bay and then recommences at Taglu.

of the Mackenzie River, to a point just east of Fort Simpson, where the line would cross the river (milepost 663). Just north of Compressor Station MF-18 (milepost 791), about 11 miles north of the 60th parallel, there would be an interconnection with the Westcoast system.

The mainline would proceed in a southerly direction, crossing the 60th parallel (milepost 802) into Alberta and continue through the province for approximately 609 miles until it reached a point near Caroline (milepost 1411).

From Caroline, a 36-inch O.D. line would run southwest for approximately 176 miles to connect with the ANG facilities near Coleman. This CAGPL line plus the expanded facilities of ANG was referred to as the "Western Delivery Leg". Also from Caroline, the 48-inch diameter mainline would follow a southeasterly course for approximately 236 miles to a point near Empress at the Alberta-Saskatchewan border. There would be an interconnection with the TransCanada system at this point (milepost 1647).

From Empress, the 42-inch mainline would proceed south-southeast through Saskatchewan for approximately 158 miles to a point on the international boundary near Monchy, Saskatchewan, where it would interconnect with the proposed Northern Border facilities (milepost 1806). (See Map 3-1 for illustration of proposed CAGPL route.)

Various alternative routes were considered and these are discussed in Section 3.1.2 of this chapter.

United States gas volumes would be transported from the Prudhoe Bay field in Alaska through the proposed Alaskan Arctic and CAGPL facilities to (a) the ANG facilities, which would then transport these volumes to the interconnecting PGT system near Kingsgate, British Columbia, for delivery to western United States markets, and (b) Monchy, Saskatchewan, where they would be delivered to the proposed Northern Border system for transportation to eastern United States markets.

Canadian gas volumes from the Taglu, Niglintgak and Parsons Lake fields in the Mackenzie Delta area would be transported through the CAGPL pipeline facilities to connections with (a) Westcoast, to provide volumes required to help meet a shortfall in its existing commitments, and (b) TransCanada, for delivery to eastern Canadian markets.

CAGPL would be a transporter of gas owned by shippers, and not a purchaser and seller of the gas. Delivery volumes were adjusted to reflect the volumes of gas required for compressor fuel and chilling fuel which would be supplied by each shipper in proportion to its throughput in the CAGPL pipeline.

With respect to the construction of community service laterals, the Applicant's position was that it was ready, willing and able to facilitate the provision of gas to those communities where natural gas service was indicated to be a more economic means of supplying fuel to the community.

The northern section of the CAGPL pipeline would run through the continuous permafrost and the wide-spread discontinuous permafrost zones, and the gas would be chilled below 32°F in this section to prevent degradation of the permafrost. The last chiller unit would be located at Compressor Station M-12 (milepost 693), with Compressor Station MF-15 (milepost 820) being the last point of cold flow. The gas would be heated at this station. The Applicant proposed a combination of insulation and heat probes/heat tracing to mitigate possible frost heave problems in this area.

The pipeline route would traverse the scattered discontinuous permafrost zone from Station MF-15 to approximately Zama Lake. Special geotechnical design criteria were applied in this area and are discussed in detail in Section 3.1.3.2 of this chapter. The remainder of the line south of Zama Lake would generally be located in the non-permafrost zone, and traditional design criteria were applied.

CAGPL planned to hydrostatically pressure test its pipeline in order to permit a maximum operating pressure equal to 80 per cent specified minimum yield strength. The design parameters of the various sections were as follows:

DESIGN CHARACTERISTICS OF CAGPL PIPE

	O.D. (inches)	Wall Thickness (inches)	CSA Grade	Maximum Allowable Operating Pressure (psig)
Mainline				
Alaska-Yukon Border				
to Empress	48	0.720	70	1680
Empress to Monchy	42	0.630	70	1680
Western Delivery Leg				
Caroline to Coleman	36	0.464	70	1440

It was proposed that major pipeline construction from Prudhoe Bay to Caroline would be completed over the three winter seasons of 1979/80, 1980/81 and 1981/82, using Arctic construction techniques for the portion of the line north of 65 degrees north latitude. Summer construction would be used for the portion south of Caroline and for some river crossings. By the addition of compressors, maximum throughput would be reached in the fifth operating year for the Base Case or in the second operating year for the No Expansion Case. It was proposed that Delta gas would come on stream first, in July 1982, with Prudhoe Bay gas coming on stream in July 1983. The construction schedules of the companion applications in this project would be consistent with that of CAGPL.

The following table shows the ultimate projected throughput volumes for the CAGPL system:

CAGPL

ULTIMATE PROJECTED THROUGHPUT VOLUMES

	BASE CASE	NO EXPANSION CASE
SUPPLY		
Alaskan Gas	2,250.0	2,000.0
Mackenzie Delta Gas		
- Niglintgak	315.0	175.0
- Taglu	1,260.0	700.0
- Parsons Lake	675.0	375.0
Total Mackenzie Delta Gas	2,250.0	1,250.0
Total Supply	4,500.0	3,250.0
DISPOSITION		
Alaskan Gas Deliveries		
- to ANG	686.0	616.8
- to Northern Border	1,525.9	1,374.7
Total Deliveries - Alaskan Gas	2,211.9	1,991.5
Mackenzie Delta Gas Deliveries		
- to Westcoast	354.7	248.3
- to TransCanada	1,678.4	892.7
Total Deliveries - Mackenzie Delta Gas	2,033.1	1,141.0
Total Fuel - Alaskan Gas and Mackenzie Delta Gas	255.0*	117.5*
Total Disposition - Alaskan Gas and Mackenzie Delta Gas	4,500.0	3,250.0

*NOTE: NEB Estimate of Fuel Used:

	BASE CASE	NO EXPANSION CASE
Alaskan Gas	138.9	78.6
Mackenzie Delta Gas	116.1	38.9

The estimated total construction costs of the CAGPL facilities were $8,989,743,000 to the end of the fifth operating year (31 October 1987) for the Base Case, or $7,925,434,000 to the end of the second operating year (31 October 1984) for the No Expansion Case (1976 dollars escalated to the year of expenditure).

Westcoast

CAGPL proposed, as part of its project, to deliver gas to the Westcoast system just north of the 60th parallel. Westcoast, though a member of the Foothills and Foothills (Yukon) groups, filed material to reflect a connection with the CAGPL system in the event that the CAGPL application should be approved.

Westcoast's proposal applied to only those facilities required for the first year of flow. This was due to the fact that Westcoast is an operating company with other sources of supply, and it felt it was very difficult, at this time, to predict exactly what facilities would be required in future years.

From CAGPL's Compressor Station M-18, Westcoast proposed to construct a new 24-inch O.D. line proceeding southwest for 141.1 miles to connect with its existing Fort Nelson mainline near Fort Nelson, British Columbia. This new line would be known as the Territories Mainline Extension, and would be constructed of 0.402-inch wall thickness, Grade 70 pipe, and operated at its design pressure of 1680 psig. (See Map 3-1)

In addition, 201.1 miles of 36-inch O.D. loop, of 0.390-inch and 0.469-inch wall thickness Grade 60 pipe, and other related facilities would be added to the existing mainline system to accommodate first year volumes, and would be operated at a pressure to conform to that of the existing system, some 936 psig. Based on Westcoast's assumption that it would receive a maximum volume of 545 MMcf/d from CAGPL under winter conditions, compression totalling 40,000 horsepower (20,000 horsepower at each of stations 4A and 4B) would be added in the summer of 1982.

Westcoast estimated that the costs of the facilities required to be constructed by it for the first year volumes would be $346,220,000 (1976 dollars escalated to the year of expenditure).

Alberta Natural

Alberta Natural proposed to transport Prudhoe Bay gas volumes received from the CAGPL system at the point of interconnection just east of the Alberta-British Columbia border near Coleman, Alberta, to a point on the Canada-United States international boundary near Kingsgate, British Columbia, for delivery to United States markets through the PGT system. (See Map 3-1)

ANG would transport gas for shippers on a contractual basis, and fuel would be provided to the pipeline by the shippers in proportion to their throughput in the line.

In order to accommodate the Prudhoe Bay gas volumes, ANG proposed to complete the looping of its existing system by the addition of 102.2 miles of 36-inch O.D., Grade 65 pipe. This additional looping would be operated at a pressure of 911 psig to conform with the operating pressure of the existing facilities. Alberta Natural also planned to expand its Kingsgate meter station and modify the existing compressor stations.

Pipeline construction would take place between 1 February

1981 and 1 January 1982, with the meter station expansion and the compressor station modifications being completed in the period 1 February to 1 July 1982.*

The estimated costs of the required ANG facilities were $74,321,000 (1976 dollars escalated to the year of expenditure). These costs assumed first gas flow in 1982 and they would be higher if the proposed first gas flow in 1983 were reflected.

TransCanada

TransCanada has not as yet made an application to the Board for the additional facilities it would require to transport Mackenzie Delta gas volumes received from CAGPL. This is due to the fact that TCPL is an operating company with other sources of supply, and it felt that it was difficult to predict at this time exactly what facilities would be required for northern gas volumes. The company did, however, make a submission to the Board indicating the facilities that would probably be required.

TCPL would be a shipper in the CAGPL project. It would receive gas from the CAGPL system near Empress, and deliver it to eastern Canadian customers. In order to accommodate the Mackenzie Delta volumes, looping, compression and related facilities would be added to the existing TCPL system. (See Map 3-1) A total of 444.4 miles of 42-inch O.D. line would be added to the Western Section; 888.0 miles of 36-inch O.D. line would be

---

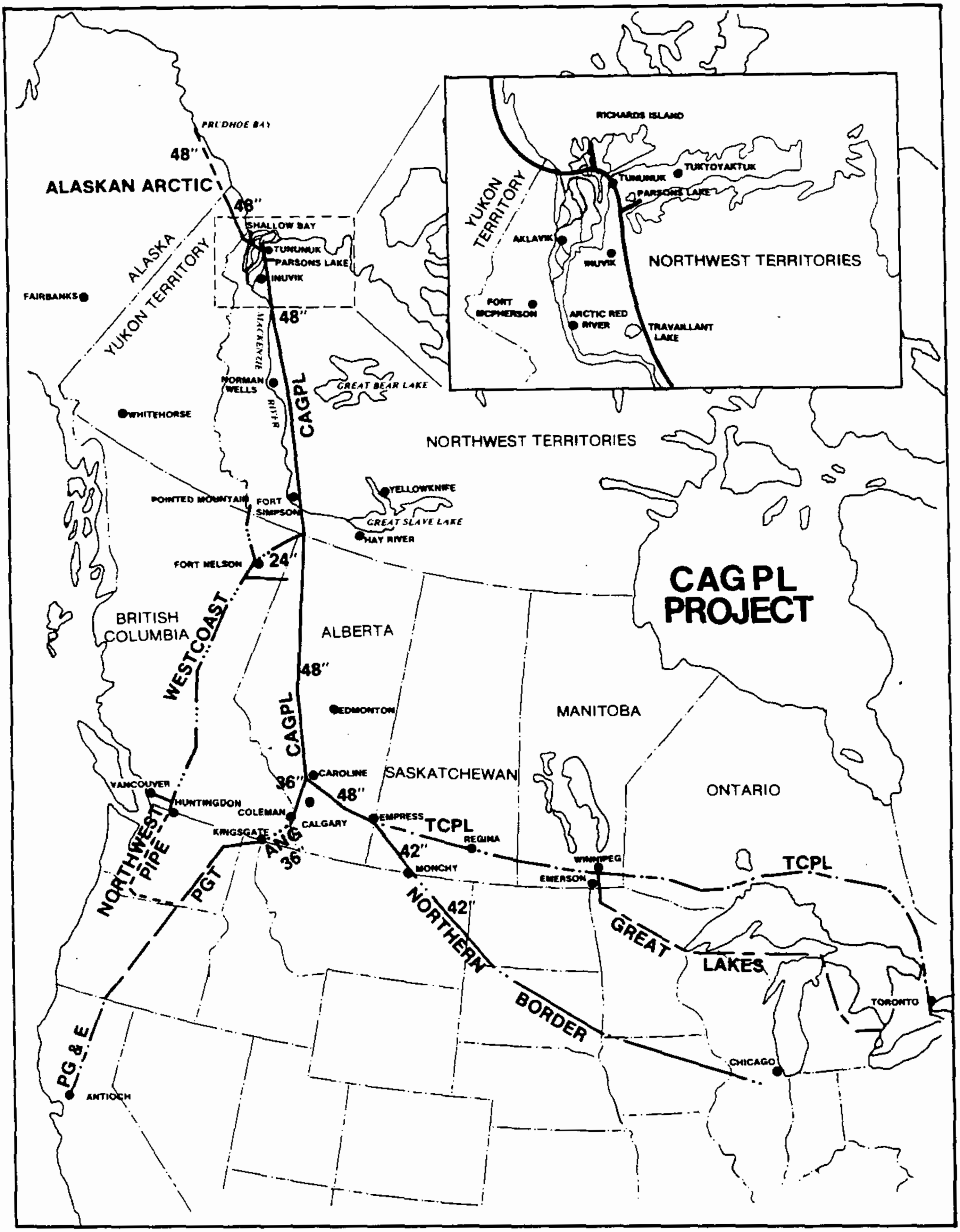
* ANG did not file revised information to take account of the delay in the first flow of Prudhoe Bay gas through the CAGPL system, i.e. delayed to July 1983.

added to the Central Section; 134.4 miles of 24-inch O.D. line would be added to the Montreal line; 40.1 miles of 24-inch O.D. line would be added to the Niagara Extension; and 33.6 miles of 16-inch O.D. line would be added to the St. Mathieu line. Compression would be added as required, for a total addition of 719,800 horsepower by 1986.

The construction of these facilities would be scheduled so as to conform with the CAGPL delivery schedule.

The costs of the facilities required to accommodate the Mackenzie Delta gas volumes were estimated to be $1,514,525,000 (1976 dollars escalated to the year of expenditure). These costs assumed first gas flow in 1981 and they would be higher if the proposed first flow of Delta gas in 1982 were reflected.

MAP 3-1



PRUDHOE BAY
48"
ALASKAN ARCTIC
48"
SHALLOW BAY
TUNUNUK
PARSONS LAKE
INUVIK
ALASKA
YUKON TERRITORY
FAIRBANKS
48"
MACKENZIE RIVER
NORMAN WELLS
CAGPL
GREAT BEAR LAKE
WHITEHORSE
NORTHWEST TERRITORIES
YELLOWKNIFE
POINTED MOUNTAIN
FORT SIMPSON
GREAT SLAVE LAKE
HAY RIVER
FORT NELSON
24"
CAGPL PROJECT
BRITISH COLUMBIA
WESTCOAST
ALBERTA
48"
EDMONTON
CAGPL
MANITOBA
CAROLINE
SASKATCHEWAN
ONTARIO
36"
48"
VANCOUVER
HUNTINGDON
COLEMAN
CALGARY
EMPRESS
TCPL
KINGSGATE
REGINA
ANG
42"
36"
WINNIPEG
TCPL
MONCHY
EMERSON
NORTHWEST PIPE
PGT
NORTHERN
42"
GREAT
LAKES
BORDER
TORONTO
CHICAGO
PG & E
ANTIOCH
RICHARDS ISLAND
TUKTOYAKTUK
TUNUNUK
PARSONS LAKE
YUKON TERRITORY
AKLAVIK
INUVIK
NORTHWEST TERRITORIES
FORT MCPHERSON
ARCTIC RED RIVER
TRAVAILLANT LAKE

3.1.2 Alternative Routes

CAGPL examined the following six basic pipeline routings in Alaska and northwestern Canada (see Map 3-2):

I Prime Route, or Cross-Delta Route (as applied for);

II Circum-Delta Route;

III Interior Route;

IV Offshore Route;

V Fairbanks Corridor; and

VI Fort Yukon Corridor.

Of the above-mentioned alternatives, the Prime Route, Circum-Delta Route, Interior Route, and the Offshore Route utilized the Mackenzie Valley corridor and deviated from each other only in regard to the portion of line from Prudhoe Bay, Alaska, east through Alaska and the Yukon Territory to the junction with the Mackenzie Valley line which would run south from the Mackenzie Delta along the east side of the Mackenzie River and into Alberta.

The Fairbanks Corridor and the Fort Yukon Corridor routes did not use the Mackenzie Valley corridor, but instead followed different routes south from Prudhoe Bay through Alaska, the Yukon, and northern British Columbia, and connected with the Prime Route in southern Alberta. Both of these alternatives would require a supply line along the Dempster Highway to attach the Mackenzie Delta reserves.

Description of Alternatives

I **Prime Route** - This Cross-Delta Route was the one applied for by CAGPL and it is described in detail in the Introduction Section of this Chapter.

II **Circum-Delta Route** - This route would depart from the Prime Route at milepost 290.6 near Shingle Point, where it would proceed in a southeasterly direction around the Mackenzie Delta, passing north of Fort McPherson, crossing the Mackenzie River just north of Arctic Red River and joining the line from Delta producing areas at a point near Travaillant Lake. From this point, the line would proceed south along the east side of the Mackenzie River Valley following basically the same route as the Prime Route.

III **Interior Route** - The Interior Route differed from the Prime Route only for that portion of line from Prudhoe Bay to the junction of the Delta supply line in Canada. The Interior Route would not follow the Coastal Plain in Alaska but instead would run southeast from Prudhoe Bay, through the Brooks Mountain Range, for approximately 297 miles to the Alaska-Yukon border. The pipeline would veer east shortly after leaving the Brooks Range, cross the border just northeast of Old Crow, Yukon, and run southeast for approximately 178 miles along the south edge of the Old Crow Flats, across the Richardson Mountains and follow the same path as the Circum-Delta Route for the 60 miles from Fort McPherson to Travaillant Lake, where it would join with the supply line from the Delta producing areas.

IV **Offshore Route** - The Offshore Route was an option which included an underwater pipeline which would roughly parallel the Arctic coastline and the Prime Route. The Offshore Route would be onshore for approximately 64 miles running east from Prudhoe Bay; it would then enter the Beaufort Sea and parallel the coastline for approximately 100 miles until it returned to the onshore mode at a point approximately eight miles east of the Alaska-Yukon border. Another 11 miles east of this point, the pipeline would follow the same route as that proposed for the Prime Route across the Delta and down the Mackenzie Valley.

V **Fairbanks Corridor** - The pipeline would run south from Prudhoe Bay through the Brooks Mountain Range generally paralleling the route of the Alyeska oil pipeline, to the vicinity of Fairbanks, Alaska. Bypassing Fairbanks to the northwest, the route would follow the Richardson/Alaska Highway to Big Delta Junction, where it would follow the route of the Alaska Highway to the Alaska-Yukon border at a point near Scottie Creek. The route in Canada would generally follow the Alaska Highway from the Alaska-Yukon border to Dawson Creek, British Columbia. From Dawson Creek, the corridor would proceed southeasterly to join the Prime Route at milepost 1282, just west of Windfall, Alberta.

Since this corridor would not pass by the Mackenzie Delta gas producing areas, a separate supply line would be required from the Delta to connect with this corridor. This gas supply line would commence on Richards Island and follow the east side of the Mackenzie Delta to Campbell Lake. From this point, it would follow the Dempster Highway to Fort McPherson and across north-central Yukon to just east of Dawson. It would then follow the existing Klondike Highway to Whitehorse to join the Alaska supply line from Prudhoe Bay.

VI **Fort Yukon Corridor** - This corridor was the same as the Fairbanks Corridor for the first 110 miles south of Prudhoe Bay. At this point, the pipeline would turn southeast to the confluence of the Porcupine and Yukon Rivers near Fort Yukon, Alaska. It would continue southeasterly along the Yukon River to cross the Alaska-Yukon border near Eagle, Alaska. From Eagle, the line would follow the Yukon River to Dawson, then the territorial highway to Pelly Crossing, where it would head directly to Watson Lake via the Pelly and Liard River Valleys. From Watson Lake, the corridor would follow the same route as the Fairbanks Corridor down to Windfall, Alberta.

This route would also require a separate Mackenzie Delta gas supply line identical to that described for the Fairbanks Corridor except it would join the Alaska supply line at Dawson.

VII **Other Corridors**

(a) In the early stages of pipeline planning, CAGPL proposed to construct the pipeline along the west side of the Mackenzie River. It was originally thought that this would place the line closer to potential future natural gas discoveries in the Eagle, Peel and Mackenzie Plains sedimentary basins. Subsequent exploration and drilling activities in these areas were not encouraging. Following the discovery of natural gas in the Mackenzie Delta and the announced location of the proposed Mackenzie Highway, and taking into account the more difficult terrain along the west side of the Mackenzie, the route was relocated to the east side of the river and the corridor on the west side was abandoned.

(b) Another alternative which was studied briefly by the Applicant was a route which departed from the Prime Route in the Northwest Territories just north of the Alberta border and crossed Alberta, Saskatchewan and Manitoba to a point on the international boundary near Emerson, Manitoba. This alternative would also have required a segment of pipeline running southwest from a point on the mainline near Cold Lake in Alberta to the international boundary at Kingsgate, British Columbia.

The Applicant rejected this route because the United States gas pipeline companies serving areas east of the Rocky Mountains expressed a desire to take gas at a border point in Montana rather than in Minnesota and because the Prime Route provided for multiple connections with Trunk Line, with TCPL at Empress, Alberta, and with ANG at the Alberta-British Columbia border.

(c) During cross-examination, it was pointed out that an alternative route making use of the Trans-Canada system from Empress to Emerson and tying into the Great Lakes system in Minnesota was briefly examined as an initial route. There seemed to be no economic advantage to this alternative. Therefore, it was decided that, because of the possibility of coal gasification plants being built along the route in the United States and the fact that it crossed what were felt to be less environmentally sensitive lands, the routing from Empress, Alberta, to the market areas in the Chicago, Illinois area via a connection to the Northern Border pipeline at Monchy, Saskatchewan was considered to be superior.

Comparison of Alternatives

The Applicant examined each of the alternative routes from the following standpoints:

(i) route characteristics;

(ii) location relative to areas of potential gas reserves;

(iii) system configuration and design;

(iv) construction;

(v) operations and maintenance;

(vi) costs; and

(vii) environmental impact.

All studies were based on the fact that gas would be shipped from Prudhoe Bay, Alaska, as well as from the Mackenzie Delta region.

The factors which were used to determine the six basic alternatives included the overall length of the line, the ease or difficulty of construction, and environmental issues, but, as was pointed out by the Applicant, the ultimate choice was based on cost considerations.

I **Prime Route** - As described in Section 3.1.1.

II **Circum-Delta Route** - As mentioned previously, this route was the one originally applied for and deviated from the Prime Route only in that it would go around the southern edge of the Mackenzie Delta instead of across the northern edge. This route would add approximately 103 miles of pipeline to the system. This increased length and location of the line was the major difference between the Cross-Delta and the Circum-Delta Routes. It was felt by the Applicant that both routes could be constructed, even though the Cross-Delta Route had potential impact on the beluga whales, the caribou and the snow geese migratory patterns, and that the impact could be controlled and construction carried out only during times of minimal disturbance to the mammals, fish and birds. Therefore, the main consideration for changing to the Cross-Delta Route from the Circum-Delta Route was one of potential cost saving, as the Cross-Delta Route was shown to be slightly less expensive.

III **Interior Route**

(i) Routing - As previously described, the Interior Route would run in a more southerly direction than the Prime Route from Prudhoe Bay, in order to avoid the Arctic National Wildlife Range in Alaska. Two options were studied for specific alignments just south of the Arctic National Wildlife Range. These options were the "Marsh Fork Option" which followed the Marsh Fork of the Canning River for 35 miles, and the "Canning River Option" which followed the main branch of the Canning River for 30 miles. While the Canning River option appeared to the Applicant to be environmentally more acceptable and would involve less difficult construction and less cost, it would run partially within the boundaries of the Arctic National Wildlife Range, while the Marsh Fork option would be entirely outside the Range.

(ii) Location Relative to Areas of Potential Gas Reserves - The Interior Route would leave the Arctic Slope area, the area of top gas prospects, at approximately mile 20. This route would pass approximately 130 miles north of centre of the Kandik Basin, ranked second as a producing prospect in northern and central Alaska, but not considered comparable to the Arctic Slope in gas prospects. No successful wells had been drilled in the Kandik Basin. Other Alaska prospects would be far south of this route.

In Canada, this route would pass through the Mackenzie Delta-Beaufort Basin and also the Eagle Plain Basin on the west side of the Richardson Mountains. Oil and gas had been encountered in these areas and further exploration was expected.

(iii) System Configuration and Design - The Interior Route would use the same size and quality of pipe as that specified for the Prime Route. The length of the Interior Route, however, would be 538 miles (Marsh Fork Option) or 533 miles (Canning River Option) compared with 492 miles for the Prime Route from Prudhoe Bay to their common intersection with the Delta line at Travaillant Lake. Other design factors were common.

(iv) Construction Considerations - Construction of facilities along the Interior Route would be accomplished within the same overall time frame as for the Prime Route. The difference in construction plans between the Interior and Prime Routes occurred where the routes were different between Prudhoe Bay and the Mackenzie Delta, as follows:

- Six, rather than eight construction spreads would be required for the total system.
- Construction in Alaska would be completed over two summers and two winters whereas the Prime Route utilized three spreads over one winter construction season. These differences in construction plans in Alaska were due to the greater quantity of bedrock along 20 miles of the Interior Route.
- Construction in Canada would be completed by four spreads in one winter instead of by five spreads in one winter as required for the Prime Route.
- Logistics functions associated with the Interior Route depended extensively on land transport rather than on barge transport, as proposed for the Prime

Route, thus requiring the construction of some long access roads. It was estimated that the logistics costs for the Interior Route would be 40 per cent higher than for the Prime Route for the portion of line between Prudhoe Bay and the Mackenzie Delta.

Construction resources required for all project facilities along the Interior Route in Canada would be less in most respects than for the Prime Route, but greater in Alaska. Construction and field pressure testing procedures would be generally the same as for the Prime Route.

Major geotechnical considerations for pipeline construction through the Interior Route were related to erosion and slope stability in mountains and foothills, construction on high ice content soils and the use of these soils for backfill, significant amounts of excavation in bedrock, and construction near water courses subject to laterally shifting channels; therefore, the Applicant reached the conclusion that the Interior Route had a greater range of construction problems than the Prime Route. Both routes would pass through high ice content soils, but considerable lengths of ditch excavation in bedrock were anticipated along the mountainous Interior Route. Much of this bedrock was said to be deeply weathered. Erosion and soil stability would be of most concern along the Interior Route.

(v) Operations and Maintenance Considerations - A preliminary plan developed by the Applicant for operations and maintenance of the facilities on the Interior Route was similar to that developed for the Prime Route but would require a significantly greater performance effort due to the increased length of the pipeline and to the topography and consequent difficulties of access and travel in the mountainous terrain traversed by the Interior Route. It was estimated that the performance effort required for operations and maintenance of the Interior Route would be in the order of 1.15 times the effort required for the Prime Route, even though the mileage ratio was only 1.092 for the Interior Route over the Prime Route.

(vi) Cost Considerations - When compared to the Prime Route, the Interior Route was shown to be considerably more expensive. This was directly attributed to a longer, more rugged route and to a greater amount of heavy wall pipe in Alaska.

(vii) Environmental Factors - After extensive studies, the Applicant determined the following general advantages and disadvantages of the Interior Route as compared with the Prime Route with respect to environmental impact:

- The Interior Route would cross much less productive waterfowl and shorebird habitat than the Prime Route, which would cross the

Arctic coastal plain, one of the most significant waterfowl and shorebird nesting, moulting, staging and migratory areas in Alaska and northwest Canada.

- Both routes would pass close to known raptor sites but it was felt the Prime Route offered more freedom for lateral movement or realignment of the pipeline away from the nest sites.
- The Interior Route would skirt the Old Crow Flats, the known habitat for numerous mammals and birds.
- The Interior Route would pass through valley bottoms by necessity, and this would have the potential of disturbing the riparian habitat in these areas and, consequently, the birds dependent on this habitat.

IV **Offshore Corridor** -

(i) Routing - As mentioned previously, the main difference between this route and the applied for Prime Route was approximately 160 miles of underwater pipeline paralleling the coast of Alaska and the Yukon in order to miss the Arctic National Wildlife Range in Alaska. The Applicant chose to examine a route in shallow waters where the water depths ranged from 20 to 30 feet. This location would offer a compromise between length of summer construction season, ice scour problems, construction difficulties and the avoidance of aquatic and bird life.

(ii) Location Relative to Areas of Potential Gas Reserves - Since any offshore route would roughly parallel the Prime Route, it would have access to the same areas of potential production of natural gas as would the Prime Route, with some variations in gathering problems.

(iii) System Configuration and Design - The offshore routing would use the same size and quality of pipe as specified for the Prime Route and the basic horsepower that would be installed at each compressor station would be the same. It was assumed that compressor stations would be constructed onshore and suction and discharge lines would be brought onshore from the offshore line. The same number of compressor stations would be required for the original design throughput and, if the system were to be expanded, the same number of additional compressor stations would be required for the Offshore Route as for the Prime Route.

(iv) Construction Considerations - Only the western portion of the Offshore Corridor was different from the Prime Route; that is, the routes were identical except for the portion in Alaska and approximately the first 20 miles in Canada. The onshore portions of the route not identical to the Prime Route were located mostly in topography very similar to the

Prime Route. The onshore sections would be constructed during the winter months using pipe from stockpile sites at Prudhoe Bay and Komakuk. Some onshore work would be required in association with the portions of offshore lines laid in shallow waters. Sections could be welded together on shore and pulled seaward, or welded on barges and pulled landward after the necessary excavation was completed. Studies carried out by the Applicant showed that conventional offshore pipe-laying techniques were feasible for the area under consideration but were limited to the summer construction season. The techniques evaluated were:

- the lay barge method;
- the bottom pull method; and
- the floating string method.

The lay barge method was the prime candidate for laying 48-inch diameter pipe in the Beaufort Sea. The maximum length of pipeline which could be installed by the bottom pull method in a single pull was said to be limited to seven to eight miles, based on the capacity of pulling equipment, the allowable pipe tension and the weight of the line. The bottom pull method would have applications for shore approaches and lines to and from onshore compressor stations.

The floating string method, as used currently, was considered risky. A modified flotation method was evaluated, but the technique required further evaluation and testing to verify the concept.

New pipe-laying techniques, such as laying pipe through a slot cut in the ice or making use of air-cushioned supported barges, would require extensive development and testing before the practicality of these concepts could be determined. Overall, the availability of pipelaying equipment, including lay barges, to handle 48-inch diameter pipe in ice-prone water, was anticipated to be a problem.

(v) Operation and Maintenance Considerations - The most critical problem which might have to be confronted by an Arctic offshore pipeline operator would be in the area of maintenance of the line, and especially in the repair of any malfunction or damage.

The main problems associated with offshore construction in the Arctic would be the possibility of extreme loads on the pipeline, such as from the grounding of large ice masses, and limited access for maintenance.

If the pipe were buried below the deepest ice scour, the probability of having an ice mass ground and produce a direct impact on the pipe would be very remote. In the event of an unusually large ice island approaching the general area of the pipeline, it was felt that once identified by ice reconnaissance the island could be towed away or blasted apart.

Successful pipeline repairs could be accomplished by adaptations of proven devices such as split sleeves, repair clamps or welding. It was felt that with additional special equipment, the maintenance access period in this area could be seven to eight months per year. It was felt that any type of repair during the break-up or freeze-up periods would appear not to be feasible.

(vi) Cost Considerations - When compared to the Prime Route, the Offshore Route was shown to be significantly more expensive. However, since no offshore project of this magnitude or in such harsh environment had previously been attempted, there was no baseline available for reference. This situation, along with the paucity of field data, caused CAGPL to place a lower level of confidence in the estimate than for the other alternatives disçussed. The main reasons for the extra costs were:

- approximately nine miles of additional 48-inch diameter pipeline;
- higher installation charges;
- concrete coating required for all offshore pipe; and
- different installation schedules, which would change the interest during construction.

(vii) Environmental Impact - The impact of the Offshore Corridor would be basically the same as for the Prime Route but with the added potential disturbance to fish, whales and seals due to the offshore construction.

V **Fairbanks Corridor -**

(i) Route - As described previously, the Fairbanks Corridor would be completely different from the Prime Route to Windfall, Alberta.

(ii) Location Relative to Areas of Potential Gas Reserves - As indicated in the discussion of the Interior Route, the major hydrocarbon producing basins in Alaska and northwestern Canada are the Arctic Slope and the Mackenzie Delta-Beaufort Basin. The Fairbanks Corridor would not pass through the Arctic Slope but instead proceed south out of the area. The Delta extension to the Fairbanks Corridor would traverse approximately the same portions of the Mackenzie Delta as would the Prime Route, and pass through the Eagle Plain Basin where some oil and gas discoveries have been made. In Alaska, the Fairbanks Route would pass through the Middle Tanava Basin and be closer to the Copper River area and Kandik Basin, all of which could contain hydrocarbon reserves. CAGPL stated that there had been no finds in these areas and, therefore, they were classed as areas of low potential.

(iii) System Configuration and Design - The Fairbanks Corridor pipeline was designed on the same basis as the Prime Route. It was assumed that each supply line would be 48 inches in diameter. From the junction of the supply lines near Whitehorse to the bifurcation point near Caroline, Alberta, there would be a single 48-inch diameter line. The basic design features would be the same as for the Prime Route.

In order to carry 2.25 Bcf/d in each supply line, the compression build-up would be as follows:

CAGPL

Compression Requirements

Operating Year	1	2	3	4	5
Number of Stations Required					
Prime Route	9	17	30	37	41
Fairbanks Corridor	7	19	32	37	41
Horsepower Required (000's HP)					
Prime Route	395	770	1200	1510	1630
Fairbanks Corridor	360	845	1360	1610	1750

(iv) Construction Considerations - The construction of the Fairbanks Corridor would involve an additional

900 miles of pipeline construction beyond the mileage required for the Prime Route. There would be the advantage that a considerable portion of the construction of this line could be carried out in the summer since the line would traverse mountainous terrain. However, the Applicant believed that the longer distance coupled with the more difficult mountain terrain made the degree of confidence, that this route could be constructed over the indicated period, much less than in the case of the Prime Route. The Applicant made the assumption, though, that both routes could be constructed over the same time period. The highway system from north of Fairbanks to Prudhoe Bay, installed for the construction of the Alyeska oil pipeline in Alaska, would be in service for the construction of the Applicant's gas pipeline. This, along with the Alaska Highway, would provide all-weather road access near, or adjacent to, the Prudhoe Bay supply line. Materials and equipment could be brought to points near the right-of-way by road through the deep sea ports of Anchorage, Valdez, Skagway and Stewart, as well as by barge to Prudhoe Bay. The most difficult segment to service would be the Delta supply line between Fort McPherson and Dawson. If the Dempster Highway were completed prior to pipeline construction, this problem could be alleviated.

The Fairbanks Corridor routing would have about 400 miles within the continuous permafrost zone and about 1,800 miles in the discontinuous zone. By comparison, the Prime Route would have corresponding mileages of 700 and 800. A great deal of the 1,800 miles on the Fairbanks Corridor in the discontinuous zone would be in mountainous terrain; therefore, there would be lesser quantities of high ice content soils. The potential for slide failures in the mountainous regions would be greater than along the Prime Route. Granular material requirements would be similar in total for both routes, but the availability would be greater for the Fairbanks Corridor.

(v) Operations and Maintenance Considerations - It was concluded that a pipeline through the Fairbanks Corridor would not present maintenance problems of greater difficulty than those anticipated for similar segments within the Prime Route. But, it was felt the performance effort for operations and maintenance of a pipeline within this corridor would be substantially larger than that for the Prime Route, due mainly to the additional 920 miles of pipeline and the mountainous terrain traversed. Major surveillance and maintenance work would be associated with control of soil erosion at water-course boundaries, and on steep grades and unstable slopes.

(vi) Cost Considerations - A comparison of costs between the Prime Route and the Fairbanks Corridor indicated that the latter would be considerably more expensive. The basic difference in the costs was due to the increased length of the Fairbanks Corridor and the corresponding increased requirement for manpower, equipment and other related materials.

(vii) Environmental Impact - According to the Applicant, the Fairbanks Corridor option had no great environmental concerns, but the required lateral from the Delta along the Dempster Highway would have an adverse environmental impact on the winter range of the caribou.

VI **Port Yukon Corridor -**

(i) Route - As described previously, the Fort Yukon Corridor was similar to the Fairbanks Corridor in that it proceeded south from Prudhoe Bay before turning east and into Canada. The separate supply line from the Delta down the Dempster Highway was also required in this alternative. Basically, the Fort Yukon Corridor would lie north of the Fairbanks Corridor in Alaska and the western Yukon.

(ii) Location Relative to Areas of Potential Gas Reserves - Similar to the Fairbanks Corridor, the Fort Yukon Corridor would move south out of the Arctic Slope area, the area of greatest potential for hydrocarbon reserves. The Fort Yukon Corridor would pass through the Kandik Basin and be closer than the Prime Route to the Middle Tanava and Copper River Basins; all of these areas were considered possible hydrocarbon areas but there had been no discoveries. The Mackenzie Delta extension would go through the Eagle Plain Basin as in the case of the Fairbanks Corridor.

(iii) System Configuration and Design - The Fort Yukon Corridor pipeline system was designed on the same general basis as the Prime Route. There would be two 48-inch diameter supply laterals, the junction being at Dawson in the Yukon. From Dawson, a single 48-inch diameter line would be required to the bifurcation point near Caroline, Alberta. The pipe would have the same quality and characteristics as for the Prime Route, and the basic design features of the system would be the same.

The horsepower requirements as compared with the Prime Route and based on 2.25 Bcf/d fifth year volumes are as follows:

CAGPL

Compression Requirements

Operating Year	1	2	3	4	5
Number of Stations Required					
Prime Route	9	17	30	37	41
Fort Yukon Corridor	8	19	31	37	41
Horsepower Required (000's HP)					
Prime Route	395	770	1200	1510	1630
Fort Yukon Corridor	380	845	1330	1610	1730

(iv) Construction Considerations - As with the Fairbanks corridor, the assumption was made for the Fort Yukon Corridor that construction could be completed over the same time period as for the Prime Route. Because the Fort Yukon route would involve approximately 415 miles of extra pipeline as compared with the Prime Route, the potential for not meeting the proposed construction schedule would be greater.

Even with the existence of the all-weather road from Fairbanks to Prudhoe Bay and the completion of the Dempster Highway, there would be long sections of this route without all-weather access. It was estimated that approximately 600 miles of the corridor would be without all-weather access.

The Fort Yukon routing would have about 430 miles within the continuous permafrost zone and about 1300 miles in the discontinuous zone. The corresponding Prime Route figures were 700 and 800 miles, respectively. A large portion of this route would be in mountainous terrain, closely paralleling rivers and streams, which could produce problems with rock and mud slides. It was estimated that the geotechnical problems would be different from those of the Prime Route, but of about equal difficulty.

The need for granular material would be less than for the Prime Route and the availability would be greater.

(v) Operations and Maintenance Considerations - It was concluded that operations and maintenance within the Fort Yukon Corridor would be more extensive and more costly than for the Prime Route. This was basically due to the increased length and the mountainous terrain traversed by this route.

(vi) Cost Considerations - A comparison between the capital costs and operating costs of the Fort Yukon Corridor and those of the Prime Route showed the Fort Yukon Corridor to be significantly more expensive.

(vii) Environmental Impact - Because of the increased length of the line and the fact that this route would cross numerous areas of great importance to waterfowl, mammals and fisheries, particularly in Alaska, it was considered by the Applicant to have very little favour with regard to minimizing environmental impact.

Foothills pointed out that the Prime Route and the Offshore Route would be the only alternatives with potential impact on the beluga whales and the snow geese migratory patterns. Also, the Prime Route could have substantial impact on the Porcupine caribou herd, and the Prime Route was the only one to run through the Arctic National Wildlife Range in Alaska. The Applicant agreed with these points but indicated that, by the use of careful construction techniques, potential impact could be kept to a minimum.

In summary, the Applicant pointed out that the reasons for choosing the Cross-Delta Route as the Prime Route and the route it was applying for, were:

- shorter distance traversed;
- feasible construction, operation and maintenance conditions;
- reduced costs; and
- apparently acceptable environmental and socio-economic consequences.

Views of the Board

The Board feels the main objective in the choice of a route is to connect two separate gas supply areas, one near Prudhoe Bay, Alaska, and one near the Mackenzie Delta in the Northwest Territories, to southern markets, taking into account technical feasibility, cost of service, environmental and socio-economic considerations. In the view of the Board, the Fort Yukon Corridor, Interior Route and Offshore Corridor have potential technical and/or environmental problems which make these alternatives undesirable. Therefore, it is felt that the major choice is between the Prime Route and the Fairbanks Corridor.

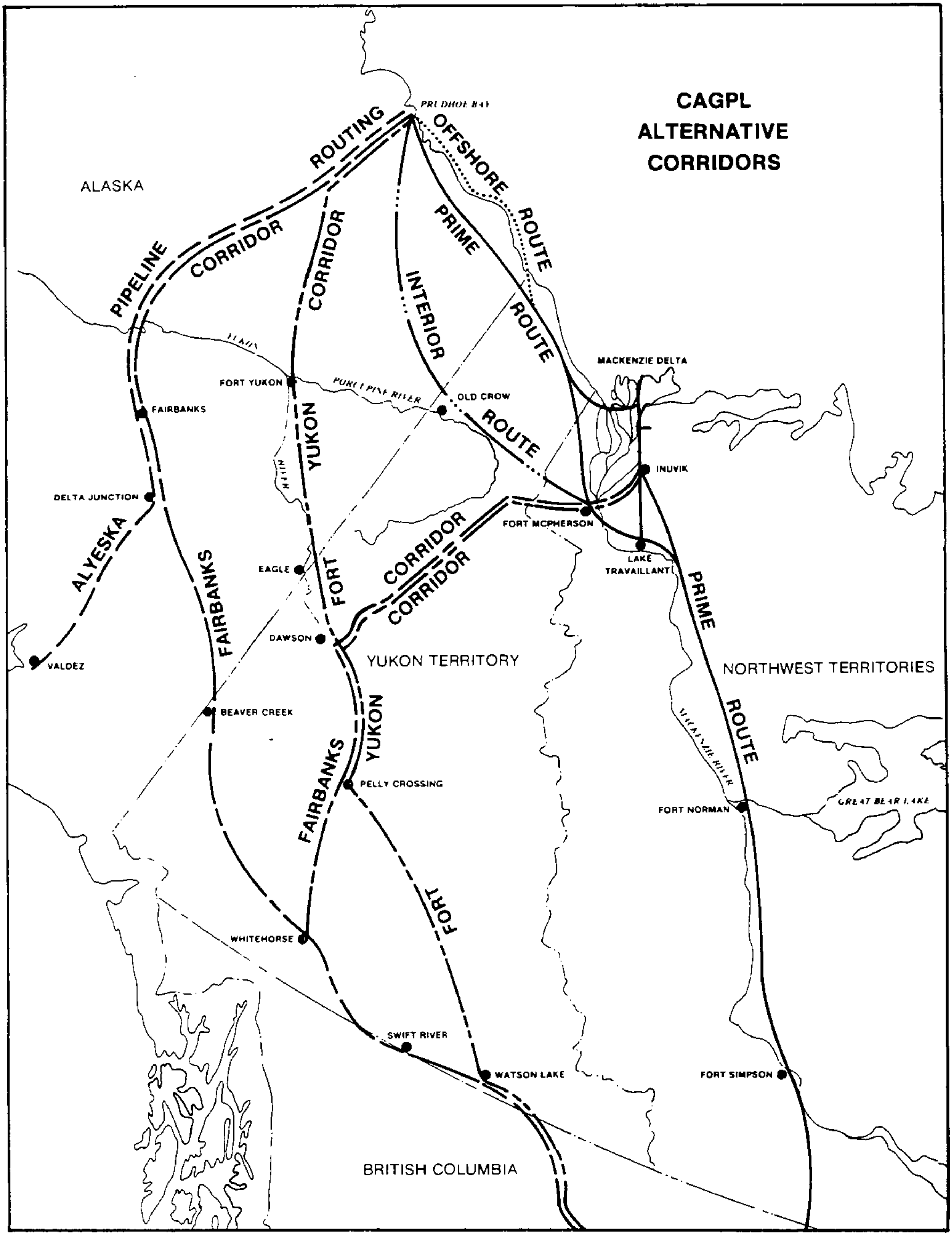
The Prime Route is the most direct route, requiring approximately 900 miles less pipeline than the Fairbanks Corridor, and therefore appears to be the most economic.

However, the Prime Route would be heavily dependent on unproven Arctic construction techniques and snow road construction, and would have limited access for logistics support and a relatively short construction season. Also, construction along the Prime Route would take place in a harsh environment and the line would cross sensitive virgin territory along the Arctic North Slope.

The Fairbanks Corridor would follow an existing transportation corridor paralleling the Alyeska pipeline and along the Alaska Highway. The potential environmental impact of this route would be much less than that of the Prime Route; there are all-weather access roads available along the majority of the route for logistics support and there could be both summer and winter construction. Therefore, the costs and construction scheduling aspects could be controlled with a greater degree of accuracy than for the Prime Route.

The Applicant stated that a pipeline along the Prime Route would be shorter and easier to construct than one built in the Fairbanks Corridor. Although it would appear to be technically feasible to construct the proposed pipeline along the Prime Route, it has the potential for greater cost over-runs than the Fairbanks Corridor route. Furthermore, the Prime Route is subject to environmental and socio-economic constraints which are discussed in Sections 6.1.1 and 5.5.2.

MAP 3-2



CAGPL
ALTERNATIVE
CORRIDORS
ALASKA
PRUDHOE BAY
ROUTING
PIPELINE
CORRIDOR
OFFSHORE
ROUTE
PRIME
ROUTE
INTERIOR
ROUTE
CORRIDOR
YUKON
FORT
MACKENZIE DELTA
INUVIK
FORT YUKON
FAIRBANKS
OLD CROW
PORCUPINE RIVER
YUKON
DELTA JUNCTION
ALYESKA
FAIRBANKS
EAGLE
FORT MCPHERSON
CORRIDOR
CORRIDOR
LAKE
TRAVAILLANT
PRIME
DAWSON
YUKON TERRITORY
NORTHWEST TERRITORIES
VALDEZ
BEAVER CREEK
ROUTE
YUKON
FAIRBANKS
PELLY CROSSING
MACKENZIE RIVER
FORT NORMAN
GREAT BEAR LAKE
FORT
WHITEHORSE
SWIFT RIVER
WATSON LAKE
FORT SIMPSON
BRITISH COLUMBIA

3.1.3 CAGPL

3.1.3.1 Facilities Design and Capacity

Introduction

The system proposed by CAGPL consisted of three supply lines in addition to the mainline and two delivery lines. The following table is a summary of the length, pipe characteristics and maximum operating pressure (MOP) for each major segment of the pipeline.

Projected Gas Volumes by Year

CAGPL's pipeline design for its "Base Case" was for projected average day throughput in the fifth year consisting of 4.5 Bcf/d, 2.25 Bcf/d from each of Prudhoe Bay and the Mackenzie Delta. Since a possibility existed that the Mackenzie Delta-Prudhoe Bay volumes would not be expanded beyond 3.25 Bcf/d, CAGPL presented an alternative "No Expansion Case" wherein the facilities would not be expanded beyond the second operating year. (Details of the supply and disposition of the volumes for the Base Case and No Expansion Case are set out in the Introduction section for the CAGPL project.)

System Configuration Mainline Pipe Selection

CAGPL applied the following criteria in selecting the pipe for the mainline from Tununuk Junction to the bifurcation point near Caroline: the pipe diameter should be as large and the operating pressure as high as possible in order to be able to transport 4.5 Bcf/d without looping; the system should provide minimum cost of service while transporting a volume of gas of 4.5

CAGPL

Length, Pipe Characteristics and Maximum Operating Pressure for Each Major Segment of Pipeline

Route	Pipeline Overall Length (miles)	Pipe Characteristics: Outside Diameter (inches)	Pipe Characteristics: Wall Thickness (inches)	SMYS(1) (psi)	MOP(2) (psig)
Supply Lines:					
Alaska-Yukon Border to Shallow Bay	141	48	0.720	70,000	1,680
and					
Shallow Bay to Tununuk	36.5	dual 36	0.540	70,000	1,680
Niglintgak to Taglu	10.8	24	0.360	70,000	1,680
and					
Taglu to Mainline	19.3	48	0.720	70,000	1,680
Parsons Lake to Mainline	12.5	30	0.450	70,000	1,680
Mainline:					
Tununuk to Caroline	1410	48	0.720	70,000	1,680
Delivery Lines:					
Caroline to Coleman	176	36	0.464	70,000	1,440
Caroline to Empress	236	48	0.720	70,000	1,680
Empress to Monchy	158	42	0.630	70,000	1,680

(1) Specified Minimum Yield Strength

(2) Maximum Operating Pressure corresponding to 80 per cent of the field test pressure.

Bcf/d; and pipe diameter, wall thickness, and grade should be commercially available in the required quantities.

The Applicant made a comparative cost of service study of lines with diameters of 42, 48 and 54 inches. At 4.5 Bcf/d, the cost of service for the 42-inch O.D. line would be approximately 3.75 cents per Mcf per 100 miles; for the 48-inch O.D. line, it would be 3.33 cents per Mcf per 100 miles; and for the 54-inch O.D. line, it would be 3.25 cents per Mcf per 100 miles.

Even though a 54-inch diameter line for the mainline between Tununuk Junction and Empress, Alberta would provide the lowest cost of service and would also provide room for possible additional gas supplies, CAGPL decided to use 48-inch diameter pipe for the following reasons: it doubted that 54-inch diameter pipe would be available in sufficient quantities, and it believed that it might have problems convincing the regulatory and financial people or potential lenders to the project of its suitability.

Supply Line Pipe Size Selection

The criteria for the Prudhoe Bay and Richards Island supply lines were the same as those for the mainline, except that each lateral was designed for a capacity of 4.5 Bcf/d even though a cost of service penalty would be incurred if the gas flows were not greater than the 2.25 Bcf/d proposed.

(a) Prudhoe Bay Supply Line:

For the Prudhoe Bay line, CAGPL designed for an ultimate total of four compressor stations in Canada, although for the proposed throughput of 2.25 Bcf/d in the fifth operating year, only two stations would be installed. If the four compressor stations were operating, an average gas throughput of 4.5 Bcf/d could be achieved.

CAGPL stated that a 36-inch diameter line could carry 2.25 Bcf/d but preferred a 48-inch to avoid incremental looping in the future to accommodate potential increases in throughput.

In answer to Foothills' question as to whether spare capacity could be achieved by means of a 42-inch instead of a 48-inch O.D. line for the Prudhoe Bay line, CAGPL admitted that a throughput of 3.5 Bcf/d or an approximate increase of 44 per cent over the projected volume of 2.25 Bcf/d could be achieved with a fully powered 42-inch O.D. line. CAGPL, however, favoured a 48-inch O.D. line because it felt that the initial cost penalty in going from a 42-inch to a 48-inch line was not significant. It estimated that there would be a difference of one cent per Mcf or four per cent increase in the overall cost of service.

CAGPL justified the oversizing of its Prudhoe Bay supply line on its belief that the gas producing fields in the Prudhoe Bay area would be developed and that gas volumes in excess of 2.25 Bcf/d would be made available to its pipeline system. It believed that expanding the facilities to accommodate those potential volume increases through incremental looping would undoubtedly be an expensive proposition because of the high mobilization and construction costs. CAGPL contended that the installation of excess initial capacity would also be desirable from the standpoint of environmental impact. Gas volume increases could be accommodated with minimum disturbance of the environment by installing compressor equipment at sites along the line.

(b) Dual Crossing of Mackenzie River at Shallow Bay:

For construction, reliability and geotechnical reasons, CAGPL proposed a dual 36-inch O.D. river crossing at Shallow Bay for a distance of approximately 36.5 miles.

Dual crossings were proposed because in the event of a break in one line, the repair time could be of the order of three months and thus the design flows could continue to be transported through the other line. In addition, handling of 36-inch O.D. pipe in construction across Shallow Bay would be simpler than for a 48-inch line.

The dual lines would be capable of carrying 4.5 Bcf/d and both lines would be operated at all times to minimize pressure drops in the system.

With regard to the separation distance of the dual lines, CAGPL stated that after looking at the contours of various scour situations, it had decided that the lines should be separated by a distance at least equivalent to the length of the river crossing so that the deep portion of a single scour hole would not expose both lines.

(c) Niglintgak and Parsons Lake Lateral Size Selection:

The 24-inch O.D. pipe size for the Niglintgak lateral and similarly the 30-inch O.D. pipe size for the Parsons Lake lateral were designed on the basis of fifth year receipt volumes from the processing plants and operating pressures of the laterals to match that of the mainline.

Delivery Line Pipe Size Selection

The criteria used by the Applicant for the delivery lines were as follows:

(a) Caroline to Coleman Line Size Selection:

CAGPL selected 36-inch diameter pipe to transport 686 MMcf/d of gas in this segment in the fifth year of operation with no compression.

If the throughput of this pipeline section were increased in the future to a level of about 1.8 Bcf/d, such capacity could be achieved by adding compressor stations at mile posts 66.7 and 123.2.

(b) Caroline to Empress Line Size Selection:

CAGPL proposed to install 48-inch O.D. line pipe and two compressor stations to carry 3.2 Bcf/d of gas by the fifth operating year. The design of this section was based ultimately on four compressor stations but only two of them were applied for and would be in operation for the projected fifth year volumes. The two additional compressor stations could be installed to increase the future capacity of this pipeline section up to 4.5 Bcf/d if necessary.

CAGPL admitted during cross-examination that a 42-inch O.D. line with adequate compression equipment could transport the indicated volumes shown in the application but it had selected a 48-inch O.D. line in order to save fuel and to provide spare capacity beyond the fifth year projected volumes.

Foothills questioned why a delivery pressure of 1,488 psig was utilized at the connecting point with TransCanada's system because this latter system could only operate at a maximum operating pressure of 880 psig. CAGPL stated that this high delivery pressure would be of value in the gas reprocessing plant at Empress where the higher Btu components would be removed before the methane gas entered TransCanada's system. Delivering the gas to the plant at the indicated higher pressure would permit it to achieve a low temperature separation by expanding through a turbo-expander which would recover the liquid hydrocarbons and re-compress the separated methane gas to the TransCanada pressure without the addition of extra compression.

(c) **Empress to Monchy:**

CAGPL proposed 42-inch O.D. pipe to carry 1.53 Bcf/d by the fifth year of operation at the maximum operating pressure of 1,680 psig.

The Applicant had designed for three compressor stations but only one of these would be installed and in operation in the fifth year. The two additional compressor stations could be installed to increase the capacity of this pipeline section up to 3.25 Bcf/d.

Station Design and Spacing

Compressor station horsepower and spacing were selected so that optimum (i.e., lowest unit cost of service) volumes for the selected pipe size could be transported without allowing gas temperatures to fall below the specified design temperatures of the pipe under normal or upset operating conditions.

CAGPL proposed 16 single unit gas turbine driven centrifugal compresssor units of 30,000 horsepower each as compression equipment from the Alaska-Yukon border to Compressor Station MF-14 located about 60 miles north of Fort Simpson, Northwest

Territories. From Station MF-15 to Monchy, Saskatchewan, it specified 23 single unit gas turbine driven compressor units of 38,000 horsepower each, which took account of higher ambient and flowing temperatures existing south of the 60th parallel. The 39 compressor stations would be installed at an average spacing of 45 miles and would all be operating by the fourth year of operation.

The compression equipment requirements varied each year up to the fourth year of operation in accordance with the Applicant's projected volumes. The following table illustrates the compressor unit build-up by year for the pipeline section between the Alaska-Yukon border and Monchy. The number of stations installed each year is expressed as a percentage of the total number of stations installed to transport the fifth year gas volume of 4.5 Bcf/d.

CAGPL

Per Cent of Compressor Units Installed by Year Versus Total Number of Compressor Units Required for Fifth Year Projected Gas Volumes

	Operating Year				
	1	2	3	4	5
Per Cent	23	51	75	100	100

It proposed a large single unit at each compressor station rather than dual smaller units because the larger units had the advantage of providing lower capital costs per horsepower combined with savings in piping, controls, installations, foundations and buildings associated with the units.

There were two concepts with regard to flowing gas temperatures upon which the Applicant's designs were based. For the northern portion of the route, i.e., north of Station MF-15, gas temperatures would be maintained between minus 10° F and plus 30° F to prevent thawing of permafrost and ensure pipe stability. (The effect of degrading permafrost upon the pipeline is explained in detail in the Geotechnical section of this report.) In order to maintain a pipe temperature below 32° F, a closed-cycle refrigeration system using 17,000 horsepower turbines and propane as the refrigerant would be installed at each compressor station from the Alaska-Yukon border up to and including Compressor M-12 (located about 23 miles north of Wrigley, Northwest Territories).

From Compressor Station MF-13, no chillers were proposed since the gas temperature would be allowed to exceed 32° F at Station MF-15. A heater was proposed at Compressor Station MF-15 in order to ensure that the temperature would be maintained in excess of 32° F.

CAGPL proposed a closed-cycle refrigeration system using 6,400 horsepower propane compressor units at each compressor station from Compressor MF-15A (located near Fort Simpson) to Compressor MF-19 (located about 35 miles south of the 60th parallel) to maintain pipeline flow temperatures between 32° F and 50° F to reduce friction loss at high gas flowing temperatures.

System Reliability

CAGPL carried out a reliability study on its entire system by means of computer simulations to verify whether its system could transport the average-day volumes of 4.5 Bcf/d under planned and unplanned compressor unit outages.

The study showed that taking into account the flow reduction during single and multiple compressor and refrigerator outages, the effect of maintenance programs and the effect of seasonal variations in air and ground temperatures, the proposed system was capable of transporting a daily capacity of 4,593 MMcf/d in its fifth and subsequent operating years.

For the purposes of its study, CAGPL assumed that an outage anywhere in the system would upset the inputs and deliveries at all points by an equal amount. For example, the CAGPL study assumed that should a compressor outage on the Prudhoe Bay leg reduce the receipt capacity from Prudhoe Bay, a corresponding decrease would occur in the receipt capacity from the Mackenzie Delta.

Similarly, in this study, it was assumed that a compressor outage on the eastern delivery leg would reduce the delivery to Coleman by the same amount as it would reduce the delivery to Monchy, whereas in actual operation an outage on the eastern leg could allow increased delivery to Coleman.

System Design for the No Expansion Case Volumes

CAGPL did not propose a system design for the No Expansion Case different than that submitted for the Base Case except in compression. For the No Expansion Case, only about 50 per cent of the compressor stations south of the Tununuk Junction, or every second station proposed for the fifth year volumes, would be needed.

In CAGPL's No Expansion Case the gas volumes would reach 3.25 Bcf/d (2.0 Bcf/d from Prudhoe Bay and 1.25 Bcf/d from Mackenzie Delta) in the second year and would remain at that level thereafter. Under such flow conditions, the entire CAGPL system would not meet the optimal design criterion (i.e., gas transported at the lowest unit cost).

CAGPL also carried out a system reliability study on its entire system for the No Expansion Case. The study demonstrated that the system could transport an average annual volume of 3.55 Bcf/d after allowing for unscheduled outages, scheduled maintenance programs, and seasonal variation in air and ground temperature. This volume would be nine per cent greater than the design volume of 3.25 Bcf/d for year two.

Views of the Board

Mainline

The Board agrees with the Applicant's choice of a 48-inch O.D. x 0.72-inch W.T., Grade 70 pipe for its mainline proposed to be operated at a maximum operating pressure of 1,680 psig after test.

This pipe is the largest commercially available in Canada with the proposed wall thickness and grade and will provide the least cost of service when the optimum flow of 4.5 Bcf/d is reached. Although flows up to 3.25 Bcf/d are more realistic based on presently known reserves, the reduced flow can be accommodated by the building of every second compressor station or a station spacing of approximately 90 miles. Under these conditions, acceptable transportation costs will be achieved while providing for cheap expansion from 3.25 to 4.5 Bcf/d by the addition of further compressors at the optimum station spacing of 45 miles.

The Board agrees with the Applicant that it is desirable to avoid looping for as long as possible because it is costly to loop in remote areas with limited access in a harsh environment and also because it would cause further environmental upset.

The Board agrees with the Applicant's choice of 30,000 or 38,000 horsepower single unit gas turbine driven compressors at the compressor stations, as these large units provide economies both in original cost and in reasonable operating costs because of their high thermal efficiency. In addition, the Applicant has satisfied the Board that the reliability of the pipeline is adequate by demonstrating that the peak day throughputs can be achieved with the loss of the critical compressor station.

For geotechnical reasons (see Geotechnical section of the report) the temperature of the flowing gas will be controlled as far south as Compressor Station MF-19 which is located about 35 miles south of the 60th parallel. The propane chillers and heater required for this purpose are satisfactory to the Board but the Applicant would be required to submit final design of its compressor stations including the chillers and heater for approval of the Board prior to construction.

Supply Lines

(a) Prudhoe Bay Extension:

CAGPL has chosen a similar 48-inch O.D. x 0.720-inch W.T., Grade 70 pipe to transport the Alaskan gas from the Yukon-Alaska border to the mainline near Tununuk Junction. The Applicant agreed that this line is oversized and that a 36-inch diameter line fully powered could transport the projected volume of 2.25 Bcf/d. The Applicant selected a larger diameter pipe in order to enable it to expand its system by horsepower additions and avoid expensive looping in an area of extreme weather conditions, with limited access and subject to severe environmental upsets. The Applicant admitted that a 42-inch line could provide a capacity of 3.5 Bcf/d, i.e. an excess of 1.0 Bcf/d beyond the fifth year volumes, but favoured a 48-inch line because it felt there was not a significant initial cost penalty to go from 42 to 48-inch diameter pipe. It estimated a difference of one cent per Mcf, or four per cent, in the cost of service on this section of the line.

The Board is not in a position to evaluate the likelihood of future increases in volumes of Alaska gas available for transmission through CAGPL facilities; however, it does agree with the Applicant that to minimize future environmental disturbances it would be appropriate to oversize the Prudhoe Bay extension rather than having to loop.

Included in the Prudhoe Bay extension are two 36-inch diameter pipelines across Shallow Bay. The Board accepts the Applicant's reasons that two 36-inch diameter lines rather than a single 48-inch diameter pipe for this crossing will be easier to construct and that the double line would provide security of service in the event of the loss of one of the pipelines.

(b) Mackenzie Delta Supply Lines:

The Board accepts the sizing of these relatively short supply lines each of less than 20 miles in length, as they are adequate to meet the anticipated flows without compression.

Delivery Lines

Caroline to Coleman:

CAGPL's choice of 36-inch diameter pipe for this 176 miles of pipeline to transport only Alaska gas would be adequate to transport either the Base Case flow of 686 MMcf/d or the more realistic No Expansion Case flow of 617 MMcf/d without compression. A smaller diameter pipe of say 30-inch diameter with compression would have the capacity for these volumes, but the larger diameter pipe would save costly fuel and could be expanded economically for additional volumes by the addition of compression without looping. The Board is therefore prepared to accept this design.

Caroline to Empress:

CAGPL has chosen a 48-inch diameter pipe for this 236-mile segment to transport the Base Case volume of 3.2 Bcf/d. This diameter pipe is oversized in relation to either the 3.2 Bcf/d or the more realistic No Expansion Case volume of 2.3 Bcf/d.

The Board considers a 42-inch diameter pipe would also be adequate although it would require additional compression. The Board is prepared to accept CAGPL's design.

Empress to Monchy:

The Applicant has selected 42-inch diameter pipe for this 158 miles of pipe which would transport Alaska gas only to the border. This pipeline is oversized for the design volume of 1.5 Bcf/d.

The Board however, is prepared to accept the Applicant's design as this diameter pipe appears to be generally consistent with the balance of the system where some expansibility has been incorporated in the design.

General

On the basis of the more realistic No Expansion Case volume of 3.25 Bcf/d, the system is generally overdesigned in all segments. However, historically when pipelines have connected new areas of supply to markets, additional exploration activity has been promoted and additional discoveries have been made.

Bearing in mind the implications of looping, already mentioned, the Board is prepared to accept the design proposed by the Applicant.

The Board is satisfied as to the adequacy of the proposed United States interconnecting facilities and that the capacity of the interconnecting Canadian facilities would be expanded as required.

3.1.3.2 Geotechnical and Geothermal Design

Frost Heave

Introduction

One of the most important geotechnical issues examined during the hearing was frost heave. The proposed CAGPL pipeline, in order not to melt the permafrost in northern areas, would operate at flowing temperatures below the freezing temperature of water. At the same time, however, where unfrozen ground is traversed in areas of discountinuous permafrost, continuous freezing would be induced in the soil surrounding the buried pipeline. This frost penetration would, in turn, produce heave of the pipeline in such areas. From an engineering point of view, then, frost heave is important because of its potential for causing damage to a high pressure pipeline and because of the extent of the problem in terms of miles of pipeline in the discontinuous permafrost zone.

Frost heave is, in simple terms, the increase in volume that occurs in a soil while it is freezing. The increase in volume is largely due to the accumulation of layers of ice formed from water that has been drawn into the freezing soil and additionally to the expansion in volume of that water on freezing. This process is termed "ice lensing" and the layers of ice that result are termed "ice lenses". It has been observed that the plane of these layers is oriented at right angles to the direction of heat flow.

The potential for damage arises from the tremendous forces that are necessary to resist the formation of ice lenses. If a pipeline were to experience frost heave more or less uniformly along its length, this fact would be of little consequence. However, if a chilled pipeline first traverses frozen or permafrost terrain and then unfrozen terrain that is susceptible to frost heaving, the soil will heave differentially, possibly damaging the pipe. A similar situation could occur in shallow permafrost at interfaces between two different soils with different frost heave characteristics.

If this problem occurred at only a few locations, frost heave would not be a major concern. However, there would be thousands of such locations, including river crossing areas, over a distance of about 400 miles between Compressor Station M-06, located on the Arctic Circle just north of Fort Good Hope, and Compressor Station MF-15, located just north of Fort Simpson.

Additional opportunities for differential heaving to occur would exist at river crossings north of Fort Good Hope and at Shallow Bay, where unfrozen river beds are encountered in the otherwise continuous permafrost zone.

It is clear that a pipeline with a built-in tendency to damage itself during operation is not acceptable from an engineering point of view. The adequacy of the design to prevent or control frost heaving is fundamental to the feasibility of the proposed pipeline.

In order to learn more about this complex problem, CAGPL funded the Calgary Frost Heave Test Site, which was operated by its primary engineering consultant, Northern Engineering Services. Extensive simulated field condition testing was commenced in 1974; buried chilled pipeline behaviour and several mitigative measures were examined over a period of more than two years.

Magnitude of Frost Heave

Attempts at accurately predicting values of frost heave magnitude must be based on a complete knowledge of the processes involved. It was admitted early in the hearing by CAGPL witnesses that a full understanding of these processes did not exist at that time.

CAGPL presented evidence in response to issues raised in cross-examination regarding a worst case or "upper bound" analysis of frost heave. If the heat carried away by the pipeline, less any heat that might be conducted to the frost front, were all liberated from the phase change associated with the freezing of pure ice, then only a finite and easily calculable amount of ice might be formed over the life of the pipeline. The amount of pure ice formed, and therefore the maximum amount of frost heave, depends on the temperature of the pipeline and a number of factors associated with its surroundings. This approach yields frost heave magnitudes of up to 20 feet or so in 20 years, depending on the conditions. Since no evidence was submitted to indicate that an annulus of pure ice would form around a chilled, uninsulated pipeline in unfrozen ground, it can be concluded that the maximum obtainable frost heaves are somewhat less than those predicted by this "upper bound" approach.

Witnesses for CAGPL stated, however, that in the absence of any attempt at frost heave control, the operation of a chilled pipeline would result in frost heaves of six feet and more in the design period, and that such magnitudes of frost heaving would not be acceptable.

With the discovery that the application of moderate loads (i.e. less than four to five thousand pounds per square foot) to the pipeline could not control frost heaving, the prospect of frost heaving in unfrozen soil located under significant thicknesses of permafrost also became a concern to the Applicant. In an effort to conservatively evaluate the possible magnitudes of heaving under permafrost, the assumption was made that a single, pure ice lense would form at the bottom of the existing permafrost. One example used to illustrate the procedure was an uninsulated pipe buried six feet deep and operating at 5° F in permafrost 44 feet thick. The analysis indicated that it is possible for two feet of frost heave to occur in about 12 to 13 years.

Permissible Magnitudes of Frost Heave

The Applicant chose a two-fold criterion for allowable frost heave magnitude; first, to limit the amount of total heave to an arbitrarily selected value and, second, to limit differential heave to values that could be withstood by the pipe.

If the entire pipe were uniformly elevated by frost heave, the integrity of the pipe would not be threatened. However, disruption of surface drainage could result, leading to ponding and erosion. CAGPL testified that frost heave design should control total heave to within two to three feet over the design period.

Differential heaving is the heaving of one segment of the line at a greater rate than adjacent segments, thus tending to deform the pipeline. The permissible amount of differential heave depends on the length of the pipeline over which it occurs, termed the "heave length", the strength of the soil holding the pipeline in place, termed the "uplift resistance", and, of course, the strength of the pipeline.

CAGPL testified that in insulated, heat-traced portions of pipeline, damage to insulation could result from differential frost heaving. The allowable differential heave calculated for an uplift resistance of 1,800 pounds per foot was stated to be about two inches. In non-insulated sections, the allowable differential heave would be determined in relation to the tolerances of the pipeline.

Evidence was presented indicating that for long heave lengths, the permissible differential heaves in shallow permafrost (where the pipeline would be uninsulated and heave would be controlled by heat probes installed below the frozen soil) varied from 24 inches to about four inches, for uplift resistances of 1,800 lbs/ft. and 10,000 lbs/ft. respectively. For very short heave lengths and higher uplift resistances, differential heave is reduced. Evidence was given that the value of the uplift resistance could be as high as 100,000 lbs./ft.

Mitigative Measures

Initially, CAGPL relied upon the "shut-off pressure" concept as the basis for the design of frost heave mitigation. The shut-off pressure was defined as that applied pressure at which lensing heave would stop. The pressure at the frost front would be created by the sum of the loads associated with the surcharge berm, deep burial overburden and the frost bulb itself. When it was found that the "shut-off pressures" were much higher than initially thought, so that the berm overburden deep burial method would not be practical, CAGPL filed an amendment to the application proposing to control frost heave by a combination of heat tracing, insulation and heat probes.

CAGPL's Initial Design

CAGPL's initial design, based on the shut-off pressure theory, included deep burial of the pipe and the construction of a non-erodable berm of up to 10 feet in height.

The initial concept was that the combined weight of the backfill, the surcharge berm and the frost bulb, which would grow bigger with time, would result in a load, or pressure, on the frost front that would reach the shut-off pressure before intolerable frost heaves occurred. At river crossings, deep burial alone was to be used. However, evidence was given that, in many cases, the depth of burial required for frost heave mitigation was exceeded by the depth of burial required to ensure that the pipeline would not be exposed by bottom scour.

The initial shut-off pressure concept theorized that frost heave was the combination of two distincly different processes with differing causes. These components were said to be "lensing heave", the formation of segregated ice lenses from water drawn into the freezing soil by an, as yet, poorly understood mechanism, and "in-situ heave", caused by the expansion occurring when water already contained in the soil turns to ice. The observation that the rate of total frost heaving diminishes with increased applied load was explained in terms of lensing heave and in-situ heave by assuming that the lensing portion was diminished by the load and the in-situ portion was not. The shut-off pressure was defined as the pressure at which lensing ceased, leaving just the in-situ component. Evidence was given that the magnitude of the in-situ component would be proportional to the magnitude of the frost penetration.

During the Board's cross-examination of CAGPL, a number of experimental observations were discussed which appeared, by themselves, to be inconsistent with the theory.

The first such observation was that a large number of the experimental results that were filed exhibited remarkably constant rates of heave as evidenced by the straight line plots of heave versus time while at the same time the rate of frost penetration was decreasing from very high to near zero rates.

This indicated a constant rate total heave process independent of the rate of frost penetration, contrary to the expectations based on the shut-off pressure theory.

The second such observation was that, in many of the experimental results filed by CAGPL, pore water was expelled from the samples in early stages of the test. CAGPL explained this initial expulsion as a transient phenomenon not relevant to the shut-off pressure theory. CAGPL agreed that, if there were no in-situ component to frost heaving, then total frost heaving would all be due to ice lensing. However, this proposition was not accepted by the Applicant as an explanation of the observed water expulsion.

CAGPL also agreed that, if total heave and lensing heave were the same, then the shut-off pressure would be the pressure required to reduce total heave to zero. Evidence was given on cross-examination that the implication of this would be that pressures required to stop total heave would be in excess of 10,000 pounds per square foot (psf). However, CAGPL also rejected this proposition.

Late in 1976, CAGPL informed the Board that a previously undetected leak in its test apparatus had been discovered by Mr. Edward Penner of the Division of Building Research of the National Research Council. The Applicant testified that, due to this leak, its previously filed material was in error and that further tests had indicated that shut-off pressures were much higher than originally thought. Subsequent evidence filed with the Board stated that the tests carried out after the discovery of the fault in the test equipment "show that shut-off pressures may be greater than 7,000 to 10,000 psf." Test data submitted by CAGPL for pressures in excess of 10,000 psf show that shut-off was not obtained. None of the test data filed with the Board indicated that shut-off had been achieved.

Frost Heave Redesign

Reasons for the Redesign

The basic reason for the redesign was that CAGPL's more recent investigations indicated that the application of nominal, or even reasonable, surcharge loads could not be relied upon to control frost heaving. For example, if the soil had a shut-off pressure of 10,000 psf, the design would require a berm about 100 feet high or burial at a depth of about 140 feet or some corresponding equivalent combination of berm height and burial depth. Evidence was given by CAGPL that berm heights of over 9 to 11 feet and burial deeper than about 15 feet were impractical.

Description of the Redesign

The basic elements of the redesign for frost heave control included the following:

(1) In overland portions of the pipeline traversing unfrozen and shallow (less than 15 feet in thickness) permafrost, the pipeline would be insulated and heat-traced.

(2) In overland portions of the pipeline traversing permafrost in excess of 15 feet thick, in which excessive amounts of frost heaving would likely occur, buried electrical heat probes would be used.

(3) In water crossing, a steel-cased insulated line would be used. At large river crossings, the line would have integral heat-tracing conductors installed in conduits contained inside the steel casing. For minor river crossings, the heat tracing cables would be installed separately in conduits.

(4) The portion of the line from Compressor Station MF-15, located at the southern edge of the Ebbutt Hills, to Compressor Station 18, located at the southern edge of the Alberta Plateau, would be operated at temperatures above freezing rather than below freezing as was previously proposed. To ensure that the flowing temperatures would be consistently above freezing south of MF-15, a heater was proposed at this station.

(5) To provide electrical power to the heat tracing cables and heat probes, a power transmission system was also proposed. This consisted of about 400 miles of overhead transmission system from Compressor Station M-06 to Compressor Station MF-15 and buried power transmission lines in the Mackenzie Delta. The buried lines would originate at Compressor Station CD-08 and extend to about a mile past Taglu to the north, from Station CD-08 to about 29 miles southeast along the mainline, and between Stations CD-08 and CD-07 across the Delta. In addition, there would be a two-mile section of power line running eastward from Niglintgak.

There would also be some remote, unattended thermo-electric generators situated between Compressor Stations MD-02 and MD-06.

Insulation

Insulation formed part of both the heat-traced river crossing design and the overland heat-trace design. No insulation was proposed in permafrost areas where heat probes were to be installed.

The insulation that CAGPL proposed to use was a closed cell polyurethane plastic foam that could be cast in place during manufacturing. For the overland sections, the insulation would be protected from the effects of moisture by a polyethylene jacket 0.2 inches thick. At the joints, the gaps in the insulation would be filled with preformed sections of insulation and sealed with a heat shrink polyethylene sleeve.

CAGPL gave evidence that the optimum insulation thickness was about one inch, but that three inches was selected to conserve fuel that would otherwise be used in the chilling process and for electrical generation.

CAGPL testified that no serious problems were foreseen with the installation of the insulated pipe. It agreed that the line would have to be installed with the polyethylene covering intact, but stated that some damage could be tolerated since the design included several factors of safety.

The Applicant expressed confidence that the insulated pipe could be transported, assembled and installed even though these portions of the pipeline would be installed during the Arctic winter. CAGPL gave evidence that, while the polyethylene proposed for fabrication of the outer jacket on the insulated pipeline would become increasingly brittle with reductions in temperature and that it "had experienced some cracking due to rough handling of the product at low temperatures", the specifications were for minus 75° F and a similar material was used in Alaska at temperatures as low as minus 85° F.

No special techniques had been developed to handle the insulated pipe at low temperatures. CAGPL also indicated that there was no way of detecting any damage that might occur during the placement of the pipe in the ditch and during backfilling. The Applicant stated that it was not concerned about the possiblity of damage since the ditch would be partially backfilled with an "approved material" such as sand, before the pipe was lowered in and that more of this material, termed bedding or padding, would be placed over the pipeline to protect it from damage during the replacement of the original soil.

Heat Tracing

CAGPL stated that insulation alone was not, in its view, an effective means of controlling frost heave. Therefore it proposed to install heat tracing, in the form of electrical resistance cables, in conjunction with the pipeline insulation. The Applicant put forward three distinct designs for the heat-tracing system: a system for overland sections, a second system for minor river crossings and a third for major river crossings.

On overland sections, two plastic insulated resistance cables would be laid in the trench beside the pipeline and partially backfilled with a bedding material, such as sand.

At minor river crossings, a configuration similar to that for the overland sections would be used. To protect the resistance cable from damage in the river bed, the cable would be placed in a metal conduit. This conduit would have to be weighted to keep it in position during backfilling.

CAGPL indicated that these designs were not very sensitive to the location of the resistance cables with respect to the pipeline. It indicated that they could be relied upon to perform adequately as long as the cables were within the pipe ditch. At major river crossings, including those in the Delta, a third design was proposed. In this case there would be 12 resistance cables, equally spaced in the annulus between the carrier pipe and the outer steel casing.

The purpose of the heat-tracing cables would be to prevent the occurrence of frost outside of the pipe. Since no frost penetration would be allowed, there could be no frost heave.

CAGPL stated that with this design the pipeline would be able to withstand power outages, if necessary, for a matter of weeks, without there being a threat to its physical security due to frost heave.

Heat Probes

In areas of permafrost more than 15 feet thick and less than 60 feet thick where frost heaving would be anticipated, CAGPL proposed to install an uninsulated pipe and heat probes. The heat probes were small, individual electric heaters that would be installed through a hole drilled in the ground at an angle to a position under the centre line of the pipe at a level below the bottom of the permafrost. Their purpose would be to provide heat to the bottom of the permafrost in an effort to balance the heat flow from the bottom of the permafrost to the pipeline, and thus prevent the advance of the frost front.

CAGPL was questioned about the theoretical basis for this design. The witness admitted that heaving could still occur in the absence of an advance of the frost front as has been observed in the experiments that CAGPL had carried out. There was also evidence that the rate of frost heaving did not appear to be affected by either the thermal gradient or the temperature in the unfrozen portion of the test samples. CAGPL indicated that no tests had been carried out to show whether or not heat probes would prevent frost heave in shallow permafrost.

CAGPL indicated that the basis of the design was the belief that the ice lenses grew at the frost front and not within the frozen soil. It was admitted that, if this assumption were to be shown to be incorrect, there would be cause to doubt the effectiveness of the design.

Electrical Design

Generation

The electrical energy needed for heat tracing would be generated by gas turbine-driven generators located in the compressor stations M07 to M13. There would be three 1,300 kW gas turbine generators and a 600 kW diesel generator. The diesel generator would be used for starting the gas turbines in emergencies. The generation at 600 V would be stepped up to 15 kV by two 600 V/15 kV transformers. The input to the transformer would be protected by a 600 V breaker while the output would be fed to a 15 kV 3 phase line via a fuse link. Two 15 kV lines would emanate from the generating station, one going upstream and the other downstream along the gas pipe. Based on a total of 400 miles of 15 kV distribution line, each station would feed a line with an average length of 25 miles upstream and 25 miles downstream.

North of Compressor Station M07, due to ice movement and flooding, about 117 miles of 15 kV underground cable was chosen instead of overhead line. In the northern sections of the pipeline and for short river crossings where the ground conditions required isolated heat traces and probes, small, self-contained generators driven by turbines were proposed. These generators would be run by an organic vapour turbine fuelled by diesel oil and would be mounted on concrete pads or piles along with the transformers, with suitable protection such as dykes and fences against flooding and ice movement. The capacity of these generators would range from 1.5 kW to 4.5 kW.

Transmission

Overhead Sections

The overhead line would require about 10,000 poles to be installed over a period of two years. The average span of poles would be 250 feet. The clearance to ground of the energized conductor would be 28 feet. The three conductors on the pole would be spaced equilaterally with 42 inches distance between. Some poles would carry 15 kV/230 kV step down transformers connected to the 15 kV line via fuse cutouts. In addition, the poles would carry boxes containing regulating transformers, rheostats and miniature circuit breakers.

The poles would have an overall length in the order of 45 feet of which about 10 feet would be buried. Based on experience in Inuvik and Tuktoyaktuk, the Applicant felt that there was no danger of the poles shifting, tilting or falling due to the effect of permafrost. Below the three conductors, a bare ground line would be strung to provide two functions: one, to support a multicore telephone cable for carrying electrical signals regarding the status of equipment to the central gas control centre in Calgary; and two, the bare wire would serve as a grounding contact for falling power conductors so that a broken conductor could be easily sensed by protective relays.

In some river crossings like Black Water and Great Bear, taller wood poles might be required to provide a clearance of 31 feet between the phase conductor and high water level. The details of the span and the height of the poles had not been worked out. It was possible that some river crossings might use steel structures.

Certain aspects of the power line design were not fully established. The exact location of guyed poles was not yet determined. The location of lightning arresters and the design of the line for protection against lightning were not yet established. The Applicant indicated the possibility of using overhead shielding wires, if necessary, to protect the lines against lightning.

Underground Transmission

In certain sections of the pipeline the transmission of electrical energy would be by underground cables rated at 15 kV. The decision to use underground transmission in the Delta had been made because of the possible effect of ice movement and flooding on the stability of an overhead line. For security of service there would be two cables, each rated at 15 kV, in trenches along the pipeline route. The total length of buried power line would be 117 miles. These cables supplying energy to the heat trace and heat probes would be operated at about 3,000 volts.

Supply of Energy to Heat Trace and Heat Probes

Overland Sections

In the section of the pipeline south of Compressor Station 15, the gas would not be chilled and there would be no heat tracing. North of Compressor Station 15, heat tracing would be used in areas where the permafrost was less than 15 feet thick. The supply of energy to the two heat trace cables buried adjacent to the pipe would be effected by cables running back to the poles of the transmission line. Such cables were specified to operate at temperatures down to -40 degrees C.

The heat probes would consist of a sealed, spiral heating element connected to a cable running back to the poles of the transmission line. The probes would generate 425 W of heat and would be spaced between 15 and 25 feet apart. The operating surface temperature of the probes could be as high as 250°F to 300°F.

Underwater Crossings

For small river crossing 1,000 feet or less in length, the heat trace would be provided by two cables contained in conduits, one on either side of, and adjacent to, the pipe. The electrical connection to these heat trace cables would be made on the river bank and the conduit would be made water-tight.

For large river crossings like the crossing of Shallow Bay, a special design for heat tracing would be used. The Shallow Bay crossing would consist of the inner gas pipeline surrounded by styrofoam insulation and 12 aluminum conduits arranged in a circle at the periphery of the styrofoam insulation. An outer jacket of steel pipe would surround these conduits. The heat trace cables would be pulled into these conduits, with six cables being used for heat tracing, and the remainder serving as spares. The electrical connection to these heat trace cables would be from a three-phase underground cable at one end of the pipeline or could be from overhead lines. Seals would be employed at the end connectors to avoid the ingress of moisture into conduits.

The large underwater crossing would consist of 40-foot lengths of pipe welded together to form 1,000-foot sections. A pull wire would be inserted in the annular conduits and the heat trace probe cable would be pulled into the 1,000-foot section. The pulled heat trace wire in each 1,000- foot section of the conduit would be compression-connected. Then each 1,000-foot section of pipe would be welded to the next. A heat shield in the outer pipe was expected to prevent damage to the cables due to the welding temperatures.

In the areas where overhead lines crossed water bodies, the line would satisfy codes and practices stipulated by governing bodies. CAGPL would be checking its designs of electrical installations to ensure they met the appropriate codes or regulations of the Department of Indian Affairs and Northern Development and the Navigable Waters Protection Act.

CAGPL felt that there was no safety problem associated with the electrical grounding of apparatus in the generating station or poles and towers of the transmission line. Induced voltages on the pipeline due to faults in the transmission line were not considered to pose any problems. Condensation in the conduits for underwater crossing was considered to be no problem. It was felt that there would be no difficulty in achieving a sufficiently low ground resistance in areas of permafrost.

Electrical Monitoring

The generating stations were expected to have a reliability of 98 per cent. The status of the generators, the 15 kV fuse cutouts and the 600 V breakers in the generating station, would be monitored remotely in Calgary. The status of remote turbine generators, fuse cutouts, heat probes and local circuit breakers would not be monitored.

Uplift Resistance

Initially, CAGPL submitted studies showing the results of stress analyses for frost heaving which incorporated the shut-off pressure concept. The utilization of this concept resulted in rather low loads and thus low predictions of stresses in the pipe. These studies included, as a variable, the uplift resistance of the soil around the pipe.

The uplift resistance is simply the resistance that the soil around the pipe has to movement of the pipe by virtue of the soil's strength. In order to move the pipe upward through the soil and thus away from the ditch bottom, this uplift resistance must be overcome. In the case of frost heaving, this upward force would be generated by the frost heaving and the uplift resistance of the pipe in the adjacent non-heaving soil would tend to resist the movement.

In its original stress analysis, CAGPL considered uplift resistances in the range of 2,000 to 20,000 lbs/ft. In the redesign evidence, CAGPL submitted stress analyses based on a constant rate of frost heaving and an uplift resistance of 1,800 lbs./ft. The testimony also indicated that these analyses were done assuming an uplift resistance of the lowest possible magnitude and that much higher uplift resistances were possible. In response to a Board request for additional information, CAGPL indicated that uplift resistances of more than 100,000 lbs./ft. could occur.

In cross-examination, CAGPL stated that it would be necessary to control uplift resistance. Early in the hearing, testimony was given regarding the possible use of plastic "slip joints" in the trench or specially treated backfill to limit the magnitude of the uplift resistance at points of interface between permafrost and non-permafrost soil along the pipeline. During the Board's cross-examination of the redesign panel, CAGPL indicated that, while a final decision had not been made, installing an additional heat-tracing cable above the pipe at permafrost interfaces was a possibility although provision had not been made for it in the cost estimates.

Views of the Board

CAGPL's redesign for frost heave mitigation is, in the opinion of the Board, generally acceptable. The design criterion of elimination of frost heave in most areas would appear to be the most prudent course at this time in view of the absence of empirical verification of frost heave predictive methods, the lack of observations of behaviour of pipeline insulating materials and the effects of frost heaving thereon under operating conditions.

In those areas where CAGPL does not propose to design for frost heave elimination, that is, in shallow permafrost, the Board does have some remaining concern. It is not clear, as admitted by the Applicant, nor is there any actual experimental observation, that ice lenses form only at the frost front. The Board has noted the evidence of the Applicant indicating that frost heave can continue after frost penetration has diminished and stopped. If ice lenses were to form behind the frost front, heat probes operating at the frost front could be ineffective and thus there would be a potential danger to the pipeline's integrity in shallow permafrost areas, particularly at frozen ground/unfrozen ground interfaces and in sections where soil type and thus heave rate change sharply in the frozen ground areas.

The Board is further of the opinion that until further experimental work is performed to establish realistic field condition design parameters, potential uplift resistances to be encountered should be assessed on a conservative basis, thus reinforcing the desirability of a no-frost-heave design at this time. The Board notes that those areas which currently are not designed for zero frost heave (shallow permafrost areas) may coincide, in many cases, with areas of highest potential uplift resistance, that is, lowest potential for tolerance of heave.

While the currently proposed design would appear to be the most prudent at this time for the reasons outlined, the Board is concerned as to the environmental disruption and extensive electrical monitoring associated with the redesign. Also of concern is the proposed 400-mile above-ground electrical transmission system.

The Board notes that the proposed electrical scheme consists of some 400 miles of overhead transmission at 15 kV, 117 miles of electrical transmission by underground cables, about 30 MW of total installed generating capacity in eight locations and a few isolated generators. The Board also notes that the lines traverse regions of permafrost and extreme temperatures which add new dimensions to reliability of supply and safety to personnel. In respect of these considerations, the Board has examined the testimony and the exhibits of CAGPL and has the following view.

The proposed electric heating scheme is within the realm of present day technology and appears to be workable. However, since there is no operating experience on a similar scheme, the

Board would wish to be further assured about certain technical and safety features of the design. The Board would find it necessary, therefore, that the Applicant submit the detailed final design for approval before the construction of any pipeline commenced.

The final design and analysis to be submitted should amplify and clarify the following areas:

- The amount, degree and frequency of maintenance and inspection of generating stations, transmission line and the miniature breaker panels.
- Mechanical stability of poles in permafrost areas and the effects of icing and galloping conductors on the line.
- An accurate voltage level of operation of heat traces in the overland and underwater sections calculated by considering the inductive reactance and the proximity of steel pipes.
- The effect of welding sections of pipe for underwater crossings on the insulation of heat trace cable compression joints, and the possibility of leakage current return through water instead of the steel pipe.
- The possibilities of explosion in the conduits of underwater crossings due to electrical faults in the heat trace cables combined with gas leaks, and the effects of such an explosion.
- An assessment of the performance and sensitivities

of the relaying schemes for isolating broken conductors, leaky cables supplying the heat trace system, heat probes and underwater heat trace cables.

- Possibilities of water condensation in underwater heat trace conduits due to changes in temperature of the water body.
- The life of heat probes and the effects of low temperatures on the life of cross-linked polyethylene cables buried in the ground.
- The details of the design and the ground resistance of power station ground grids and ground mats installed at valves and other locations indicating the "step and touch" potentials in accordance with the AIEE "Guide for Safety in Alternating Current Substation Grounding" No. 80 of March 1961.
- Safety to operating personnel and animals due to induced voltage from faults and lightning strikes on the 15 kV line, indicating maximum fault currents and resistance to ground of the ground mats in summer and winter.
- Assessment of the lightning performance of the 15 kV line and a description of the design features including the location of arrestors.
- Details of intentional and other electrical grounding of the pipeline.
- An outline of the reliability of the equipment for

monitoring the status of various equipment.

- Periodicity of check and maintenance of ground mats and other grounding schemes.
- Evidence that cables and lines crossing water bodies and other overhead lines would satisfy the relevant local and Federal regulations and codes.
- Field tests substantiating the calculated induced voltages, before operations commence.

Thaw Settlement

Introduction

Thaw settlement is the antithesis of frost heave. While frost heave presents a problem where a chilled pipeline traverses unfrozen ground, thaw settlement can occur where a warm pipeline crosses permafrost terrain. Thaw settlement is the subsidence that occurs when soil, containing large amounts of ice, is melted and the resulting water drains away. As with frost heaving, if the settlement were uniform over the length of the pipeline, no problems would result that would threaten the pipeline's integrity. However, the proposed pipeline would run warm through about 220 miles of discontinuous permafrost between Fort Simpson and Zama Lake where the condition of the soil alternates between frozen and unfrozen at irregular intervals.

Magnitudes of Thaw Settlement

Predicted Settlement Magnitudes

Initially, CAGPL had preferred to design for frost heave rather than thaw settlement in the discontinuous permafrost zone.

Thus, the last point of cold flow (below 32°F) was placed as far south as was necessary to avoid sections of high settlement potential. Later, when the proposed last point of cold flow was moved further north by some 150 miles, from milepost 810 to milepost 660, thaw settlement became a significant problem. Areas of high thaw settlement potential, which previously would have been operated at below-freezing temperatures, would now be operated at above-freezing temperatures. The most significant segment affected in this manner would be the 60 to 70-mile long segment traversing the Alberta Plateau.

CAGPL testified that the results of the work done on the Alberta Plateau indicated that about 80 per cent of the terrain was permafrost, as opposed to about 30 per cent in areas further north but at lower elevations. It was indicated that permafrost in this region was up to 38.5 feet in depth. The occurrence of deep, widespread permafrost was said to be due to the existence of deep, poorly-drained, elevated peat bogs called peat plateaux and which, due to the latitude, elevation and the insulating nature of the peat material, were all frozen. In some cases, the permafrost extended only to the bottom of the bogs and in others it extended many feet below the level of the peat. The depth of the peat itself varied from a foot or less to over 50 feet. Thaw settlement estimates, based on drill hole data, indicated possible settlements of up to some 16 feet due to thawing of the bogs.

Since it would be very difficult and time-consuming to take a large number of bore hole samples and test each one in order to determine the amount of settlement that would occur at any given location, CAGPL developed a technique to predict the amount of settlement that could be expected from easily measured soil properties. This technique relied on a measurement of the original water content of the soil samples.

CAGPL admitted that this technique had a high degree of uncertainty, the uncertainty sometimes approaching the magnitude of the estimated settlement itself. This uncertainty was due to the great amount of scatter in the data used to establish the correlation. The Applicant indicated that the correlation could be improved by increasing the number of categories for which the correlation was done. In the submission before the Board, there were only three such categories correlated, those being fine-grained soils, coarse-grained soils and peat. Of the three, the data for peat was the most scattered.

CAGPL indicated that in many cases the uncertainty of the prediction was not important since it was evident that the actual settlement would exceed the settlement permitted by the design very quickly after the pipeline went into operation. In such cases, the only recourse would be to support the pipe.

Permissible Settlement Magnitudes

The permissible amount of thaw settlement would depend on the span over which the settlement occurred. Curves were submitted relating the permissible loads on the pipe to the amount of settlement permitted and the free span between supports. These curves were presented assuming a temperature differential of 85 Fahrenheit degrees and a permissible curvature of 0.00145 ft^{-1}.

The temperature differential is the difference between the temperature at which the pipe is placed in the ground and the temperature at which it is operated. This is important, since the steel pipe will attempt to expand as the temperatures increase, causing axial or column-type loading of the pipeline. In areas of significant thaw settlement, the restraining value of the soil around the pipe will diminish. Under these circumstances, should the maximum allowable temperature differential be exceeded, the pipe would buckle elastically.

The curvature, referred to above, is defined as the inverse of the radius - in this case, the radius of the bend in the pipeline. In studying thaw settlement, the Applicant studied the transverse or beam-type loads on the pipe due to the weight of the soil above it. If this type of load were too large for the span of pipe involved, the maximum allowable curvature would be exceeded and the pipe would be overstressed.

From these analyses, the Applicant established a maximum allowable settlement, at any point, of three to four feet. If it were evident that this criterion would be exceeded, special design measures would be taken.

Mitigative Measures

Initial Design

Before the frost heave re-design, CAGPL's design was simply to chill the line far enough south to avoid the major problem areas. South of the previously proposed last point of cold flow, the permafrost is confined to peat bogs that are generally not very deep. The Applicant indicated that, where the thaw settlement for normal burial would be excessive, it generally would have been possible to simply dig the trench a few feet deeper and eliminate or sufficiently reduce the thaw settlement. Areas that were found to have a thaw settlement potential too great to handle in this manner would have been avoided by minor re-routing.

Re-Design for Thaw Settlement

Design Description

It goes without saying that with the northward relocation of the last point of cold flow, those portions of the pipeline that initially were south of that point would remain south of it. Thus, south of the Alberta Plateau, the design was unchanged.

However, from milepost 661, on the southern edge of the Ebbutt Hills, to milepost 881, south of the Northwest Territories-Alberta border, a new design was necessary to mitigate the effects of thaw settlement.

The new design consisted of four basic components:

(i) pile-type pipe supports that would be installed in the unfrozen ground below the permafrost;

(ii) deep burial in areas where this technique would reduce the settlement to tolerable amounts;

(iii) grading the peat plateaux to the level of the surrounding terrain so that the pipeline could be buried below the water table of the peat bog; and

(iv) concrete weighting to control buoyancy in thawed areas.

In most areas deep burial would be sufficient to eliminate excessive settlement. Deep burial would also put the pipe below the water table. Thus, the pipeline would have to be weighted, probably with a continuous concrete coating to prevent it from floating.

In areas of excessive thaw settlement, CAGPL proposed the use of pile supports along with concrete weighting and grading of the peat plateaux. The peat plateaux would be graded so that a part of the width of the right-of-way would be level with the surrounding terrain. A ditch would be cut in the graded area and the pipe placed in the ditch. Parts of the ditch would be widened to allow the installation of the pile supports. To avoid buoyancy problems, the pipe would be weighted, probably with a continuous concrete coating.

Operation

During the hearing, CAGPL described how the design would work. As the peat around the operating pipeline melted it would settle. In areas designed to accommodate small settlements the pipeline would settle with the soil. In areas designed for large settlements the pipe would be left supported by the pile supports but covered by water. As the settlement progressed the peat that was initially graded off would be used to fill in the resulting settlement ponds. This would require continued activity along the right-of-way after construction but CAGPL gave testimony that no one location would be expected to require maintenance every year.

Pile Supports

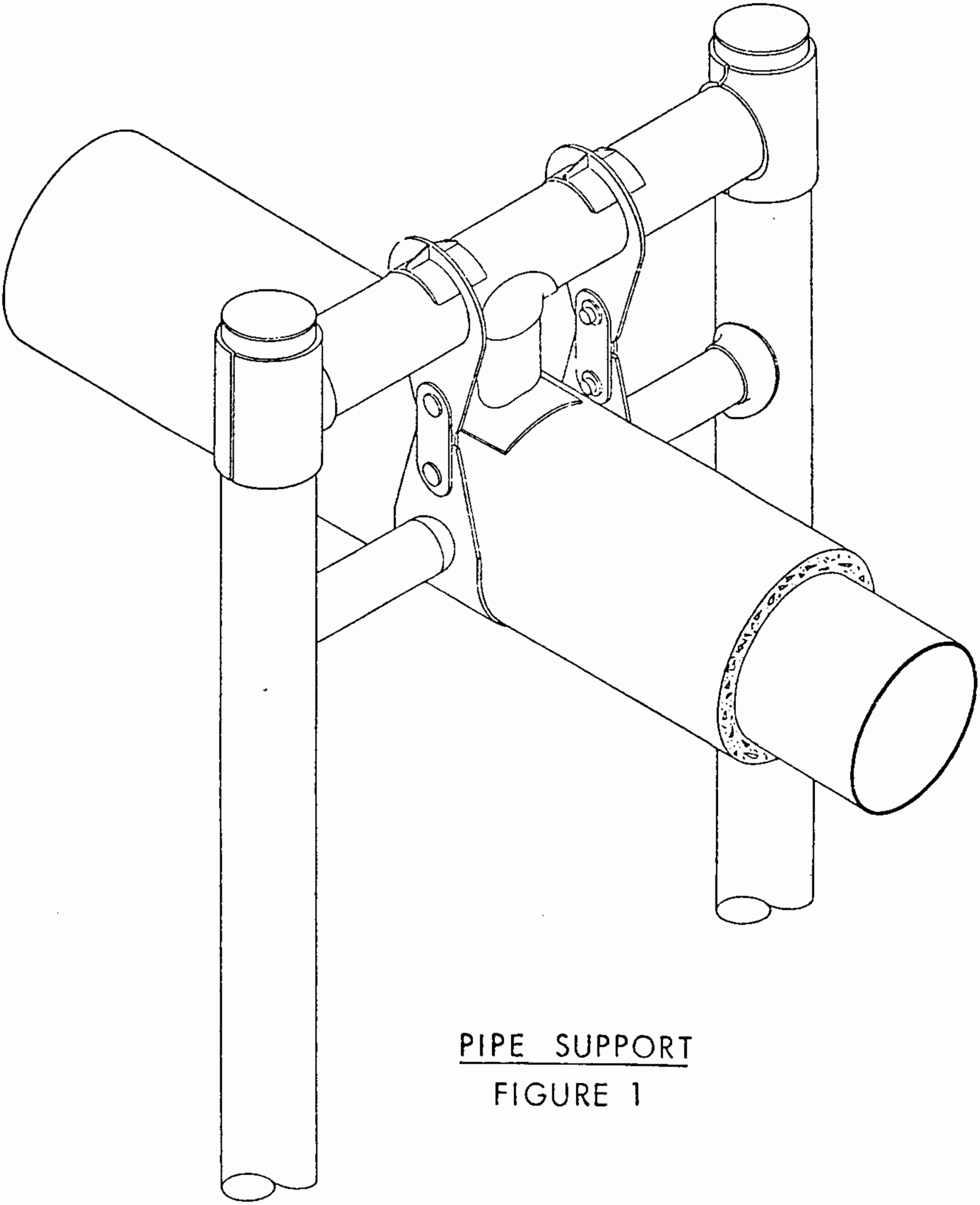
Each pile support would consist of two piles from which the pipe would be suspended. The submitted design would allow longitudinal movement and some lateral movement of the pipe (see Exhibit No. N-AG-3-179, Appendix 10, Figure 1, attached). The piles would be placed in holes drilled to the bottom of the permafrost and then driven into the solid, unfrozen soil below. The pipe support members would then be installed and the line backfilled.

CAGPL indicated that the overriding consideration in the design of the pile supports was the limiting of lateral movement of the pipe; thus eliminating or reducing the pipeline's negative buoyancy would not allow the support's design to be altered.

Evidence was given that approximately 19.6 miles of pile-supported pipe were included in the preliminary design, requiring over 1,000 supports to be installed. This assumed an average spacing of about 100 feet.

The spacing was derived by assuming a maximum net load on the pipe of 1,500 pounds per foot. The net load on the pipe included the submerged weight of the pipe plus the weight of any overburden acting on the pipe. Evidence was given that 1,500 pounds/foot was a greater net weight than would normally be expected.

Exhibit No. N-AG-3-179
Appendix 10
Figure 1



PIPE SUPPORT

FIGURE 1

CAGPL admitted that if there were areas from which the water would drain if they were to thaw, the design would have to be altered, either by adjusting the pile spacing or adjusting the weight of the over-burden. These areas would have to be identified in advance of construction.

Pipe Weighting

CAGPL planned not only to weight the pipeline in areas of thaw settlement but also in parts of the route where a flooded ditch was a probability. Evidence was given that much of the route in the discontinuous permafrost and muskeg areas would have wet ditches and that weighting would be required to cause the pipe to sink during construction. For these reasons, a total of 111 miles of continuous concrete coating was proposed.

In the initial design buoyancy control was based on 20 per cent negative buoyancy, the 20 per cent being related to the weight of the water displaced. CAGPL indicated that in establishing the weighting requirements, it had considered a range of negative buoyancies between 5 per cent and 20 per cent. The actual value to be used was not clearly set out and was subject to further design work.

Route Optimization

In cross-examination, Counsel for Foothills queried the fact that, in spite of the change from cold flow to warm flow, CAGPL had not changed the route. CAGPL agreed that in portions of the line that were chilled, it would be desirable to maximize the fraction of the route traversing frozen ground and that in portions of the line that were unchilled, it would be desirable to maximize the fraction of the route traversing unfrozen ground.

It added, however, that due to the random occurrence of the peat plateaux and speckled bogs, an attempt by CAGPL to maximize the length of unfrozen terrain that would be traversed south of the last point of cold flow had not proved fruitful.

Views of the Board

With regard to thaw settlement, it is the view of the Board that while the design for the mitigation of the effects of settlement appears adequate, there is some cause for concern regarding the plan to backfill the thaw ponds in peat lands. Since it appears that thaw will occur laterally as well as vertically, and since the pipeline would provide a source of heat during both summer and winter, it may prove difficult to safely approach the pipeline with heavy equipment.

While it is evident that considerable investigation of the proposed route has been carried out by CAGPL, a more complete assessment would be necessary before the design could be finalized.

Buoyancy Control

Introduction

There are two principal reasons for controlling the natural buoyancy of the pipe: (a) to submerge the pipe in a river crossing or water-filled ditch during construction, and (b) to keep the pipe from floating to the surface during operation and, in some cases, after construction but before operation.

During the hearings, CAGPL described five methods which could be used for buoyancy control these being concrete weighting, ditch flooding, frost anchors, deep burial and heavy-walled steel casing. The last of these was introduced as part of the "Frost Heave Re-Design".

CAGPL testified that, with the exception of the steel-cased line segments, continuous concrete coating served as the basis for the cost estimates on all parts of the line requiring buoyancy control. The choice of other methods would be a matter of economics.

Buoyancy Control Methods

CAGPL indicated early in the hearing that the methods described for buoyancy control were presented as possibilities and that a final set of solutions could only be developed after further study.

Concrete Weights

The concrete weighting system that CAGPL appeared to favour was the continuous concrete jacket type. The cost estimates were based on this method, and it was indicated that in many areas other concrete weighting systems were not appropriate. For example, concrete saddle weights could not be relied upon to stay in place in an area of thaw settlement.

Concrete-coated pipe could be used to satisfy both construction and operational requirements for negative buoyancy. In areas where the ditch might be flooded during construction and in river crossings, this system had already been selected.

Ditch Flooding

Ditch flooding was one of the novel buoyancy control techniques put forward by CAGPL as a possibility. This method could only be used where the active layer, even in disturbed terrain, was shallow relative to the depth at which the pipe would be buried. It could not be used in water crossings.

The technique is very simple. The pipe would be placed in the trench and the trench would then be partially backfilled and partially flooded, the water being allowed to freeze. The backfilling would then be completed.

The regions in which this system could be used would be chosen with the aid of the Applicant's geothermal model. It would be necessary to its success that the backfill be completely frozen by the end of winter and that the summer thaw-back not be great enough to release the pipe.

CAGPL indicated that this system would be particularly well-suited to construction of the Prudhoe Bay supply line along the Arctic coast, but it could be used elsewhere. Assessments made of this region indicated that there would be an adequate supply of water for ditch flooding.

Frost Anchors

A frost anchor consists of two rods which are placed in the frozen ground and are attached to the pipe by a strap or some similar means.

CAGPL indicated that this type of buoyancy control device would be well-suited to the Mackenzie Delta region. This region experiences flooding during the spring run-off and during summer storms. These events are usually of quite short duration and would only be a problem after construction and before start-up of the line. After the pipeline was in operation, the chilled line would freeze itself into place and buoyancy would no longer be a problem. It was also indicated that it would be possible to use frost anchors along the Arctic coast.

CAGPL testified that the design of a usable frost anchor was still in the conceptual stages. Tests had been carried out to determine the pull-out resistance of the rods, but no other design work had been done.

CAGPL also indicated that this technique had not been used before in North America.

Deep Burial

Deep burial for buoyancy control would consist of simply burying the pipe deep enough to permit the weight of the backfill to hold the pipe in place against any buoyant forces that might develop. In ice-rich terrain, the native soil would have to be replaced with thaw-stable borrow material.

CAGPL indicated that this technique could be used almost anywhere except along the Arctic coast and in unfrozen marshes or muskeg. Along the Arctic coast, large amounts of borrow would be required to replace ice-rich soils, and, in unfrozen marshes and muskeg, weights would be required to sink the pipe during construction.

CAGPL was unaware of any other pipeline which has incorporated the weight of the backfill as part of the design for buoyancy control. However, it indicated that in many instances other pipelines were held in place by the weight of the backfill.

Steel Cased River Crossing

As part of the re-design submitted by CAGPL in early 1977, a new method of buoyancy control was introduced employing steel casings at heat traced river crossings. The steel casing would serve two purposes: first, to protect the insulation, and in large crossings, the electrical cables, from damage by water or construction activity; and second to provide enough weight not only to sink the pipe but to force the line to conform to the shape of the underwater ditch.

The locations where this type of construction would be used included the dual channel crossings in the Mackenzie Delta and all rivers that would be crossed by a chilled pipeline and which have frost-susceptible beds.

CAGPL admitted that this design would result in a pipeline for which the allowable curvature would not be very large. However, it expressed confidence that the submarine ditches could be well enough prepared to avoid overstressing of the line or having insufficient burial.

Views of the Board

With regard to buoyancy control, the Board is of the opinion that, in general, the methods proposed for buoyancy control are adequate.

Permafrost

Permafrost is defined as soil, the temperature of which is below 32°F all year round. It can be solid rock, sand, clay, boulders or bog. It may not even be frozen in a real sense because of dissolved salts or minerals. During the hearing, the term permafrost was more loosely used to mean soils that actually contained frozen water. Most of its unique properties arise from the frozen water content.

Permafrost can be divided into two broad categories, continuous and discontinuous.

Continuous Permafrost

Continuous permafrost areas are those that are almost totally frozen, except under water bodies such as lakes and rivers. There are occasional unfrozen patches that are not under water, but these are rare. Permafrost depths vary from over 1,000 feet in the high Arctic to about 100 feet or so in the southern portions of the continuous zone.

The CAGPL pipeline system would traverse continous permafrost terrain from Prudhoe Bay, along the Arctic coast, through the Mackenzie River Delta and along the Mackenzie River to about milepost 263 near Fort Good Hope.

Since water freezes at a definite temperature, the interfaces between permafrost and unfrozen soil are distinct and there is no gradual transition from one to another. At the edges of rivers and lakes, the permafrost boundaries are almost vertical. This feature becomes important in building a pipeline across these interfaces.

While all permafrost is not ice rich, some areas contain massive ice formations which are often many feet thick. Other areas contain a considerable amount of ice distributed throughout the soil, sometimes in layers. This feature of permafrost is the main reason for operating the pipeline at below-freezing temperatures, since thawing this ice would cause very large settlements.

Another feature of permafrost terrain is the so-called active layer. This is the surface layer that thaws in summer and freezes again in winter. Its thickness can vary from a few inches on the Arctic coast to several feet in the southern parts of the continuous zone. The depth of this layer at any location depends on the properties of the surface. Surface disturbances can cause a large change in the thickness of the active layer, usually increasing it.

Discontinuous Permafrost

Discontinuous permafrost terrain is simply terrain that is a mixture of frozen and unfrozen ground. In some areas the ground is predominantly frozen with small thawed islands of various sizes and in other areas most of the ground is thawed with permafrost inclusions. The thickness of the permafrost in such areas varies from about 3 feet to 200 feet. The active layer thickness can vary from about 3 feet to nearly 10 feet. Variations in the proportions and thickness of permafrost terrain are affected by latitude, elevation, surface characteristics, terrain type and the aspect of slopes.

In general, the proportion of the ground that is frozen diminishes with decreasing latitude. However, on the Alberta Plateau increased altitude has a marked effect on the proportion of permafrost. CAGPL indicated that north of the Alberta Plateau the percentage of permafrost terrain was about 30 per cent while in some places on the plateau itself the percentage rose to about 80 per cent.

CAGPL also indicated that in the region south of Willowlake River, it was possible to correlate the terrain type with the occurence of permafrost. Testimony was given that in this part of the route permafrost always occurred in peatlands. The Applicant indicated that north of Willowlake River no similar correlation was possible. One possible reason put forward by CAGPL during the hearing was that south of Willowlake River the permafrost had been degrading for the past two hundred years, the peatlands thawing much less rapidly than the other terrain types.

Identification of Permafrost

The accurate identification of permafrost and the location of its boundaries is essential to the success of CAGPL's design in the discontinuous permafrost zone. In the chilled section of the pipeline it is important to heat trace the line only in non-permafrost segments since heating the permafrost would result in intolerable thaw settlements. In the unchilled section, it is important to design the line to withstand thaw settlement in segments traversing permafrost. Such areas must be identified in advance of the actual installation since the necessary materials must be brought to the site before construction.

CAGPL's evidence indicated that a great deal of study had been done of the terrain along its proposed route. A significant part of this effort was directed towards the study of permafrost, its occurence and its properties.

As well as the traditional methods of exploration such as soil sampling, CAGPL has undertaken the development or refinement of at least three other methods that are not commonly used in conventional pipeline design. These three techniques were terrain typing, aerial photography and geophysics. These techniques are not independent. Each relies, to varying degrees, on the others.

Terrain Typing and Aerial Photography for Permafrost Identification

CAGPL submitted evidence and testified that, on the basis of the appearance of the ground, the identifiable vegetation and surface features, it is possible to divide the terrain along the pipeline route into identifiable "terrain units". Each of the different types of terrain units can be characterized by common properties. Evidence was given that one of the properties used to characterize the terrain was "the occurrence and distribution of ground ice and the distribution of frozen and unfrozen ground in the discontinuous permafrost zone".

The process of terrain typing involved investigating areas that were similar in appearance and correlating their appearance with their properties. For example, is was determined that GLB (Glacial Lake Basin) terrain was generally susceptible to frost heaving and the BS (Speckled Bogs) and PT (Peat Plateau) generally contained permafrost.

Testimony was given by the Applicant that the occurrence of permafrost could only be determined accurately from air photos in the region south of Willowlake River. North of this point, other methods would have to be employed.

Geophysics For Permafrost Identification

CAGPL submitted evidence describing the development of geophysical exploration techniques for the detection of permafrost. These techniques are, in reality, methods of measuring the electrical resistivity of the soil and rely on the fact that, generally, frozen soil has a very much higher resistance than unfrozen soil.

CAGPL admitted that the geophysical method was not fully developed but stated that any technique that indicated the presence or absence of permafrost was better that "going blind" even if it were not 100 per cent reliable.

The accuracy that CAGPL indicated has been achieved was, in its opinion, very useful. Testimony was given that with proper interpretation and calibration with "ground truth" information, it was possible to measure the thickness of permafrost to an accuracy of ± 30 per cent and to establish the location of boundaries between frozen and unfrozen ground to ± 15 feet. There were, however, some difficulties.

The witness for CAGPL stated that gravel and sand, even in the unfrozen state, had high resistances and would be indicated by the equipment in the same way as frozen ground. In addition, soil with multiple layers of different materials gives results that are, in the absence of a knowledge of the soil stratigraphy (layering), difficult to interpret. For these reasons, plus the general variability of soils, it would be necessary to drill a large number of calibration test holes in conjunction with a geophysical survey.

The Applicant testified that since the geophysical technique could only locate permafrost interfaces with an accuracy of ± 15 feet, it would be possible for a small, unfrozen zone, on the pipeline route, to be overlooked by a geophysical survey. However CAGPL indicated that it was confident that these small unfrozen islands could be identified by the construction crew during ditching. CAGPL indicated that it would be necessary for a continuous geophysical survey, and the associated drilling, to be done at least a year and a half ahead of the construction of the pipeline and preferably earlier.

Exploratory Drilling for Permafrost Identification

The standard method for investigating soils is to drill holes and take samples of the soils at verious depths. CAGPL, in preparation for its application and even during the course of the hearing, was engaged in this type of exploration.

Drilling exploratory test holes is, in many instances, the only means of determining what is below the surface. The detection of permafrost under rivers, and determinations of soil stratigraphy and water content can only be done by soil sampling. The correlation of terrain types with typical properties as well as the calibration and verification of geophysical surveys must be done by drilling holes and obtaining samples.

CAGPL testified that test holes numbering in the thousands had been drilled by it or by others from whom data were available such as the Department of Public Works. The Applicant also indicated that a very large and as yet undertermined number of holes would have to be drilled before it would be possible to complete the design of the pipeline.

Views of the Board

With regard to permafrost and the difficulties associated therewith it is evident that CAGPL has made a considerable effort to familiarize itself with the various aspects of the novel and complex problems that permafrost terrain might pose to the designers of a pipeline. The Board is satisfied that the most significant problems have been identified.

With regard to the proposed methods of permafrost exploration and identification, while the geophysical methods presented by CAGPL appear to yield excellent results, the results presented were rather limited. The Board agrees with CAGPL's position that, while more development is required, it is useful to have a tool of this nature in addition to other more costly and time-consuming methods such as test hole drilling. The geophysical methods put forward by CAGPL appear to have the potential for reducing the number of test holes that would be required to map permafrost along the pipeline route, and should improve the confidence of the builder that the number of undiscovered non-permafrost segments along the route would be small. In the event that a certificate were issued, CAGPL would be required to provide confirmative evidence that the geophysical methods put forward could be relied on to produce consistent results.

Slope Stability

Introduction

Slopes are a terrain feature that occur almost everywhere and the Arctic Coast and the Mackenzie Valley are no exception. Instability, or the potential for landslide-type failures, is an ever-present danger wherever there are slopes. The somewhat unusual properties of the soils that occur along the pipeline route, particularly the occurrence of ice-rich permafrost in fine-grained soils, make this problem somewhat more severe for pipelines built in the north.

CAGPL described the various types of slope failures and their causes in its application and during the hearing. Failures were divided into two categories, shallow failures and deep-seated failures.

Shallow failures can be caused by thawing. Since thawing can be accelerated by construction, shallow failures would be expected to be more of a concern on the pipeline right-of-way than in the adjacent terrain. Shallow failures, by themselves, are not a major threat to the pipeline. However, their occurrence could be followed by erosion.

Deep-seated failures generally involve soil to a depth of eight to ten feet. They can be caused by a number of thaw-associated mechanisms and by creep of frozen and unfrozen soils. This type of failure would be much more of a threat to the integrity of the pipeline since the earth that slides may contain the pipeline.

In its assessment of the problem of slope stability, CAGPL relied, to a great extent, on aerial photography and airphoto interpretation. Stereo pairs were used to determine slope angles, and terrain typing was used to assess the likelihood of instability. The Applicant indicated that some sites had been drilled to verify the assessment and that other sites had been visited or simply over-flown.

Identification of Stable and Unstable Slopes

CAGPL submitted several criteria on which it had based its slope stability assessment. The first of these was the 3° slope criterion. Evidence was given that slopes under 3° were generally stable under all conditions. CAGPL testified that this was an arbitrary division point based on experience. A second criterion was the appearance of the surface. If bedrock was visible in the photographs or was evident during the visits, the Applicant concluded that instability was not likely. Clay slopes would be considered more likely to fail than gravel slopes.

CAGPL testified that a considerable amount of additional work would have to be done investigating those slopes that were considered as possibly unstable. Soil samples would have to be taken from these slopes and tested in the laboratory to determine the ice content and the propensity for the soil to drain itself when thawed.

Measures for Slope Stability Control

CAGPL's evidence indicated that the most important measure that would be taken to reduce slope instability on the pipeline route would be to judiciously select a route that avoided unstable slopes wherever possible. It was indicated that this was not a total solution.

Other techniques for slope stabilization that were submitted by CAGPL included construction of toe berms, revegetation, and minimizing disturbance due to construction. The Applicant indicated that the fact that the gas was chilled was a stabilizing measure in itself in that it tended to maintain the soil around the pipeline, in continuous permafrost areas, in a more solidly frozen state. The Applicant agreed that, since the redesign left less ground chilled,' the slope stability problem might be increased somewhat.

Extent of Slope Stability Problems

CAGPL testified that there were about 700 potentially unstable slopes along the pipeline route. It was also indicated that slope instability was not confined to the discontinuous permafrost zone, and that "Instability is a very common feature in permafrost terrain." (It was not clear if the number of 700 was based on the study of only the discontinuous zone.)

Some of the more important slopes that must be stabilized would be at the banks of rivers. In some cases, rerouting to avoid potentially unstable river crossing would not be practical. When questioned about the results of its assessment of the potential for instability, CAGPL replied, "There are some rivers (in permafrost terrain) where it is very difficult to find any stable ground."

CAGPL stressed the fact that the design put forward was preliminary and that a considerable amount of work would be required to prepare the final design.

Views of the Board

With regard to slope stability, the measures proposed to ensure the security of the pipeline appear reasonable and workable. However, considering the stated prevalence of slope instability in permafrost terrain, the Board believes that extreme care would have to be taken in the selection of the route. In addition, in view of the indication by witnesses for Foothills of the difficulties encountered along the Alyeska Pipeline with regard to slope stabilization, particularly the stabilization of cut slopes, the Board believes that extreme care would be required to avoid disturbing sensitive, sloping terrain during construction. Should a certificate be issued, CAGPL would be required to satisfy the Board as to the completeness of its final assessment and the adequacy of its construction procedures with regard to sensitive, sloping ground.

Drainage and Erosion Control

Erosion Control Methods

CAGPL stated that revegetation would be its primary method of controlling erosion. However, other methods of control would be required to prevent serious erosion in the early years after construction.

The approach taken by CAGPL to erosion control was to prevent build-ups of moving water on the right-of-way. This would be accomplished through the use of backfill mound breaks to allow water to cross the right-of-way on side slopes, diversion dikes to divert water off of the right-of-way, flow obstructions to break up flow and to limit its velocity, granular berms to reduce erosion due to flow along the pipeline, granular caps to allow water movement through the backfill mound and gabions (gravel filled screen retainers) in areas of large potential settlement.

Backfill mound breaks are gravel protected breaks in the spoil berm placed over the pipeline. The water intercepted by the pipeline right-of-way would be directed towards a mound break and permitted to cross it and leave the right-of-way.

Diversion dikes are low earth barriers designed to divert water to the side of the right-of-way where the line is descending a slope. They would be placed in a herringbone pattern along the slope and spaced so that the flow of water would not build up sufficiently to cause erosion.

In areas where the flow through the mound breaks would be sufficient to cause erosion on the downslope side, flow obstructions such as rocks and trees would be placed on the right-of-way to break up the flow and reduce its velocity to the extent necessary to prevent erosion.

Where significant flows along the pipeline between mound breaks were possible, granular berms would be used. This would involve covering the upslope side of the berm and the adjacent ground with gravel for all or part of the distance between mound breaks.

The granular cap was intended to allow water to pass through the backfill mound in areas where it would be undesirable to collect the flow and allow it to cross at a mound break. The effectiveness of this design would depend on the level to which the backfill would be kept frozen by the chilled pipe.

CAGPL testified that while, in general, gravel would thaw deeper than other soils, it would be possible for the frost bulb to form in the berm to a level above the rest of the right-of-way, turning the berm into a barrier.

While gabions were mentioned as a possible measure in areas of high thaw settlement potential, CAGPL admitted that they were not looked upon favourably and probably would not be used.

Hyrological Methods

In order to use the various methods proposed for controlling erosion, a knowledge of the amount of water that might be intercepted by the pipeline is required.

If the erosion control measures are needlessly overdesigned, then they would also be overly costly, and if they are underdesigned, unacceptable erosion would occur, which would also be costly.

CAGPL has used, at least for the purposes of cost estimating, a method of drainage basin modeling. In its simplest form, this model states that when it rains water soaks into the ground at the lesser of either the rate at which the rain is falling or some maximum rate that depends on the soil properties. Any water that does not soak into the ground will run downhill on the surface. Thus, the more intense the rain storm and the longer the slope, the greater would be the rate of arrival of the run-off at the right-of-way. CAGPL used the relationship between the run-off rates and the storm intensity, along with the intensity distribution of storms and cost assumptions for construction and maintenance, to prepare a preliminary sample design. Testimony was given indicating that the results of the analytical study, described above, agreed reasonably well with designs using more traditional methods that rely heavily on historical data.

This technique was attacked by Foothills in cross-examination on the basis that the mathematical approach could not be used to indicate the correct location of such items as mound breaks and diversion dikes on the right-of-way. CAGPL agreed but stated that that was not the intent. The method had been used to prepare cost estimates and to indicate to the designer what work was still required in the field.

Subsurface Drainage

CAGPL testified that in some areas, the presence of the chilled pipeline would interrupt subsurface drainage. This was more of a concern in permafrost areas since ponding due to blocked drainage would result in permafrost degradation and thaw settlement. Several methods of assuring the subsurface drainage were proposed.

One of the most controversial proposals put forward was the insulated culvert. CAGPL proposed to place insulated culverts under the pipeline and build granular gathering and dispersal beds at either end. It claimed that as long as there was a significant flow through these culverts, they would not freeze closed.

A second proposal that was put forward was the creation of diversion ditches in the undisturbed ground beside the pipeline. These ditches would be formed without removing the vegetation by simply removing the snow cover and driving over the required location a few times. When the spring came, the area disturbed in this way would melt deeper and settle, forming the required channel.

The third method mentioned was the use of granular berm caps. These were discussed in the previous section.

Views of the Board

With regard to the proposed methods of drainage and erosion control, while the actual location and extent of the measures to be taken would be part of the final design, it is the view of the Board that the methods proposed by CAGPL are reasonable and proven in practice.

With regard to the methods that would be employed in sizing the structures, it appears that the methods of predicting the flows that they will be required to handle are adequate. However, as was indicated by the Applicant, a considerable amount of work remains to be done in the preparation of the final design.

With regard to the control of subsurface flow, it is the view of the Board that the somewhat controversial design has not been shown to be effective and, should it become part of a final proposal, the Board would have to be satisfied as to its utility. While the question of subsurface flow and the possible blockage of it by a chilled pipeline is of some concern from an environmental point of view, the Board is satisfied that such an occurrence would not pose a threat to the integrity of the pipeline.

Borrow Materials

In its original application, CAGPL stated prior to the frost heave redesign that it would require approximately 30 million cubic yards of borrow material for the construction of the pipeline and related facilities; of this, 27.8 million cubic yards would be required north of the 60th parallel. This included a requirement for 5.77 million cubic yards for the Prudhoe Bay lateral from the Alaska-Yukon border to Travaillant Lake. The route revision selecting the Cross-Delta rather than the Circum-Delta alternative involved a borrow requirement of 2.73 million cubic yards. CAGPL indicated the requirements for this route revision but did not state how borrow requirements would be reduced by dropping the previously proposed route. Total estimates were not revised. Similarly, the Applicant stated that in the frost heave redesign, surcharge berms had been eliminated, but it did not revise its borrow requirements accordingly.

The Applicant detailed its requirements in terms of total volumes required for each construction spread. Within each spread, a general breakdown was given of the requirementss for various facilities. However, a breakdown of the materials quality required for these facilities was not provided.

In order to supply the required quantity of materials, it was proposed to open borrow pits in unconsolidated materials, and quarries in rock. On the average, there would be a pit every eight to ten miles. However, on some sections the distance between pits might be condierably greater than ten miles.

The Applicant submitted detailed information on over 200 pits located on the Prime Route and on various alternative routes. The listing included preferred pits and alternatives, should some not be acceptable from a materials quality or an environmental point of view.

Included for each proposed pit was information on its location, deposit and materials types, the estimated dimensions of the deposit, overburden thickness, recovery depths, and also general information on ice contents and drainage characteristics. Estimated volumes of materials recoverable from the deposit and volumes required for the project were given for each pit. The above information was obtained principally from existing government reports and the Applicant's geotechnical information.

The Applicant recognized that in some areas there would be a paucity of some types of materials, e.g., from Richards Island to Thunder River (mileposts 0-172) there would be abundant sand but little gravel. The greatest demand for material would be for the

Delta crossing. However, there were no borrow sources for a 52-mile stretch from Shingle Point to the Ya Ya Esker.

Most of the borrow materials required for the project would be for general fill or subgrade for which quality requirements would not be stringent. The Applicant stated, however, that it would require higher quality materials, of specific grades and sizes, for various specialized uses on many aspects of the project. These would include surfacing materials for airstrips and roads, aggregate for concrete, graded material for gabions, other slope and river bank protection, and drainage requirements, including sized material for rip-rap. The requirement for sand bedding material to protect heat trace cables was also identified.

The Applicant stated that, in the development of borrow pits, it would make further evaluations on a site-by-site basis.

Views of the Board

The Applicant has stated its quality requirements only in general terms. It is obvious that there would be shortages of materials in some areas. Good quality and specific quality materials would not necessarily be found at the location where the demand for them was greatest. Exploitation of deposits outside the pipeline corridor, and extensive crushing and processing of materials to meet some of the specialized requirements of the project, probably would be necessary. The probability of the need to bring materials from outside the corridor or from considerable distances within the corridor is high, especially for river bank and slope protection material and for sand bedding material required for heat trace cables. The

Board is cognizant that since filing the detailed reports on borrow, dated July 1974 and April 1975, the requirement for bedding material for the pipe has been changed from general fill to high quality sand. The Applicant has not indicated the proposed source of this material nor how it would be processed.

The Board is of the opinion that processing and placement of the material might also present problems, particularly if sand were mined in permafrost areas directly and placed in the winter. There is the possibility that it would have sufficient moisture to provide particle cohesion, resulting in hard, irregular chunks for bedding of the insulated pipe and the possibiity of insulation damage. It might be necessary to have the sand thawed, dried, stockpiled and kept in a dry loose state until placed.

If the total projected demands for granular materials by the pipeline project, highway, community needs and industrial development are considered, areas of shortages and/or depletion of high grade granular materials can be identified.

The Board would require that the Applicant re-examine the availability of materials in light of the latest estimates of quantity and quality and the current modifications to the project design.

Since most of the granular requirements for the project are for general fill, the specifications of which are fairly wide-ranging, no major problems are expected. However, in the Delta area where there is a paucity of coarse material, some haul distances may be exceedingly long. The Board would require the

Applicant to coordinate its demands for materials with others having need of granular materials.

River Crossings

General Design Description

CAGPL submitted two significantly different river crossing designs. The first would apply to river crossings in the part of the system where the gas would be flowing at temperatures above freezing and where frost heave would not be a problem. The second type of design would apply to crossings at which frost heaving would be a problem. Notwithstanding the differences that would exist between these two designs many problems are common to all river crossings.

CAGPL stated that the key factors affecting river designs were scour, which would determine the depth of burial required, and lateral migration of the channel, which would determine the location of the sag bend and the weighting requirements.

Flood Predictions

CAGPL gave evidence that, while the crossing designs would not generally be sensitive to extreme floods, certain aspects of the designs, such as pipe weighting and the design of river training structures, would require a knowledge or an estimate of the magnitude of extreme flood events.

In response to a Board request for additional information, CAGPL replied, "The Applicant recognizes that there is a lack of hydrological information for small streams, particularly north of the 60th parallel..... The Applicant has developed techniques to improve the accuracy of the design flood estimates in these areas where data are lacking. The techniques being used by the Applicant include regression analysis, watershed simulation and other modelling techniques."

One method put forward by CAGPL was based on the drainage area. This method stated that the maximum discharge from a drainage area was proportional to the square root of the area drained. It was admitted that this curve was empirically derived. It was based on recorded extreme floods from rivers all over the world.

While the filed material indicated that drainage areas had been modelled, CAGPL testified that no drainage basin characteristics other than area were considered. The inclusion of other characteristics, such as slope, and types of materials, would require a major research project lasting many years.

Regression analysis is a method of curve fitting that gives a best fit curve through a set of data points. When asked how this technique could be used in the admitted absence of data, the witness replied that this method "has been used by various governmental people with respect to hydrology in the Mackenzie River Valley so that I think it is an appropriate method."

It was repeatedly stressed by CAGPL that a detailed knowledge of the maximum flood was not essential since many of the analyses involved the assumption that the river was full to its banks.

River Bottom Scour

Scour is the removal of bottom material by the river current. While some scour can be caused by ice gouging, CAGPL indicated that this would be very limited.

The basis of the scour calculations was given as the average depth of the river channel. In order to calculate the scour depth, the depth was multiplied by a factor. The witness indicated that at a confluence, the factor used could be from 2.5. to 3, while in a relatively straight part of the river, it would be between 1.4 and 1.8. It was also indicated that the greatest depth of scour could be expected at the confluences of two or more river channels. Deep scour would also be expected at the outside of bends in a river.

CAGPL gave evidence that there is a definite relationship between the width of a river and its depth. While the witness admitted that using this relationship to estimate river depths from aerial photographs did not produce very exact results, it was nonetheless possible to predict the location of scour holes in rivers at river bends and confluences. CAGPL indicated that the increases in depth in relatively straight portions of a river occurred in an unpredictable manner.

Another form of bottom scour which was discussed was sediment waves. The Applicant described these waves as analogous to sand dunes. These waves can travel several feet a day and may be up to ten feet or more in height. The witness indicated that these forms are not evident from visual inspection. CAGPL stated that studies would be required in order to determine the type of sediment wave that might be expected and soundings would have to be taken to "identify such bed-forming processes" to ensure that the pipe would be buried below the trough of these waves.

Bank Stability

During the hearing, CAGPL indicated that instability was very common in permafrost terrain. Landslides are a frequent occurrence and there are some rivers where it is very difficult to find stable ground. It was indicated that constructiom might aggravate the situation by increasing the thickness of the active layer.

CAGPL's concern about river bank stability was not limited to rivers in permafrost terrain. Testimony was given that the Smokey River, a river already crossed by Trunk Line, was unstable as well. It indicated that this crossing would be one of the most difficult crossings to build in Alberta and that bank stability problems would require intensive study.

CAGPL stated that this was one of a number of crossings under consideration for relocation. It stated that it had not done any drilling here and thus did not know precisely how stable the slope was at this point. If it were judged less expensive to relocate than to stabilize the currently proposed crossing, the relocation would be made.

Where it was expensive or impossible to locate the pipeline in stable river banks, or where the pipeline was inadvertently installed in an unstable slope, CAGPL indicated that certain measures could be taken. These measures as set out during the hearing, were:

for slopes in thawed ground:

installation of toe berms;

unloading slopes by grading; and

draining slopes to reduce pore water pressure;

and

for slopes in frozen ground:

gravel blankets;

insulation to prevent thaw; and

installation of toe berms.

Bank Erosion and Channel Shifting

In its submissions in response to the Board's request for additional information, CAGPL stated, "Lateral migration resulting from bank erosion is probably the major cause of pipeline exposure at a buried river crossing. Bank erosion is a sporadic process in which significant amounts of material are removed only during periods of high flow. There are numerous examples where a river bank has been relatively stable over a period of years during which floods were moderate and yet has been subjected to more than 100 feet of erosion during the course of a single major flood...... In Northern regions the phenomenon is further complicated by the occurrence of ground frost at or near the boundary of an eroding bank."

When questioned about this statement, CAGPL indicated that it was confident that erosion of this kind could be anticipated. CAGPL stated that it had between 25 and 40 years of bank erosion history in the form of aerial photographs. It felt that with this information, plus a knowledge of the properties of the river bank material, a useful assessment could be made of the amount of migration that must be allowed for in the design.

The witness stated that the complication that arose where the banks were frozen derived from the higher resistance of ice to erosion. While the surface of the bank would probably erode very rapidly during a flood, the erosion of the underlying frozen ground would be limited to the rate at which the flowing water could melt the ice. In such a case, the erosion would occur at a more uniform rate and sudden 100-foot bank migrations could not be as common as they are further south.

It is important in designing a river crossing to locate the sag bends(1) far enough back from the existing river bank so that erosion does not uncover the pipe.

CAGPL stated that it would be possible to control river bank migration by the use of river training structures and bank armouring. Bank armouring could be provided in the form of rip-rap or gabions. Other methods such as concrete armouring or prefabricated erosion control systems were also mentioned as possibilities.

Dual Crossings

The Applicant has chosen to construct dual crossings at several major river crossings. Testimony was given that this was a policy decision taken by CAGPL. One of the reasons given for

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(1) Sag Bend: the downward bend in the pipe beginning the transition from normal burial depth to the crossing depth.

dualing the crossings was the very long downtimes that could be experienced in the event of a failure at a crossing. Testimony was given that the pipeline could be out of operation for as long as three months if a failure occurred in early spring.

While testimony was given that the decision to build dual crossings was not due to geotechnical considerations, the spacing of the crossings was based on the estimate that the deep part of a single scour hole would not be more than one river width in length.

CAGPL testififed that the statistics on failures were not of much use in deciding whether or not to construct dual crossings. It indicated that it did not know if dualing the crossings would be beneficial or not. It was stated, however, that in the event of a failure, complete service would not be lost, and that gas would continue to be delivered at something more than half the design rate.

Most of the dual river crossings are in the Mackenzie Delta and all of these are of the steel-cased, heat traced design.

Design for Frost Heave

The main differences in the design at crossings where frost heave would be a problem are the existence of the insulation and heat tracing and the method of buoyancy control. In crossings where frost heaving would not be a problem, no insulation or heat tracing was proposed and negative buoyancy would be provided by a concrete weighting system (probably continuous concrete coating). At heat traced crossings, the buoyancy control would be provided by the thick-walled outer steel pipe.

Shallow Bay Crossing

Crossing Design

The proposed crossing of Shallow Bay would consist of two 36-inch diameter thermocased lines and would be about five miles in length. These crossings would be constructed approximately 200 feet apart.

One of the unique problems faced at this crossing is the continual rapid erosion of the west bank. CAGPL indicated that there were two possible designs that could be adopted. It could bury the line deeper on the west side and allow the west bank to erode, or measures such as bank armouring could be taken to prevent the erosion from continuing.

Geotechnical Problems

During the hearing, Foothills attempted to show that the crossing of Shallow Bay would be an extremely difficult undertaking involving a great many problems.

Permafrost in Shallow Bay

During its investigation of Shallow Bay, CAGPL discovered that the bottom was underlain with permafrost. CAGPL indicated that the depth of the permafrost table varied across the channel and was generally nearer the channel bottom on the west side. This was said to be due to the erosion of the west bank that would gradually cause the channel to widen in that direction. The permafrost would be shallower in the more recently formed parts of the channel.

Scour in Shallow Bay

In its investigation of the region around the proposed crossing of Shallow Bay, CAGPL discovered several depressions in the channel bed, some as deep as 55 feet. (This would be about 25 feet deeper than the planned maximum depth of burial below the water surface.) CAGPL felt that these depressions were the result of scour that occurred perhaps 250 to 300 years earlier at a confluence of the flows from Reindeer and Titalik Channels with the flow in Shallow Bay. Now that one of the channels had moved and Shallow Bay had widened, this scour was no longer occurring.

Ditch Stability

In its testimony, CAGPL described the ditching trial that was done in Shallow Bay in September of 1975. The Applicant dug a 20-foot deep trench with a barge-mounted clam shovel and monitored the condition of the trench walls over a six-day period. CAGPL's conclusion was that the three to one side slopes of the test excavation were practical, indeed conservative, for the installation of the pipeline. The ability of the soil under Shallow Bay to sustain such steep slopes was attributed to the high clay content of the channel bed material.

Views of the Board

With regard to the design of river crossings, the Board is generally satisfied with the approach that CAGPL has taken to the design of river crossings. There are, however, some specific points upon which the Board would have to be satisfied further, should a certificate be issued.

First, the Board is somewhat apprehensive regarding the degree of confidence that the Applicant expressed in its ability to predict the location and particularly the extent of bottom scour. The Applicant would be required to satisfy the Board that the river crossings were adequately designed from this point of view.

Secondly, regarding the problem of channel shifting and bank erosion, the Board is concerned about the reliance CAGPL has placed on only 25 to 40 years of erosion history to determine the probable extent of further channel shifting and bank erosion for a project with a life of a similar length. Considering the number of crossings that have not experienced extreme floods in the past 40 years, it would appear that a very cautious approach should be taken to this problem.

Thirdly, with regard to the crossing of Shallow Bay, while the Board is satisfied that this crossing could be successfully constructed, there is some concern on the part of the Board regarding the depressions that have been discovered in the channel bed. While these depressions may well be the result of scour that has occurred in past centuries, the Board believes that a second possibility which must be considered is that they are thaw depressions left by the thawing of massive ice forms that were exposed by bank erosion, the presence of which is well documented by CAGPL's drill hole data. If this were the case, further erosion of the west bank of the Shallow Bay channel could expose more such ice formations along the route of the pipeline near the crossing, causing considerable settlement. The Applicant would be required to satisfy the Board that CAGPL's assessement had considered this possibility.

Monitoring

CAGPL indicated that a very important part of its geotechnical design was the monitoring that would be carried out. It was expected that the disturbance due to construction would initiate processes, such as thawing in slopes, that would have to be watched. In addition, problems arising out of the pipeline's operation, such as frost heaving, would have to be monitored to ensure that the problem was identified and corrected before damage occurred.

Monitoring of Slope Stability

CAGPL indicated that it would be necessary to monitor marginally stable slopes both before and during operations. The monitoring methods proposed were, in part, designed in accordance with the theory of the causes of slope instability. CAGPL testified that landslides could be produced by any process that increased the soil pore water pressure, and increased pressures could be caused by thawing of ground ice or heavy rains. Thus, CAGPL proposed to measure both the soil temperatures and the pore water pressures in suspected slopes. These would be monitored by the use of thermistor strings and piezometers. In addition, CAGPL stated that slope indicators would be used to monitor movement of the slopes.

Monitoring of Frost Heave

The extent of the requirement for monitoring frost heave was greatly reduced by the adoption of the insulation - heat trace design. However, there would still be a requirement for the monitoring of frost heaving in areas of shallow permafrost where the Applicant has proposed to use deep heat probes to control heaving. CAGPL testified that the only practical method for monitoring frost heave was the use of risers attached to the pipe. It was indicated that risers would be placed about 40 feet apart near transitions from frozen to thawed ground, and a few hundred feet apart in permafrost areas.

CAGPL stated that a similar approach would be taken with respect to monitoring thaw settlements.

General

CAGPL very briefly discussed the use of electronic and acoustical devices to monitor the position of river crossings. Prior to the redesign, several other methods were put forward as possibilities for monitoring river crossings, including the use of an inclinometer run through a carrier pipe attached to the pipeline.

While CAGPL indicated that monitoring was an important item and that monitoring would be carried out, details would be determined as part of the final design.

Views of the Board

With regard to monitoring, the Board considers the approach taken by CAGPL towards monitoring appropriate in view of the remoteness of the route and the unique hazards that would be faced by a pipeline in the Mackenzie Valley and along the North Slope. However, considering the preliminary nature of the monitoring proposals and the route assessment, the Board would require a detailed monitoring plan to be submitted for its review.

3.1.3.3 Stress Analysis and Materials Engineering

Stress Analysis

Introduction

The stress analysis performed by CAGPL related principally to its proposed 48-inch diameter x 0.720-inch wall thickness pipe. CAGPL recognized the need for checking the combination of primary and secondary loading to which the pipeline might be subjected. For this reason, a more detailed stress analysis was performed than would normally be associated with a conventional buried pipeline.

Outline

CAGPL's approach to the stress analysis was first to identify the modes of structural failure that should be considered in the pipeline design. These were local instability or wrinkling, overall instability or buckling and overstressing or overstraining in tension. CAGPL then established design criteria which defined the limiting stresses and strains for the failure modes and the limits that were to be adhered to for design purposes. The pipeline design was then subjected to a formal structural analysis for the specific and combined loading situations which were predicted to be applicable. These included gas pressure, temperature differential, the loading imposed by frost heave, thaw settlement, buoyancy, the combined effects of bending and membrane stresses, and the effects of restraint, bend configuration and construction. Consideration of the loading under operating and test conditions was also given to the specific case of pipe restrained in a sleeve-type crack arrestor.

Analytical Techniques

The analytical techniques used in establishing the stress analysis were based on those first developed for the Alyeska pipeline and extended to be applicable to the CAGPL pipeline. This analysis was essentially theoretical, but some experimetal verification was conducted, albeit for Alyeska pipe rather than for CAGPL pipe.

Experimental Verification

Attempts to obtain data on the CAGPL pipe were unsuccessful due to problems encountered during experiments. CAGPL's position was that the Alyeska data provided sufficient verification in that the principles of the analysis were well tested. In effect, CAGPL adopted the Alyeska buckling criterion which was obtained from tests conducted on thinner wall pipe than that proposed in the CAGPL project. For this reason, CAGPL argued that the adopted bending criterion was conservative for its pipe, although the loading imposed on the CAGPL pipeline would be more severe due to the greater instability of the terrain.

Design Criteria

According to CAGPL, the final stage in the stress analysis was the generation of design guidelines identifying the design criteria which placed restrictions on combined stresses and strains in the pipeline. These design criteria would then be considered in the final design of the pipeline as well as in the construction phase.

Special Considerations

With respect to secondary stresses associated with sleeve-type crack arrestors, CAGPL's analysis showed that the tolerable amount of bending or critical radius of curvature of the pipeline was reduced by approximately ten per cent adjacent to crack arrestors and this curvature remained within the established design criteria. Further results of the axisymmetric stress analysis revealed that the biaxial state of stresses in the pipe under the sleeve was less severe than the biaxial state of stresses in the rest of the pipe. As a result, the sleeve region of the pipe would remain practically elastic for all combinations of internal pressure and temperature differentials which could be encountered during the operation of the pipeline. Lower biaxial effective stresses in the sleeve region would enhance the effectiveness of the sleeve in stopping the propagation of longitudinal cracks in the pipe. With respect to the state of stresses in the pipe with crack arrestor sleeves, stress concentrations were detected at and near the edge of the sleeve. The stress concentrations were of larger magnitudes for larger temperature differentials and higher internal pressures. Placement of crack arrestors would be allowed within one foot of the girth welds, but not in the vicinity of the T-joints.

As part of final design, CAGPL was prepared to conduct stress analysis on short radius bends and special analysis of fatigue crack formation during shipment of pipe with attached crack arrestors. The latest redesign of the assembly of the crack arrestors made the analysis of fatigue crack formation in the vicinity of the crack arrestor during transportation redundant. It was proposed in the redesign that crack arrestors would be mounted on 8-foot lengths of pipe, brought to the construction site and welded into the line in the field. The line pipe would thus be transported free of crack arrestors.

Materials Engineering

Introduction

CAGPL indicated that fracture control formed an important consideration in the design of the proposed pipeline. For this reason, a specific design solution was developed for the various stages of failure control. The first such stage was identified as fracture initiation and its prevention. The second stage involved the prevention of brittle fracture propagation and the control of ductile fracture propagation, should initiation occur. This was viewed as a secondary or supplementary measure in fracture control. The basic questions involved were related to how effectively fracture initiation was controlled and whether the supplementary designs for prevention of fracture propagation were necessary and adequate.

Fracture Initiation

The design approach with respect to fracture initiation was based on specifying sufficient notch toughness in the pipe and long seam welds to sustain a large defect. This was done by using a theoretical analysis developed by the Battelle Memorial Institute of Columbus, Ohio ("Battelle") and supported by substantial full-scale testing. The notch toughness requirement involved the specification of a Charpy impact value which corresponded to a critical through-wall defect size, under service conditions, equal to 85 per cent of that which would be obtained for infinite toughness. Critical defect size for both through-wall (6.35 inches) and part through-wall (11 inches) defects was provided by full-scale tests on 48-inch diameter by 0.720-inch and 1.25-inch wall thickness pipe. CAGPL stated that, in practice, the actual minimum critical defect size would be somewhat less than that provided by this approach since the 85 per cent correlation used the overall specified average toughness rather than the minimum.

With respect to the adequacy of these critical defect sizes, CAGPL stated that they were significantly larger than the sizes that would be detected during pipe manufacture. Similarly, they were approximately twice the size of defects that would be detected during hydrostatic testing. CAGPL stated that there was little likelihood of such small defects growing to critical size in service and therefore the occurrence of damage by outside force was considered to be the principal potential cause of fracture initiation. For this type of fracture initiation, CAGPL stated that the effects of external loading causing movement and structural instability were of most concern.

CAGPL also provided for fracture control in the required components, such as valves and fittings. The approach adopted relied entirely on the prevention of fracture initiation, since large scale propagation in such components was not a concern. A conservative criterion, based on a critical flaw size equal to twice the thickness, was adopted and the required specified toughness was given using an established linear elastic fracture mechanics analysis.

Brittle Fracture Propagation

CAGPL acknowledged that the occurrence of brittle fracture propagation must be prevented. Brittle fracture propagation is conditioned by the high fracture velocity relative to gas decompression velocity that is associated with brittle fracture. Brittle fracture, because it travels faster than the acoustic wave in the natural gas, will always have the initial line-pressure level at and ahead of the crack tip. The velocity of the brittle fracture is inversely proportional to the ductility of the steel. The ductility of the steel can be measured in the percentage of the shear area of the fracture surface. Shear areas of Drop Weight Tear Tests (DWTT) agree best with the shear areas of full-scale pipe tests. Therefore the DWTT shear area criterion was chosen as the design criterion against brittle fracture, which requires predominantly shear or ductile behaviour. This criterion (60 per cent minimum and 85 per cent average DWTT shear area) is similar to those now generally applied to conventional pipelines, and its validity for the 48-inch diameter by 0.720-inch wall thickness pipe was confirmed in full-scale tests. The above fracture toughness specification is sufficient to prevent brittle fracture propagation.

Ductile Fracture Propagation

CAGPL stated that it had not been able to assure itself that it would be able to prevent ductile fracture propagation in its pipe, and considered methods for its control. Historically, concern with respect to ductile fracture propagation originated with the occurrence of a small number of long ductile failures in conventional pipelines. The original CAGPL approach was to adopt the Battelle Hypothesis which predicted the toughness requirement of the pipe to arrest a propagating crack. However, as a result of some early full-scale tests, under simulated operating conditions, it was recognized by Battelle that fracture arrest through specifying notch toughness could not be assured. The failure of the test to produce the anticipated results was subsequently concluded to have stemmed from the specific decompression characteristics of relatively rich gas, the effects of frozen backfill and the fracture characteristics of the proposed high strength, high toughness steel.

Crack Arresting

Changes in the operating conditions and gas composition as means of producing a self-arresting fracture design were given consideration; however, CAGPL adopted the use of mechanical crack as being the most economical method of providing positive control of ductile crack propagation. The proposed crack arrestor would consist of a split sleeve placed around the pipe every 300 feet. On the basis of cost estimates on similar designs, CAGPL concluded that this device would increase the cost of service by a maximum of one per cent as compared with the cost of service penalties of between five and 25 per cent associated with other design solutions.

The rationale behind accepting this cost penalty was based on CAGPL's belief that the economic implication of a service interruption of indefinite duration was not tolerable. Therefore, even if the statistical probability of such a failure were low, the fact that it was not zero led to the need for a reliable, positive fracture arrest design to act as a form of insurance.

The selection of a 300-foot spacing was based on estimates of the length of failure above which the outage time increased and below which outage time was independent of length of failure. This spacing proposal was preliminary and might be subject to change.

CAGPL conducted a series of full-scale "Athens" tests at Battelle on 48-inch diameter, 0.720-inch wall thickness, Grade 70 line pipe in order to determine conditions required for ductile fracture arrest. This test program demonstrated that:

(a) pipe of a toughness level (Charpy V energy of 169 foot-pounds) much higher than that commercially available could not be relied upon to control the fracture length;

(b) mechanical crack arrestors provided control of fracture length;

(c) girth welds did arrest primary fracture, but secondary fracture did initiate on the other side of the weld.

Later, CAGPL testified that a propagating crack in one of the above-mentioned tests also bypassed the mechanical crack arrestor.

These observations led CAGPL to consider the reliability of the proposed crack arrestor relative to other types of built-in crack arrestors. CAGPL considered the role of girth welds but concluded that this was not a reliable means of positive crack arrest design. This was based on the fact that not all girth welds had arrested fracture propagation and the concern regarding initiation after girth weld arrest. Bypassing of a mechanical crack arrestor in one test also introduced some uncertainty. Nonetheless, CAGPL felt that these devices could provide a high degree of positive fracture control, approaching absolute assurance.

Materials Specifications

Status

CAGPL prepared and filed formal materials specifications for line pipe and other components. In general, these followed the normal practice for such specifications and tended to meet or exceed established minimum standards. However, CAGPL recognized that the pipe specifications represent some extension of the standard requirements for material testing.

The specifications had not been finalized, as development was still underway in such areas as the DWTT requirements for heavy wall pipe, revision of mill qualification requirements, details on negotiable items, such as variation in test frequency and special tests, and the provisions of the requirements for weldability demonstration.

Implementation

With respect to the implementation and enforcement of these specifications, CAGPL undertook to provide for third party inspection of the manufacturing process. In addition, CAGPL planned to introduce a new concept of quality assurance, a statistical analysis of the physical test data and those variables that would be measured in the pipe mill. The result of this analysis would be related to normal variation of that property. Assessment of this comparison would determine if additional samples should be tested.

Field Welding

CAGPL produced a general specification for field welding which it considered to be more stringent than the normal requirement, particularly with respect to notch toughness requirements. It felt that some emphasis was required in this area due to the loading conditions imposed on the circumferential welds. Toughness was specified using the crack opening displacement technique, which related directly to the longitudinal strain criteria resulting from the stress analysis and allowed the calculation of critical defect sizes. Specific welding procedures for girth welds, to be used for experimental fracture toughness measurements, had not yet been finalized by the Battelle Institute.

Similarly, CAGPL had not fully qualified the welding procedures to be used in the field.

Inspection of Field Welding

With respect to the inspection of field welding, the Applicant planned to utilize non-destructive testing. This would involve the use of radiography as the primary technique, along with other supplementary methods such as ultrasonics. The Applicant proposed using third party inspection but reserved the right to final decision with respect to test results. However, detailed procedures for the inspection remained to be determined.

Materials Supply and Availability

Line Pipe

The Applicant had conducted a detailed evaluation of the capabilities of all manufacturers claiming the capability to supply the required line pipe. This involved visiting manufacturing facilities and reviewing technical data made available by manufacturers. A selection of primary suppliers was then made based on the ability to meet the quantity requirements within the project schedule, the ability to meet the required specifications, the quotation of competitive prices and contract terms, and CAGPL's desire to maximize Canadian content.

The suppliers selected to date were Stelco, with which a letter of intent had been negotiated, Mannesmann, with which a conditional supply agreement had been negotiated for supply from Germany, and U.S. Steel, with which negotiations had been initiated for supply from the United States. The above commitments and negotiations related entirely to the required 1.7 million tons of 48-inch diameter mainline pipe. Of this, 1.1 million tons were to be manufactured by Stelco, 0.4 million tons were to be manufactured by Mannesmann, and the remaining 0.2 million tons might be obtained from U.S. Steel. In addition, 90,000 tons of heavy wall pipe would be manufactured mainly by Mannesmann, although some domestic supply was possible. No definite commitment had been made for the 220,000 tons of pipe less than 48 inches in diameter, but CAGPL expected to obtain most of this in Canada from Stelco.

The 48-inch diameter pipe-manufacturing facility of Stelco was installed relatively recently with an annual design capacity of 500,000 tons. CAGPL used a more conservative figure of 400,000 tons, since it appeared that plate supply to the mill might restrict capacity. On this basis, Stelco was considered to have committed essentially 100 per cent of its 48-inch diameter pipe mill capacity to CAGPL for a three-year period. While acknowledging that Stelco had limited experience with the size and type of pipe required, CAGPL expressed confidence in its capacity estimates, based on the production rates achieved during a recent order for 42-inch diameter pipe. This pipe had a 0.750-inch wall thickness similar to the required pipe, but it was of a lower pipe grade material and of smaller diameter.

With respect to the quality of material that Stelco could produce, CAGPL had obtained a small trial order amounting to 150 tons, or 20 joints, of pipe. This pipe was described as being of the size and grade of pipe required. CAGPL's specifications were met except for dimensional tolerances and some under-strength in the non-expanded form. CAGPL believed that the optimum product would be obtained by cold expansion of the pipe. The problem with cold expansion of spiral weld pipe was that it required the development of new technology within a restricted time frame. To meet the present production schedule, the cold expansion facility must be installed and proven by early 1978. The development had only gone as far as expanding some 42-inch diameter pipe using a facility in the United States. Further testing of the effects of expansion on pipe properties remained to be done. CAGPL stated that the unexpanded pipe was acceptable, but no formal commitments had been given for its purchase, should the cold expanded product not be available.

Mannesmann had been selected as the primary foreign supplier on the basis of its ability to meet both quantity and quality requirements. With respect to quantity, a projected annual capacity of 1,200,000 tons could be provided by this mill. Since the Applicant's commitment only amounted to approximately 500,000 tons and an option to increase the order existed, a degree of supply security was provided for. With respect to quality, CAGPL based its confidence on this manufacturer's wide experience in making similar large diameter pipe, on the evaluation of the manufacturing facilities, and on the test data supplied by the manufacturer for similar materials. CAGPL admitted that no pipe material meeting its specifications had been produced and the samples of pipe that it had acquired were not entirely acceptable. However, it remained satisfied that this manufacturer would be able to produce the required product and a formal demonstration of this ability was not required at the time of the application.

The present selection of U.S. Steel as a line pipe supplier was considered conditional. This supplier did not have a suitable facility, nor had it produced any demonstration product. A facility was under construction which was projected to be operational in late 1977. The Applicant's basis for this selection was very limited in technical terms and was related only to the confidence that sufficient technical "know-how" existed.

The 42-inch diameter pipe could be made by Stelco in the same facility as the 48-inch diameter pipe. In addition, a second mill in Alberta, with some modification, might be capable of producing 42-inch diameter pipe. The full booking of both the 48-inch diameter mill and the available plate-making capacity might strain the total projected pipe-making capability of Stelco. It seemed probable that plate from other domestic or foreign suppliers might be required. The supply of pipe with diameters less than 42 inches was of less concern and the requirements could be met by existing domestic facilities.

Components

With respect to components such as valves and fittings, CAGPL did not foresee any particular problems, even though no such components had been purchased to the required specification and some extension of manufacturing technology was involved. CAGPL was relying on the proven technical capabilities of the manufacturers to develop the required product. In view of the number of manufacturers available, including some in Canada, CAGPL did not foresee any apparent supply problem. In the absence of any firm commitments at the time, this was subject to the qualification that other large projects did not have conflicting requirements.

Views of the Board

Stress Analysis

A complete analytical stress analysis was performed by CAGPL and, with minor reservations, is acceptable to the Board. However, the degree of reliance that should be placed on a purely theoretical analysis which has had no previous application to an operating pipeline and which has not been experimentally verified on CAGPL's pipe is a matter of some concern. Furthermore, the validity of the results of the structural analysis, which showed that the pipe's behaviour will be within the design criteria, is dependent upon the accuracy of the estimation of the application of external loads. In particular, any changes in the predicted behaviour of frost heave will require recalculation of pipe stresses and strains.

On the basis of the analysis provided, crack arrestors would not induce an inherently dangerous stress situation. However, the measure of safety built into the structural design is reduced to some degree by their presence.

It was not apparent how CAGPL proposed to take into account site-specific field problems in the final design process. No indication was given of the means of monitoring the pipeline to ensure structural stability during its testing and operation. It is anticipated that these matters would be dealt with in a design manual which would be examined as part of the final design approval.

Materials Engineering

CAGPL provided reasonable measures against fracture initiation and brittle fracture propagation by specifying adequate fracture toughness of the line pipe material. Since the inherent material properties could not prevent fracture initiation caused by the external force or by the structural instability, CAGPL analyzed ductile fracture propagation extensively. Full-scale experiments conducted for CAGPL showed that propagating ductile fractures could not be fully contained by the specified inherent line pipe properties. Therefore, CAGPL correctly explored the means of external positive fracture control. The proposed regularly-spaced mechanical crack arrestors cause moderate stress intensification in the line pipe. In principle, the Board agrees with the adoption of external crack arresting devices, but modification in design may be required to alleviate the associated stress problem in the pipe.

Materials Specifications

Materials specifications prepared for various sizes of line pipe and pipeline components by CAGPL were considered to represent normal practice for pipeline specifications. In some areas, specific requirements were not finalized. Implementation of statistical analysis of the physical test data and its implementation in the quality control process are viewed as a positive improvement.

Supply and Availability

The Board considers that Canadian and German suppliers of line pipe would be secure sources for CAGPL's proposed requirements. With respect to availability of line pipe from the United States supplier, it appears that some uncertainty exists as to the ability of this manufacturer to produce pipe on time. With other supply alternatives open, there is no concern about the availability of the required quantities of line pipe for CAGPL. Final decision on the acceptance of the cold-expanded line pipe produced by Stelco is dependent on the quality of the cold-expanded product.

3.1.3.4 Right-of-Way

CAGPL stated that it would be necessary to acquire a right-of-way up to 120 feet in width, with some variation depending upon local requirements, along the selected Mackenzie route to facilitate the construction of its pipeline. In some northern areas further additional right-of-way might be required to accommodate power lines and ancillary facilities. The area of lands to accommodate compressor and meter stations would be determined from time to time.

CAGPL confirmed that it would comply with all requirements, including those relating to drainage, imposed upon it in forested and agricultural areas. It would also restore the lands affected or otherwise compensate for damages caused. It proposed to provide for input by landowners prior to its application for approval of plans, profiles and books of reference and submit to the Board all relevant information. It indicated that all other statutory and regulatory approvals would be sought during the final design stage.

Views of the Board

CAGPL showed an understanding and appreciation of right-of-way problems which could arise from pipeline construction, particularly in the areas of negotiation, acquisition of lands and settlement of damages caused, as well as the need to obtain all further regulatory approvals.

The Board would require that CAGPL comply with all of the Board's directions regarding the acquisition of rights-of-way and other lands, including but not necessarily limited to specific directions as to the rights of and notice to all potentially affected property owners to ensure an orderly land acquisition and an equitable settlement program.

3.1.3.5 Communications

CAGPL stated that, in order to maintain the operation of a pipeline in the most efficient manner, a highly reliable communication and supervisory control system was required. CAGPL investigated three systems to provide the required service. These were coaxial cable, satellite and terrestrial microwave. The coaxial cable system was ruled out due to technical problems and prohibitive costs.

CAGPL considered the satellite system to be more desirable than the terrestrial microwave system. The microwave system would entail the construction of tall towers at compressor stations and other operations sites, whereas the satellite system would function with smaller earth stations. Also, repeater towers and associated facilities would not be required, since facilities for the satellite system could, in most cases, be located right at compressor stations. It was also pointed out that in the event of a malfunction of one of the repeater stations, communications would be maintained from all other stations since the earth stations operated independently of each other.

CAGPL would require the use of 45 to 50 per cent of one of the 12 transponders on the satellite in order to maintain the required level of communications and supervisory control. Cost estimates were based on being charged for the use of one transponder.

CAGPL reported a cost saving of approximately two per cent for the terrestrial system over the satellite system. Since the cost estimates from the telephone companies and Telesat Canada were accurate only to within ten per cent, CAGPL felt this cost saving was not sufficient to offset the advantages of the satellite system.

Construction Communications System

CAGPL stated that the communications system required for construction of the pipeline differed from the system required for the operation of the line. Nevertheless, in the conceptual design for the final system, an attempt was made to use as many of the final facilities as possible for the construction phase.

Where the required capacity was not available on the existing public network, CAGPL, in co-operation with the common carrier in the area, proposed to expand or extend the existing facilities to provide the following services during construction of the pipeline:

(i) telephone services to all construction camps;

(ii) mobile radio services to provide voice communication for engineers, the Applicant's representatives and government inspectors; and

(iii) data services to aid logistics material control and administration.

During construction, the satellite system would use permanent earth stations, temporary earth stations, existing common carrier facilities, temporary microwave systems and mobile radios. All communications equipment would be transportable by aircraft.

Services required for the operation of the pipeline included:

(i) voice communications, consisting of:

(a) company automatic telephone system connecting all offices and facilities;

(b) party line system connecting gas control centre, district offices and compressor stations; and

(c) mobile radio system for operations and maintenance personnel.

(ii) data transmission, consisting of:

(a) data acquisition and supervisory control systems using assigned circuits between remote terminal units and master terminal units; and

(b) administrative data network to interconnect terminals located in company offices and sharing channels with the telephone system.

Supervisory Control Systems

CAGPL stated that the supervisory control systems essential to the operations and maintenance of the pipeline were:

(a) Gas Control System - which would enable the operators at the gas control centre in Calgary to monitor and control the essential operational parameters of remote unattended compressor and metering stations; and

(b) Maintenance Information System - which would enable the maintenance personnel at various districts to monitor essential performance parameters of major equipment installed at the compressor stations.

Views of the Board

The Board concludes that either the terrestrial microwave system or the satellite system could provide the necessary communications service. Each system was shown to have certain advantages and disadvantages and the overall cost estimates, as reported, were virtually the same. The Board therefore accepts the Applicant's choice of the satellite system.

3.1.3.6 Construction

Construction Mode

CAGPL stated that all mainline pipeline north of Caroline, Alberta, except certain river crossings, was scheduled to be constructed during the winter months because of concerns for the environment and to avoid interference with the major migratory movement of animals.

CAGPL testified that in the permafrost areas north of the 65th parallel, Arctic winter pipeline construction techniques would be used while conventional winter pipeline construction techniques would be used in the regions south of the 65th parallel. The major difference between the two techniques is the former's use of snow roads and snow work pads for the protection of the sensitive ground surface. If natural snow were not available when and where required for the roads and work pads then it would be hauled from other locations or manufactured snow would be used.

CAGPL did not expect that compressor station or meter station construction would be affected by the presence of permafrost, the season of construction or adverse weather because the facilities would be constructed on granular work pads.

Construction Techniques

CAGPL planned to construct snow and/or ice roads and a working surface along the entire right-of-way in the sensitive permafrost areas. Construction of the snow roads and the snow work pads would commence in September and October so that pipeline construction could start in November.

If snow were not available for road construction, snow would either be manufactured by artificial methods or hauled in from other areas. CAGPL testified that along the North Slope areas where the snow tended to blow away, snow fences would be placed on the right-of-way to harvest the snow and to ensure sufficient snow supplies during the early part of the winter. In response to questioning by Foothills as to whether the snow fences would prevent the migration of caribou, CAGPL stated that the caribou would not be in large herds and would not be making a significant migration during the period when the snow fences were in place. But it was planned to leave gaps in the snow fences to facilitate any possible caribou movement.

Foothills questioned CAGPL's proposal to construct a pipeline in the North from snow pads and snow roads. Foothills submitted rebuttal evidence stating that Alyeska had been disappointed in its experience with snow roads and instead had constructed a granular pad along its pipeline right-of-way.

CAGPL proposed that a very high percentage of the pipe ditch along the Mackenzie Valley and also the North Slope would be excavated with a wheel-type ditching machine. Geotechnical analysis of the bore hole data in the North indicated that a substantial part of the proposed route contained a high content of silt, and after witnessing the Sans Sault test, conducted with inferior equipment, CAGPL felt confident that its proposed ditching machines could excavate a high percentage of the proposed pipe trench. Ditching tests were conducted in March 1977 near Norman Wells, to further assess the capabilities of wheel-type ditchers and recently developed ditcher teeth technology. CAGPL proposed that an Arctic ditcher capable of excavating an eight-foot wide ditch twelve feet deep would be used in the North. CAGPL was convinced this Arctic ditcher would be capable of excavating a mile of ditch per day; however, design of this ditcher was not yet complete.

CAGPL proposed the use of portable artificial lighting along the right-of-way during the winter construction. Such lighting would be stationary when in use and lighting towers would have to be lowered in order for the unit to be moved. CAGPL estimated that 34 lighting units would be required and yard tests had been conducted to test their portability and efficiency. Foothills disputed the portability of the lighting plants and suggested that their constant relocation during the construction of the pipeline would tend to reduce the expected productivity of the entire spread.

CAGPL proposed to use manufactured building modules to construct camps at stockpile sites or at future compressor station locations. It estimated that only one and one-half to two months would be required to set up an 800-man camp along the North Slope. Foothills submitted, in evidence, that three months were required to construct an 800-man camp for the Alyeska project. CAGPL's basis for the camp construction schedules was advice from suppliers that this would be feasible. CAGPL agreed that the ability to construct and have the camps ready for use was critical in meeting the construction schedules proposed for the North Slope. However, if it found in the first two years of construction that it had not allowed sufficient time, then it planned to move a spare spread from the south to augment the two planned for the North Slope.

CAGPL proposed to install crack arrestors on the pipeline to control the propagation of ductile fractures. It was expected that these crack arrestors would confine a pipeline failure to a short distance. Foothills expressed concern about the feasibility of operating bending machines and coating machines over these crack arrestors. CAGPL pointed out that the pipe-bending operation would not be affected because arrestors would not be placed at bends. CAGPL submitted evidence of modifications that could be made to a taping or coating machine to accommodate the crack arrestors.

CAGPL proposed to use insulated pipe with heating cables to prevent frost heave after the pipeline was placed in operation. The pipe would be insulated prior to shipment to the field and the field welds insulated before the pipe was lowered into the ditch. CAGPL proposed that heating cables would be placed in the ditch, under the pipe trench or encased with the pipe insulation. The method of installation for the heating cables would depend upon the location and the soil condition. A power line would be required alongside the right-of-way for the heating cable power supply.

CAGPL submitted evidence that an additional 20,000 tons of freight would be required to accommodate this frost heave redesign proposal and this would involve a substantial cost increase.

Foothills questioned CAGPL's proposal to dredge the three crossings in the Mackenzie Delta over a two-year period. Foothills suggested that the three dredges proposed for the operation might not be capable of completing the excavation in the two summers and also that the shallow trench left open over the winter months might fill in, resulting in a need for re-excavation the following year. CAGPL disputed these concerns and felt that its dredging consultants had correctly estimated the equipment requirements and the dredging of the channels and pipe installation would be on schedule with the entire pipeline construction.

CAGPL proposed to construct airstrips at all compressor station sites which were not accessible by an all-weather road or which did not have an existing airstrip nearby. This would require the construction of seventeen 2,400-foot long airstrips and four 6,000-foot long airstrips. Granular material would be used in the construction of the airstrips which would be suitable for fixed-wing aircraft during the construction and operation phases of the project. Buildings, electrical generating facilities and communication facilities would be located either at the airstrip or at the nearby compressor station.

CAGPL proposed to use standard winter pipeline construction practices in such areas as:

pipe-handling, hauling, stringing;

pipe-bending;

line-up for welding;

welding;

protective coating for field joints;

lowering-in and tie-ins;

pipe weighting;

trench bedding and back-fill;

gauging and cleaning; and

clean-up and restoration.

Weather protection would be provided as extensively as possible; however, CAGPL recognized that some of the above-listed activities would require construction workers to work without weather protection barriers. CAGPL proposed that outdoor construction work would cease when the wind chill reached a chill zone of 5 as described in the Burns Report filed during the hearing.

CAGPL maintained that the curtailment of some activities due to severe weather conditions would merely create a slow-down and progress would return to normal when weather conditions permitted resumption of all activities. Foothills disputed this claim and maintained that stoppage of some activities would eventually affect the spread progress and force a shut-down.

CAGPL proposed that most construction workers from Southern Canada would be hired through union halls in the south. These construction workers would, for the most part, be skilled in their respective crafts. CAGPL proposed, through co-operation and participation with the contractors and unions involved, to conduct indoctrination in the southern centres where these persons would be hired.

Southern Canadians would also be given orientation-type training, safety, fire and survival training upon arrival at the construction site. Orientation would involve such items as familiarization with camp life, camp rules, special emphasis on northern lifestyle, northern culture, and an understanding of the northern peoples. CAGPL also proposed to provide training and familiarization programs with respect to special environmental considerations related to northern projects.

CAGPL proposed to provide construction work and training opportunities to northern residents in keeping with their desires and consistent with their abilities to learn. This would, of course, require the agreement of the contractors and also the co-operation of the native peoples and the native organizations. CAGPL hoped that many northern residents would seek to achieve the qualifications and training necessary to enable them to become permanent employees in the operations and maintenance phase of the proposed pipeline.

CAGPL stated that the proposed construction techniques were basically the same techniques employed to construct large-diameter pipelines during the winter in southern and central parts of Canada. Construction costs of this pipeline, however, would be increased significantly due to the following construction requirements:

- preservation of the permafrost and its protective surface layer;
- necessity to construct a snow working pad and snow roads;
- extreme cold and windy environment;
- lack of daylight during the working season;
- necessity to excavate permanently frozen soil; and
- frost heave mitigative measures in discontinuous permafrost.

These factors would affect the construction productivity and increase the overall cost of the project relative to pipeline projects in Southern Canada.

Construction Logistics and Schedule

CAGPL submitted evidence that material and equipment for the construction of the pipeline would originate at many locations in

Canada, the United States and offshore. The three principal transportation modes in the area south of the 60th parallel would be road, railroad and air transport.

Foothills questioned the ability of CAGPL to complete the construction of 408 miles of pipeline along the North Slope during one winter season. Foothills suggested that this portion of the pipe could be constructed during one winter season only if the planned snow roads could be constructed, the snow-making machines could be produced as expected, the Arctic ditcher performed in the permafrost, the portable lighting plants were adequate for the construction schedule and the constructiion camps could be moved as scheduled.

Foothills also doubted whether CAGPL's contractors could lay an average of 4,000 feet per day of 48-inch diameter pipe along the North Slope under severe weather conditions.

Foothills claimed that Alyeska's winter pipeline construction productivity had been far less than CAGPL's forecasted production rates.

Although lacking any pipeline construction experience under the severe weather conditions of the North Slope, CAGPL felt that some production would be maintained on the cold windy days and the estimated production rates would be achieved. CAGPL calculated these production rate estimates by utilizing the knowledge of eight pipeline contractors, some of which had experience in Arctic construction.

CAGPL stated that some parts of TransCanada's experience in winter construction in Northern Ontario were comparable to its proposed winter operations. This comparison was questioned by

Foothills who suggested that weather conditions in Northern Ontario for winter construction were not so severe as on the North Slope nor were the terrain conditions similar.

CAGPL proposed to construct major staging areas at Hay River and Axe Point, Northwest Territories, where fuel, material and equipment would be placed on river barges and taken down the Mackenzie River to wharves and stockpile sites along the river.

CAGPL proposed to use existing provincial and territorial highways as extensively as possible. If the Dempster Highway were completed from near Dawson City, Yukon to Inuvik, Northwest Territories and the Mackenzie Highway from the 50th parallel to Fort Good Hope, then CAGPL proposed to use these highways as well.

CAGPL proposed that the existing CN, CP, Northern Alberta Railway Co., Great Slave Lake Branch and British Columbia Railway would be used to transport fuel, pipe and other material to the staging area at Hay River, Northwest Territories. CAGPL was advised by CN/CP than an additional 550 (89-foot long) flat cars would be required for transportation of the pipe to the Hay River staging area. These cars would be dedicated to the project and would be absorbed by the railway industry following completion of the project.

CAGPL submitted evidence that six licensed operators were currently operating barges on the Mackenzie River, with a total capacity of approximately 500,000 tons per barging season. The barging season lasted approximately 4.5 months per year. The typical operation involved a train of six 256-foot long barges pushed by a tug, with each barge having a capacity of 1,500 tons, or a total of 9,000 tons per barge set. A single barge set had a seasonal capacity of 10 trips, i.e., 90,000 tons per season. The six existing barge sets would be capable of transporting about 540,000 tons per season. CAGPL proposed that an additional nine barge sets would be required to transport the following material and equipment to the stockpile sites along the Mackenzie River:

Material to be Transported to CAGPL Stockpile Sites (000's Tons)

	Year 1	Year 2	Year 3	Year 4	Year 5
Canada/Alaska Border to MP 644	574	492	379	36	17
MP 644 to Caroline, Alberta	605	524	55	54	23
Coleman Lateral	149	79	9	5	9
Monchy Lateral	103	210	14	9	14

CAGPL proposed that a total of 20 wharves and 28 stockpile sites along the Mackenzie River and along the North Slope would be required for unloading and storing the material and equipment. Five wharves already exist along the Mackenzie River, while the additional 15 would be constructed prior to the material shipment.

CAGPL planned to utilize the existing facilities of the large airlines and small charter services into the major airports. To meet the requirements for transporting approximately 800 men between Edmonton and each construction camp and to transport approximately 80 tons of supplies to each camp every month, the proposed plans were to construct airstrips large enough to accommodate STOL type aircraft such as the Twin Otter. Helicopters would be used extensively throughout the early development stages of the project; however, the use of helicopters would diminish to one or two machines per spread during the mainline construction phase. Due to their high cost, large helicopters such as the Skycrane would be used only in emergencies.

Temporary winter roads and snow and ice roads would be used as extensively as possible in the North and CAGPL anticipated the useful life of a snow road to extend well past the spring shut-down of mainline construction due to the insulating quality of the packed snow.

CAGPL proposed that the pipeline construction from Prudhoe Bay, Alaska to Caroline, Alberta would be completed through three winter working seasons. The plan assigned four construction spreads to commence work on sections of the mainline north of Fort Simpson to the Mackenzie Delta in the first winter. These four construction spreads would have their equipment remain on site through the first summer and continue working the next spreads the following winter.

An additional five spreads would work on southern segments of the mainline in the first winter and move to the delivery lines south of Caroline for the summer. These five southern spreads would move north to complete the Canadian portion of the mainline in the second winter.

CAGPL proposed to start and complete the Prudhoe Bay to Tununuk section of the pipeline during the third winter season. Foothills contested this plan and stated that, should CAGPL not be capable of carrying out this construction in one winter season, then the cost of the entire project would be affected.

CAGPL proposed to construct all support facilities prior to the pipeline construction. Preparatory functions such as surveying, clearing and grading, snow road construction, winter road construction and material stockpiling would also be carried out prior to the start of any pipeline construction.

CAGPL submitted evidence that installation of major river crossings would be carried out as separate projects and construction scheduled to meet the completion of the pipeline construction.

Compressor station construction would be scheduled to meet the required start-up date for the particular station. CAGPL felt that weather or time of year would not affect the station construction since the facilities would be placed on granular work pads or cleared areas, depending upon the soil conditions, and most of the work would be protected from the weather by temporary enclosures. CAGPL proposed to prefabricate the station buildings and equipment as much as possible and assemble these prefabricated units on site.

Construction Resources

CAGPL estimated that the peak manpower requirements would occur during the first two winter seasons, when 7,500 to 8,000 men would be employed on the pipeline construction for each winter season. Another manpower requirement peak was expected to occur during the third winter season; however, this would amount to only 5,000 men. CAGPL felt that these requirements would be small in relation to the total available labour force and expressed confidence that, in terms of total numbers, no shortage would exist.

CAGPL felt that labour with certain specific skills and experience such as heavy equipment operators and heavy duty mechanics might be in short supply. Given sufficient lead time, it was possible this shortage could be overcome by training new operators and mechanics and upgrading experienced ones.

CAGPL assumed that no other major pipeline project would be in progress in Canada during the peak manpower demand years and therefore, sufficient workmen as well as supervisory and engineering staff would be available. Welders might be in short supply but CAGPL expected that a large percentage of the welding would be automatic and a larger supply of welder operators rather than welders would be needed.

CAGPL expected no steel shortage or undue delays in manufacturing of material or equipment and felt optimistic and confident the construction resource requirements could be met as planned.

CAGPL estimated that the following approximate major resources would be needed for the project:

Equipment: 700 crawler-type tractor units such as dozers, rippers and pipelayers;

400 units of earth moving equipment such as backhoes, ditchers, scrapers, graders and loaders;

300 units of compressors, drills, etc.;

650 units of welding equipment;

100 units of specialty equipment such as pipe benders, crushing plants, line-up units, etc.;

350 trailer units such as floats, lowboys, tankers, vans and pipe haulers;

200 trucks in the 5 to 16-ton class; and

1,300 units in the 1/2 to 5-ton class.

CAGPL proposed that the following quantities of manufactured and processed materials would be utilized or consumed during construction:

CAGPL Construction Materials Requirements

(Quantities in 000's of Tons)

	1st Winter & Summer	2nd Winter & Summer	3rd Winter & Summer	4th Winter
Fuel and Lubricant	28.0	158.0	125.0	64.0
Equipment Repair and Parts	3.5	9.0	6.5	3.0
Welding Supplies	-	2.2	1.2	0.5
Explosives	3.7	4.5	1.8	0.5
Fertilizer and Seed	-	8.1	1.2	0.7
Foodstuffs	1.8	6.1	9.2	-
Cement and Reinforcing Steel	-	68.2	69.8	15.8
Methanol	-	10.0	5.0	10.0
Lumber	-	2.4	0.4	0.2
TOTALS	37.0	268.5	220.1	94.7

GROSS TONNAGE - 620.3

NOTE:

This list does not include pipe for the pipeline or contractor's equipment, or the 20,000 tons of material required for the frost heave control.

Views of the Board

The Board is of the opinion that construction of the proposed 48-inch diameter pipeline in the Provinces of Alberta and Saskatchewan should not present any unforeseen construction problems for the contractors. Considerable experience has been gained by pipeline contractors in both Alberta and Saskatchewan. The construction techniques proposed for these areas are well established and CAGPL's estimated costs appear realistic.

The section of the proposed pipeline north of the 60th parallel will be constructed in a region where long distances of wet soils underlain by permafrost, both continuous and discontinuous, are present. Access to the proposed right-of-way is limited in the summer months and in the winter the ground surface must be protected from damage to prevent permafrost degradation in the years succeeding the proposed pipeline construction.

CAGPL's project north of the 60th parallel is fully dependent upon the Mackenzie River to ship all of the construction materials and equipment on barges during the four to five summer months. The pipeline construction north of the 60th parallel is proposed for the winter months when the Mackenzie River transportation system is shut down.

The Board feels that a scheduling problem exists both in material delivery and also in completing a season's work during a short winter work period. The Board has assessed CAGPL's construction program and identified those items which it feels will affect the pipeline construction progress.

CAGPL proposed to construct a 48-inch diameter pipeline of a wall thickness which has never before been manufactured in Canada. This fact will present some problems with the pipe mills in the initial manufacturing phases, since the Canadian pipe mills at this time are not capable of producing this volume of 48-inch diameter pipe. CAGPL has recognized this problem and therefore has decided to rely on foreign pipe manufacturers for a large portion of its pipe supply. The Board considers that the Canadian content as outlined by CAGPL should not be reduced but also is aware of potential problems of pipe supply from Canadian pipe mills. The Board feels that the Canadian mills may be hard pressed to deliver their portion of the mainline pipe within the required time frame. To the extent that turned out to be the case, the Board believes that CAGPL would be able to obtain the balance from the foreign pipe manufacturers.

Scheduling of pipe shipments to the pipeline right-of-way are considered to be the greatest material constraint. The pipe must reach the staging point at Hay River, Northwest Territories, so that pipe shipments can be arranged to coincide with the four to five-month summer shipping season. If this is carefully managed, the Board feels that the possibility of insufficient pipe arriving at the right-of-way for the next winter's construction could be avoided.

The Board is concerned because this is the first pipeline project which would be fully dependent upon snow pads and snow roads during construction in the winter months. Because of this dependency, the Board feels that the feasibility of snow roads and snow pads must be assured. The Board is of the opinion that CAGPL should demonstrate, at least one year in advance of the start of pipeline construction, that it can satisfactorily build artificial snow roads. The Board is satisfied that snow roads and snow pads, if constructed to the proper standards, would permit the construction of the pipeline; however, the Board has some concern that the Applicant has not provided sufficient snow-making equipment to supplement the natural snowfall. In the first year of construction, CAGPL would be expected to demonstrate its ability to provide sufficient natural and artificial snow in order to meet its construction schedule in subsequent years. In addition to providing the required amount of snow-making equipment, the Applicant should also make a survey of the total water requirements for these snow-making machines and also the ancillary equipment and vehicles required to transport the water from the water sources. CAGPL should also be certain that the proposed water sources have sufficient water for the intended use. Any certificate issued by the Board would be conditioned accordingly.

The Board has the same concern regarding the Applicant's reliance on an Arctic-type wheel ditcher. CAGPL has proposed the usage of an Arctic-type ditcher to excavate the major portion of the pipeline trench and has based its construction schedule and cost estimates on the availability of this Arctic ditcher. At this time, an Arctic ditcher has not been completely designed, and if a wheel-type ditcher cannot operate satisfactorily in permafrost, drilling, blasting and backhoe equipment will be required to carry out the trenching. The possible need for this alternate equipment must be known in advance of the shipping season. The Board believes, therefore, that the Applicant must demonstrate, at least one year in advance of the start of pipeline construction, that it has a workable Arctic ditcher. If this cannot be accomplished, then CAGPL must re-align its spreads to perform the work by the conventional method of drilling and blasting and excavating the trench with a backhoe or by other means. It would, therefore, have to amend its construction schedule and probably its cost estimates. The Board would condition a certificate to require the Applicant to either prove the workability of an Arctic ditcher or to amend its equipment required per spread and its construction schedule.

The Board is also concerned about the estimated down-time because of the weather conditions. There is limited information on weather in the CAGPL application and disagreement assumptions between CAGPL and Foothills as to tolerance levels for workmen working outside in the Arctic winter conditions. However, the Board recognizes that if the first year's construction fell short of its expectations on account of weather, the Applicant would have time for adjustment in the second and third year of the pipeline construction.

The Applicant has proposed to use portable lighting plants during the winter construction of the pipeline. The Board is aware of Arctic construction in Russia in the winter months where the absence of natural daylight is overcome by the use of portable lighting plants. During the Alyeska oil pipeline construction, portable lighting plants were also used. CAGPL's scale of operations and the anticipated weather conditions along the Prudhoe Bay to Tununuk segment may be more extreme than the experience cited and the portable lighting system could be a contributing factor to reduced rates of construction.

The Applicant intends to use crack arrestors over its entire pipeline spaced every 300 feet. The final design for these crack arrestors has not yet been completed and will be subject to the approval of the Board. The Board is concerned about the proposed method of installation of the crack arrestors and the effect the installation will have on construction progress. When a final design for the crack arrestors has been arrived at and approved by the Board, the Board believes it would be necessary for the Applicant to demonstrate that they can be installed with the manpower and equipment available and in the time frame proposed.

The Applicant has proposed to install heat-tracing cables, insulation and casing pipe to control the expected frost heave problem. This proposed design is a recent innovation and may be subject to application problems which may affect the construction schedules. The Board would require the Applicant to demonstrate that the installation can be made under field conditions in a satisfactory manner.

The Board feels that the Applicant should have its final designs completed well in advance of the start of pipeline construction. The Board would require as a condition of a certificate that a design manual be produced by the Applicant and submitted to the Board for approval. This design manual should identify the various soil conditions along the route and the various types of designs required for the particular soil types.

The Board is concerned about the timing of the North Slope section of the pipeline between Prudhoe Bay and Tununuk. The other sections of the proposed pipeline have the advantage that if the first year of construction fell short of the construction schedule, then steps could be taken in the subsequent years to catch up with the time frame. In the case of the North Slope leg of the project, being the last section of the project, it would be critical that this be constructed and completed in one year as proposed by the Applicant in order for Alaska gas to flow as scheduled. After a review of the Applicant's experience during the first winter's construction, the Board would wish to be assured that adequate contingency provisions were incorporated in the construction plan for the Prudhoe Bay to Tununuk segment in the third winter, having in mind that additional spreads or supplementary equipment would have to be moved during the previous summer's shipping season. For this reason, any certificate issued to the Applicant would require it to satisfy the Board one year in advance of the pipeline construction on the North Slope of its capability to build this section in one winter season.

In addition to the above, a certificate would be conditioned to require the Applicant to file its construction specifications in advance of any pipeline construction.

3.1.3.7 Operations and Maintenance

CAGPL's compressor stations would be designed and constructed to operate by remote control from a gas control centre in Calgary.

The pipeline operations and maintenance organization would be divided into divisions and districts, each with headquarters at a suitable location. Each district headquarters would have the responsibility for supervising the maintenance of those portions of the pipeline located within its district. Maintenance activities would be planned by the district supervisory staff on the basis of routine inspection reports compiled in the district headquarters.

Evidence was submitted that the exact number of personnel initially required at the compressor stations had not been decided and would be a function of the type and amount of equipment required at a particular compressor station.

To ensure the continuous, safe operation of the pipeline and also to preserve the environment, CAGPL proposed to provide ground transport and work equipment capable of performing all scheduled maintenance activities and of making a rapid response to emergency situations.

CAGPL proposed to supply conventional types of pipeline equipment and also such equipment as dictated by the various conditions which existed along the proposed pipeline route. The location of the equipment storage bases and the quantity and variety of equipment at each operating base would depend on the accessibility from allweather road systems, on the availability of contracted services and on the particular regional conditions of terrain and climate.

CAGPL's plan for the operations and maintenance of the proposed pipeline embodied the use of both fixed-wing aircraft and helicopters for line patrol and the transport of personnel and materials from operating bases to compressor stations, communication sites, measurement stations and points along the pipeline right-of-way. CAGPL submitted evidence that each of the airstrips it proposed would be manned on a 24 hours a day basis during any period of the year when it would be considered that aircraft might have to land under instrument flight rules.

CAGPL would rely more heavily on fixed-wing aircraft because it was felt that they could fly in weather conditions that might ground helicopters.

All CAGPL's flights would be authorized only by senior district supervisory staff who would schedule all maintenance work at the remote sites. The aircraft line patrol flights would be carried out monthly, ideally at an altitude between 100 and 150 feet above the right-of-way. During periods when these patrols might disturb wildlife, the line patrols would be made at an altitude of 500 feet and at a lower altitude only when essential to accurately inspect a suspect area on the right-of-way. During sensitive periods for wildlife, other flights would be scheduled along routes and at altitudes to minimize disturbances.

Living accommodation would be provided at the district headquarters. Final plans had not been drawn up but these would be determined by the type of accommodation most likely to create and maintain good long-term employee-employer relationships, to satisfy the desire of employees to purchase their own accommodations and to meet the regulations imposed by local or territorial government authorities.

CAGPL also proposed to supply temporary living accommodation at the compressor stations for personnel who would be required to be there longer than one day, either for maintenance purposes or to control the airstrip.

CAGPL proposed to convert the compressor stations to remote operation as quickly as possible. CAGPL felt that the initial stations might require a longer commissioning period, but presumably the succeeding ones would demand fewer personnel and less time to reach the remote operation mode. After that, CAGPL proposed to have personnel at each station only on a temporary basis as operating or weather conditions dictated.

CAGPL stated that its final design and plans for repairs to a break during operation of the proposed pipeline had not yet been formulated. It would stock at strategic sites the types and kinds of equipment it felt would be necessary to provide access to the areas where problems might occur.

CAGPL stated that should a break occur in summer, in a very wet area inaccessible by heavy ground vehicles, a temporary repair would be made using a smaller diameter pipe air-lifted to the break area by helicopter. This temporary repair would be removed and replaced with 48-inch diameter pipe when ground conditions were such that heavy vehicles could travel to the break site. CAGPL felt that the temporary repair would create negligible loss of throughput and would not require much additional horsepower to maintain the desired flow.

Foothills contested CAGPL's suggested ability to keep the pipeline ditch free of water during a repair in the summer months in a wet area. CAGPL felt that by dyking the break area and pumping the water from it, the ditch would be kept free of most of the water. Some concern was raised by Foothills that if a break occurred in a permafrost area in summer, water flowing into the ruptured pipe would begin to freeze because of the frost bulb around the pipeline and because of the cooling caused by the pressure drop when the gas escaped from the pipeline. CAGPL felt that very little freezing of water would occur inside the pipe.

CAGPL believed that personnel experienced in operations and maintenance would be drawn from existing southern pipeline systems. Although CAGPL agreed that it would probably have a 20 per cent turnover of staff each year in the Arctic regions, this would not affect its ability to operate and maintain the system.

Views of the Board

The Applicant proposes to operate its pipeline by remote control in its early operating years. Based on the operating history of existing pipelines, the Board does not share the optimism of the Applicant that the remote control mode can be introduced in the short time span proposed by the Applicant. If that should be the case, then CAGPL will simply have to continue to provide the necessary operating staff.

The possibility exists that failures in remote areas along the system could occur during operation of this pipeline. CAGPL has recognized this by its proposal to install crack arrestors every 300 feet in order to keep the potential failures to a manageable length and by its plans to effect repairs in a relatively short time. The Applicant's maintenance program obviously will have the required pipe and repair equipment available to make these repairs and the Board is satisfied the Applicant will take the necessary steps to ensure that the repairs are properly made.

3.1.3.8 Cost of Facilities

Introduction

CAGPL presented estimates of the cost of the facilities it proposed to construct in Canada for two different cases. The first of these, the Base Case, assumed that CAGPL would transport 4.5 Bcf/d, 2.25 Bcf/d each from Prudhoe Bay and the Mackenzie Delta by the fifth operating year. The second case, the No Expansion Case, assumed transportation of 3.25 Bcf/d, 2 Bcf/d from Prudhoe Bay and only 1.25 Bcf/d from the Mackenzie Delta by the second operating year.

Cost estimates were presented on two bases:

i) Unescalated - costs in the first quarter of 1976; and

ii) Escalated - costs escalated from 1976 forward to the year of actual construction.

CAGPL

ESTIMATED COSTS OF FACILITIES

(Millions of Dollars)

	Unescalated	Escalated
Base Case (4.5 Bcf/d)	5,642.788	8,989.743
No Expansion Case (3.25 Bcf/d)	5,047.892	7,925.434

Development of Cost Estimates

CAGPL used the following basic parameters in estimating the cost of its facilities:

the cost for mainline pipe;

escalation rates for computing escalated costs;

lists of facilities and equipment required for operation and maintenance purposes; and

the basic project schedule which was worked out by CAGPL in co-operation with Northern Engineering Services (a consulting engineering firm retained by CAGPL for this project).

Costs were then developed at a detailed level by line segment (13 segments were included in the detailed cost estimates). As a first step, material costs were estimated by identifying all the components of a cost item. This was usually done by material take-off from preliminary design drawings. Estimating prices for components were then obtained from manufacturers or suppliers. Applicable duties and federal taxes were then added along with freight costs.

Installation costs included labour and equipment costs as well as the necessary goods and services required to maintain the construction program.

Labour cost estimates for pipeline installation were based on current agreements between unions and the Pipeline Contractors Association. Labour costs were based on an 84-hour work week and included overtime premiums and fringe benefits. Costs were included for recruiting and processing labour as well as for an estimated labour turnover. Productivity for different seasons and regions was accounted for. Similarly, station construction labour rates were based on Building Trades Agreements, and civil work rates were based on Road Builders Agreements.

As a general rule, construction equipment costs were based on purchasing new equipment, and prices were based on quotes from equipment suppliers. Estimates of costs were also provided for fuel, lubricants, repairs and expendable and consumable supplies.

Mobilization, catering, subsistence allowances, and construction camp costs were estimated separately.

Costs for items such as borrow material were developed in a detailed manner which included developing detailed equipment requirements. Equipment and labour costs were then handled in the same manner as for pipeline construction.

Costs were entered by year and by segment as data input for a computer program which then grouped costs into categories, added appropriate provincial sales taxes, calculated escalation, and tabulated costs by cost category, year and segment. Indirect costs were also calculated and added to the direct costs.

A forecast of escalation factors was made for each individual category. For each category, an historical statistical series was examined to determine past performance of the relevant prices in comparison with the overall performance of the Canadian economy and general price trends. Most of these statistical series were selected by examining the degree to which various pipe indices have correlated with actual costs incurred in the construction of major pipeline facilities in Canada.

The following escalation rates were utilized to convert the 1976 dollar estimate to the year of material purchase or installation.

CAGPL

ANNUAL INFLATION RATES

(percent)

	1977	1978	1979	1980	1981	1982	1983
Line Pipe	5.0	3.0	3.0	3.0	3.0	3.0	3.0
Wages & Salaries	10.0	8.0	8.0	8.0	8.0	8.0	8.0
Non-Residential Construction Materials	5.0	5.0	5.0	5.0	4.0	4.0	4.0
Construction Machinery & Equipment	6.0	3.5	3.5	3.5	3.5	3.5	3.5
Diesel Fuel	4.9	5.7	3.0	3.0	3.0	3.0	3.0
Freight	7.0	6.0	6.0	6.0	5.0	5.0	5.0
Compressors & Turbines	5.0	4.5	4.5	4.5	4.5	4.5	4.5
Other Compressor Chilling and Measuring Station Materials	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Project Average	5.0	4.0	4.0	4.0	4.0	4.0	4.0

CAGPL made no provision for any risk associated with the Canadian dollar exchange fluctuations with the United States dollar in the period between 1976 and the year of construction.

Cost Summary

The following is a summary of the escalated costs of the facilities for the Base Case and the No Expansion Case.

CAGPL

ESCALATED COSTS OF FACILITIES

(Millions of Dollars)

	Base Case	No Expansion Case
Direct Costs		
Land	2.588	2.588
Pipeline	4,004.979	3,988.382
Compressor Stations	1,670.306	838.691
Ancillary Facilities	658.965	654.424
Measuring Stations	34.748	34.748
Operations and Maintenance Facilities	113.410	113.410
Communication Facilities	54.374	49.273
Indirect Costs		
Pre-Permit Costs	216.000	216.000
Operation Prior to Service	135.866	120.532
Engineering	392.360	340.889
Contingencies	212.538	184.656
Allowance for Funds Used During Construction	1,493.609	1,381.841
TOTAL INVESTMENT	8,989.743	7,925.434

Major Direct and Indirect Cost Categories

Whether 4.5 Bcf/d (Base Case) or 3.25 Bcf/d (No Expansion Case) are assumed to flow through the CAGPL system, the length and the size of the pipelines would remain the same under both flow conditions. The only difference in facilities for the two cases would be the number of compressor stations installed and the spacing between each compressor station (See the Design Section of this chapter.). Therefore, as a general rule, the direct costs and the pre-permit costs (an indirect cost item) would remain about the same for both cases. Exceptions would be the compressor and the compressor station related facilities costs such as pipeline manifolds, gravel pads, helicopter pads and communications.

The major items included in the total investment cost estimates were:

(a) Land

Land costs included the purchase in fee simple of permanent facilities lands and the associated acquisition costs.

(b) Pipeline

This category included the purchase of all pipe, and the detailed construction cost estimate schedules included pipe price f.o.b. plant, taxes, duties, ocean freight, rail freight and all handling up to the northern staging sites (Hay River and Enterprise). Transportation and material-handling costs from the staging sites to the construction sites were included in the logistics portion of the Pipeline Ancillary Costs (i.e., Materials Handling and Freight Barge).

For cost estimating purposes, CAGPL assumed two sources of supply for its line pipe, one from the Stelco pipe mill in Welland, Ontario and the other from the Mannesmann pipe mill in West Germany.

Mainline Pipe

With regard to mainline pipe, CAGPL stated the project would require 1,700,000 tons of 48-inch O.D. x 0.720 W.T., Grade 70 pipe of which 1,100,000 tons would be produced by Stelco at an f.o.b. plant price of $645 per ton and 400,000 tons from Mannesmann at an f.o.b. plant price of about U.S. $525 per ton. The remaining 200,000 tons might be obtained from U.S. Steel; however, no price was given.

The Applicant considered the price of pipe from Mannesmann to be confidential and it used for price estimation purposes a price of U.S. $525 per ton f.o.b. plant being an average of four tenders received from Mannesmann and Hoesch in West Germany, Italsider in Italy and a consortium of four major pipe mills located in Japan.

CAGPL negotiated its pipe contract with Mannesmann on the basis that the transfer of title of pipe would occur in Vancouver, British Columbia. For cost estimation purposes it used costs of $35 per ton for shipping pipe from a European location to a staging site in the Vancouver area and $21 per ton for the handling charge for offloading and for loading to railcars in Vancouver.

The average price of pipe to site (exclusive of freight and handling charges to the construction sites) was estimated to be $662.05 per ton under the assumption that approximately 65 per cent of the pipe being shipped to each construction spread would be from Stelco and the remaining 35 per cent would be from Mannesmann.

CAGPL assumed that about 220,000 tons of line pipe less than 48 inches in diameter would be procured in Canada. The estimated f.o.b. plant price for both the 42-inch O.D. x 0.630 W.T. and the 36-inch O.D. x 0.464 W.T. line pipe was $650 per ton.

Heavy Wall Pipe

Heavy wall pipe required at compressor stations, metering stations, river crossings, pipeline assemblies, etc. was assumed to be purchased from Mannesmann at the price of $660 and $790 per ton f.o.b. plant.

Other Items

The pipeline category also included internal and external coating, concrete weights to counteract pipeline buoyancy, mainline valve assemblies, major river crossings, heat-tracing equipment, crack arrestors, training and miscellaneous. The miscellaneous items under pipeline direct costs were calculated as one per cent of the total direct costs of all pipeline materials and were intended to include material costs for items not specifically identified, such as road and railway crossing materials, test loads, signs, markers and fence gates.

Installation Costs

The installation costs of mainline pipe were included in this category together with the costs of construction equipment, installation of heat tracing, testing and other miscellaneous installation costs. These miscellaneous costs were calculated as two per cent of the installation direct costs and included double jointing of pipe and restoration costs where applicable.

The pipeline installation costs were based on estimates made mainly by the Applicant's consulting firm, Northern Engineering Services.

As discussed in the Geotechnical Design section, the Applicant proposed to insulate and heat trace 138.4 miles of pipe and install heat probes over a distance of 119 miles to prevent frost heave of the pipeline when the chilled gas traversed discontinuous permafrost. In addition, for a distance of about 131 miles, where thaw settlement might create critical pipe stress problems, the Applicant proposed using pipe supports and continuous concrete pipe coating. Estimated cost to mitigate frost heave and thaw settlement was $180 million (including material and installation).

According to CAGPL, most pipeline installation contracts would be of the "cost incentive type", but in developing its cost estimates, CAGPL did not define a type of target or how a contractor's incentive would work but estimated that a contractor's profit and administration would be 20 per cent of contractor's labour, 5 per cent expendables, 10 per cent of equipment cost and 5 per cent as extras.

Construction equipment costs were based on the assumption that CAGPL would purchase the equipment. The Applicant assumed that at the conclusion of the project, the salvage value of the equipment, including the staging site equipment, would be the same as the cost of demobilizing and moving out the equipment.

(c) Compressor Stations

These costs were based on the assumption that a ground station pad (cost included in ancillary facilities) would be in place and included all remaining costs associated with a compressor station.

(d) Ancillary Facilities

These costs included all site development, the off right-of-way facilities required to support construction of permanent facilities, equipment and the logistics requirements such as barge freight, materials handling, air support, etc.

CAGPL assumed that all construction material and equipment for the project would be moved down the Mackenzie River and along the Beaufort coast by means of 12 barge strings, three of which were already in operation (a barge string is composed of one tug and 12 barges). CAGPL assumed that it would pay only the published tariff rates because the barge operators would purchase the barge strings.

CAGPL assumed that, at the conclusion of the project, the traffic on the river would be increasing at about eight per cent per year and the barge operators would then utilize the nine additional barges to meet the traffic growth.

In operating year three, and until the traffic could absorb all the new barges, CAGPL would pay a charge of 17.7 per cent per year to cover depreciation and cost of money.

CAGPL's method of calculating freight costs differed from that used by Foothills in several respects. Foothills assumed a rate of 16 2/3 per cent for barge depreciation and this charge would cease at the conclusion of the transportation of its material and equipment. CAGPL assumed a lower rate of depreciation of 6.7 per cent, and such depreciation charges would continue until the traffic on the Mackenzie could utilize the nine new barge strings. CAGPL also included in its freight operating cost a charge of cost of money of 11.0 per cent until the barges could be utilized somewhere else.

(e) Measuring Station

The measuring station costs included all the permanent materials and equipment and the installation of these items.

(f) Operation and Maintenance Facilities

These costs included all permanent off right-of-way facilities of the operating headquarters in Calgary and district offices and included all buildings, houses, office furniture, etc., required for the personnel who would operate and maintain the pipeline system.

(g) Communication Facilities

These costs included the provision for leasing Telesat communication facilities for use during both the construction and operating phases of the facilities.

(h) Pre-permit Costs

CAGPL included $216 million as a pre-permit cost to cover such items as engineering and environmental studies, and legal costs.

(i) Operation Prior to Service

These costs included the project management functions of the Applicant.

(j) Engineering

Six percent of the total direct cost was included for engineering, design, procurement, non-destructive testing and inspection of the system during the design and construction phases.

(k) Contingency

An allowance of 3.25 per cent of direct costs was used as a contingency to provide for potential errors in or omissions from the estimates which were based on preliminary design.

The adequacy and composition of this relatively small allowance for contingencies were questioned. CAGPL stated it had not intended to cover the cost of moving additional spreads onto the North Slope, for example. It was planned that funds for such major items would be available from the allowance in the financial plan of a substantial sum, in excess of $1 billion, for cost overruns over and above the capital cost estimates.

The 3.25 per cent contingency item did not allow for possible changes in the exchange rate between the Canadian and the United States dollars, or for possible delays in offshore deliveries but it would provide for extra costs incurred if, for example, material could not be shipped around Alaska, but had instead to be shipped on the Mackenzie River.

Views of the Board

The Board generally agrees that, subject to cost changes resulting from changes which could occur in the final design stage as a result of site-specific terrain analysis, CAGPL's cost estimates are reasonable. As these changes will not be known until further terrain analysis is undertaken, the costs associated with the changes, if any, cannot be quantified at this time.

The Board is of the opinion that CAGPL, through its detailed studies, has properly identified the major problem areas and carefully taken account of them in its cost estimates which can be summarized as follows:

	1976 Costs (Millions of Dollars)
Materials	
Pipe	1905
Stations and others	1432
Installation	
Pipeline	1171
Stations and others	360
Indirect Costs	
Pre-permit	216
Operation Price to Service	109
Engineering and Contingencies	450
Total	$ 5643

The largest material item is the line pipe which at $1905 million includes taxes and freight charges to the site. The pipe costs reflect the agreed pipe prices covered in the letter of intent signed with the pipe manufacturers. The Board is of the opinion that the estimated pipe costs in the year of procurement or installation should be realistic if the project adheres to the construction schedule, if the assumed pipe escalation factors are correct, and if the Canadian dollar is at par with the United States dollar. While the pipe escalation factors used by CAGPL are less than half of those used by Foothills (Yukon) and its partners, the Board notes that the Applicant has signed letters of intent containing escalation clauses with its pipe suppliers.

The second largest material item is the compressor units for which the Applicant obtained quotes from the manufacturers. Similarly, if the project adheres to its construction schedule and the escalation factors are correct, these prices should be realistic.

The Applicant proposed target-type contractual arrangements for the construction of its pipeline facilities. On this basis, the Applicant and contractor would mutually agree on the labour costs which are reflected in the most part by the estimate plus a reasonable profit. Under such type of contract, the contractor would be protected from a certain number of uncertainties and there would be an incentive to maximize its profit by meeting or bettering its construction schedules.

The Applicant will purchase the equipment and write off the majority of it over the construction period.

The Board is of the opinion that the construction costs should be achieved provided the construction schedule is adhered to, and the assumed inflation factor for labour is correct.

CAGPL has a number of problems where there is a risk of cost overrun such as:

1) availability of an Arctic ditcher;

2) snow road construction;

3) limited shipping season of four to five months;

4) limited working period of 90 days; and

5) harsh climatic conditions.

Although the Applicant has addressed itself to all these problems to the best of its ability, nonetheless, these uncertainties could affect the final cost of the pipeline. These effects have been discussed in the Risk of Cost Overrun Section of the report. Subject to the views expressed there, the Board accepts the Applicant's cost estimate of $8,990 million as realistic.

3.1.4 ALBERTA NATURAL

3.1.4.1 Facilities Design and Capacity

System Configuration

The facilities proposed to transport the Alaska gas volumes from the CAGPL receipt point near Coleman, Alberta into the interconnecting PGT pipeline system at the international boundary near Kingsgate, British Columbia, consisted of the addition of 102.2 miles of 36-inch diameter line which would loop out the existing ANG system.

In addition to the existing throughput capability of 1,195 MMcf/d, the system was designed to receive approximately 690 MMcf/d of Prudhoe Bay gas from CAGPL in the 1986-87 operating year.

The addition of approximately 102.2 miles of 36-inch O.D. x 0.350-inch W.T., Grade 65 pipe designed to operate at 911 psig when tied into the existing Flathead Ridge, Elk River and Kootenay River loops (four miles in total), all installed in 1970, would completely loop the existing pipeline system; the additions would operate at the same pressure as the existing system.

The proposed facilities would also include additional metering facilities at the existing Kingsgate Meter Station and modification of the pipeline at compressor stations 2A and 2B to operate the existing compressors in two-stage compression.

ANG stated that when developing the facilities design, it had attached considerable importance to the fact that 36-inch diameter pipe had been used for river crossing loops which had recently been installed. Incorporation of these existing loops into the design would minimize the environmental impact of its project, since it would decrease the number of river crossings that otherwise would be required and would avoid a significant routing deviation in the Flathead Ridge area. Considerable cost savings would also be realized and the utilization of these loops would avoid the installation of approximately four miles of pipeline in difficult terrain.

The Applicant's existing pipeline system would be capable of transporting an average day gas volume of about 1,195 MMcf and a maximum day volume of 1,325 MMcf. With the additional 102.2 miles of 36-inch O.D. pipeline facilities and modifications to compressor stations 2A and 2B the ANG system would be able to transport an average and a maximum day throughput of 2,093 and 2,367 MMcf respectively.

System Reliability

ANG's system was designed to transport the combined flow of 1,750 MMcf/d from Alberta and Alaska sources. 1,059 MMcf/d of Alberta gas would be pressurized at Compressor Station No. 1 and mixed with 690 MMcf/d of Alaskan gas at the discharge side of the same compressor station.

The Applicant performed a system reliability study of its existing system with the additional proposed facilities. The results of the study showed that an annual average capacity of 2,230 MMcf/d could be achieved even with the loss of the critical compressor unit. Therefore, no loss in annual throughput would be expected with a compressor unit outage.

Views of the Board

The Board is satisfied with ANG's intention to expand its existing system by looping with 36-inch O.D., 0.350-inch W.T., Grade 65 pipe to operate in conjunction with its existing 36-inch O.D. mainline at 911 psig. It recognizes the advantages of having two major river crossings and a difficult construction area in the Flathead Ridge already looped with 36-inch O.D. pipe and the economies that will be achieved by operating a looped system with a combined flow on the same right-of-way. The looping program would provide a double line for the entire 106.6 miles of the ANG system and the Board is satisfied that adequate reliability for the projected additional fifth year operating volumes of approximately 687 MMcf/d, combined with its existing flow requirements, will be provided. The Board therefore, accepts ANG's design as part of the CAGPL project.

ANG did not apply to transport the volumes of gas which could be delivered to its system if the Foothills (Yukon) project were approved, as it is not a partner in that group. Nonetheless, the Board recognizes the advantages inherent in using an existing right-of-way as compared to building a new pipeline in the same area. In the event the Foothills (Yukon) project were certificated, consideration should be given to these advantages.

3.1.4.2 Geotechnical and Geothermal Design

Alberta Natural's application related to the expansion of an existing system that has been operated and maintained successfully for a number of years. The Applicant testified that the greater part of its route was composed of stable terrain and that while there were areas of potential slope instability, their location was known and no problems were foreseen. The Applicant has already constructed loops in the areas of greatest concern, these being Flathead Ridge and the major river crossings. Since the configuration of this existing looping is compatible with that of the proposed additional facilities, no further construction would be required in these areas.

Views of the Board

Although ANG has many years of operational experience in relation to geotechnical problems along its route, it would be required to satisfy the Board as to the adequacy of the final design of river crossings and slope stabilization.

3.1.4.3 Stress Analysis and Materials Engineering

ANG's proposed mainline looping of 36-inch O.D. by 0.350-inch wall thickness line pipe would, according to the Applicant, be laid in solid ground where limited areas of erosion or slope instability were anticipated. Therefore, ANG did not present to the Board either a stress analysis or fracture control design. ANG's materials specifications for high strength steel line pipe complied with the CSA Standards Z184, Z245.1 and Z245.2. The Applicant specified Grade 65 line pipe with a minimum Charpy V-notch energy for any single specimen of 30 ft-lbs and an average of 40 ft-lbs for three specimens of any heat. Further, an average DWTT minimum shear area of 60 per cent for two specimens of any heat and an all-heat average of 85 per cent were specified by ANG. All cross-tie assemblies necessary to connect the proposed looping to the existing 36-inch O.D. pipeline would be made from Grade 52 pipe. Specifications for welded fittings, flanges and valves were also provided.

Views of the Board

The Board considers ANG's materials specifications generally satisfactory. However, the Applicant would be expected to submit a stress analysis and final welding and materials specifications to the Board for approval, if this application were certificated.

3.1.4.4 Right-of-Way

ANG proposed to use existing loops plus new line on its existing right-of-way to avoid significant routing deviations, as well as decrease the number of crossings of navigable waters. ANG would use its existing 100-foot wide right-of-way with the exception of some areas where additional right-of-way would be acquired from the provincial Crown.

Assurances were given that topsoil would be removed and replaced where necessary, that clean-up practices would be followed and that damages caused by pipeline construction would be made good. It was also stated that the right-of-way would be returned to its appropriate condition to satisfy all concerned. ANG undertook to seek all necessary regulatory approvals and provide the Board with all necessary documentation.

Views of the Board

ANG, a company under the Board's jurisdiction for over two decades, has shown in the past its appreciation of and understanding of requirements in regard to right-of-way matters.

The Board would, nevertheless, require that ANG comply with all of the Board's directions regarding the aquisition of rights-of-way and other lands, including but not necessarily limited to specific directions as to the rights of and notice to all potentially affected property owners to ensure an orderly land acquisition and an equitable settlement program.

3.1.4.5 Construction

ANG proposed to add approximately 102 miles of 36-inch pipeline loop to its existing system in southern British Columbia. The Applicant proposed to construct the additional pipeline and upgrade its existing facilities during one continuous construction period beginning in April, 1981 and completing the installation in December of the same year. The Applicant felt that the proposed construction schedule was realistic and recognized that, due to the construction restraints in the mountainous terrain, some tie-ins and pipeline testing would have to be deferred until the following spring.

Views Of The Board

The Board recognizes that ANG has had many years of experience constructing and operating pipeline facilities along its proposed route. It is satisfied with the construction plan proposed but if a certificate were issued, it would be conditioned to require the Applicant to submit detailed construction specifications for approval of the Board in advance of any pipeline construction.

3.1.4.6 Operations and Maintenance

The Applicant felt that the additional facilities could be maintained with very little change to its existing operations and maintenance program.

Views of the Board

The Board is satisfied with the present operating and maintenance programs of the Company.

3.1.4.7 Cost of Facilities

Cost Estimating Procedure

The Applicant developed the capital cost estimates of its facilities utilizing quotations from material suppliers, discussions with pipeline contractors and its own experience from owning and operating the existing pipeline along the proposed route.

The costs were based on first quarter 1976 dollars escalated to the anticipated year of expenditure. The yearly escalation factors utilized were developed by consultants for CAGPL and were available to the Applicant through its participation in the Gas Arctic - Northwest Project Study Group.

Cost Summary

ANG estimated a total cost of $74,321,000 for the facilities that would be required to transport the Alaska volumes of about 690 MMcf/d in late 1981. These costs assumed first flow in 1982 and they would be higher if the CAGPL proposed first gas flow in 1983 were reflected.

The following is a summary of the escalated construction costs of the total facilities:

ANG

ESCALATED COST OF FACILITIES

(Millions of Dollars)

Pipeline Looping (102.2 miles, 36-inch O.D. x 0.350-inch W.T., Grade 65)	49.284
Conversion of Stations 2A and 2B to Parallel Configuration	0.720
Kingsgate Meter Station - Additional Facilities	1.761
Total 1976 Costs Unescalated	51.765
Escalated to Year of Construction	67.642
Interest During Construction	6.679
Total Cost	74.321

ANG's unescalated costs with respect to materials, installation and other related costs are summarized as follows:

ANG

SUMMARY OF MATERIALS, INSTALLATION AND OTHER RELATED COSTS

(Millions of Dollars)

Materials	25.5
Installation	21.0
Other Related Costs	5.3
Total 1976 Costs	51.8

Pipe (including internal coating and freight) would amount to $21.9 million or about 86 per cent of the total materials costs.

Cost of Materials

Line Pipe Cost

For cost estimating purposes, ANG used pipe quotes from one manufacturer only. Those were from Stelco, which could produce pipe meeting ANG specifications at its Camrose, Alberta pipe mill. It was, however, ANG's intent, before purchasing its pipe from Stelco, to obtain quotes from other manufacturers.

Escalation Factors

ANG used escalation factors of five per cent for 1977 and four per cent thereafter to convert first quarter 1976 cost estimates to cost estimates escalated to year of construction.

Application of these factors resulted in the 1976 cost estimate of $51.8 million being escalated to $74.3 million.

Views of the Board

The Board accepts ANG's design and foresees no abnormal construction problems. In coming to this conclusion, it relies on ANG's experience in the construction and operation of its existing pipeline in this area. The Board is satisfied that the cost estimates of ANG fully reflect this experience.

In developing its costs, the Applicant assumed first flow from Alaska in 1982. Using the Applicant's escalation rates, the Board estimates that the escalated costs would be about $78 million if the anticipated date of first gas flow in 1983 were reflected.

The largest cost item under Materials is the line pipe accounting for about $22 million. The estimate was based on quotations from a Canadian pipe manufacturer and includes known transportation charges to the construction site.

ANG planned to install its proposed facilities within a one-year period.

Since these facilities will avoid two major river crossings and a difficult construction area in the Flathead Ridge, and will share the right-of-way of the existing ANG pipeline, no major pipeline construction problems are anticipated.

Since the Applicant has had discussions with pipeline contractors and also has experience in constructing and operating a pipeline in the area, the Board is of the opinion that the construction should be completed within the estimated costs, provided the construction schedule is met and the assumed inflation factor for labour is correct.

The Applicant used a composite inflation rate of five per cent for year 1977 and four per cent for the subsequent years. If a comparison is made of the Applicant's rates with those used by Foothills (Yukon) and its partners, ANG's are about half of the others. The Board is of the opinion that escalation rates in the order of seven to eight per cent would be more realistic in the light of the evidence submitted by experts during the hearing.

If ANG's inflation rates were doubled and applied up to year 1983, the inflation costs would be in the neighbourhood of $38 million instead of $15.8 as shown above and the total estimated cost (escalated) for the project would become about $90 million.

The Board is prepared to accept the Applicant's total 1976 unescalated cost of $52 million but believes that the escalated cost could be in the neighbourhood of $90 million rather than $74 million as estimated by ANG.

3.1.5 WESTCOAST

Westcoast proposed to construct certain facilities to enable it to receive Mackenzie Delta gas volumes from either Foothills or CAGPL. Because these facilities would be identical for either project, with the exception of the design and related costs of the Territories Mainline Extension, and because Westcoast is a member of the Foothills group, these facilities will be discussed in the Westcoast section under the Foothills Project.

3.2 FOOTHILLS GROUP PROJECT

3.2.1 Introduction

Foothills

Foothills' proposed pipeline was designed to transport a maximum of 2.4 Bcf/d of Mackenzie Delta gas to Canadian markets. It proposed to construct a 42-inch O.D. line running south from the Taglu natural gas processing plant (milepost 0) in the Mackenzie Delta. A 24-inch O.D. supply line, approximately ten miles in length, would be constructed to transport gas from Niglintgak northeast to Taglu. A 15-mile, 30-inch O.D. supply lateral from the Parsons Lake gas plant would join the mainline at milepost 51.

From this point, the mainline would continue in a south-southeasterly direction through the Northwest Territories, on the east side of the Mackenzie River, for approximately 635 miles. Just east of Fort Simpson, the mainline would cross the Mackenzie River (milepost 686). At milepost 778, there would be a connection with the proposed main community service lateral serving the Great Slave Lake area communities (described in greater detail below).

The mainline would continue south to milepost 817, approximately 7 miles north of the 60th parallel, where the proposed Foothills pipeline would terminate. The Trunk Line (Canada) and Westcoast interconnecting pipelines would begin at this point. (See Map 3-3.)

The Applicant also proposed to construct lateral lines to serve various northern communities, as indicated in the following table:

FOOTHILLS

Proposed Community Service Laterals

Community Served	Diameter of Lateral (inches)	Length (miles)	Milepost of Mainline Connection
Inuvik	6	15.1	78.6
Fort Good Hope	3	2.3	283
Norman Wells	3	2.3	372
Fort Norman	3	4.8	419.5
Wrigley	3	3.9	556.9
Fort Simpson	4	19.4	688
Great Slave Lake Area Communities	3 to 10	419.6	778

The main 10-inch O.D. lateral that would serve the Great Slave Lake area communities would run northeast from the mainline for approximately 93 miles to a bifurcation point. At this point, there would be a connection with a secondary 6-inch O.D. line which would run southeast for 120 miles to Pine Point. A 4-inch O.D. line would run from milepost 68 on this secondary lateral for 7.5 miles to Hay River.

From the point of connection with this secondary lateral at milepost 93, the main lateral would be an 8-inch O.D. line. It would proceed northeast to milepost 104.5 where there would be a connection with a 3-inch O.D. line, 5.1 miles in length, that would serve the community of Fort Providence. The main 8-inch O.D. lateral would continue in a northeasterly direction until lateral milepost 223. A 3-inch O.D. line, 6 miles in length, which would run to Rae-Edzo, would connect with the main lateral at this point. From milepost 223, the lateral would take a southeasterly direction and continue for another 58 miles to Yellowknife (lateral milepost 281).

Various alternate methods of connecting Mackenzie Delta gas were studied in conjunction with Foothills (Yukon) and will be discussed in Section 3.2.2 of this chapter.

The Mackenzie Delta gas volumes flowing through the Foothills system would be transported to (a) eastern Canadian markets through the facilities of Foothills, Trunk Line (Canada), Trunk Line and TransCanada, and (b) to the Westcoast system to help meet a shortfall in its existing commitments. Foothills would transport the gas for shippers on a contractual basis. Gas volumes required for compressor fuel and chilling fuel would be provided to the Foothills pipeline by each shipper in proportion to its throughput in the line, and delivery volumes would be adjusted to reflect this.

The northern section of the pipeline would run through the continuous and wide-spread discontinuous permafrost zones, and the gas would be chilled below 32°F in this section to prevent degradation of the permafrost. The last chiller unit would be located at Compressor Station 13 (milepost 629), with Compressor Station 14 (milepost 688), just south of Fort Simpson, being the last point of cold flow. In discontinuous permafrost areas where the ground would be unfrozen but the gas would still be chilled, insulation would be used to mitigate possible frost heave problems. In the section south of Fort Simpson, where the line would traverse the scattered discontinuous permafrost zone, Foothills' design took into account the thaw settlement problems that would be encountered.

Construction of the facilities required to permit the first flow of gas would be completed over a 4-year period. The northernmost 50 miles of the line would be constructed in the autumn season, working from a gravel pad. The remainder of the line would be built during the winter seasons using winter construction techniques. Two compressor stations would be completed and four others would be partially constructed in the autumn of 1982. The partial stations would be completed and eleven additional full stations would be added over the first three operating years.

It was proposed that the Delta reserves would come on stream in November, 1982. Full utilization of the facilities would be obtained in the fifth operating year. The construction schedules of the companion applications in the Foothills group project would coincide with the Foothills delivery schedule.

The Foothills 42-inch pipeline would be constructed of 0.540-inch wall thickness, Grade 70 pipe. The line would be hydrostatically tested to permit a maximum allowable operating pressure of 1440 psig, but Foothills proposed to operate its pipeline at a derated pressure of 1250 psig due to metallurgical considerations.

The following table outlines the ultimate projected throughput volumes (reached in 1987) for the Foothills project system:

FOOTHILLS PROJECT SYSTEM

ULTIMATE PROJECTED THROUGHPUT VOLUMES

(MMcf/d)

Foothills Section	
Supply	
Mackenzie Delta Gas	2,400.0
Disposition	
Off-Line Deliveries to	
Northwest Territories	14.0
Fuel in Northwest Territories	86.8
Deliveries	
- to Westcoast	475.0
- to Trunk Line (Canada)	1,824.2
Total Disposition	2,400.0
Trunk Line (Canada) Section	
Supply	
Receipts from Foothills	1,824.2
Disposition	
Fuel in Alberta	70.0
Deliveries to TransCanada	1,754.2
Total Disposition	1,824.2

The estimated costs of the Foothills pipeline facilities were $3,085,000,000 (1976 dollars escalated to the year of expenditure).

Westcoast

Westcoast made application to the Board with respect to receiving Mackenzie Delta gas volumes under the Foothills project. If Westcoast is able to purchase gas from the Delta producers, it would act as a shipper in the Foothills pipeline. Westcoast, as an owner of this gas, would then treat these volumes as part of its common supply for transportation within its own system. In the alternative (i.e. if Westcoast is unable to negotiate supply contracts with the producers), it would not be a shipper in the Foothills line, but would transport the gas through its system for shippers on a contractual basis. In this case, gas volumes required for compressor fuel in the Westcoast pipeline would be supplied by each shipper in proportion to its throughput in the line.

Westcoast applied to the Board for only those facilities required for the first year of flow. This was due to the fact that Westcoast is an operating company, with other sources of supply, and felt it was very difficult to predict exactly what facilities would be required in future years. However, because there was no projected increase in the volumes delivered by Foothills to Westcoast, there would be no increase beyond the first year in the facilities required for Delta gas.

From the termination point (milepost 817) of the Foothills pipeline approximately seven miles north of the 60th parallel, Westcoast proposed to construct a new 30-inch O.D. line proceeding southwest for 140.6 miles to connect with the existing Fort Nelson mainline near Fort Nelson, British Columbia. This new line would be known as the Territories Mainline Extension and would be constructed of 0.375-inch wall thickness, Grade 70 pipe, and operated at its design pressure of 1250 psig.

Based on its assumption that it would receive a maximum daily volume of 500 MMcf/d (475 MMcf/d average) of Mackenzie Delta gas from Foothills, Westcoast also planned to add 201.1 miles of 36-inch O.D. looping, compression totalling 40,000 horsepower and other related facilities to its existing system. The looping pipe would be of 0.390-inch and 0.469-inch wall thickness, Grade 60 pipe, with the operating pressure of the loop segments conforming to that of the existing pipeline, some 936 psig. (See Map 3-3.)

Construction of the Territories Mainline Extension would take place in the winters of 1980/81 and 1981/82, with the looping being added in 1981 and 1982. Compression facilities would be added in the summer of 1982.

The estimated costs of the applied for facilities were $388,185,000 (1976 dollars escalated to the year of expenditure).

Trunk Line (Canada)

Trunk Line (Canada), a wholly-owned subsidiary of Trunk Line, would transport Mackenzie Delta gas volumes received from Foothills just north of the 60th parallel through Alberta to Empress, where they would be received by TransCanada for delivery to eastern Canadian markets. Trunk Line (Canada) would act as a transporter of gas for shippers on a contractual basis. Volumes required for compressor fuel would be provided by each shipper in proportion to its throughput in the pipeline.

The facilities required by Trunk Line (Canada) to transport Mackenzie Delta gas volume under the Foothills group project were outlined as follows:

(a) Schedule A facilities, consisting of additions required to be made to the existing Trunk Line facilities in order to transport first year northern gas volumes.

In order to ensure federal jurisdication over the facilities required to move northern gas and in order to obtain the lowest long term cost of service, it was proposed that Trunk Line would cause Trunk Line (Canada), its wholly-owned subsidiary and a company under federal jurisdiction, to apply for, construct and control the operation of these facilities. These additional facilities would be owned by Trunk Line and leased back to Trunk Line (Canada) under a proposed leasing arrangement between the two companies. Application has not as yet been made for these facilities due to the fact that Trunk Line is an operating company with other sources of supply, and found it was difficult to predict at this time exactly what additional facilities would be required. Nevertheless, Trunk Line did outline in its submission the new facilities that would probably be required to transport northern gas volumes.

(b) Schedule B facilities, consisting of additions to the existing Trunk Line system that would be required for full flow of northern gas. These facilities would be owned by Trunk Line but would be applied for, constructed and controlled by Trunk Line (Canada) under the lease agreement, as outlined in section (a) above. Application has not as yet been made for these facilities.

(c) Schedule C facilities, consisting of the Trunk Line mainline system in existence prior to the construction of the facilities required to transport northern gas. Trunk Line (Canada) would, when required, lease spare capacity in these facilities in order to transport northern gas volumes.

(d) Schedule E facilities, consisting of a new 81-mile pipeline, to be owned, constructed and operated by Trunk Line (Canada), between the southern terminus of the proposed Foothills pipeline just north of the Northwest Territories-Alberta border and the northern terminus of the existing Trunk Line system at Zama Lake, Alberta. Application was made to the Board with respect to this line.

(e) Schedule AA facilities, consisting of existing Trunk Line facilities to be leased to Trunk Line (Canada) if required to complete a continuous 42-inch diameter pipeline across Alberta.

It was proposed that, through a combination of the above facilities, there would exist, by the end of five years of northern gas flow, a continuous 42-inch diameter pipeline across Alberta owned or leased by Trunk Line (Canada). Included in the lease were clauses to the effect that Trunk Line would provide the required services for the operation and maintenance of the leased facilities. Also included was an option for Trunk Line (Canada) to purchase these facilities from Trunk Line.

The Schedule A and Schedule B facilities would consist of the addition, as required, of approximately 880 miles of mainline, compression totalling approximately 309,000 horsepower, and other related facilities to the existing Trunk Line system. (See Map 3-3.) The mainline additions would be constructed of 42-inch O.D. pipe of various wall thicknesses and would be operated at pressures to match those of the existing system. An exception to this would be the section from Zama Lake to Gold Creek Junction, some 300 miles in length, which would be isolated from the existing adjacent facilities and operated at 1250 psig by the second year of northern gas flow.

Construction of these additional required facilities would commence in the winter of 1980/81 and would be completed by the summer of 1986.

The estimated costs of the Schedule A and Schedule B facilities, as outlined in the submission by Trunk Line, were $1,052,600,000 (1976 dollars escalated to the year of expenditure). As previously indicated, no application has been made to the Board with respect to these facilities.

The Schedule E facilities applied for by Trunk Line (Canada) consisted of a new 81-mile, 42-inch O.D. pipeline to be constructed between the southern terminus of the proposed Foothills pipeline seven miles north of the Northwest Territories-Alberta border and the northern terminus of the existing Trunk Line system at Zama Lake, Alberta. (See Map 3-3.) This line would be owned and operated by Trunk Line (Canada).

The 42-inch O.D. line would be constructed of 0.469-inch wall thickness, Grade 70 pipe, and would be hydrostatically tested to permit a maximum allowable operating pressure of 1250 psig. Construction would take place in the winter of 1981/82.

The estimated costs of the Schedule E facilities were $94,800,000 (1976 dollars escalated to the year of expenditure). Therefore, the total estimated cost of all facilities needed to complete a continuous 42-inch line across Alberta (i.e. Schedule A, Schedule B and Schedule E facilities) would be $1,147,400,000.

Trunk Line

As indicated in the above section under the description of Schedule C facilities, Trunk Line (Canada) planned to lease spare capacity, when required, in the existing Trunk Line system until the continuous separate 42-inch line was completed, after approximately five years of operation, and thereafter as needed. An outline of probable required facilities additions to the existing system was provided under the description of the Schedule A and Schedule B facilities which would be leased to Trunk Line (Canada).

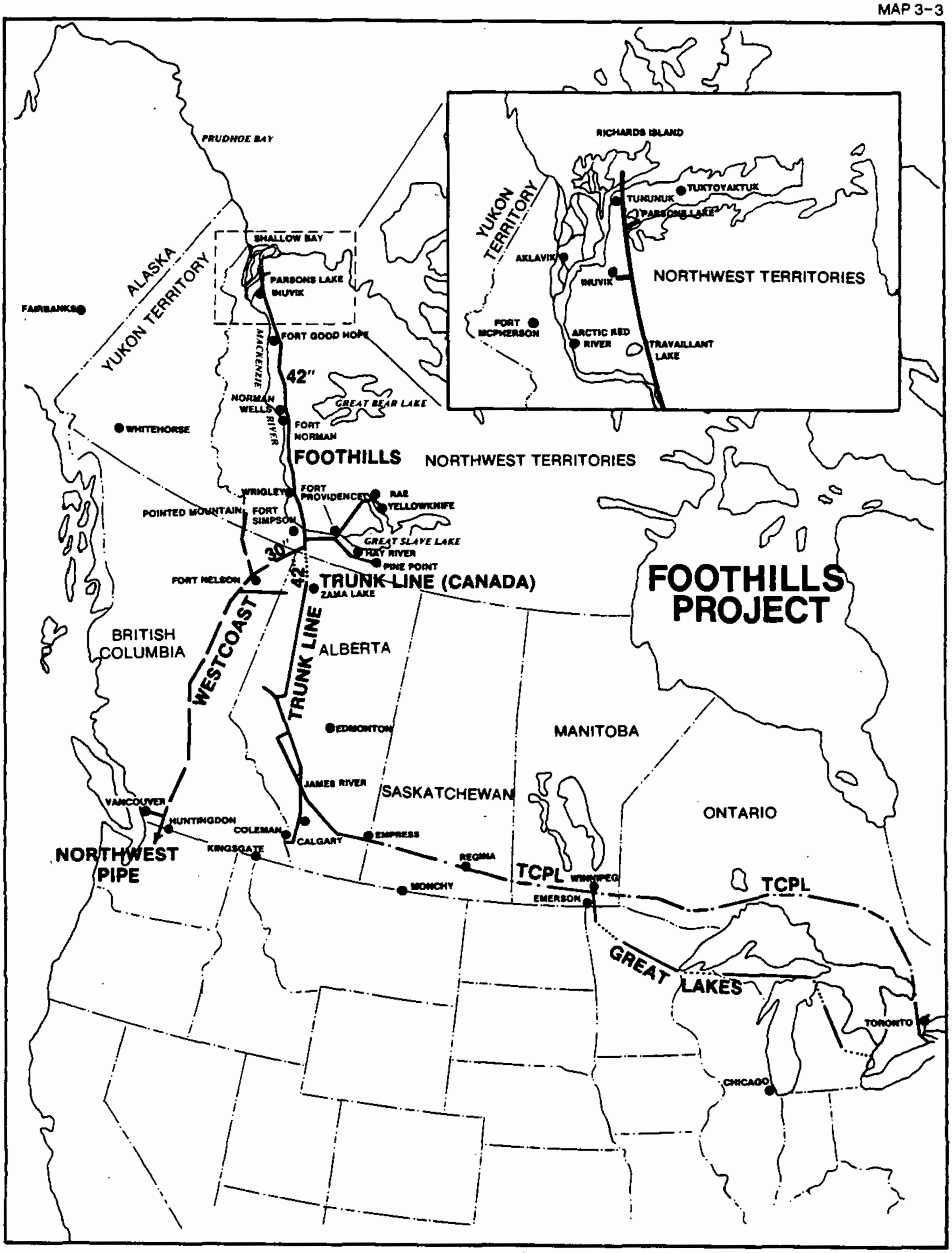
However, Trunk Line also filed the results of an optimization study which examined the possibility of increased use being made of the existing Trunk Line pipeline system in which spare capacity would be available due to a decrease in Alberta origin gas volumes. In this case, a portion of the Mackenzie Delta gas would be diverted into a part of the system whose use had not previously been proposed for the transportation of northern gas. Under this plan, 792 miles of additional pipeline construction would be required over the first five operating years, as compared to the 877 miles indicated in Trunk Line's supporting exhibits for the Foothills group project, i.e. a reduction of 85 miles. Also, there would be a reduction of some 74,400 horsepower in the amount of compression required, i.e. from 308,500 horsepower to 234,100 horsepower. The estimated cost of these reduced additional facilities would be $760,300,000, as compared to $961,500,000 (1976 dollars escalated to the year of expenditure, not including interest during construction), i.e. a saving of $201,200,000.

Following this plan, then, would result in an increase in the use of the existing Trunk Line facilities and a decrease in the additional Schedule A and Schedule B facilities required. However, it should be noted that this optimization study was filed as illustrative only of possible savings that could be achieved, and that Trunk Line (Canada) and Trunk Line continued to rely on the information previously filed in support of their respective application and submission.

TransCanada

It was proposed, as part of the Foothills group project, that Trunk Line (Canada) would deliver Mackenzie Delta gas volumes to TransCanada at Empress for transportation to eastern Canadian markets. TransCanada, a member of the CAGPL consortium, did not, however, make an application to the Board for facilities to transport the aforementioned volumes to be received from Trunk Line (Canada).

MAP 3-3


FOOTHILLS PROJECT
PRUDHOE BAY
ALASKA
YUKON TERRITORY
FAIRBANKS
SHALLOW BAY
PARSONS LAKE
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"
FORT NELSON
TRUNK LINE (CANADA)
ZAMA LAKE
BRITISH COLUMBIA
WESTCOAST
TRUNK LINE
ALBERTA
EDMONTON
MANITOBA
ONTARIO
JAMES RIVER
SASKATCHEWAN
VANCOUVER
HUNTINGDON
COLEMAN
CALGARY
EMPRESS
REGINA
NORTHWEST PIPE
KINGSGATE
MONCHY
TCPL
WINNIPEG
EMERSON
GREAT LAKES
TORONTO
CHICAGO
RICHARDS ISLAND
TUKTOYAKTUK
TUNUNUK
PARSONS LAKE
YUKON TERRITORY
AKLAVIK
INUVIK
NORTHWEST TERRITORIES
FORT MCPHERSON
ARCTIC RED RIVER
TRAVAILLANT LAKE

3.2.2 Alternative Routes

The Applicant indicated that in its examination of various route alternatives, it was apparent that the most economical and beneficial route would be the shortest distance between the point of origin and the point of termination, taking into account constraints of a topographical, environmental or sociological nature. The logical location, therefore, appeared to be along the Mackenzie Valley, which was the most direct route from Richards Island (point of origin) to the existing gas transmission facilities in Alberta and British Columbia (point of termination).

While the only alternatives originally studied by Foothills were refinements to the route which was described in CAGPL's original application, at a later date the Applicant filed four studies related to alternate methods of connecting Mackenzie Delta and Beaufort Sea gas.

The purpose of these studies was to review the possibility that the reserves in the Delta would not develop to the extent originally expected. The Applicant stated that Studies 1 and 2, the portion of Study 3 relating to the addition of Delta gas, and Study 4 were carried out in some detail following considerable field reconnaissance. Feasibility and costs, in particular, were studied, but there were no environmental or socio-economic impact reports included in the studies. However, it was stressed by the Applicant that these studies were filed for information purposes and were not to be construed as changes in the applications before the Board.

The pipeline systems in these studies were designed to transport an average day volume of approximately 1.2 Bcf/d of gas. The capability of these systems could be expanded to about 1.3 Bcf/d without looping. This proposed throughput would require approximately 10 to 12 Tcf of reserves. Foothills pointed out that if, at the time of construction of the connecting pipeline, the reserves had increased considerably over the present level and were increasing year by year by substantial amounts, then the 42-inch diameter pipeline up the Mackenzie Valley, as proposed and applied for by Foothills, would be more appropriate.

The following is a description of the four studies of alternative means of connecting Mackenzie Delta gas, three of which involved connection with the Foothills (Yukon) line:

Study No. 1 - This system would be constructed of 30-inch diameter pipe and would follow the same routing as the Foothills Project's 42-inch O.D. pipeline, from the Mackenzie Delta south to tie into the northern extremities of Trunk Line's and Westcoast's existing systems. (See Map 3-4) The Trunk Line (Canada) system would be connected to the southern end of the Foothills Mackenzie Valley pipeline by a new 30-inch diameter pipeline to tie in with existing Trunk Line facilities. Trunk Line facilities would be expanded as necessary to carry Delta gas to the TransCanada system at Empress. The Westcoast system would be connected to the Foothills system, as before, by a new pipeline to tie in with existing facilities near Fort Nelson, British Columbia. Westcoast facilities would be expanded as required.

The Foothills mainline would consist of 817 miles of 30-inch diameter, 0.386-inch wall thickness Grade 70 pipe. The pipeline would be operated chilled to Station 17 at milepost 703.4.

The maximum allowable operating pressure would be 1440 psig, but the system would operate at 1375 psig. This pressure was arrived at by applying the Battelle hypothesis for limiting propagating ductile fractures.

At full volume of 1,200 MMcf/d, there would be 20 compressor stations required, each having 16,000 horsepower compressors. The Trunk Line system would require four 16,000 horsepower units, five 10,000 horsepower units and one 4,000 horsepower unit to handle full Delta volumes. The Westcoast system could achieve the increased capacity by looping without adding compression.

The gas balance for this system would be as outlined in the following table. It was assumed that 800 MMcf/d would flow on 1 November 1984, and on 1 November 1985 this would be increased to 1,200 MMcf/d.

Although the cost of facilities would be lower for the 30-inch O.D. Mackenzie Valley pipeline than for the proposed 42-inch O.D. line, there would be very little difference in the cost of service if each line was carrying 1,200 MMcf/d. The main reason for costs not being lower for the 30-inch diameter pipe was reported to be the higher fuel requirements. Study No. 1 had higher capital costs and cost of service than the other three studies relating to alternate methods of connecting Mackenzie Delta gas.

Exhibit No.
FH(Y)-114-48
p. 1-8

GAS BALANCE
MACKENZIE VALLEY 30" PIPELINE STUDY
ANNUAL AVERAGE DAY VOLUMES AT DELTA COMPOSITION
(MMCFO at 14.73 PSIA & 60°F)

	CALENDAR YEAR						
	1984	1985		1986		1987	
	Nov. 1/84-Dec. 31/84	Jan. 1/85-Oct. 31/85	Nov. 1/85-Dec. 31/85	Jan. 1/86-Oct. 31/86	Nov. 1/86-Dec. 31/86	Jan. 1/87-Oct. 31/87	Nov. 1/87 Dec. 31/87
Delta Receipt	800.0	800.0	1200.0	1200.0	1200.0	1200.0	1200.0
Fuel Gas	19.1	22.7	49.8	56.2	49.8	56.2	49.8
Gas to Communities	-	-	7.5	7.5	7.5	7.5	7.5
Station 20 Delivered	780.9	777.3	1142.7	1136.3	1142.7	1136.3	1142.7
Delivered							
AGT(Canada)	455.9	452.3	817.7	811.3	817.7	811.3	817.7
Westcoast	325.0	325.0	325.0	325.0	325.0	325.0	325.0
AGT(Canada)							
Receipt at Station 20	455.9	452.3	817.7	811.3	817.7	811.3	817.7
Fuel to Empress	11.2	11.0	28.2	27.7	28.2	27.7	28.2
Delivered to TransCanada	444.7	441.3	789.5	783.6	789.5	783.6	789.5
Westcoast							
Receipt at Station 20	325.0	325.0	325.0	325.0	325.0	325.0	325.0
Fuel to Ft. Nelson	-	-	-	-	-	-	-
Delivered to Ft. Nelson	325.0	325.0	325.0	325.0	325.0	325.0	325.0

Study No. 2 - As an alternative to transporting Mackenzie Delta gas to southern Canada via Mackenzie Valley route, Foothills examined the feasibility of connecting the Mackenzie Delta gas via a pipeline route which would approximately parallel the Dempster and Klondike Highways between the Mackenzie Delta and Whitehorse, where it would connect to the Foothills (Yukon) 48-inch diameter pipeline. (See Map 3-5) Once again, initial flows were assumed to be 800 MMcf/d with a build-up to 1,200 MMcf/d.

South of Whitehorse, the 48-inch diameter mainline capacity would be increased by the addition of compression equipment sufficient to allow transportation of the additional Delta volumes to a Westcoast receipt point south of Fort Nelson, British Columbia, and to a TransCanada receipt point at Empress, Alberta. An average day volume of 325 MMcf/d would be delivered to Westcoast and the remainder, less fuel, would be delivered to TransCanada.

An additional 4.6 miles of 48-inch diameter pipe would have to be added to the mainline in the Yukon as a result of a route revision to move the line north of Whitehorse. No other additions would be required on the 48-inch diameter mainline for the first year volumes, but to carry the second year volumes of 1,200 MMcf/d, a total of approximately 21.6 miles of 48-inch diameter loop would be required to be added to Trunk Line (Canada)'s facilities in Alberta. Line looping was chosen over compression because of lower cost.

Total additional pipeline facilities would consist of 736.6 miles of 30-inch diameter line for the main Dempster supply lateral, approximately 12 miles of 24-inch diameter and 12 miles of 16-inch diameter line for the supply laterals from Parsons Lake and Niglintgak respectively, and some 26.2 miles of 48-inch diameter mainline looping.

The Dempster lateral would be 30-inch diameter, 0.386-inch wall thickness, Grade 70 pipe with the northern 485 miles operated in the chilled mode.

The maximum allowable operating pressure would be 1440 psig. The chilled section would be operated at 1375 psig and the warm section at 1440 psig.

At full volume throughput of 1,200 MMcf/d from the Delta, there would be 16 compressor stations required, each with 16,000 horsepower units. The nine most northerly stations would have 11,000 horsepower propane chillers provided.

The 48-inch diameter mainline would require three new compressor stations with double 29,000 horsepower compressor units, a single 40,100 horsepower unit addition to an existing station, and a single 29,000 horsepower unit in each of three other existing stations.

In British Columbia, three existing stations would require additional horsepower; four new stations, each with double 29,000 horsepower units, would be required; and two new stations, each with double 24,000 horsepower units, would also be required. In Alberta, five new stations from the Alberta-British Columbia border to James River would be required, four with single 38,000 horsepower units and one with a single 32,700 horsepower unit. Four new stations from James River to Empress would be required, each with a single 32,700 horsepower unit.

The gas balance for the combined Alaska Highway-Dempster Highway system is shown in the following table. Gas was assumed to begin flowing on 1 October 1981 at a volume of 1,600 MMcf/d received at Prudhoe Bay. These volumes would be increased on 1 January 1983 to 2,400 MMcf/d received at Prudhoe Bay. The Mackenzie Delta volumes would commence on 1 November 1984 at a rate of 800 MMcf/d and increase to 1,200 MMcf/d on 1 November 1985.

Study No. 2 was shown to have higher capital costs and cost of service than those estimated under Study No. 3, and lower costs than those estimated for Studies 1 and 4.

Exhibit No.
FH(Y)-114-48
p. 2-15

COMBINED DEMPSTER HIGHWAY AND ALASKA HIGHWAY PROJECT WITH 30" DEMPSTER LATERAL
CONNECTING TO 48" ALASKA HIGHWAY LINE AT WHITEHORSE

GAS BALANCE

ANNUAL AVERAGE DAY VOLUMES AT MIXED COMPOSITION

(MMCFD @ 14.73 psia & 60°F)

SEGMENT	1981 (Oct 1 - Dec 31)	1982	1983	1984 (Jan 1-Oct 31)	1984 (Nov 1-Dec 31)	1985 (Jan 1-Oct 31)	1985 (Nov 1-Dec 31)	1986 (Jan 1-Dec 31)
Alcan Receipt at Prudhoe Bay	1600.0	1600.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0
Fairbanks Delivery	30.0	30.0	45.0	45.0	45.0	45.0	45.0	45.0
Fuel to Alaska/Yukon Border	15.3	25.1	38.7	40.2	31.1	40.2	31.1	38.7
Foothills (Yukon) Receipt from Alaska	1554.7	1544.9	2316.3	2314.8	2323.9	2314.8	2323.9	2316.3
Fuel to Whitehorse	6.6	6.3	13.1	12.9	14.1	12.9	14.1	13.1
Foothills (Yukon) Receipt from Delta	0.0	0.0	0.0	0.0	800.0	800.0	1200.0	1200.0
Fuel to Whitehorse	0.0	0.0	0.0	0.0	16.9	18.3	40.4	44.0
Alaska, Delta Volume at Whitehorse	1548.1	1538.6	2303.2	2301.9	3092.9	3083.6	3469.4	3459.2
Fuel to Yukon/B.C. Border	6.4	6.8	14.7	14.7	42.3	42.7	56.7	57.6
Westcoast Receipt	1541.7	1531.8	2288.5	2287.2	3050.6	3040.9	3412.7	3401.6
Fuel to C.S. N-2	7.4	7.8	14.7	14.9	47.5	46.2	76.1	70.1
Westcoast Delivery @ C.S. N-2	0.0	0.0	0.0	0.0	309.5	309.5	309.8	309.8
Volume at C.S. N-2	1534.3	1524.0	2273.8	2272.3	2693.6	2685.2	3026.8	3021.7
Fuel to B.C./Alberta Border	4.1	4.3	9.8	10.0	18.3	18.0	29.2	27.0
AGTL (Canada) Receipt	1530.2	1519.7	2264.0	2262.3	2675.3	2667.2	2997.6	2994.7
Fuel to Caroline Jct.	7.4	8.4	18.8	18.9	33.0	33.0	49.3	49.2
Volume at Caroline Jct.	1522.8	1511.3	2245.2	2243.4	2642.3	2634.2	2948.3	2945.5
Delivery to Western Leg	422:0	442.0	659.0	659.0	659.0	659.0	659.0	659.0
Delivery to Eastern Leg	1080.8	1069.3	1586.2	1584.4	1983.3	1975.2	2289.3	2286.5
Western Leg Receipt at Caroline Jct.	442.0	442.0	659.0	659.0	659.0	659.0	659.0	659.0
Fuel to Kingsgate	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Delivery at Kingsgate	442.0	442.0	658.7	658.7	658.7	658.7	658.7	658.7
Eastern Leg Receipt at Caroline Jct.	1080.8	1069.3	1586.2	1584.4	1983.3	1975.2	2289.3	2286.5
Fuel to Alberta/Saskatchewan Border	3.3	3.2	7.1	7.1	16.2	16.3	19.7	19.8
Delivery to T.C.P.L.	0.0	0.0	0.0	0.0	403.2	402.2	727.4	726.1
Foothills (Saskatchewan) Receipt at Empress	1077.5	1066.1	1579.1	1577.3	1563.9	1556.7	1542.2	1540.6
Fuel to Saskatchewan/U.S. Border	3.4	4.9	10.2	10.2	9.5	10.1	10.0	10.5
Delivery to Monchy	1074.1	1061.2	1568.9	1567.1	1554.4	1546.6	1532.2	1530.1
Total Prudhoe Bay Receipts	1600.0	1600.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0
Total Delta Receipts	0.0	0.0	0.0	0.0	800.0	800.0	1200.0	1200.0
Total Receipts	1600.0	1800.0	2400.0	2400.0	3200.0	3200.0	3600.0	3600.0
Total System Fuel	53.9	66.8	127.4	129.2	229.2	238.0	326.9	330.3
Total Delivery to U.S.	1546.1	1533.2	2272.6	2270.8	2258.1	2250.3	2235.9	2233.8
Total Deliveries to Canada	0.0	0.0	0.0	0.0	712.7	711.7	1037.2	1035.9
Total Deliveries	1546.1	1533.2	2272.6	2270.8	2970.8	2962.0	3273.1	3269.7
Fuel Consumption Percentage	3.4	4.2	5.3	5.4	7.2	7.4	9.1	9.2
Total Delivery to U.S. at 1000 BTU/cu.ft.			2585.8					2484.5
Total Delivery to U.S. @ 1137.8 BTU/cu.ft.			2272.6					2183.6

Study No. 3 - This study was a modification of Study No. 2, whereby the 48-inch diameter mainline would be rerouted and the 30-inch diameter Dempster Highway pipeline would connect with the 48-inch diameter line just east of Dawson where the Dempster and Klondike Highways meet. Two possible alternative reroutings of the 48-inch diameter mainline were considered under this study and are discussed in detail in Section 3.3.2, Foothills (Yukon) - Alternate Routes (See Map 3-6).

Depending on which route was chosen, the 48-inch diameter pipeline in Alaska would be 699.6 miles or 755.0 miles long, as compared to 731.4 miles by the Alaska Highway route. The 48-inch diameter line through the Yukon would be 613.5 miles long, as compared to 517.2 miles by the Alaska Highway route. The Dempster Highway connection to the Delta would be 460.1 miles, as compared to 736.6 miles if the 48-inch diameter mainline were not rerouted. Therefore, the possible rerouting would add either 64.5 or 119.9 miles to the 48-inch diameter mainline, depending on the route, and would shorten the 30-inch diameter Dempster pipeline route by 276.5 miles.

At full volume of 1,200 MMcf/d, there would be eight compressor stations required on the Dempster lateral, all powered with 16,000 horsepower compressors. Each station would have 11,000 horsepower propane chillers.

In the Yukon, the following mainline facilities would have to be added:

a single 26,500 horsepower unit in one station
and single 29,000 horsepower units in seven
other existing stations; and

six new compressor stations each with double 29,000 horsepower units.

In British Columbia, the following additional facilities would be required:

three existing stations increased in horsepower;

four new stations each with double 29,000 horsepower units; and

two new stations each with double 24,000 horsepower units.

In Alberta, the following additional facilities would have to be installed:

five new stations from the British Columbia border to James River, each with single 38,000 horsepower units; and

four new stations from James River to Empress, each with 32,700 horsepower units.

The gas balance for this combined system is outlined in the following table.

Study No. 3 was shown to have the lowest cost of facilities and cost of service for Canadian gas of the four alternatives studied.

Exhibit No.
FH(Y)-114-48
p. 3-13

COMBINED DEMPSTER HIGHWAY AND ALASKA HIGHWAY PROJECT WITH 30" DEMPSTER LATERAL
CONNECTING TO REROUTED 48" ALASKA HIGHWAY LINE AT DAWSON

GAS BALANCE

ANNUAL AVERAGE DAY VOLUMES AT MIXED COMPOSITION

(MMCFD at 14.73 psia and 60° F)

SEGMENT	1981 (Oct 1 - Dec 31)	1982	1983	1984 (Jan 1 - Oct 31)	1984 (Nov 1 - Dec 31)	1985 (Jan 1 - Oct 31)	1985 (Nov 1 - Dec 31)	1986 (Jan 1 - Dec 31)
Alcan Receipt at Prudhoe Bay	1600.0	1600.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0
Fairbanks Delivery	30.0	30.0	45.0	45.0	45.0	45.0	45.0	45.0
Fuel to Alaska/Yukon Border	18.4	28.5	42.3	44.0	33.9	44.0	33.9	42.3
Foothills (Yukon) Receipt From Alaska	1551.6	1541.5	2312.7	2311.1	2321.1	2311.0	2321.1	2312.7
Fuel to Dawson	2.9	2.1	4.3	4.1	3.2	3.2	3.2	3.2
Foothills (Yukon) Receipt From Delta	-	-	-	-	800.0	800.0	1200.0	1200.0
Fuel to Dawson	-	-	-	-	9.9	12.2	27.6	29.5
Alaska, Delta Volume at Dawson	1548.7	1539.4	2308.4	2306.9	3108.0	3095.6	3490.3	3480.0
Fuel to Yukon/B.C. Border	13.7	13.0	28.1	28.4	79.8	81.2	112.2	110.4
Westcoast Receipt	1535.0	1526.4	2280.3	2278.5	3028.2	3014.4	3378.1	3369.6
Fuel to C.S. N-2	7.4	7.8	14.7	14.9	47.5	46.2	76.1	70.1
Westcoast Delivery @ C.S. N-2	0.0	0.0	0.0	0.0	309.5	309.5	309.8	309.8
Volume at C.S. N-2	1527.6	1518.6	2265.6	2263.6	2671.2	2658.7	2992.2	2989.7
Fuel to B.C./Alta. Border	4.1	4.3	9.8	10.0	18.3	18.0	29.2	27.0
AGTL (Canada) Receipt	1523.5	1514.3	2255.8	2253.6	2652.9	2640.7	2963.0	2962.7
Fuel to Caroline Junction	7.4	8.4	18.8	18.9	33.0	33.0	49.3	49.2
Volume at Caroline Junction	1516.1	1505.9	2237.0	2234.7	2619.9	2607.7	2913.7	2913.5
Delivery to Western Leg	442.0	442.0	659.0	659.0	659.0	659.0	659.0	659.0
Delivery to Eastern Leg	1074.1	1063.9	1578.0	1575.7	1960.9	1948.7	2254.7	2254.5
Western Leg Receipt at Caroline	442.0	442.0	659.0	659.0	659.0	659.0	659.0	659.0
Fuel to Kingsgate	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Delivery to Kingsgate	442.0	442.0	658.7	658.7	658.7	658.7	658.7	658.7
Eastern Leg Receipt at Caroline	1074.1	1063.9	1578.0	1575.7	1960.9	1948.7	2254.7	2254.5
Fuel to Alta/Sask Border	3.3	3.2	7.1	7.1	16.2	16.3	19.7	19.8
Delivery to T.C.P.L.	0.0	0.0	0.0	0.0	400.8	398.5	721.6	722.7
Foothills (Sask) Receipt at Empress	1070.8	1060.7	1570.9	1568.6	1543.9	1533.9	1513.4	1512.0
Fuel to Sask/U.S. Border	3.4	4.9	10.2	10.2	9.5	10.1	10.0	10.5
Delivery to Monchy	1067.4	1055.8	1560.7	1558.4	1534.4	1523.8	1503.4	1501.5
Total Prudhoe Bay Receipts	1400.0	1600.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0
Total Delta Receipts	0.0	0.0	0.0	0.0	800.0	800.0	1200.0	1200.0
Total Receipts	1600.0	1600.0	2400.0	2400.0	3200.0	3200.0	3600.0	3600.0
Total System Fuel	60.6	72.2	135.6	137.9	251.6	264.5	361.5	362.3
Total Deliveries to U.S.	1539.4	1527.8	2264.4	2262.1	2238.1	2227.5	2207.1	2205.2
Total Deliveries to Canada	0.0	0.0	0.0	0.0	710.3	708.0	1031.4	1032.5
Total Deliveries	1539.4	1527.8	2264.4	2262.1	2948.4	2935.5	3238.5	3237.7
Fuel Consumption Percentage	3.8	4.5	5.6	5.7	7.9	8.3	10.0	10.1
Total Delivery to U.S. @ 1000 BTU/cu ft.			2576.4					2451.3
Total Delivery to U.S. @ 1137.8 BTU/cu ft.			2264.4					2154.4

Study No. 4 - As an alternative to Study No. 2, Foothills considered connecting Delta gas to the 48-inch diameter mainline Alcan system at Tetlin Junction, Alaska. The Delta lateral would be a 30-inch diameter line following the Dempster and Taylor Highway corridors to Tetlin Junction. South of Tetlin Junction, the 48-inch diameter mainline would follow the same route as the originally filed Foothills (Yukon) Project and would be expanded by the addition of compression to carry the increased volumes. (See Map 3-7) The average day delivery to Westcoast just south of Fort Nelson would be 325 MMcf/d and the rest of the 1,200 MMcf/d of Delta gas, less fuel, would be delivered to TransCanada at Empress, Alberta. The only additional 48-inch diameter line required to carry the Delta gas would be 21.6 miles of loop in Alberta.

The Dempster lateral would be 646.1 miles of 30-inch diameter line with 11.6 miles of 16-inch diameter and 12.4 miles of 24-inch diameter line required to connect Niglintgak and Parsons Lake respectively.

The Dempster lateral would have 0.386-inch wall thickness in Canada and 0.429-inch wall thickness in Alaska; both sections would be Grade 70 pipe. The maximum allowable operating pressure would be 1440 psig, but stations were located on the assumption of operating at 1375 psig.

The Dempster-Taylor lateral would be operated in the chilled mode over the entire length.

At full volume of 1,200 MMcf/d, the Delta lateral would require 13 compressor stations, of which 12 would have single

16,000 horsepower units and one would have a single 10,000 horsepower unit.

In Alaska, the following additional facilities would be required:

a single 26,500 horsepower unit with chilling at one existing station; and

one new station with two 26,500 horsepower units complete with chilling.

In the Yukon, the following additions would be required:

single 29,000 horsepower units at each of the seven existing stations; and

six new stations each with double 29,000 horsepower units.

In Alberta, the additions would be:

five new stations from the British Columbia border to James River, four with single 38,000 horsepower units and one with a single 32,700 horsepower unit; and four new stations from James River to Empress each with single 32,700 horsepower units.

The gas balance for this combined system is shown in the following table.

Study No. 4 was shown to have higher capital costs than Studies 2 and 3. Foothills, therefore, did not calculate the cost of service for this study.

Exhibit No.
FH(Y)-114-48-1
p. 4-17

COMBINED DEMPSTER HIGHWAY AND ALASKA HIGHWAY PROJECT WITH 30" DEMSPTER LATERAL
CONNECTING TO 48" ALASKA HIGHWAY AT TETLIN JUNCTION

GAS BALANCE

ANNUAL AVERAGE DAY VOLUMES AT MIXED COMPOSITION
(MMCFD @ 14.73 psia & 60°F)

SEGMENT	1981 (Oct 1 - Dec 31)	1982	1983	1984 (Jan 1-Oct 31)	1984 (Nov 1-Dec 31)	1985 (Jan 1-Oct 31)	1985 (Nov 1-Dec 31)	1986 (Jan 1-Dec 31
Alcan Receipt at Prudhoe Bay	1600.0	1600.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0
Fairbanks Delivery	30.0	30.0	45.0	45.0	45.0	45.0	45.0	45.0
Fuel to Tetlin	11.0	18.8	33.9	35.3	27.1	35.3	27.1	33.9
Foothills Receipt from Delta	0.0	0.0	0.0	0.0	800.0	800.0	1200.0	1200.0
Fuel to Tetlin	0.0	0.0	0.0	0.0	14.8	17.7	38.9	42.1
Alaska, Delta Volume at Tetlin	1559.0	1551.2	2321.1	2319.7	3113.1	3102.0	3489.0	3479.0
Fuel to Alaska/Yukon Border	4.3	6.3	4.8	4.9	12.6	14.2	17.0	18.4
Foothills Receipt	1554.7	1544.9	2316.3	2314.8	3100.5	3087.8	3472.0	3460.6
Fuel to Yukon/B.C. Border	13.0	13.1	27.8	27.6	64.4	66.9	92.0	94.4
Westcoast Receipt	1541.7	1531.8	2288.5	2287.2	3036.1	3020.9	3380.0	3366.2
Fuel to C.S. N-2	7.4	7.8	14.7	14.9	47.5	46.2	76.1	70.1
Westcoast Delivery @ C.S. N-2	0.0	0.0	0.0	0.0	309.5	309.5	309.8	309.8
Volume at C.S. N-2	1534.3	1524.0	2273.8	2272.3	2679.1	2665.2	2994.1	2986.3
Fuel to B.C./Alta. Border	4.1	4.3	9.8	10.0	18.3	18.0	29.2	27.0
AGT(Canada) Receipt	1530.2	1519.7	2264.0	2262.3	2660.8	2647.2	2964.9	2959.3
Fuel to Caroline Jct.	7.4	8.4	18.8	18.9	33.0	33.0	49.3	49.2
Volume at Caroline Jct.	1522.8	1511.3	2245.2	2243.4	2627.8	2614.2	2915.6	2910.1
Delivery to Western Leg	442.0	442.0	659.0	659.0	659.0	659.0	659.0	659.0
Delivery to Eastern Leg	1080.8	1069.3	1586.2	1584.4	1968.8	1955.2	2256.6	2251.1
Western Leg Receipt at Caroline Jct.	442.0	442.0	659.0	659.0	659.0	659.0	659.0	659.0
Fuel to Kingsgate	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Delivery at Kingsgate	442.0	442.0	653.7	658.7	658.7	658.7	658.7	558.7
Eastern Leg Receipt at Caroline Jct.	1080.8	1069.3	1586.2	1584.4	1968.8	1955.2	2256.6	2251.1
Fuel to Alta./Sask. Border	3.3	3.2	7.1	7.1	16.2	16.3	19.7	19.8
Delivery to T.C.P.L.	0.0	0.0	0.0	0.0	397.0	393.7	712.5	710.7
Foothills (Sask) Receipt at Empress	1077.5	1066.1	1579.1	1577.3	1555.6	1545.2	1524.4	1520.6
Fuel to Sask/U.S. Border	3.4	4.9	10.2	10.2	9.5	10.1	10.0	10.5
Delivery to Monchy	1074.1	1061.2	1568.9	1567.1	1546.1	1535.1	1514.4	1510.1
Total Prudhoe Bay Receipts	1600.0	1600.0	2400.0	2400.0	2400.0	2400.0	2400.0	2400.0
Total Delta Receipts	0.0	0.0	0.0	0.0	800.0	800.0	1200.0	1200.0
Total Receipts	1600.0	1600.0	2400.0	2400.0	3200.0	3200.0	3600.0	3600.0
Total System Fuel	53.9	66.8	127.4	129.2	243.7	258.0	359.6	365.7
Total Deliveries to U.S.	1546.1	1533.2	2272.6	2270.8	2249.8	2238.8	2218.1	2213.8
Total Deliveries to Canada	0.0	0.0	0.0	0.0	706.5	703.2	1022.3	1020.5
Total Deliveries	1546.1	1533.2	2272.6	2270.8	2956.3	2942.0	3240.4	3234.3
Fuel Consumption Percentage	3.4	4.2	5.3	5.4	7.6	8.1	10.0	10.2
Total Delivery to U.S. at 1000 BTU/cu. ft.			2585.8					2461.3
Total Delivery to U.S. @ 1137.8 BTU/cu. ft.			2272.6					2163.2

Views of the Board

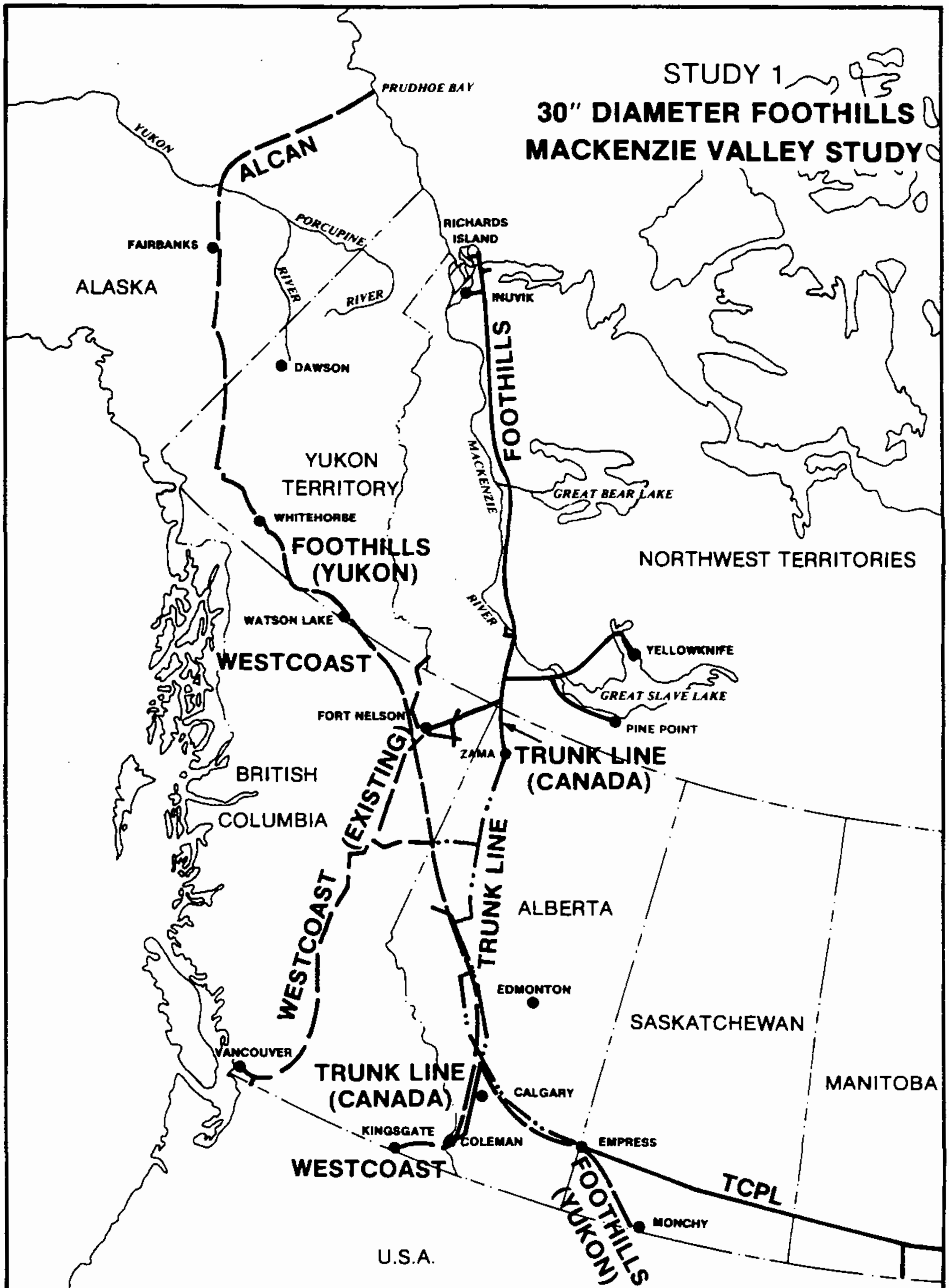
With respect to the alternative of a 30-inch diameter pipeline instead of a 42-inch diameter pipeline up the Mackenzie Valley, the Board agrees with Foothills that even for the lower throughputs of 800 MMcf/d building up to 1,200 MMcf/d, the 30-inch diameter alternative would not offer any significant economic advantage. If a pipeline were to be built up the Mackenzie Valley, and given any reasonable prospect of modest increases in presently established reserves, then the 42-inch diameter pipeline as proposed would be more appropriate than a 30-inch diameter pipeline.

However, based on the assumptions with respect to Mackenzie Delta-Beaufort Sea reserves contained in the Applicant's study, the Board believes that one of the alternatives employing a route along the Dempster Highway would be superior from a cost and engineering point of view. If the available reserves reach 10 to 12 Tcf with matching flows of 800 MMcf/d as postulated in the study, the most attractive alternative would be that described in Study No. 3 connecting to the 48-inch diameter Foothills (Yukon) line near Dawson.

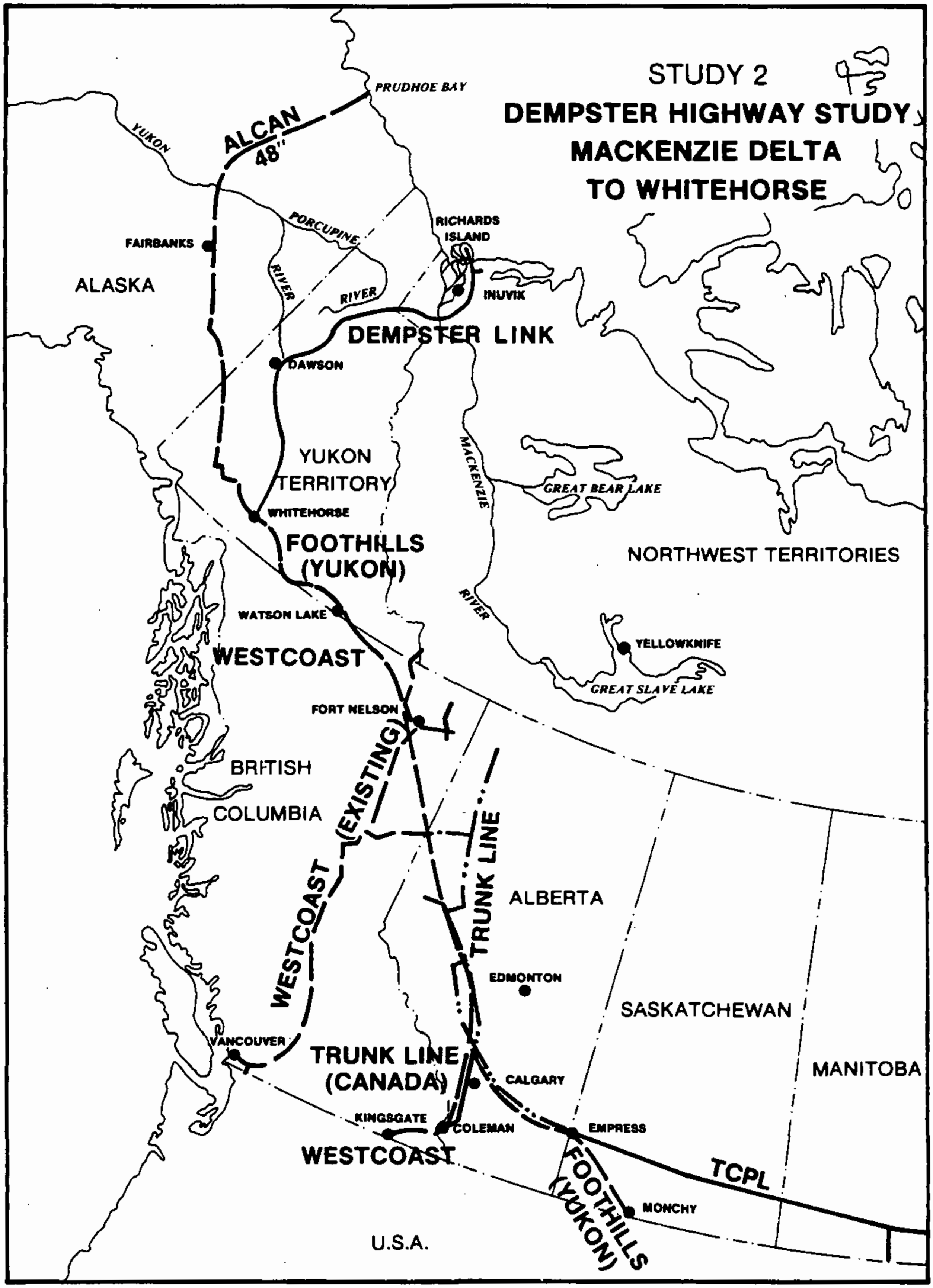
Because of the lack of detailed investigation of the alternative routes contained in the study, the preliminary cost estimate used for the comparative capital cost estimates must be used with caution. However, there would appear to be economic benefits to Canadian shippers and producers in transporting Canadian gas in the system described in Study No. 3 compared to either the 42-inch diameter pipeline or the 30-inch diameter alternative pipeline up the Mackenzie Valley. There would be a marginal increase in cost for United States shippers, compared to the route contained in the Foothills (Yukon) application, where the pipeline would follow the Alaska Highway instead of being routed through Dawson.

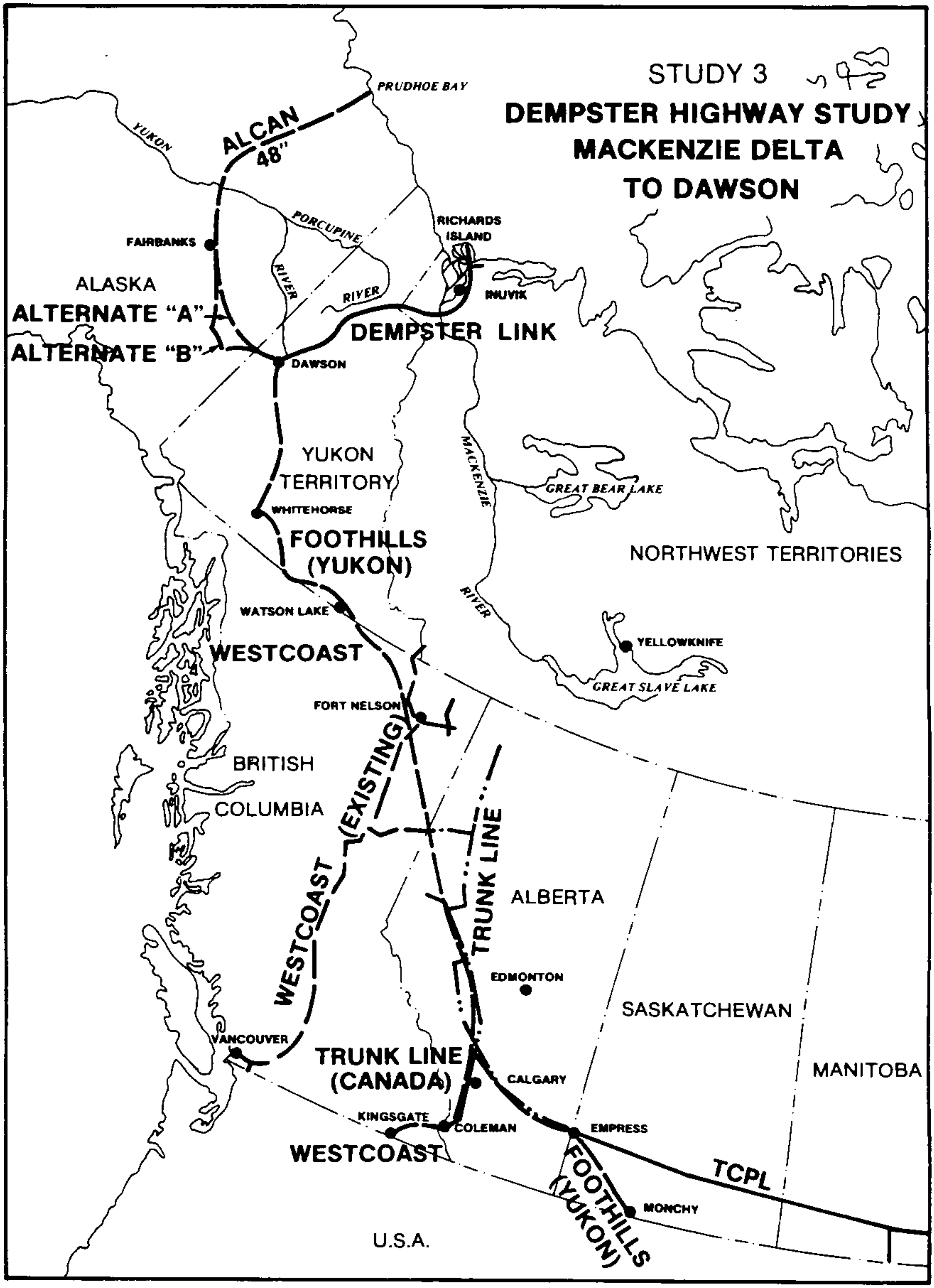
There was little in the way of evidence placed before the Board concerning environmental or socio-economic aspects of the alternative routes discussed in Studies 2, 3 and 4, and obviously studies would be required before an alternative route could be adequately appraised by the Board.

Nonetheless, if it appeared that the Foothills pipeline could not be constructed for technical, economic, environmental or socio-economic reasons, the Board believes that the pipeline system outlined in Study No. 3 offers the potential of connecting Mackenzie Delta gas to markets on an acceptable economic basis.

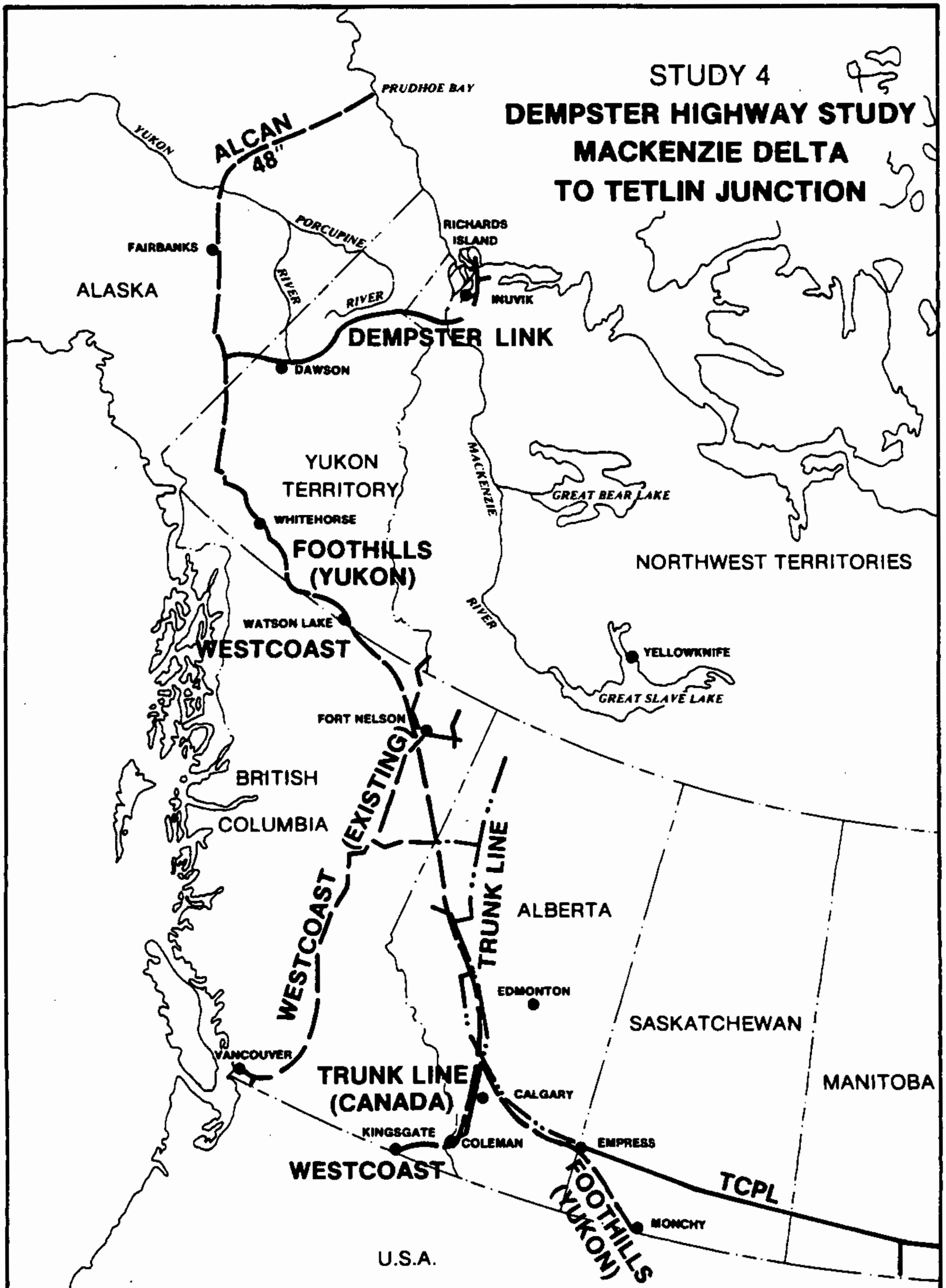

STUDY 1
30" DIAMETER FOOTHILLS
MACKENZIE VALLEY STUDY
PRUDHOE BAY
YUKON
ALCAN
PORCUPINE
RIVER
RIVER
FAIRBANKS
ALASKA
DAWSON
RICHARDS ISLAND
INUVIK
FOOTHILLS
MACKENZIE
RIVER
GREAT BEAR LAKE
YUKON TERRITORY
WHITEHORSE
FOOTHILLS (YUKON)
NORTHWEST TERRITORIES
WATSON LAKE
WESTCOAST
YELLOWKNIFE
GREAT SLAVE LAKE
FORT NELSON
PINE POINT
ZAMA
TRUNK LINE (CANADA)
BRITISH COLUMBIA
WESTCOAST (EXISTING)
TRUNK LINE
ALBERTA
EDMONTON
SASKATCHEWAN
VANCOUVER
TRUNK LINE (CANADA)
CALGARY
MANITOBA
KINGSGATE
COLEMAN
EMPRESS
WESTCOAST
TCPL
FOOTHILLS (YUKON)
MONCHY
U.S.A.

MAP 3-5


STUDY 2
DEMPSTER HIGHWAY STUDY
MACKENZIE DELTA
TO WHITEHORSE
PRUDHOE BAY
ALCAN
48"
YUKON
PORCUPINE
RIVER
RIVER
FAIRBANKS
ALASKA
RICHARDS
ISLAND
INUVIK
DEMPSTER LINK
DAWSON
YUKON
TERRITORY
WHITEHORSE
MACKENZIE
RIVER
GREAT BEAR LAKE
FOOTHILLS
(YUKON)
NORTHWEST TERRITORIES
WATSON LAKE
YELLOWKNIFE
WESTCOAST
GREAT SLAVE LAKE
FORT NELSON
(EXISTING)
BRITISH
COLUMBIA
WESTCOAST
TRUNK LINE
ALBERTA
EDMONTON
SASKATCHEWAN
VANCOUVER
TRUNK LINE
(CANADA)
CALGARY
MANITOBA
KINGSGATE
COLEMAN
EMPRESS
WESTCOAST
FOOTHILLS
(YUKON)
TCPL
MONCHY
U.S.A.


STUDY 3
DEMPSTER HIGHWAY STUDY
MACKENZIE DELTA
TO DAWSON
PRUDHOE BAY
YUKON
ALCAN
48"
FAIRBANKS
PORCUPINE
RIVER
RIVER
RICHARDS
ISLAND
INUVIK
ALASKA
ALTERNATE "A"
ALTERNATE "B"
DEMPSTER LINK
DAWSON
YUKON
TERRITORY
WHITEHORSE
MACKENZIE
GREAT BEAR LAKE
FOOTHILLS
(YUKON)
NORTHWEST TERRITORIES
RIVER
WATSON LAKE
YELLOWKNIFE
WESTCOAST
GREAT SLAVE LAKE
FORT NELSON
(EXISTING)
BRITISH
COLUMBIA
TRUNK LINE
ALBERTA
WESTCOAST
EDMONTON
SASKATCHEWAN
VANCOUVER
TRUNK LINE
(CANADA)
CALGARY
MANITOBA
KINGSGATE
COLEMAN
EMPRESS
WESTCOAST
FOOTHILLS
(YUKON)
TCPL
MONCHY
U.S.A.

MAP 3-7



STUDY 4
DEMPSTER HIGHWAY STUDY
MACKENZIE DELTA
TO TETLIN JUNCTION
PRUDHOE BAY
YUKON
ALCAN
48"
FAIRBANKS
ALASKA
PORCUPINE
RIVER
RIVER
RICHARDS
ISLAND
INUVIK
DEMPSTER LINK
DAWSON
YUKON
TERRITORY
WHITEHORSE
MACKENZIE
GREAT BEAR LAKE
FOOTHILLS
(YUKON)
NORTHWEST TERRITORIES
RIVER
WATSON LAKE
WESTCOAST
YELLOWKNIFE
GREAT SLAVE LAKE
FORT NELSON
BRITISH
COLUMBIA
(EXISTING)
WESTCOAST
TRUNK LINE
ALBERTA
EDMONTON
SASKATCHEWAN
MANITOBA
VANCOUVER
TRUNK LINE
(CANADA)
CALGARY
KINGSGATE
COLEMAN
EMPRESS
WESTCOAST
FOOTHILLS
(YUKON)
TCPL
MONCHY
U.S.A.

3.2.3 FOOTHILLS

3.2.3.1 Facilities Design and Capacity

Facilities Location Description

The system proposed by Foothills consisted of:

(a) 817 miles of 42-inch O.D. pipe starting at the Taglu natural gas processing plant in the Mackenzie Delta and terminating approximately seven miles north of the 60th parallel where the proposed interconnecting pipelines of Trunk Line (Canada) and Westcoast would begin;

(b) a 15-mile, 30-inch O.D. supply lateral from the Parsons Lake gas plant joining the mainline at milepost 51;

(c) a 10-mile, 24-inch O.D. supply lateral from the Niglintgak gas field to the Taglu natural gas processing plant; and

(d) lateral lines to serve certain northern communities with gas.

The following is a summary of the proposed community service laterals:

FOOTHILLS

PROPOSED COMMUNITY SERVICE LATERALS

Community Served	Diameter of Lateral (inches)	Approximate Length (miles)	Milepost of Mainline Connection
Inuvik	6	15.1	78.6
Fort Good Hope	3	2.3	283
Norman Wells	3	2.3	372
Fort Norman	3	4.8	419.5
Wrigley	3	3.9	556.9
Fort Simpson	4	19.4	688
Great Slave Lake Area	3 to 10	419.2	778
Total Length of Laterals		467.0	

Projected Gas Volumes

The following table outlines the proposed average daily receipt and delivery volumes for the Foothills system:

FOOTHILLS

PROJECTED THROUGHPUT VOLUMES

(MMcf/d)

SUPPLY	Nov. & Dec. 1982	1983	1984	1985	1986	1987
Mackenzie Delta Gas	798.2	866.2	1266.5	1667.1	2066.4	2400.0
DISPOSITION						
Deliveries						
-to N.W.T. Communities	0	1.2	7.9	10.3	12.7	14.0
-to Westcoast	473.3	475.5	475.1	475.1	475.0	475.0
-to Trunk Line (Canada)	315.3	379.2	765.0	1143.1	1515.1	1824.2
Fuel in Northwest Territories	9.6	10.3	18.5	38.6	63.6	86.8
Total Disposition	798.2	866.2	1266.5	1667.1	2066.4	2400.0

System Configuration

Mainline Pipe Selection

Foothills carried out system studies to determine the optimum design of its mainline for the projected fifth operating year throughput of 2,400 MMcf/d.

The approach taken by the Applicant to establish acceptable measures of optimization included the following parameters:

(a) the first year cost of service for a given system would be representative of the total cost of that particular system based on full throughput for the first year;

(b) the entire system, compression as well as pipe size, should be optimized; and

(c) the system must yield the lowest cost of service at the proposed throughput of 2,400 MMcf/d.

The alternative designs selected for analysis included the following pipe diameter, maximum operating pressure and compression horsepower configurations:

(a) 36-inch, 42-inch and 48-inch diameter pipe;

(b) maximum operating pressures of 911, 1086, 1250, 1440 and 1680 psig; and

(c) 24,000 horsepower and 37,000 horsepower.

The following table is a summary of the results of the analysis for the design volume of 2,400 MMcf/d:

FOOTHILLS

NORMALIZED COST OF SERVICE

FOR DESIGN VOLUME OF 2,400 MMcf/d

Pipe Diameter (inches)	Pipe Wall Thickness (inches)	Maximum Operating Pressure (psig)	With 24,000 Horsepower (¢/Mcf/100 miles)	With 37,000 Horsepower (¢/Mcf/100 miles)
36	0.402	1250	1.238	1.085
	0.463	1440	1.064	0.955
	0.540	1680	0.976	0.893
42	0.368	911	1.253	1.090
	0.469	1086	1.081	0.977
	0.469	1250	0.932	0.861
	0.540	1440	0.895	0.845
	0.630	1680	0.898	0.864
48	0.402	911	0.967	0,883
	0.536	1250	0.905	0.867

Foothills selected 42-inch diameter x 0.540-inch W.T. Grade 70 pipe to be operated at 1250 psig, although capable of being operated at 1440 psig, station-spacing of approximately 48 miles, and compressors of 26,500 horsepower in the permafrost section and 29,000 horsepower in the non-chilled section of the pipeline because:

(a) the design provided the minimum cost of service for the fifth year volumes of 2,400 MMcf/d while taking into account the results of Foothills' pipe stress analysis;

(b) the pipe selected was of a size, wall thickness and grade commercially available in Canada;

(c) the operating pressure and temperature for the pipeline system were such that the risk of ductile fracture propagation would be minimized; and

(d) it permitted the flow capacity to be increased in the future by operating at the higher pressure of 1440 psig (80 per cent of specified minimum yield strength), if metallurgical considerations permitted (See Stress Analysis section of this report).

The principal reason for reducing the design pressure of 1440 psig to a derated operating pressure of 1250 psig was to reduce the stress levels to which the pipe would be subjected, due to internal pressure. By examining the pressure and temperature to which this pipe would be subjected during operation in the permafrost area, Foothills determined that a reduction of pipe stress, consistent with reducing the operating pressure from 1440 psig to 1250 psig, would limit propagating ductile cracks, should they ever occur. (The stress levels are discussed in detail under metallurgical requirements in the Stress Analysis section of this report.)

In response to CAGPL cross-examination, Foothills stated that the line size was not based on the known gas reserves but on projections of anticipated reserves additions made by its consultants.

The pipeline was designed on the basis that the entire pipeline would be buried. In order to avoid permafrost degradation and critical pipe movements, the Applicant planned to chill its gas from the Taglu receipt line to a temperature between zero and 32° F. The temperature would be maintained below 32° F by means of gas-chilling stations installed at the first 13 gas compressor stations. The gas-chilling stations would consist of a closed-cycle refrigeration system using single unit turbines of 15,000 horsepower per station and propane would be used as the refrigerant.

At Compressor Station CS-14, located near Fort Simpson, a heater would be installed to raise the flowing gas temperature above 32° F, and at Station CS-17, seven miles north of the 60th parallel, an aerial cooling system would be used to maintain the gas discharge temperature below 80° F.

The 80° F maximum temperature for gas discharge was based on economic justification of using coolers versus the additional horsepower that would be required at a higher flowing gas temperature.

Station Design and Spacing

The criteria used by Foothills in selecting the unit sizes for its compressor stations were:

(a) gas compressor equipment selected must be commercially available;

(b) selected units must be proven and not experimental;

(c) the reliability and mechanical availability must be high; and

(d) gas compression units must not be so large that they would violate the temperature constraints imposed on the pipeline.

Foothills selected units of 26,500 horsepower for compressor stations in the chilled portion of the pipeline, i.e., stations 1 to 13, and 29,000 horsepower for the balance of the system, i.e., stations 14 to 17.

Although Foothills' analysis showed that the 37,000 horsepower unit would provide a lower cost of service, that unit was discarded in favour of 26,500 and 29,000 horsepower units due to the need to keep gas temperatures low and because of the greater reduction in flow resulting from a possible outage of one of the larger size units. The smaller sized units would allow a number of manufacturers of proven units to bid on supply of compressor units.

System Reliability

The Applicant's design was based on a maximum capacity of 2,650 MMcf/d and an annual load factor of 95 per cent in order to enable it to carry an average throughput of 2,400 MMcf/d.

The Applicant assumed that its gas turbine driven centrifugal compressor units would be available 98 per cent of the time over a nine-month period and 97 per cent over a three-month summer season. The Applicant further assumed that all 17 units in its system would be operating 71 per cent of the time.

Based on the above assumptions, Foothills carried out compressor unit outage studies and concluded that the loss of a unit would result in a ten per cent reduction in the maximum capacity. The system, therefore, would be capable of meeting its projected annual throughput volume of 876 Bcf even with the loss of a critical compressor unit for 106 days.

In addition, in the event of an outage on the Foothills system, the flow to market could be maintained through the use of Alberta storage fields and by other means, such as exchanges and increased production from existing fields in Alberta. Alberta's flow could be increased to make up a portion of the shortfall. (Section 3.2.5 discusses the use of the existing Trunk Line system to provide security of supply.)

Community Gas Service Line Size Selection

Foothills proposed to construct pipeline systems consisting of a total of 467 miles of pipe to provide natural gas to eleven communities in the North.

The pipe size selection was based on the following criteria:

(a) the volumes required should be related to the population of each community projected to 1988;

(b) the pipe should be commercially available; and

(c) the maximum operating pressure should be 1400 psig.

Standard pipe sizes were selected for supply laterals and Foothills recognized that each line would have a capacity in excess of the requirements up to 1988.

Views of the Board

The Board agrees with the Applicant's choice of a 42-inch O.D. x 0.540-inch W.T. Grade 70 pipe for its main line, provided a flow of 2.4 Bcf/d is achieved by the fifth operating year.

Foothills satisfied the Board that this diameter pipe with a maximum operating pressure of 1440 psig, compared to 36-inch and 48-inch diameter pipe at various operating pressures, would result in the least cost of service for a fifth year volume of 2.4 Bcf/d.

The Board agrees with the Applicant's choice of 26,500 or 29,000 horsepower single unit gas turbine driven centrifugal compressors with 48-mile station spacing, as these large units provide economies both in original cost and, because of their high thermal efficiency, in operating costs.

For geotechnical reasons the flowing gas would be temperature-controlled as far south as compressor station 14 near Fort Simpson. The propane chillers and heater required for this purpose are satisfactory to the Board but the Applicant would be required to submit final design of its compressor stations, including the chillers and heater, for approval by the Board prior to construction.

Although the Applicant based its design on a maximum operating pressure of 1440 psig, it planned to derate the operating pressure to 1250 psig, at least in the early years, to reduce the risk of a ductile propagating failure. This is discussed in more detail in the metallurgical section of this report. The Board agrees with this reduction in operating pressure.

Foothills has satisfied the Board of the reliability of its system by demonstrating that an average throughput of 2.4 Bcf/d could be maintained with the loss of a critical unit, that the risk of a ductile propagating failure would be reduced with the derated pressure, and that it would have storage facilities and interconnecting pipeline facilities in Alberta which it could rely on in the event of a pipeline malfunction.

The Board is satisfied that the design of the Mackenzie Delta short supply lines is adequate.

The Board notes the Applicant's proposal to provide service to a number of northern communities along the pipeline route. The Board agrees in principle with providing service to northern communities but believes that final design of the laterals should await more detailed market studies and awarding of franchises for gas distribution in the communities concerned. Applications for certificates for the laterals should be made by Foothills at that time.

The Board is generally satisfied with the Foothills design based on the fifth year operating flow of 2.4 Bcf/d, but, as stated elsewhere in this report, it is not satisfied that the project is economically feasible for the more realistic flows of between 800 and 1,200 MMcd related to presently known Mackenzie Delta reserves.

3.2.3.2 Geotechnical and Geothermal Design

Introduction

The fact that Foothills and Foothills (Yukon) are essentially the same group organized under different corporate names has led to the adoption by Foothills (Yukon) of the applicable portions of the Foothills evidence with respect to geothermal and geotechnical design. Because of this, most of the topics common to both applications will be discussed in this section and only subjects unique to the Foothills (Yukon) Project are discussed in the corresponding sections on Foothills (Yukon).

In addition, the fundamentals of such matters as frost heaving, buoyancy, thaw settlement, etc. have been described in some detail in the corresponding sections of the report on CAGPL. Descriptions and definitions of these items will not be repeated in the sections of the report dealing with Foothills and Foothills (Yukon).

Frost Heave

Introduction

Foothills proposed a route along the Mackenzie Valley that is only slightly different from the route that was chosen by CAGPL. For this reason, many of the problems are common to both Applicants. Frost heaving is one such problem.

Extent of Frost Heave Problems

Foothills would operate the proposed Mackenzie Valley pipeline at below freezing temperatures from the origin, in the Mackenzie Delta, to a point near Fort Simpson. At this location, a heater would be used to raise the gas to above-freezing temperatures. Submissions and evidence put forward by Foothills indicated that about 400 miles of this chilled portion of its system would be in the discontinuous permafrost region. Foothills submitted evidence and gave testimony that of this 400 miles, only 42.7 miles of the route presented a serious frost heave problem. It was stated that the estimate was probably not precise, and that the actual mileage might be greater or less by a mile or two, but that the estimate was essentially correct.

The basis upon which these estimates were made was somewhat vague. At one point, Foothills testified that the estimate of 42.7 miles for the Mackenzie Valley was based on a report prepared by its consultants on the difficulty of ditching. Later testimony stated that the estimate was based on an analysis of the terrain typing along the route, and on a third occasion the witness stated that he could not remember how it was arrived at. The Applicant testified that determination of the precise mileage presenting frost heave problems would be a part of final design.

Foothills stated that it had very little concrete information about the proposed route north of Fort Simpson. Moreover, in cross-examination, it indicated that it was not reasonable to assign the same properties to soils found north of Fort Simpson as to those found south of Fort Simpson, even though the terrain typing procedures indicated the soil types to be similar. Specifically, the Applicant indicated that it would be hazardous to equate the frost heaving properties of till-like soils found in the area south of Fort Simpson with those of similarly classified soils found north of Fort Simpson.

Foothills testified that no attempt had been made to include shallow permafrost terrain in its study of the extent to which frost heaving would be experienced along its route, Foothills had no way of determining the depth of the permafrost. Foothills agreed that, to the extent that sections of shallow permafrost might prove frost-susceptible, the estimates of the miles of route susceptible to frost heaving would be in error. However, it was also pointed out that even if the distances were doubled, the increases in the cost of the project would not be great.

Frost Heave Design

Design Description

Initially, Foothills adopted the surcharge berm method of frost heave control that had been advanced by CAGPL. It was indicated that the adoption of this method was due to the fact that Foothills, through its parent company Trunk Line, had been part of the CAGSL consortium.

During the hearing, Foothills began to express doubts about the shut-off pressure method of frost heave control. It indicated that the magnitudes of heave that the method could predict were unreasonable to the point of being impossible. As the hearing progressed, the Foothills design evolved to insulation with replacement of frost susceptible soil. This involved insulating the pipeline to reduce the heat flow into the cold gas stream, thus reducing the extent of freezing in the soil, and replacement of the frost-susceptible soil to varying depths below the pipeline, depending on the conditions.

The first such design put forward involved insulation of the trench with flat sheets of Styrofoam insulation. The design that Foothills later proposed required six inches of Styrofoam insulation wrapped completely around the pipe. This design would be used in unfrozen ground and in permafrost less than 15 feet thick if it overlaid frost-susceptible soil.

In addition, in areas of shallow permafrost between 15 and 30 feet in thickness, two inches of insulation would be applied to the pipe.

Foothills indicated that the bedding material to be used to replace the frost-susceptible soil would be sand with a limit of five to ten per cent on the amount of fines (silt and clay).

Design Theory

The manner in which Foothills believed its proposed design would work is quite simple. The insulation would reduce the rate at which heat would be removed from the soil by the chilled pipeline, thus reducing the amount of soil and water that could be frozen during the life of the pipeline. The soil directly under the pipeline would be replaced by granular soil, such as sand, that was not frost-susceptible. Foothills testified that until the frost front had advanced through the bottom of the replaced soil, no frost heave would occur. By the time that the frost front reached the frost-susceptible soil, the rate of heat flow would have been even further reduced to the point where, during the remainder of the life of the pipeline, the amount of heave that would occur would be tolerable.

In support of this design, Foothills stated that it relied on the assumption that the amount of heave that occurred would never exceed the amount of soil frozen. Thus, for every foot that the frost front advanced into the soil, a maximum of one foot of ice, and thus one foot of heave, would occur. This relationship was described by the term "segregation ratio", which is defined as the amount of heave divided by the distance from the pipe to the frost front. (Thus one foot of frozen soil and one foot of ice formed below the pipe would represent a segregation ratio of 0.5 or 50 per cent.)

To support the assumption that segregation would never exceed 50 per cent, Foothills stated that it relied upon the two-dimensional mathematical frost heave model that it had filed with the Board, and the tests carried out for CAGPL at the test site in Calgary.

Foothills agreed that one of the tests carried out at the Calgary test site was similar to the Foothills design. A 48-inch diameter pipe was placed in a 9.5-foot trench that had been partially backfilled with three feet of gravel. This would be the same as the Foothills design without insulation. This test section behaved quite differently than would have been expected based on Foothills' design. The test section began heaving at a more or less constant rate while the frost front was still in the gravel below the pipe and the heaving continued at the same rate for months after the frost front had entered the soil below the gravel. Foothills had submitted evidence that no heaving would occur until the frost front entered the frost-susceptible soil below the gravel.

Foothills believed that the heaving that had occurred while the frost front was still in the gravel was simply due to the nine per cent volume increase of the water in the gravel as it changed into ice. The Applicant's witness did not believe that the observed heave was due to ice lense formation; he believed that the same amount of heave would have occurred regardless of the time required for the frost front to penetrate the gravel.

Frost Heave Prediction

Foothills stated that it relied upon predictions of frost heave to support the feasibility of its design. The Applicant presented several methods by which it studied the magnitudes of frost heaving that were possible and probable. These methods included:

(1) the "Upper Bound" approach,

(2) the "2-D Mathematical Frost Heave Model", and

(3) results of experiments carried out by others.

Upper Bound Solution

Foothills established a limit or "upper bound" on the magnitude of frost heaving by simply calculating the amount of ice that could be formed around the pipe if all of the heat removed by the chilled pipe came from freezing water. Evidence was submitted that a 48-inch diameter pipeline with 12 inches of Styrofoam insulation around it, operating at 15° F, would be capable of freezing an annulus of ice 3.5 feet thick. Foothills did not indicate what the upper bound heave would be for its proposed design, viz. a 42-inch diameter pipeline with six inches of insulation around the pipe.

2-D Frost Heave Model

Foothills stated that it relied on the assumption that the segregation would not exceed 50 per cent. One of the major items put forward in support of this assumption was the two-dimensional mathematical frost heave model (2-D model). Using this model Foothills had, according to its testimony, performed calculations showing that the segregation would, in fact, not exceed 50 per cent.

Experimental Results

Foothills testified that it had not carried out frost heave experiments of its own. It relied upon the work of others, including CAGPL, to demonstrate experimentally that the segregation ratio would never exceed 50 per cent.

One of the experiments that Foothills relied upon was described in a paper published by Penner and Ueda of the National Research Council (Figure 2, Exhibit No. N-PD-805). The witness stated that in all of the experiments described in the literature that the Applicant had investigated, the segregation ratio was never greater than 10 to 20 per cent; he was not aware of evidence to the contrary.

Exhibit No. N-PD-805
Figure 2

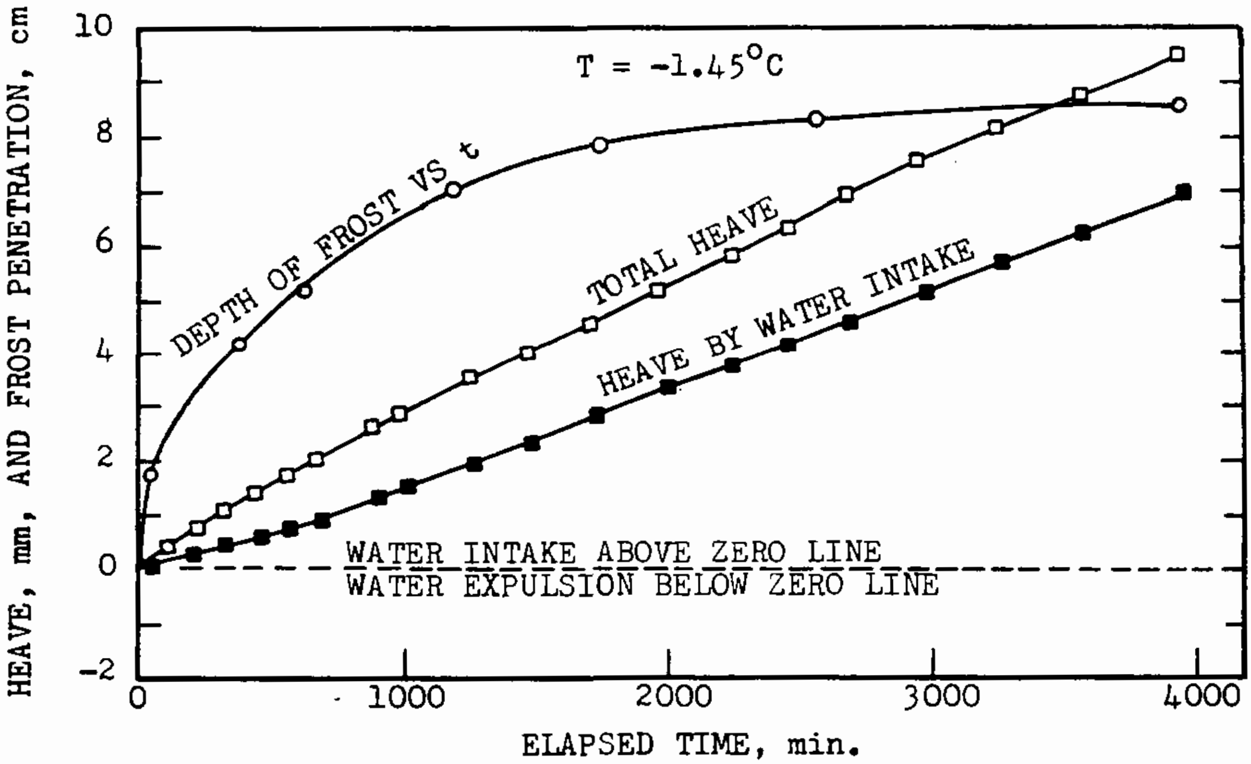


Fig. 2 - Frost penetration and heave rate measurements at 1 kg/cm^2 for Soil No. 2

Uplift Resistance and Permissible Differential Frost Heave

The term "uplift resistance" as used in connection with frost heaving of a chilled pipeline, is the amount of upward force required to move a pipe through the soil around it. This resistance becomes important in the case of differential frost heave. If a portion of the pipeline were to heave and an adjacent part did not, then, in order for the pipeline to avoid damage, it must be strong enough to withstand the stresses applied to it as it is forced through the soil on the non-heaving side of the interface. If it is not strong enough, the pipe will be deformed and perhaps fail.

Foothills testified that the uplift resistance would probably not be as great as 10,000 pounds per foot of length of the pipeline. The witness testified that an uplift resistance of 10,000 pounds per foot was "quite high" and would be difficult to obtain. Further, Foothills testified that a considerable movement would be required for the full uplift resistance to be mobilized. An example cited was the case of an uplift resistance of 10,000 pounds per foot being generated by a movement of ten inches through a soil with a stiffness of 12,000 pounds per square foot. Foothills agreed that such a soil would be very soft and compressible.

Foothills agreed that under some conditions the uplift resistance of 10,000 pounds per foot might be mobilized by a movement of about one inch rather than ten inches.

Foothills submitted evidence that for an uplift resistance of 10,000 pounds per foot, the tolerable differential heave over a length of 50 feet would be a bit less than 1.5 feet. This contrasts with the Applicant's estimated maximum frost heave of 2.2 feet in 30 years for a 42-inch pipe, in 32°F soil, with six inches of insulation around the pipe, operated at 15°F and having three feet of non-frost-susceptible bedding under the pipe. Assumptions made in respect of the calculation were that the segregation ratio was 50 per cent and that there would be no heave for the two and one-half years required for the frost front to penetrate the bedding material.

Evidence was given that the length over which frost heaving would be expected had an effect on the permissible differential heaves. Foothills gave evidence that, at the level of the pipeline base, the heave length would generally be much more than 50 feet. Foothills agreed that for shorter heave lengths, the design stresses would be exceeded and that for heave lengths less than 30 feet the insulation could be damaged. However, Foothills indicated that, since no heave was expected until the frost front had passed out of the bedding material, the frost bulb would redistribute and absorb the loads due to frost heaving, thus preventing damage to the pipe or insulation.

2-D Model

The 2-D Frost Heave Model is a mathematical description of frost heaving; thus any meaningful examination of the model was, of necessity, couched in mathematical terms.

Foothills' witnesses were examined at length by the Board on what it considered a significant mathematical error in the formulation of the model. The Applicant's responses during this examination did not satisfy the Board as to the accuracy and reliability of Foothills' model for predicting frost heave.

Views of the Board

The evidence put forward by Foothills with regard to the extent of the potential frost heaving problem is, in the view of the Board composed of inconsistent and, at times, conflicting information with respect to the terrain involved, questionable concepts as to the nature of frost heaving, and errors in soil classification.

The Board is concerned about some aspects of the Applicant's classification of soils as to their frost susceptibility. For example, Foothills stated that the soil for which CAGPL presented the test results of Penner and Ueda, was one of the least frost-susceptible soils that had been included in the assessment of frost-susceptible terrain. This soil was composed of 62 per cent sand, 23 per cent silt and 15 per cent clay and was shown to have heaved at rates up to five feet per year and to have a shut-off pressure in excess of 10,000 psf. Foothills proposes to use sand, with a total silt and clay content of between five and ten per cent, for bedding and it would rely on that bedding to exhibit no heave. The Board's view is that Foothills, having not yet carried out experimental work cannot be certain that its proposed bedding material would not be frost-susceptible.

It is the view of the Board that the design for frost heave control put forward by Foothills has not been shown to be feasible as filed. The Board is of the view that the underlying assumption that ice segregation will not exceed 50 per cent is without foundation. Indeed, there appears to be a considerable body of information that would suggest that this is not the case. Further, the assumption that frost heaving must stop when frost penetration stops is unsupported by the literature and experiments submitted by CAGPL, and is, in the view of the Board contradicted by these same sources of information. The two-dimensional mathematical frost heaving model appears to contain a significant error in its formulation. It is the view of the Board that this model has not been proven to yield dependable results. Further, considering the results of the full-scale frost heave tests carried out by CAGPL in which heaving occurred in spite of soil replacement beneath the pipe, the acceptability of the Foothills' plan based on soil replacement is in doubt.

Finally, the matter of uplift-resistance was left unresolved. No tests had been carried out and considerable confusion exists as to what values of uplift resistance are reasonable for use in design and whether the proposed design could successfully accommodate such values as may be encountered along the proposed route in the event of frost heave occurring.

In view of Foothills' request that its certificate application for the Mackenzie Valley project be held in abeyance, the Board considers it unnecessary to comment further on its concerns respecting potential frost heave problems along the Mackenzie Valley route.

While concerns respecting potential frost heave problems on a Foothills (Yukon) Alaska Highway project would be parallel in nature, the length of pipeline where such problems could arise within Canada would be much shorter. Nevertheless, immediate and extensive experimental frost heave work would be a prerequisite to the safe design and operation of the latter project; this has been dealt with in the section of this report on Foothills (Yukon) geotechnical matters.

Thaw Settlement

Extent of Thaw Settlement

Foothills indicated that, along the Mackenzie Valley pipeline route, thaw settlement would occur between Fort Simpson, the last point of cold flow, and the Northwest Territories-Alberta border. Testimony was given that less than 50 per cent of this portion of the route was frozen, the permafrost being associated mainly with fine-grained soils overlain by peat. Foothills indicated that, as a general rule of thumb, permafrost would be found under peat deposits in excess of five feet deep but not under shallower peat deposits.

Magnitude of Thaw Settlements

Foothills testified that the maximum thaw settlement that it anticipated along the Mackenzie Valley route would not be greater than about 3 1/2 feet. In areas where bedrock was near the surface, this could represent 3 1/2 feet of differential settlement.

Foothills was questioned about this assessment. CAGPL, whose route would be about 20 miles to the west, had submitted bore hole data indicating that in some areas south of Fort Simpson thaw settlements would be much greater than 3 1/2 feet. Foothills testified that the route that it had selected was much less swampy than the CAGPL route and thus the thaw settlement potential would be considerably less.

The Applicant indicated that much more drilling would be required to properly delineate the thaw settlement problem for final design.

Thaw Settlement Predictions

Foothills submitted information indicating how it planned to determine the thaw settlement potentials from test hole samples. The methods put forward included visual estimation of excess ice content, laboratory testing of frozen samples taken from the field, and correlation of frozen bulk density with the thaw settlement.

Visual Ice Method

The Applicant testified that one method of estimating thaw settlement potential that was particularly well-adapted to the field was the estimation, by visual means, of the excess ice content of samples taken from test holes. The Applicant indicated that this method was sensitive to human errors in estimating and generally tended to yield estimates that were high.

Laboratory Testing

The Applicant gave evidence that the best method of obtaining thaw settlement data was to bring frozen samples into the laboratory and thaw them under a load. This method, it said, would determine actual thaw settlement magnitudes to be expected.

Bulk Density Method

The bulk density method would involve measuring soil samples to determine the density in the frozen state, and determining the settlement by comparing the density with a curve of bulk density versus thaw strain, as a percentage. The determination of the curve involved the use of thaw settlement data obtained from laboratory testing.

Foothills agreed that the data used to determine the curve were very scattered and that the resulting curve was not valid for the case of pure ice, the curve under-predicting this case by some 20 per cent. Foothills stated that the correlation was only good in the range where data were available and it felt that the curve would yield conservative results since most of the data points fell below the curve.

When questioned as to the uncertainty of thaw settlements calculated from the curve, the witness agreed that at some bulk densities the uncertainty was nearly as great as the predicted settlement, but maintained that the laboratory test results used in deriving the curve generally yielded thaw settlement estimates that were greater than those which would actually occur in the field. For this reason, the Applicant was confident that this method would yield conservative results.

Permissible Values of Thaw Settlement

The Applicant stated that the permissible differential thaw settlement would be about three to four feet over a span of 200 to 300 feet. If greater settlement was anticipated in any location, corrective measures would have to be taken. For short spans of less than 100 feet, very large settlements could be tolerated since the pipe would support itself.

Mitigative Measures

Foothills submitted evidence that in areas that were identified as having a large thaw settlement potential, mitigative measures would be taken.
These included:

(a) rerouting the pipeline onto thaw-stable terrain;

(b) replacement of ice-rich soil with granular borrow; and

(c) insulation to reduce the magnitude of thawing and thus the magnitude of the thaw settlement.

While it was not a part of the design, the Applicant stated that in areas where these measures would not be effective, it might be necessary to install pipe supports. The Applicant also indicated that if, for some reason, a section of high thaw settlement potential were not detected and excessive differential settlement occurred, it could be necessary to shut down the pipeline and make repairs.

Views of the Board

With regard to Foothills' assessment of the magnitude and extent of potential thaw settlement along its route, the Board is of the opinion that further information would be required for confirmation or revision of the assessment, and that considerable additional investigative work would be required before the final design could be completed. However, the Board is of the view that, with additional time, effort and funds, a safe design could be prepared.

With regard to the methods put forward by the Applicant for predicting that settlement, the Board believes that the bulk density method of estimating thaw settlement is not adequate for design purposes and that the method requires considerable refinement. The method, as submitted by Foothills, yields estimates for which the uncertainity is, at times, as large as the estimate. At the extreme end of the scale, i.e. for pure ice, the thaw settlement would be under-estimated by greater than 20 per cent. Test hole logs showing pure or nearly pure ice have been submitted by the Applicant. It is the opinion of the Board that the density of the frozen soil in a thawed and consolidated state must also be known for the bulk density method to be of use.

Buoyancy Control

In its initial submission, Foothills indicated that it planned to design the buoyancy control measures to take advantage of the weight of the overburden where this would be practical. In subsequent testimony, Foothills took the position that buoyancy control was a routine matter normally left to the contractors.

Buoyancy Control Methods

In unfrozen ground where buoyancy might pose a problem, Foothills proposed the use of concrete saddle weights placed over the pipeline. In marshy areas and in areas of thaw settlement where buoyancy problems would arise, the Applicant indicated that such weights could not be relied upon to stay on top of the pipe, and that bolt-on or continuous concrete coating would be the preferred method.

At river crossings, concrete coating was proposed. In river crossings where frost heaving would be a problem, concrete coating would be applied over the insulation.

Foothills indicated that it had no plans to use frost anchors in permafrost areas.

Views of the Board

With regard to the Foothills proposals for buoyancy control, it is the view of the Board that the measures proposed are feasible and have been proven through many years of use in other areas.

Permafrost

Extent of Permafrost

Foothills indicated that its route traversed continuous permafrost terrain from the beginning of its pipeline in the Mackenzie Delta to about Fort Good Hope on the Arctic Circle. This assessment was based on a review by Foothills of published data and on the information available through its earlier participation in the CAGSL study group.

Foothills indicated that its pipeline would traverse discontinuous permafrost terrain from about Fort Good Hope to the connection with Trunk Line (Canada) near the Alberta border, a distance of about 600 miles. This assessment was based on published information and the results of test drilling programs by the Applicant and others.

The chilled portion of the pipeline would extend as far south as Fort Simpson. South of Fort Simpson, the line would be operated at above-freezing temperatures.

Identification of Permafrost

Foothills indicated that its estimate of the extent of permafrost, particularly in the discontinuous zone, was based on air photo interpretation and terrain typing which had been verified, in some regions, by test hole data.

Foothills indicated that it did not believe that geophysical methods of permafrost exploration were reliable and did not propose to employ them. The sole method of permafrost investigation that Foothills put forward was the drilling of test holes. The Applicant testified that test holes would be placed close enough together to provide "a good appreciation of the ice that would occur below the ditch line". In addition, drilling would be the only method that Foothills would rely upon to locate the interfaces between thawed and frozen terrain and to measure the thickness of the permafrost.

Foothills testified that, initially, the test holes would be spaced about 1,000 to 2,000 feet apart and, depending on the variability between holes, other holes would be placed between them. It was indicated that this drilling program and its planning would be part of the final design.

Views of the Board

The feasibility of Foothills' proposed exclusive use of test hole boring to locate interfaces between thawed and frozed ground over the first 400 miles of route in discontinuous permafrost terrain is highly uncertain. Since the failure to discover even a few such interfaces could conceivably result in pipeline failure from uncontrolled frost heaving, it is imperative that every effort be made to avoid missing any such locations.

In view of Foothills' plans regarding the investigation of permafrost terrain in the discontinuous permafrost zone and the large number of test holes that such an investigation would require, and in view of the apparently good results that CAGPL has obtained with the geophysical methods that it has described in its submissions, it is the opinion of the Board that Foothills should reconsider its decision not to use this method. Accepting that geophysical methods are not 100 per cent certain, they would appear to provide a considerable amount of useful information at a reasonable cost.

Slope Stability

Foothills submitted that no detailed analysis of slope stability had been carried out along its route. It indicated that the most serious slope stability problems were anticipated at river crossings where major landslides could be initiated by erosion of the toe of the slope, and in northerly portions of the route where slopes had high ice contents.

Measures for Slope Stabilization

In its submissions, Foothills outlined several methods of assuring that the proposed pipeline would not be damaged by slope failures. The principal method proposed would simply be to avoid unstable slopes where this was possible. In the event that stable terrain could not be found, several possible methods could be used to stabilize the slopes. At river crossings, bank armouring, toe loading berms and bank cuts could be used to prevent erosion of the toe of the slope and to reduce the effective slope of the bank. Gravel blankets could be installed to slow melting and encourage consolidation of permafrost slopes. The Applicant indicated that this method would be used to reduce the potential for instability of cuts in permafrost. Other methods put forward as possible solutions included burying the pipeline deep enough to avoid damage in the event of a failure and reducing the thermal disturbance by insulating the pipe.

Foothills indicated that the material presented to the Board was very preliminary and that extensive investigation would be necessary for final design.

Foothills indicated that marginally stable slopes would be monitored during operation and, in the event of an imminent slope failure, steps would be taken to protect the pipeline.

Views of the Board

Regarding the matter of slope stability, the Board is of the view that additional material would be required from Foothills to facilitate a full assessment of the extent and magnitude of the problem.

With regard to mitigative proposals, an assessment by the Board of specific measures which would be used by Foothills would have to await final design.

Drainage and Erosion Control

Hydrological Studies

Foothills presented sample designs based on studies done in eight drainage (or catchment) basins along the Mackenzie Valley route. The run-off predictions were based on drainage basin modeling since there has been effectively no gauging done of small streams in Northern Canada. Testimony was given that this was due both to the remoteness of the region and the impracticality of gauging such small streams.

The model used was a technique developed by P.S. Eagleson,(1) primarily for use as an urban planning tool. The applicability of the model to fairly large drainage areas had been verified by Eagleson using rivers and streams in Connecticut and by Foothills' consultants using drainage areas in the Northwest Territories and in the Yukon.

Testimony indicated that this model had been used to develop flood frequency curves for the eight areas studied. These curves formed part of the data used to prepare the conceptual design presented by Foothills.

Drainage and Erosion Control Design

Foothills testified that drainage and erosion control measures had only been designed for one of the eight drainage areas for which flood frequency curves had been generated.

The design that was presented was said to be "conceptual". General descriptions of the preliminary recommendations were given with indications as to the work left to be done before the designs were finalized.

There was somewhat less than unanimity among the witnesses with respect to the basis for the design of drainage and erosion control measures. Testimony was given that, ideally, each drainage area should be studied to allow the selection of a

(1) P.S. Eagleson, "Dynanics of Flood Frequency", **Water Resources Research**, Volume 4 November 4, 1972.

return period(1) that gave the minimum capital and maintenance costs over the life of the pipeline. One witness stated that similar studies carried out for the sizing of culverts for highways in the north had resulted in the designs based on floods with return periods between 20 and 1,000 years. He went on to state that "...each one of them (streams) has to be looked at in terms of what the return period of a certain maximum velocity is." The witness stated that it was not standard practice to select a "design return period based on a representative drainage area".

Further evidence was submitted that the design was to be based on a return period of 50 years. Testimony was given that 50 years was a conventional return period that had been used in Alaska and on many projects of this type.

A second witness went on to say that it was not appropriate to look upon erosion control as an economic matter, and that the choice of a design return period of 50 years was not the result of an economic analysis. The objectives were said to be simple: to maintain the existing drainage courses and to prevent erosion until, after four or five years, revegetation would diminish the likelihood of significant erosion.

(1) The average interval of time within which an event of a given magnitude is equalled or exceeded is known as the return period. Thus, speaking of floods, in 100 years it is probable that one event equal to or greater than the 100-year flood will occur and that two events equal to or greater than the 50-year flood (one of which could equal or exceed the 100-year flood) will occur. It is not necessary for 50-year floods to be 50 years apart. They can occur in two consecutive years but the probability of this happening is very low.

Control Measures

The measures that would be taken by Foothills to control erosion fall into two major categories: surface preparation and the construction of control structures.

In areas where significant erosion would occur, use would be made of clearing techniques that caused a minimum of disturbance to the soil surface. Ice and snow work pads would be used to prevent disturbance during construction. Tree stumps and roots would be left, except over the ditch. Grading would not be used where there were steep cross slopes.

Drainage control structures would be provided to carry water off the right-of-way. Berm breaks would be installed to carry water across the right-of-way at natural drainage courses and where significant amounts of water would collect on cross slopes. Where the slopes were parallel to the right-of-way, diversion berms or dykes would be constructed to carry water to the side of the right-of-way, preventing a build-up of fast moving water along the pipeline.

It was indicated that these measures were mainly proposed to prevent major erosion until revegetation had taken place. Evidence was given that revegetation could take as long as five years to become well established.

Foothills testified that revegetation would be done by seeding, perhaps during the winter, from the air. In areas where severe erosion could take place, such as on steep slopes, "vegetative mats" were proposed to be installed to aid revegetation.

Foothills testified that the pipeline route would be frequently over-flown as part of its monitoring program and any erosion would be repaired.

Views of the Board

The objective of the designer of drainage and erosion control measures is to assure that the pipeline would be adequately protected from failure due to erosion and related problems while, at the same time, not being over-cautious to the point that the cost of the protective measures exceeds the cost of repairs that would have been necessary, over the life of the pipeline, if no special measures had been taken.

With regard to Foothills' method of determining the return periods to be used in the design of drainage and erosion control measures, it is the view of the Board that the use of the fixed 50-year return period for all streams may lead to excessive costs, both capital and maintenance. There may be places where the use of a return period in excess of 50 years would be more appropriate, the extra capital expenditure being more than offset by savings due to lower maintenance costs. In other instances, a 50-year return period may prove to be overly long, the reductions in capital expenditures due to the adoption of a less cautious design being greater than the increases in maintenance costs over the life of the pipeline. While the expenditures involved may not be large in relation to the total costs of the project, the consequences of a failure, on the other hand, could be serious and expensive.

The selection of a 50-year return period for design purposes does not assure that the first severe flood will occur in 50 years, or even that, over the life of the pipeline such floods will occur an average of 50 years apart. Since the return period applies to each individual stream, if the pipeline crosses 100 drainage basins, it is quite probable that at least two of these drainage areas will experience floods of magnitudes in excess of the 50-year flood for each year of operation and that one drainage area will experience a flood in excess of the 100-year flood magnitude. In the view of the Board, it would appear necessary for Foothills to study each drainage basin individually to ensure not only that the designs that might be built are economic but that erosion of a magnitude that could threaten the integrity of the pipeline would not occur.

With regard to the correctness of the methods of estimating the flood frequency curves for unmonitored drainage basins, the Board notes that the results presented, comparing records for large drainage areas with the estimated curves, appear to be in excellent agreement.

With regard to the type of measures proposed for erosion control, the Applicant's proposals appear logical and reasonable.

Borrow Materials

The Applicant stated that it would require approximately 17 million cubic yards of granular material for its project. Modifications to the project plan eliminated the requirement for approximately 43 miles of surcharge berm, but there would be an additional requirement on Spread 1Af of some 900 thousand cubic yards.

The Applicant detailed the requirements for each construction spread; volumes of borrow and concrete aggregate for each facility were tabulated. While it did not detail the quality requirements of materials for each facility, it indicated that the principal requirement would be for gravel. Supplementary borrow areas would also be required for select back-fill of the pipeline, but final quantities could not be determined until construction was in progress.

The Applicant indicated the general location and the amount of material to be mined from each pit. Most of the pits designated were those previously investigated and described by geotechnical consultants for the Department of Indians Affairs and Northern Development.

The Applicant indicated approximately 70 borrow areas on the construction spread maps; however, only 29 were listed as sources of borrow for the project.

Most of the borrow material required would be for general fill for which quality requirements were not stringent; however, higher quality materials would be required for specific uses. These would include surfacing materials, concrete aggregate and graded material for erosion and drainage control, and river bank protection.

The Applicant would construct a summer work pad for the most northerly 50 miles of right-of-way. The requirements for this facility were approximately 2.0 million cubic yards of gravel fill and fine granular bedding material to be taken from three borrow areas.

A significant quantity of sand bedding material would be required to protect the insulation coating on the pipe for an estimated 43 miles. For the insulated pipe construction mode, an additional .56 cubic yards of gravel per foot would also be required.

Views of the Board

It is the opinion of the Board that the Applicant has presented sufficient quantitative information on its requirements for granular material; however, it has not given detail on the quality requirements for each of the facilities within each construction spread. Further information would be needed prior to construction, in order to evaluate the feasibility of individual pit operations.

Although over 70 pits are indicated on the construction spread maps, only 29 pits are proposed for development. This would require inordinately long haul distances in many cases. The Board believes that, should the Applicant be granted permission to construct the proposed facilities, it would have to open many pits in addition to those presently indicated.

There are portions of the route where possible competition with communities for granular resources would be a possibility; shortages or depletion of high grade granular materials would also be possible. To prevent these anticipated problems, the cumulative requirements of industry and the communities should be analyzed before permission is given to mine granular materials.

The proposal to build a gravel work pad from mileposts 0 to 50 would require sand bedding material and gravel fill. Gravel is a scarce commodity in the Delta, but there are several large, widely scattered deposits containing excellent material; again, haul distances may be relatively long. The Applicant would have to demonstrate to the Board that its demands for material from these sources were co-ordinated with other demands on the same deposits.

The sand bedding requirement for the insulated work pad could be easily met on the Delta; however, there is a question of the quality of the material. The sand in this area which is predominately fine-grained, often containing appreciable amounts of silt and ice, would be placed in the frozen state in the winter. The Board is concerned about potential wash-outs of this material during the summer season and would have to be assured of the feasibility of the use of the sand cushion-insulation construction method in this area.

The Board is also concerned about the use of this material for insulated pipe in the ditch. Mining and placing of the material in the winter could result in frozen chunks on the ditch bottom, causing damage to pipe insulation. The Applicant would have to demonstrate to the Board how it would solve these materials handling problems.

River Crossings

Foothills indicated that its river crossing designs were preliminary. It stated that the crossing locations were selected before an assessment was made of the scour potential and that only the crossing at Fort Simpson had been investigated by drilling.

Scour

Scour estimates were made for several rivers; the witness for Foothills testified that these estimates were unsatisfactory, primarily because of the lack of data for the crossings.

The primary method that was employed in making the preliminary estimates was the set of equations developed by T. Blench, a consultant on river hydrology, and presented in a book by C.R. Neil. The witness indicated that the information concerning the crossings was limited, most of it being obtained from aerial photographs which did not yield any information on river bed topography. In addition, the witness indicated that he was not sure of the applicability of the Blench equations.

An additional technique that was put forward by Foothills for the assessment of scour was the determination of the depth of the post-glacial alluvium* on the river bottom. While this determination would not yield the maximum possible scour, it would tell the designer what the maximum scour had been since the

* Post-glacial alluvium is the material that has been deposited on the river bottom by the action of the river since the last glacial retreat. The depth of this material indicates the depth to which the river had been able to scour the bottom in the past.

last ice age. The witness indicated that the interface between the post-glacial alluvium and the glacial till or bedrock underneath could be determined either by drilling the river bed or by seismic methods.

Bank Stability

As with scour, the assessment by Foothills of river bank stability problems was preliminary. While some drilling and soil sampling had been carried out, the majority of the work involved measuring of slope angles and determining the existence of past slide activity, both of which were determined from aerial photographs. Foothills testified that several of the initial crossings had been relocated as a result of these investigations, and that more relocations might occur as a result of further work. The witness expressed some concern over slopes which had high ice contents and indicated that special measures might be necessary in some places. Foothills indicated that it intended to review the experience along the Alaska Pipeline route before the stabilization measures were finalized.

Foothills indicated that a more complete assessment of the proposed river crossings would form part of the final design.

Views of the Board

With regard to river crossings, it was clear that the assessment of the proposed river crossings was incomplete and that considerable additional work would be necessary in advance of any construction.

In the event that a certificate were issued, Foothills would be required to satisfy the Board as to the adequacy of the final design.

Monitoring

During the hearing Foothills indicated that it intended to monitor the pipeline for the occurrence of frost heaving and thaw settlement by the use of standard survey methods, using metal risers or targets attached to the pipe, and to monitor for slope movement by the use of slope markers which would also be surveyed periodically to check for movement. Plans for the use of piezometers, to measure for excess pore pressure at potentially unstable slopes, and thermistor strings, to check for thermal degradation of permafrost slopes, were also discussed. However, it was indicated that these devices were only to be used during the pre-design phase and not during operation. Foothills indicated that while some new devices, such as "smart" pipeline pigging devices, would be given consideration, the principal method of monitoring that the Applicant would rely on was frequent surveillance by air, ground vehicle and foot patrols.

Foothills indicated that the areas that would require monitoring would be defined by the drilling program for final design.

Views of the Board

With regard to monitoring of the proposed pipeline, the Board is not convinced that the plans proposed by Foothills are adequate. Considering the remoteness of the proposed route and the harshness of the environment in which it would be operated, it would be prudent for Foothills to employ the very latest methods such as remote monitoring of such devices as piezometers and thermistors in banks, movement transducers on potentially unstable slopes, smart pigs to detect deformations in the case of frost heave or thaw settlement, etc., to ensure, to as great an extent as possible, that natural forces do not cause an unanticipated failure of the pipeline. In the event that a certificate were issued, Foothills would be required to submit a complete monitoring plan to the Board for approval.

3.2.3.3 Stress Analysis and Materials Engineering

Stress Analysis

Introduction

Foothills described the stress analysis of the proposed pipeline as an evolutionary process encompassing three developmental phases: conceptual, intermediate and final stage. In the conceptual stage of the design, Foothills decided on a buried pipeline design which assumed straight, longitudinally and laterally constrained pipe for the purpose of mathematical modeling, and line pipe of conventional dimensions (42-inch O.D. and 0.54-inch wall thickness) and operating pressure (1250 psig) requiring only proven methods of pipeline design and construction. At this stage, the general behaviour of the structure was estimated very approximately due to the limited availability of field data. When more field data and information became available, the model was refined and upgraded in the intermediate stage and the accuracy of the analysis was correspondingly improved.

The stress analysis submitted to the Board covered physical properties of the line pipe; consideration of installation, pre-operational and operational loading conditions, seismic design and buoyancy design; consideration of frost heave, thaw settlement and wash-out loading situations; and design criteria.

Analytical Techniques

A linear stress analysis for elastic line pipe behaviour was employed for the calculation of strains and stresses due to transverse loads, internal pressure and temperature changes. According to the chosen Tresca yielding criterion, yielding would occur at the maximum allowable operating pressure (corresponding to a hoop stress of 80 per cent of SMYS) when a compressive stress of a magnitude of 20 per cent of SMYS was acting in the longitudinal direction.

If the pipeline were permitted to undergo large deformation, the analysis applied would be a non-linear, elasto-plastic analysis, taking into account all operational and loading conditions to which the pipeline might be subjected. In particular, it accounted for the internal gas pressure to which the pipeline was subjected, the temperature variations during operation, the constraint imposed on the pipe by the surrounding soil, as well as the various longitudinal and lateral loads acting on the pipeline resulting from such phenomena as frost heave, differential settlement and wash-out. The equation defining the problem was a fourth order ordinary differential equation, which took into account the axial effects of large deformations, as well as the non-linear material effects. This differential equation was solved by means of finite difference techniques using a computer program developed specially for this project. The results of this computer analysis submitted to the Board were related to the parameters governing frost heave and differential settlement, which was in accordance with the priorities assigned by Foothills. The area of concern was related to the frost heave pressure exerted on the pipeline by the frost bulb. The frozen bulb was assumed to be an elastic medium which transmitted loading onto the pipe and was, therefore, simulated with various values of elastic spring constants in the computer simulation, but it did not involve a direct application of geotechnical data. It was recognized by Foothills that the real distribution of pressure acting on the pipe as a result of frost heave was likely a very complex function of a number of parameters, including soil density, soil deformation, moisture content, creep rates, frost bulb size and others. Foothills acknowledged that the accuracy and confidence levels associated with the stress analysis were related to the accuracy of the input data and, therefore, it intended to obtain site-specific geotechnical data for the final design.

Experimental Verification

The results of the elasto-plastic stress analysis were verified against the test results of the full-scale tests of the line pipe used for the Alyeska pipeline, carried out at the University of California, with respect to the midspan deflection as well as longitudinal strains and bending moment as a function of curvature. For analytical prediction, assumptions were made with respect to the geometric and load configuration, the stress-strain curve of the specimen and the von Mises yield criterion. In Foothills' opinion, the agreement between the analytical predictions and the test data was very satisfactory.

Special Considerations

Foothills submitted two documents prepared by its stress analysis consultant covering the results of four tests carried out to investigate the state of stresses and strains in the vicinity of split-sleeve unwelded crack arrestors. The tests were basically laboratory-type tests, in that they did not approximate Foothills' pipeline conditions. The tests utilized smaller diameter, thinner-walled pipe in free-standing short lengths, i.e. with no longitudinal restraint. Within these limitations, the more significant conclusions, comments and recommendations were as follows:

> Such devices imposed detrimental effects such as local stress concentrations at least as high as 3,650 psi longitudinal flexural stress and 7,200 psi circumferential flexural stress in the experiments performed. Pressure testing would not necessarily remove all flexural stress concentrations imposed

by the devices. It was noted that while the numerical values seemed rather small, they did contribute directly to the total stress in any given situation, and that the implication of compressive strains and stresses was significant since an internal pressure resulting in a hoop stress of 80 per cent of SMYS left a reserve of only 20 per cent of SMYS for longitudinal stress before yielding, according to the Tresca criterion. It was recommended that further work be carried out to assess the degree of reduction in local buckling strength induced by such devices. Finally, it was concluded that such devices should only be considered and accepted as proper and safe design features of pipelines after their effects had been explicitly taken into account in the design process.

In cross-examination, it was questioned whether the proper conclusion of the report was that crack arrestors could be used if their effects were taken into account in the design process and, in this respect, that the forces were no different from any other forces to which the pipeline would be subjected. Foothills agreed.

Materials Engineering

Introduction

With respect to large diameter line pipe, the starting point in the Foothills fracture control design was to specify pipe with the maximum toughness currently available in Canada. The resulting toughness was, in effect, higher than had been specified by other Applicants.

Foothills applied some form of fracture control design to all principal materials used in the pipeline. In general, the prevention of fracture initiation through provision of adequate toughness at the design temperatures was considered as the primary design technique. In the case of large diameter line pipe, the design technique was extended to consideration of fracture propagation as a supplementary measure.

Fracture Initiation

The resistance of the pipe to fracture initiation was assessed in terms of critical defect sizes.

For fracture initiation, the use of relatively high notch toughness values resulted in a very large critical crack-like defect size. This was calculated in accordance with the accepted theoretical analysis. While no direct full-scale testing of the proposed pipe had been done to confirm this, the available experimental support for this approach included similar pipe sizes. For the proposed pressure of 1250 psig and the specified minimum toughness of CV = 50 ft-lbs, a theoretical critical defect size of 7.2 inches was obtained. Foothills felt that hydrostatic testing prior to the pipeline going into service would ensure that such defects, close to critical size, would be detected and removed. Similarly, the probability of third party damage during operation was considered to be very low and the most probable cause of initiation was considered to be an external force.

Foothills also placed some emphasis on the use of instrumented defect detection devices during operation.

Fracture initiation control was also proposed for mill welds. The approach used was to provide equivalent toughness in the welds relative to the parent metal, after compensating for the orientation of the weld in the pipe. Foothills acknowledged that this was an approximation based on critical defect-size calculation considering only the hoop stress component.

Foothills made no provision for notch toughness of the heat-affected zone.

Brittle Fracture Propagation

With respect to brittle fracture progagation, Foothills adopted a conventional drop weight tear test requirement to ensure ductile behaviour should any fracture propagation occur.

Foothills stated that the specific requirements for drop weight tear test shear area of 60 per cent had not been set as high as found experimentally by Battelle to be required (85 per cent), since an even lower requirement in the CSA standards (35 per cent) suggested that the proposed design was adequate without being particularly conservative.

Ductile Fracture Propagation

With respect to unstable ductile crack propagation, Foothills viewed the probability of its occurrence as remote. This was based primarily on the low historical occurence of this type of failure, the low probability of initiation occurring, and the action of built-in crack arrestors to limit the potential crack propagation length. However, Foothills recognized that such a failure was at least theoretically possible at a design pressure of 1440 psig and, therefore, derated the pressure to 1250 psig. The derating to a pressure where a condition for self-arrest would exist in the specified pipe was claimed by Foothills to be a conservative approach.

Fracture Arrest

The degree of conservatism provided was based on the applicability of the Battelle hypothesis for self-arrest to the specific pipe material. It was apparent that the present material was of a grade and type for which the Battelle hypothesis had not been firmly established by full-scale tests. Foothills argued that these effects were compensated for by specifying notch toughness using the CV-100 approach, which appeared to give a conservative measure of fracture behaviour. However, the degree of conservatism this offered was not clear in view of the general uncertainty about being able to apply the Battelle hypothesis for self-arrest and the lack of any past experience with the CV-100 specifications.

Under the design conditions and using a theoretical gas decompression curve, the Battelle hypothesis predicted fracture arrest in pipe which had a fracture toughness of CV-100 = 80 ft-lbs. Similarly, such a condition should apply to all normal operating pressures and temperatures. In qualitative terms, this meant that at least 50 per cent of the pipe should arrest a propagating fracture. If a random distribution of such pipe were assumed, the length of any rupture should be short. Estimates of a 150-foot average failure length and a 400-foot maximum failure length were given by Foothills, subject to the results of an ongoing statistical study.

Foothills indicated that full-scale burst tests involving actual gas composition and frozen backfill conditions had been considered but no commitment was given to conduct such tests.

Fracture Toughness of Small Diameter Pipe and Pipeline Components

For small diameter electric resistance welded pipe, Foothills provided for a modest level of notch toughness in the pipe as a design measure against fracture initiation. This was based on the calculation of critical defect sizes and a demonstration that these sizes were maximized with relatively low levels of notch toughness. No provision was made for fracture propagation even though the possibility for some concern in this area was acknowledged.

For components, Foothills established a design criterion based on a conservative "leak before break" criterion. The critical crack sizes for the tentatively proposed toughness levels were calculated but Foothills viewed these as only approximate for the operating pressures. A more conservative approach might be to use the fracture initiation analysis for hydrostatic test conditions.

Crack Arresting Mechanisms and Devices

Fracture control by selective placement of high toughness pipe was rejected as impracticable.

With respect to the possibility of operating the pipeline above the proposed derated pressure, Foothills acknowledged that significant economic benefit existed, but that it was premature to consider such a possibility. Foothills discussed several technical requirements for such a pressure increase. The most basic of these was that the same level of protection against unstable ductile crack propagation must exist at a higher pressure as would exist at the presently proposed pressure. In addition, the uncertainties associated with external loading must be resolved through operating experience, and the effects of gas composition variation and backfill would have to be accounted for.

The only alternative to the present approach appeared to be the use of mechanical crack arrestors, but this was rejected on the basis that it was a new and unproven concept which might introduce detrimental effects.

Materials Specifications

Status

Foothills provided the specification of the principal materials to be used in the pipeline. For small (30-inch and 24-inch) and large (42-inch) diameter pipe, valves and pipe-coating, a formal Company standard specification was submitted along with a specification sheet covering the specific application. In addition, a materials specification index was submitted to cover most other component materials which were to be purchased to industry standards. The general approach adopted in preparing these specifications appeared to be based on the selection of essentially conventional and proven materials which the Foothills parent company had experience with. Foothills acknowledged that the project required some extension of materials technology but felt that the addition of supplementary requirements to established specifications was adequate.

In the case of components, the approach was to employ types of valves and fittings which had seen some low temperature service in the past. The major supplementary requirement was for conservative notch toughness properties at the design temperature.

For community service laterals, Foothills proposed the use of small diameter electric resistance welded pipe.

With respect to 42-inch diameter pipe, Foothills attempted to specify the highest quality of pipe, particularly in terms of notch toughness, currently available in Canada. However, the basic materials were similar to those already in service. While it was acknowledged that the specific combination of diameter, wall thickness and material was unique in this application and represented a limit in currently established technology, Foothills intended to purchase the required pipe from its two primary suppliers in Canada and appeared satisfied with the quality.

In support of its view that the pipe specifications could be met by the mills, Foothills filed a completion report for one manufacturer and the mill test data for both manufacturers on the ten miles of trial pipe obtained. In general, it appeared that the specification requirements could be approached if not met in absolute terms. More specifically, not all pipe received from

Stelco met the average toughness or yield strength requirements, weld toughness requirements, or dimensional tolerances.

Implementation

The implementation and enforcement of the specifications were provided for by the qualification procedure required and by the use of conventional third party inspection practices. At present, Foothills considered its primary pipe suppliers to be qualified, although formal qualification of Stelco steel required demonstration of mill weld toughness. Pipe made from domestic plate originating with outside suppliers was said to have met the specifications but no formal data on its qualification were submitted in support. Foothills acknowledged that the two prospective pipe mills using the long seam welding process had not yet met the specification. With respect to third party inspection, Foothills was depending on established third party inspection agencies using the presently established practices. The formal program for doing this had not yet been set out.

Field Welding

Foothills also submitted specifications for the field welding and double jointing of pipe. In addition, sample welding procedures for automatic welding and manual welding procedures were submitted by Foothills. In general, Foothills relied on successful past experience in field welding similar materials using these procedures, and on the weldability testing and field installation of the trial pipe made to the present specifications. However, Foothills recognized that the proposed pipe was nearing the practical limit for conventional manual procedures. Associated with this was the acknowledgement of a general need for closer adherence to procedures and the acceptance of lower rates of production. This was said to have been accounted for in construction planning.

The use of automatic welding as an alternative was being considered. The need for some further development work with this process was accepted even though some experience presently existed under more moderate temperatures.

The addition of a notch toughness requirement to the procedure qualification represented the only significant supplement to the present CSA requirements. The need for such a requirement appeared to result from a greater concern about longitudinal strain due to external loading acting across the weld when compared with more conventional pipelines. However, the specified impact toughness of 20 ft-lbs was based on general experience rather than any specific fracture initiation design criterion or calculations using static fracture mechanics tests. Foothills recognized that such a design and test technique might be more relevant to predicting failure, but felt that all defects, including cracks, would be restricted in accordance with the very conservative CSA defect acceptance standards. For this reason, further consideration of notch toughness was not considered necessary.

Inspection of Field Welding

With respect to inspection of field welds, Foothills specified 100 per cent x-ray radiography similar to that presently applied in conventional pipelines. In addition, supplementary non-destructive testing would be carried out in individual cases. For automatic welding, some use of ultrasonic inspection instead of, or in conjunction with, radiography was contemplated although some further development in this area might be required. The administration of field inspection policies was generally established and an undertaking to use formally qualified people for interpretation was given. However, the final details of this were not established.

Materials Supply and Availability

Line Pipe

The major materials item is line pipe, and for this Foothills assessed availability in some detail. This involved the comparison of the Foothills tonnage requirements for large diameter pipe, along with those of related expansions, with the tonnages and production rates presently available from five Canadian pipe mills. In addition, the availability of plate and skelp was assessed on the same yearly basis. The figures used in this comparison were based on previous experience with these manufacturers and on the tonnages that were dedicated to the project by the manufacturers themselves. In general, this comparison indicated that only 27 per cent of the theoretical Canadian capacity would be used in the peak year, and this gave a large measure of flexibility in supply. The possible expansion of at least one facility was said to increase this flexibility although no dependence on this was acknowledged. In view of this, Foothills had not considered any non-Canadian suppliers as further back-up.

With respect to pipe making, a reasonably good demonstration of capability was provided by the newer spiral mills in making the trial pipe. Stelco was able to realize the required production rate and Ipsco had some scope for improvement, considering possible minor mill modifications. Foothills considered that these mills would supply the majority of the required pipe and might be able to meet all its requirements for 42-inch diameter pipe. However, the capabilities of the two older pipe mills were less certain. Neither had made the required pipe or been formally qualified, although they had made similar pipe in the past.

Plate and skelp availability required some consideration as this might limit pipe production rates. With respect to IPSCO, the spiral pipe-making facilities used a coil product that could only be made by this manufacturer. However, the present coil capacity appeared adequate in relation to the pipe-making capacity. The other facilities used a plate product and therefore could meet any shortages by using plate from other suppliers. Algoma might dedicate some tonnage for this purpose.

In addition, the use of non-Canadian plate was investigated as a contingency. Foothills undertook to co-ordinate and control the usage of outside plate in these pipe mills so that it could be optimized.

While a secure supply of mainline pipe appeared to exist, Foothills recognized a probable need for some foreign heavy wall pipe, particularly for low temperature service. The exact amount of imported pipe was not established, although Foothills indicated that domestic supply for conventional design temperatures was available. The supply of small diameter pipe for community service laterals was also domestically based. This factor was of some importance when the conventional electric resistance welded pipe was selected over the alternative of using seamless pipe, produced solely by Algoma.

Pipeline Components

With respect to components such as valves, flanges and fittings, Foothills expected that the majority could be purchased in Canada, but acknowledged that some foreign supply would be necessary and that the percentage breakdown was not firmly established. In addition, a possible shortage of valves was recognized, although no definite alternative had been provided for.

Views of the Board

Stress Analysis

Although the stress analysis performed by Foothills was not as thorough as that of CAGPL, it did cover all the essential pipe loading situations and it is therefore considered adequate by the Board. However, the mathematical model for differential frost heave requires refinement as more data become available as a result of site-specific and geotechnical analysis of frost heave action. It is not apparent how Foothills would propose to take into account site-specific field problems in the final design process. No indication was given of the means of monitoring the pipeline to ensure its structural stability. It is anticipated that methods of implementation of the results of the stress analysis would be incorporated into a design field manual and submitted for final design approval.

Materials Engineering

The line pipe toughness specified by Foothills is considered by the Board to be sufficient to inhibit fracture initiation and brittle fracture propagation, but not ductile fracture propagation. Since inherent material properties cannot prevent fracture initiation caused by external forces or structural instability, a sound method of ductile fracture propagation control would be required. The line pipe properties specified by Foothills cannot provide positive ductile fracture propagation control. External fracture control methods were therefore considered by Foothills. Foothills opted for a reduction of operating pressure to 1250 psig from 1440 psig (80 per cent SMYS). This ductile fracture propagation control method was not proven experimentally for this specific design. The Board would require full scale tests to be carried out using the proposed pipe under simulated operating conditions, taking into account the actual pipe length distribution, actual gas decompression behaviour and frozen backfill conditions before final design could be approved.

The lack of any consideration of the fracture toughness criteria for the heat affected zone of the 42-inch O.D. pipe is of concern and the Board would require Foothills to provide such criteria in seeking final design approval.

Materials Specifications

It is the view of the Board that the Foothills philosophy of specifying high quality conventional materials is sound. Materials properties selected are considered acceptable provided that the supplementary specification proposed by Foothills for mainline pipe in low temperature service with respect to fracture toughness could be maintained by the mills. The field weldability of the proposed pipe has been satisfactorily established, although improvements of welding procedures and processes would be beneficial. Finally, the detailed procedures for field and manufacturer inspection would require further assessment, even though the basic principles adopted are adequate.

Supply and Availability

It is the view of the Board that most of the line pipe could be acquired from domestic sources, whereas the sources of pipeline components are not identified. The domestic line pipe of the specified quality and required quantity is considered reasonably secure; technological competence and production capacities of Canadian pipe mills are adequate. Some modifications and expansion of existing manufacturing facilities would be required.

3.2.3.4 Right-of-Way

Foothills stated that it would require a permanent right-of-way 60 feet in width and that Board approval would be sought should a greater width be necessary. It was also indicated that it would assume responsibility for rights-of-way and sites for all lateral pipelines and metering stations. Foothills stated that it had discussions with the Department of Indian Affairs and Northern Development regarding the necessary landrights and that it did not expect to receive serious objections from private landowners along the route. It was also confirmed that approvals for the crossings of navigable waters, railways and utilities would be sought from the appropriate authorities.

Views of the Board

Foothills indicated an appreciation of possible right-of-way problems which could arise from pipeline construction in the area of negotiation and acquisition of lands. It further indicated that it would obtain all regulatory approvals required.

The Board would require that Foothills comply with all of the Board's directions regarding the acquisition of rights-of-way and other lands, including but not necessarily limited to specific directions as to the rights of and notice to all potentially affected property owners to ensure an orderly land acquisition and an equitable settlement program.

3.2.3.5 Communications

Foothills investigated various alternatives for providing the required communication system. A satellite system was briefly studied but ruled out, mainly because it was felt that this would duplicate the existing terrestrial system now in operation along the Mackenzie Valley. Two alternatives for a terrestrial system were investigated: a privately owned system completely dedicated to the Applicant's use, and a system which leased space from an existing common carrier. Even though no formal studies were carried out, Foothills came to the conclusion, based on experience gained in Trunk Line, that leasing from an existing system would be economically superior to building a new system. Therefore, Canadian National Telecommunications (CNT) was requested to develop a suitable plan.

Construction Communications System

The construction communications would be provided by a temporary expansion of the permanent communications system consisting mainly of existing CNT facilities. Once construction began, lateral connections, similar to those required for permanent communications, would be installed from the construction camp sites to the CNT main long haul system. Upon disbandment of the camps, the communications equipment at these sites would be dismantled and relocated at selected compressor station sites.

Two primary requirements which would be met by the construction communications system were as follows:

(a) communications for pipe-laying and compressor station contractors would consist of voice and telex services for ordering supplies and equipment, to provide administrative control and to ensure personnel safety.

Internal contractor communications would operate by means of private commercial mobile radio telephone. In addition, the CNT public mobile radio telephone system could be used as a back-up for camp telephone circuits; and

(b) communications services over the entire pipeline system for exclusive use of the Applicant's construction personnel would include private voice communications from the construction camp sites to district headquarters; from district headquarters to the staging area at Enterprise; and from district headquarters and staging area to the operations centre located in Yellowknife. These circuits would eventually become part of the permanent system.

Permanent Communications System

The permanent system would provide communications services between pipeline installations such as compressor stations, meter stations, district headquarters and the head ofice at Yellowknife.

The two main requirements to be met by the permanent communications system would be:

(a) to provide for normal administrative traffic requirements and the dispatch of maintenance personnel; and

(b) to provide a medium for a sophisticated supervisory control system that would remotely operate the pipeline and monitor its performance.

The administrative network would consist of telephone and telex interconnection between compressor stations, meter stations, district headquarters, operations head office and executive headquarters.

Mobile radio telephone services would be provided for repair and maintenance personnel to communicate with their respective operating headquarters. This service would also include air-ground interconnection by a commercial mobile radio telephone system owned by the Applicant. Public mobile radio telephone channels would be available in the event of an emergency.

Telemetry and Supervisory Control Systems

The gas control centre at Yellowknife would monitor the operation of the line and would have facilities for remote and unattended operation of the pipeline installations. The system would provide automatic reaction within pre-set limits for operation of the pipeline and would provide for manual override for selected functions, such as starting and stopping stations in the case of upset conditions.

A maintenance information system would provide equipment performance data to a central processor which would be programmed to establish the frequency of maintenance work and predict the nature of equipment failures. This would allow the maintenance and repair personnel to predetermine their equipment maintenance requirements, thus minimizing station outages.

All of the above requirements could be handled by 60 channels on the microwave system. It was felt that the CNT system capability was adequate to allow the dedication of these channels for pipeline use.

CAGPL suggested that to increase technical reliability, the Foothills gas control centre should be on the mainline and not in Yellowknife. Eight microwave repeater stations would be required to carry communications from the mainline to the gas control centre in Yellowknife. CAGPL further argued that its proposed satellite system was superior to the microwave system on the basis that, if one of its earth stations malfunctioned, the others would continue to operate independently, and thus communications to the rest of the system would not be affected.

Foothills argued that, in the event of a microwave tower malfunction, partial services could be maintained by alternative routings, such as the tropo-scatter system from Hay River to Yellowknife or the DEW line system. Although complete communications would not be maintained, it felt that adequate signals could be received at the gas control centre in Yellowknife so that operation of the pipeline could continue while repairs were being made to the tower.

Views of the Board

The Board concludes that either the terrestrial microwave system or the satellite system could provide the necessary communications service. Each system was shown to have certain advantages and disadvantages and the overall cost estimates, as reported, were virtually the same. The Board therefore accepts the Applicant's choice of a terrestrial microwave system.

3.2.3.6 Construction

Construction Mode

Foothills stated that most of the pipeline construction would be carried out during the winter season because of mobility and environmental considerations. Due to the short hours of daylight in the northern regions, winter construction would not commence until late January and would continue until April of the same year.

However, because of the high winds, the extreme cold and the lack of available daylight during the winter season along the Arctic coast, Foothills had decided to construct 50 miles of the most northerly spread from a 60-foot wide granular work pad during the period 15 August to 31 October preceding the first winter season of major pipeline construction. The wind chill temperatures for the coastal stations (obtained from the Canadian Government weather data for Tuktoyaktuk, Shingle Point and Komakuk Beach), indicated that during the months of February, March and April it would be necessary to curtail construction operations for about 41 days out of the 89-day period or 46 per cent of the time. The criteria used to establish this 41-day period was a wind chill lower limit of -35°F. Foothills believed that the reasonable productivity that could be expected in the coastal area during a working season would be equivalent to one and a half months. This short work period was deemed insufficient to meet Foothills' schedule. The remaining portion of this spread would be constructed during the following winter season.

CAGPL contested Foothills' ability to construct 50 miles of the most northerly spread in late summer, stating that the proposed 60-foot wide granular pad would be too narrow and should be at least 87 feet wide. CAGPL also felt that Foothills would have difficulty constructing the pipeline because of the numerous water crossings.

Construction of the compressor stations and meter stations would not be affected by weather or available daylight since these facilities would be constructed on prepared work pads at fixed locations.

Foothills proposed to transport materials and personnel by ground transport as extensively as possible and to use helicopters when conditions would not permit travel across the terrain.

Construction Techniques

Foothills planned to machine clear non-sensitive areas of the right-of-way and access routes one year in advance of pipeline construction. Foothills proposed to take special steps to prevent damage to vegetative cover in areas designated by territorial authorities as sensitive, that is, areas underlain by fine-grained, ice-rich or highly erodable soils. In these areas the smaller plant species would be maintained to prevent thawing or erosion of the permafrost. Clearing would be done by hand and in some areas the vegetative cover would be removed and replaced after completion of the pipeline construction. Felling of merchantable timber would be done by hand in late fall and early winter.

Foothills proposed that conventional winter pipeline construction techniques, as developed over a ten-year period, would be employed as extensively as terrain conditions would allow in areas designated by territorial authorities as non-sensitive. In areas lacking permanent roads, winter roads would be constructed for access, material movement and pipeline construction. Foothills stated that techniques and specialized equipment had been developed for processing, compacting and maintaining winter road surfaces.

In areas designated as sensitive, adaptations to conventional winter pipeline techniques would be employed. Foothills proposed to construct snow or ice roads prior to the start of pipeline construction. Foothills stated that some preparatory work for the construction of snow roads would commence on or about 10 November but actual snow road construction would not commence until 30 November.

CAGPL questioned Foothills' ability to get its snow roads in before Christmas, as a delay in completion of the snow roads would delay the start of pipeline construction, but Foothills argued that snow roads or snow pads were not required in the entire area, but only in the sensitive areas. Construction techniques for snow road development would be those already established for snow roads built in past years in the Arctic.

Foothills proposed that trenching methods would be modified to suit the soil conditions in areas of sensitive terrain and where underlying permafrost was evident. If a conventional ditching machine could not penetrate the frozen soil, or if an Arctic ditcher were not available, then Foothills proposed that drilling and blasting would be used to break up the ditch line. Excavation of blasted material would then follow with either a conventional ditcher or a backhoe. Foothills gave evidence that blasting would scatter soil beyond the right-of-way limits in some areas and in some cases mats would be required over the ditch line to prevent this. The soil would be processed to break up the large pieces prior to back-filling the ditch.

Foothills planned to use conventional construction methods for river crossings. Major river crossings would be constructed by a separate spread during the summer months. Minor river crossings would be installed during the winter seasons. Foothills did not propose installing double pipelines across major rivers but would install a tow cable alongside the river crossing as a contingency measure for pulling across a temporary or new pipe in the event of a failure during the operation of the system.

Foothills stated that all work would cease on the winter construction spreads when the wind chill temperature dropped to -35° F and winter construction on the northern spreads would not commence until late January. Discussions with pipeline contractors had led it to conclude that very little production could be expected in December and January in the Arctic due not only to the cold but also to the added adverse factor of lack of daylight. CAGPL contested this conclusion and gave evidence that some contractors had continued to work in temperatures as low as -58° F.

Foothills testified that it would test a large portion of the pipeline using a warm water test media instead of a water-methanol mix. However, a water-methanol mix would be used in areas of water scarcity. In areas of seasonal frost a standard hydrostatic test would be used. Foothills had decided to avoid the use of methanol as much as possible due to the high cost of transportation, storage, handling and disposal. Where warm water tests were used the water requirements would be 60 times greater than in a water-methanol test.

In reply to CAGPL's question as to whether Foothills had carried out a geothermal analysis on testing a 14-mile segment with warm water in permafrost of 12°F it stated that an analysis was made and the results indicated that the testing was feasible. Foothills' geothermal calculations showed that for a 10-mile section the expected thaw bulb after three days with warm water in permafrost would not exceed more than a six-inch annulus around the pipe.

CAGPL contested the feasibility of a warm water test plan because water might not be available in the large amounts required, considerable heat would be required to warm the water, and there would be a possibility of the water freezing. Foothills maintained that its decision to adopt a warm water test procedure was one of economics due to the high cost of handling, storage, shipping and disposal of the methanol and this advantage would overshadow the disadvantages of the need for larger volumes of water and added costs for heating fuel.

Foothills stated that large amounts of granular material would be required to construct access roads, stockpile sites, compressor and meter station pads, the work pad for the 50 miles of summer construction on spread one and to bed and pad the pipeline where necessary. The granular material would be taken from borrow pits near the pipeline right-of-way. The location of these borrow pits was determined from information produced by the Department of Indian Affairs and Northern Development. In some cases the borrow material would have to be hauled a distance of 20 miles.

Foothills proposed to strip and stockpile the top soil from the borrow pits. This material would be returned to the borrow pit and revegetated after the borrow pits were no longer required.

Foothills proposed to use the stockpile sites located along the Mackenzie River as camp sites for the pipeline construction crews. CAGPL queried the size of the proposed camp sites which range from seven up to 31 acres. It felt that the areas allotted were too small to accommodate both the camps and storage areas for such construction material as pipe.

Foothills indicated that compressor station and meter station construction would not be affected by lack of daylight, low temperatures or restrictions caused by sensitive terrain because all construction activities would be carried out on a granular pad and in a relatively confined and permanent location. Most of the construction activities would be protected from the weather by temporary or permanent shelters. Access to and from the station sites would be by ground support vehicles or by helicopters when weather conditions or the season prevented travel across the sensitive terrain.

Construction Logistics and Schedule

Foothills stated that Edmonton, Alberta would be the major material shipment centre except for such items as mainline pipe, valves, and larger material components for compressor stations which would come directly from other locations south of the 60th parallel. These larger components would be shipped directly to Hay River/Enterprise in the Northwest Territories by rail or by transport trucks. The bulk of the balance of the material would be transported from Edmonton to the Hay River/Enterprise staging area in the Northwest Territories by rail. Truck and air transport would be limited between Edmonton and Hay River/Enterprise due to the higher cost.
Air transport would be restricted to transportation of personnel, perishable goods and emergency medical services.

Foothills planned to ship material by rail in containers from points in Southern Canada through to Hay River/Enterprise where it would be off-loaded onto barges for shipment down the Mackenzie River to the 14 wharves and 17 stockpile sites. Truck transport from Hay River/Enterprise would also be utilized to distribute material directly to the Axe Point staging point or other stockpile sites. Material would be held at stockpile sites until the winter roads or snow roads were constructed and then the material would be distributed to sites along the right-of-way.

In assessing the logistics of the project, Foothills expected that an increased number of rail cars, barge sets and highway vehicles would be required to meet the demands of the project. Shipment along the Mackenzie River was stated to be limited to approximately four and one-half months a year and demands on the existing facilities would be high.

The five existing wharves along the Mackenzie River would be upgraded if such upgrading were acceptable to the communities. Nine new wharves would be constructed near favourable storage areas and close to the construction camp sites. Some of these wharves would be temporary floating structures which would be moved onto land for the winter season and removed completely after completion of the pipeline construction.

Foothills had commissioned Marine Pipeline Construction of Canada to assist in developing a construction schedule for completion of the pipeline construction in two consecutive winter seasons and one summer season (15 August to 31 October) for the most northerly 50-mile section.

Foothills and its consultant arrived at the following schedule for the pipeline construction which lists the spreads along the 817-mile route starting with Spread 1 in the Mackenzie Delta to Spread 8 at the 60th parallel.

Foothills Construction Schedule

Northwest Territories

Spread	Total Mileage	Production Per Day in Ft.	Miles/Season	Working Days Required Per Season
1	50	5280	50 (Summer)	77
	39	3000	39 (Winter)	85
2	98	3000	49 (Winter)	93
3	100	3000	50 (Winter)	95
4	108	3000	54 (Winter)	102
5	110	3500	55 (Winter)	90
6	110	3500	55 (Winter)	90
7	135	4200	67.5 (Winter)	94
8	67	4200	67 (Winter)	94

The construction schedule of the compressor and meter stations would be determined by the start-up date for the particular facility. Foothills planned to prefabricate a large portion of the compressor and meter station facilities in modules. Shipping and assembly of the modules would be scheduled so that the facility would be completed in phase with the remainder of the construction.

Foothills estimated that the peak manpower requirements would occur during the two winter seasons of the mainline pipeline construction when approximately 5,600 men would be employed.

With numerous contractors working simultaneously, Foothills anticipated that there would be a shortage of experienced help, and that tradesmen with limited experience would be accepted by the contractors. This would have an effect on the estimated production at the start of the construction season but would improve with time. Foothills did not expect a shortage of manpower.

Arrangements would be made with suppliers of equipment, fuel and other materials and services to schedule manufacturing so that shortages would not occur. Again, Foothills was optimistic and confident that construction resource requirements would be available as required.

Construction Resources

Foothills estimated that the peak manpower requirements of 5,600 men would be met from the Canadian labour pool. Some tradesmen might come from the United States but the number of non-Canadians permitted to work on this project would depend upon government immigration restrictions. Foothills was confident that there would be no shortage of construction labour.

Foothills assummed that no other major pipelines project would be in progress in Canada during the peak manpower demand years and sufficient workmen as well as supervisory and engineering staff would be available. There might be a shortage of welders but Foothills expected that a large percentage of pipe welding would be automatic and for such an operation a larger supply of welder operators rather than welders would be needed.

Foothills expected that no steel shortage or shortage of raw materials for manufacturing material and equipment would occur and felt the majority of the material and equipment could be produced in Canada.

Foothills testified that the following quantities of manufactured and processed materials would be required during the construction phase of the project:

Foothills Construction Materials Requirements

(Quantities in Tons)

	Year 1	Year 2	Year 3	Year 4	Year 5
Pipeline		295,163	243,820		
Camps	640	9,152			
Stations		15,900	2,800	3,400	22,500
Contractor Equip.					
Sidebooms, Dozers,					
Etc.	960	41,940			
Fuel	42,645	122,182	105,930	10,912	2,384
Materials		47,722	40,325		
Methanol		24,000			
TOTALS	44,245	556,059	392,875	14,312	24,884

GROSS TONNAGE - 1,032,375

NOTE:

1. Materials include the following:
   a. Cement and reinforcing steel
   b. Block valve and scraper assemblies
   c. Coating and wrapping materials
   d. Welding rod
   e. Seed and fertilizer

Views of the Board

In the same manner as CAGPL, Foothills is dependent upon the Mackenzie River with its short summer shipping season of four to five months and its requirement to construct all but the northernmost 50 miles during the short winter construction period of some 90 days. Therefore, it has constraints similar to those of the CAGPL project which are of concern to the Board.

The Board is concerned about the availability of sufficient granular material for the construction of 50 miles of work pad at the northern end of Foothills' proposed line. Foothills proposes a pad 60 feet wide and CAGPL has suggested that a pad width of 87 feet would be required. In any case, the Board would require further assurance as to the location and availability of the granular fill required, before it approved Foothills' present construction plan.

In addition to the above, a condition of the certificate would require the Applicant to file its construction specifications well in advance of any pipeline construction.

3.2.3.7 Operations and Maintenance

Station Operation and Maintenance

Foothills proposed that for its operations and maintenance organization, a main office would be located at Yellowknife together with a gas control centre, a major maintenance centre and a supply depot. The company head office would be at Calgary.

The northern section of the system between Richards Island and the Alberta-Northwest Territories border would consist of three districts which would have headquarters at Inuvik in the northern district, at Norman Wells in the central district and at Fort Simpson in the southern district. Each of these headquarters would have sufficient personnel, equipment and supervision to operate and maintain the pipeline within its district.

The major maintenance centre at Yellowknife would provide special equipment and expertise for maintenance work not capable of being performed through the district headquarters.

The supply depot located at the main office in Yellowknife would function as a central supply source and as a staging point for shipments to or from the southern region of the system.

Compressor Station Operation

The compressor stations would be designed to provide a fail-safe mode of operation and Foothills' intent was to operate all stations on an unmanned basis. Foothills indicated that its compressor stations would require 24-hour surveillance during the start-up phase of the station operation, but these start-up periods would probably become shorter as more experience was gained with the compressor station installation.

Foothills proposed that once the unmanned mode of operation was reached, the routine functions of starting, stopping and controlling the gas compressor units, the gas chilling equipment and the auxiliary support systems would be handled remotely by the main gas control centre. A district supervisory console located at each district headquarters would permit surveillance of the station operating conditions and would display changes implemented by the main gas control centre.

Station Maintenance

Foothills proposed that the routine maintenance of the compressor station would be performed by maintenance personnel on routine visits to the station sites. In order to avoid deterioration of equipment and unscheduled station shut-downs, maintenance programs would be developed to schedule inspection and repairs to equipment and controls at regular intervals. The maintenance personnel would inspect station alarms and controls and would correct malfunctions in the equipment to ensure maximum reliability of the compressor stations.

Pipeline Surveillance and Maintenance

The pipeline would be constructed through varying types of permafrost and sensitive terrain. Each of the districts would be responsible for inspecting and maintaining its assigned portion of the right-of-way and would apply the utmost attention to avoid disturbance to the terrain and environment. Foothills proposed that in the permafrost and sensitive terrain areas, ground travel would be restricted to emergency maintenance during the summer and heavy equipment would not be transported or employed unless absolutely essential. In the event that some maintenance were necessary to ensure integrity of the pipeline, helicopter transportation and low ground pressure vehicles would be employed to perform the temporary repairs.

Foothills proposed that the conventional type of line patrol would be by aircraft, either helicopter or small fixed-wing. The pipeline patrol program would be supplemented by ground patrol carried out in a small vehicle suitable to the terrain to be patrolled, or on foot by specially trained individuals. All patrols would be under the supervision of the district supervisor who would ensure that the frequency and method of the patrols would not be detrimental to the terrain and/or wildlife.

Foothills proposed that in the event of a major pipeline failure during the summer months, in an environmentally sensitive area such as a permafrost region or muskeg terrain, helicopter transportation would be used to bring in pipe sections, men and equipment for a temporary repair. The pipeline would be temporarily repaired with 24-inch diameter pipe to maintain the system in operation and, during the winter months, the temporary 24-inch diameter line would be replaced with permanent 42-inch diameter pipe. Foothills felt that very little loss of throughput would result with the reduced diameter temporary repair line.

Similar procedures would be followed in the event of a failure at a river crossing during a period of spring break-up when the water level was high and ice flows prevented dredging and placing a new crossing. Foothills proposed that a tow cable would be placed alongside the pipe at each of the river crossings for this purpose. A larger diameter pipe would replace the temporary crossing in the summer months when conditions were suitable for dredging.

Foothills proposed that the operations and maintenance personnel would be drawn from its parent companies in the south and from other pipeline systems. Although a staff turnover would be expected in the Arctic regions of the pipeline, Foothills was confident the turnover would not affect its ability to operate and maintain the pipeline system.

Views of the Board

The Board is satisfied that the operations and maintenance procedures proposed by Foothills would be adequate.

3.2.3.8 Cost of Facilities

Capital Cost Development

The Foothills system would include 817 miles of 42-inch O.D. mainline, a 15-mile 30-inch O.D. supply lateral to Parsons Lake gas field, a 10-mile 24-inch O.D. supply lateral to Niglintgak gas field, 17 compressor stations, 465 miles of small diameter laterals to provide gas to northern communities and the necessary ancillary facilities.

The estimated costs of the facilities were based upon the first quarter of 1976 costs and were escalated to the appropriate year of material purchase or installation. The following escalation rates were utilized to convert the 1976 dollar estimate to the year of material purchase or installation.

FOOTHILLS

ESCALATION FACTORS

(per cent)

Cost Component	Annual Inflation Rate 1977	1978	1979	1980	1981+
Line Pipe	6.0	6.5	7.0	6.5	6.0
Wages and Salaries	10.0	8.5	8.0	8.0	7.5
Non-Residential Construction Materials	6.0	6.5	6.5	6.0	6.0
Construction Machinery and Equipment	6.5	6.0	6.0	6.0	6.0
Land, Freight, Communication, Misc.	6.0	6.0	5.5	5.5	5.5
Compressors and Turbines and related equipment	6.0	6.5	6.0	6.0	6.0

Foothills informed the Board that the inflation rates selected for each of the categories shown did not reflect a demand-supply analysis for each particular year but were developed primarily from extrapolation.

In the case of line pipe, escalation factors differed considerably from those of CAGPL's, being more than 100 per cent higher in certain years.

Foothills stated that all quotations on materials were obtained from Canadian manufacturers, agencies or representatives in Canada, and all the cost estimates were stated in Canadian dollars. In estimating the costs of imported materials, Foothills assumed the continued parity between Canadian and United States dollars.

The Applicant has taken into consideration, in the development of its cost of facilities, the type of contractual arrangements that it anticipated would be necessary in order to obtain realistic tenders from pipeline contractors.

It was conceived that under such contracts, the Applicant would pay all of the contractor's costs, plus a reasonable profit. This profit might be a fixed percentage of the cost, a fixed project fee, or a fee with a built-in incentive whereby the contractor might share in the benefit of an "under-run" or be penalized by an "over-run" of estimated costs; this type of contract was commonly referred to as the "target estimate" type of contract. Under this type of contract, the "estimated target cost" was established jointly by the owner and the contractor, and this "target estimate" formed the basis of the anticipated cost of the spread, and became the basis of establishing the contractor's fee, arrived at by negotiation.

Foothills anticipated that a fixed price type of contract might be practical for the construction of the laterals to serve the northern communities with gas and for some of the most southerly spreads of the mainline.

In addition, Foothills anticipated that subsidization of contractors might be required in some form because the magnitude of the equipment and financial resources that would be required for a project of this magnitude would be such that these requirements might strain most of the pipeline contractor's resources.

Cost Summary

The escalated costs of facilities designed to carry an average of 2.4 Bcf/d by the fifth operating year were estimated to be $3,085 million which included an allowance for funds used during construction of $511.9 million.

The following is a summary of the escalated construction costs of the total facilities.

FOOTHILLS

ESCALATED COSTS OF FACILITIES

	(Millions of Dollars)
Land and Land Rights	2.8
Pipeline (817 miles, 42-inch O.D. 0.540-inch W.T., Grade 70)	1,041.4
Compressor Stations	454.7
Support Facilities	640.5
Operation and Maintenance	65.7
Meter Stations	16.0
Communications and Control	23.3
Northern Community Laterals	75.6
Pre-Permit Costs	10.5
Head Office and Pre-Operations	33.8
Engineering	92.8
Contingency	116.0
Allowance for Funds Used During Construction	511.9
TOTAL	3,085.0

Major Direct and Indirect Cost Categories

Details of the cost components shown in the summary are as follows:

(a) **Land and Land Rights**

Land costs included the purchase in fee simple of lands for permanent facilities. Land Rights included the lease of an easement for the right-of-way, the lease of lands for temporary facilities during the construction period and the associated acquisition costs.

(b) **Pipeline**

This category included the purchase of all pipe and its transportation to Edmonton, Alberta. Freight charges from Edmonton to material stockpile points were included in Support Facilities.

The following table shows the pipe requirements and the estimated costs per ton.

FOOTHILLS

PIPE REQUIREMENTS AND COSTS PER TON

Description	**Quantity** (ft.)	**Cost** ($/ton)
42-inch O.D. x 0.540-inch W.T.	4,215,605	725
30-inch O.D. x 0.386-inch W.T.	65,472	644
24-inch O.D. x 0.309-inch W.T.	57,552	671

NOTE: (Heavy wall pipe representing about 164,040 feet was omitted in the above table.)

This category also included scraper trap and by-pass assemblies at each compressor station, internal and external coating for the line pipe, concrete weights to counteract pipeline buoyancy and miscellaneous materials such as cathodic protection, signs and culverts.

The installation costs of the mainline carrier pipe were covered in this category. The pipeline installation costs were based on estimates provided by a pipeline contractor.

As discussed previously in the Geotechnical Design section, the Applicant proposed to use insulation over a distance of approximately 43 miles to control frost heave of the pipeline where the chilled gas traversed discontinous permafrost. The additional cost to mitigate frost heave was estimated to be $60 per foot or about $14 million for the entire 43 miles.

Foothills considered that a ten per cent profit including head office overhead was a reasonable return for a pipeline contractor on a no-risk contract. Although no back-up data were provided, Foothills claimed that the profit margin for contractors working on the Alyeska project was less than ten per cent on a no-risk contract.

Foothills did not plan to purchase pipe construction equipment but would rent it from the construction contractor or from a third party.

Foothills made no provision in its cost estimates for water-hauling, snow-manufacturing or snow-blowing equipment because it did not require artificial snow. According to Foothills, its construction would be starting late in the season and on the basis of past meteorological records, it assumed that sufficient snow would be available.

(c) **Compressor Stations**

These costs assumed that a station ground pad (costs included in Support Facilities) would be in place and included all remaining costs associated with a compressor station.

(d) **Support Facilities**

These costs included all site development, the off right-of-way facilities required to support construction of permanent facilities and the logistics requirements such as freight, air support, river transportation and the 60-foot wide granular work pad to construct the most northerly 50 miles of the pipeline.

The costs for the support facilities were examined in some detail during the hearing, particularly the revised method for estimating the costs of river transportation. In the original evidence, Foothills had assumed the acquisition of four barge sets at a cost of $25,041,000 but in its amended filing, Foothills assumed that the barging costs would include an annual write-off of 16 2/3 per cent as well as the operating cost paid to a barge operator.

Foothills assumed it would not pay more than the accelerated write-off of 16 2/3 per cent for two years, that is, one year in the case of two sets and another year in the case of four sets as it believed that the barges would be utilized elsewhere.

The Applicant anticipated constructing about 1250 miles of temporary roads of which about 656 miles would be snow roads. The cost of these temporary roads was estimated to about $8,000 per mile.

(e) **Operation and Maintenance**

The Operation and Maintenance facilities costs included all required off right-of-way facilities including all buildings, houses, office furniture, transportation equipment, heavy work equipment, tools and equipment.

(f) **Meter Station**

The meter station costs included permanent materials and equipment including installation costs.

(g) **Communication and Control**

These costs included the provision for use of temporary communication facilities during the construction phase and permanent communication facilities during the operating phase. These costs reflected capitalized lease charges and construction contributions.
Also included in this category were the costs associated with the provision of a permanent supervisory control system.

(h) **Gas to Communities**

These costs included all costs associated with the construction of lateral connections from the mainline transmission system to provide gas to eleven communities.

(i) **Pre-Permit Costs**

Foothills included $10.5 million as a pre-permit cost of which $7.5 million would be spent between 1 May 1976 and 31 December 1977. Cost items such as further studies on soils, slope stability and the environment were included in the $7.5 million.

(j) **Head Office and Pre-Operation**

These costs would be associated with the pre-permit stage prior to the pipeline system commencing operation in 1982. These costs included the project management function by the Applicant and on-site training of future operating and maintenance personnel during the construction phase.

(k) **Engineering and Overhead**

A provision of four per cent of the direct costs was made for the engineering and overhead, and included all the engineering design, procurement and inspection of the system during the construction phase.

(l) **Contingency**

An allowance of five per cent of direct costs was used as a contingency which would provide for potential errors or omissions in the estimate as the estimates were based on preliminary design.

Views of the Board

In order to determine the geotechnical impact of its project, Foothills relied mainly on information and materials obtained by Trunk Line through its participation in the various Arctic gas study groups, on information gathered from field reconnaissance and limited drilling program along the Applicant's route and on information gathered from stereo air-photo studies, including terrain typing. Time constraints did not permit Foothills to conduct detailed field studies, laboratory testing programs and theoretical analysis.

In view of the limited detailed studies, the Board is of the opinion that the lack of data affected the geotechnical design of the pipeline. The Geotechnical section of the report discusses the theory and design of frost heave control.

As CAGPL made a complete study of the frost heave and thaw settlement problem, the Board postulates that 450 to 500 miles of similar frost heave and thaw settlement control to that proposed by CAGPL on its system could equally apply over Foothills' 817 miles of pipeline. In addition, the Board has made a preliminary estimate of the costs to account for the 500 miles or so of frost heave and thaw settlement controls, and assumed that the costs would be equivalent to those used by CAGPL for the segment between Tununuk Junction and the 60th parallel. For the purpose of this preliminary study, the Board gave no credit to the materials and installation costs used by Foothills to cover frost heave control because it considered them minimal with respect to the overall redesign changes.

The Board's study indicated that an additional cost of $240 million (escalated) would need to be added to the Applicant's costs of facilties to properly account for mitigative measures for frost heave and thaw settlement. The average installation cost, including such additional measures would be about $4.1

million per mile, an increase of about eight per cent over the Applicant's original estimated cost per mile.

The total escalated cost of the facilities estimated by Foothills in terms of materials, installation and other related facilities can be summarized as follows:

	Costs (Millions of Dollars)
Materials	1,318
Installation	966
Other Related Costs	801
TOTAL	3,085

The total cost estimated by the Board, including the additional frost heave and thaw settlement control of $240 million, is $3,325 million.

The Board is of the opinion that both the materials and construction costs estimates are reasonable, provided an additional allowance up to $240 million is made, the construction schedule is adhered to, and the assumed inflation factor for labour is correct.

Foothills has the potential for incurring cost overruns in a number of areas related to:

1) performance of the ditcher in permafrost;
2) snow road construction;
3) limited shipping season of four to five months;
4) limited working period of 90 days; and
5) harsh climatic conditions.

Although the Applicant has addressed itself to all these problems to the best of its ability, nonetheless, these uncertainties could affect the final cost of the pipeline. These effects have been discussed in the Risk of Cost Overrun section of the report.

3.2.4 WESTCOAST

3.2.4.1 Facilities Design and Capacity

Facilities Description

Westcoast applied to the Board for only those facilities required for the first year of gas flow in 1982. This was due to the fact that Westcoast, as an operating company with other sources of supply, felt it was very difficult to predict exactly what facilities would be required in future years. However, because there was no projected increase in the volumes delivered by Foothills to Westcoast (475 MMcf/d average and 500 MMcf/d peak day), the facilities requirements for these volumes would remain the same for the first five years of operation.

The following facilities were applied for:

(a) Territories Mainline Extension:

This extension would be constructed in 1982 and would consist of 141 miles of 30-inch diameter pipe, starting at the terminus of the Foothills system (approximately seven miles north of the 60th parallel) and terminating at the Westcoast gas-treating plant located near Fort Nelson, British Columbia.

(b) Additions to Existing Facilities:

The following additions would be made to the existing Fort Nelson and Fort St. John mainlines:

1981 Additions:

approximately 50.3 miles of looping with 36-inch O.D. pipe at various locations on the Fort Nelson mainline.

1982 Additions:

approximately 39.3 miles of looping with 36-inch O.D. pipe at various locations on the existing Fort Nelson mainline;

approximately 111.5 miles of looping with 36-inch O.D. pipe on the existing Fort St. John mainline;

compressor facilities of 20,000 horsepower at the existing Compressor Stations 4A and 4B; and

compressor impeller modifications at existing compressor stations, as well as additional communication and metering facilities.

Systems Configuration

Pipe Size Selection

(a) Loop Lines

Westcoast selected 36-inch O.D. x 0.390-inch W.T., Grade 60 pipe for its loop lines, mainly to have the same diameter pipe as its existing loop lines along the Fort St. John and Fort Nelson mainlines.

(b) Territories Mainline Extension

Before determining the optimum line size to transport the Mackenzie Delta gas, the Applicant considered several routes for this mainline extension.

The estimated costs for the alternative routes varied from $86,358,000 to $158,027,000. The route selected by Westcoast had the shortest distance, the lowest capital cost, the lowest cost of service and, in Westcoast's opinion, the least environmental impact.

Once the route of the connecting line was selected, the Applicant made optimum design studies of this line. For that purpose, it carried out cost of service studies for 24, 26, 30 and 36-inch O.D. pipe sizes at a flow of 500 MMcf/d and the results are tabulated below.

WESTCOAST

TERRITORIES MAINLINE EXTENSION

ECONOMIC EVALUATION OF VARIOUS DIAMETER PIPELINES

	Diameter in Inches			
	24	26	30	36
Capital Investment ($ millions)	102.6	114.5	128.6	156.9
Average 10-year Cost of Service (¢/Mcf)	12.04	11.60	12.14	14.79

Even though the 26-inch diameter line offered the lowest cost of service per Mcf, the Applicant selected the 30-inch O.D. x 0.375-inch W.T. Grade 70 pipe for reasons of reliability and future capacity. It would not require the installation of a compressor station, thus avoiding the potential for a flow reduction during a compressor unit outage. In addition, the larger line size could transport more gas in the future if such need developed.

Westcoast planned to pressure test this line with air to a pressure level of 90 per cent of the specified minimum yield strength (SMYS) of the pipe in order to operate it at 72 per cent of SMYS i.e., 1250 psig.

It should be noted that if the line pressure in the Foothills system were to increase to 1440 psig, the Territories Mainline Extension would not be able to operate at this higher pressure and a pressure limiting station would be required at the point of interconnection.

System Reliability

For the 1982-83 operating year, Westcoast's system would be capable of transporting 1,688 MMcf/d or 112 per cent of the system's average day requirements. For that operating year, a reliability study provided by the Applicant indicated that, with the loss of the most critical compressor unit along the entire system, there would be no reduction in the Westcoast peak day capability.

Views of the Board

Territories Mainline Extension

Route:

The Applicant satisfied the Board that its chosen route of 141 miles of 30-inch diameter pipe starting at the terminus of the Foothills system and terminating at the Westcoast gas treating plant near Fort Nelson is the shortest connection to its system with the least capital cost, lowest cost of service and least environmental impact as compared to a number of other alternatives.

Design:

The Board agrees with the Applicant's choice of 30-inch O.D. x 0.375-inch W.T. Grade 70 pipe, provided an average flow of 475 MMcf/d is achieved by the fifth operating year.

Westcoast demonstrated, by means of cost of service comparisons with a number of other pipeline diameters operating at 1250 psig and for a flow of 475 MMcf/d, that a 26-inch O.D. pipe had a marginally lower cost of service than the 30-inch diameter pipe. The Board is satisfied, however, with the Applicant's explanation that the 30-inch diameter pipe chosen would be preferable in terms of reliability and future capacity and would not require compression for the proposed volumes.

Existing Westcoast Facilities

The Board is satisfied with Westcoast's application to incrementally expand its existing facilities by a combination of 36-inch O.D. loop and horsepower additions, being consistent with its present design.

Alternate Plan to Connect with CAGPL Pipeline

Although Westcoast is a member of the Foothills and Foothills (Yukon) groups, it stated that its purpose in constructing the facilities applied for would be to receive certain volumes of Mackenzie Delta gas from either Foothills or CAGPL at approximately the same delivery point.

At the Board's request, Westcoast made a submission with respect to a possible connection to the CAGPL line comparing a 24-inch O.D. pipeline, with a maximum operating pressure of 1680 psig similar to CAGPL's operating pressure, to a 30-inch diameter pipe, with a maximum operating pressure of 1250 psig similar to Westcoast's existing application, neither line requiring compression for the proposed 500 MMcf/d anticipated flow. The Board is satisfied that the 24-inch O.D. pipe has the least capital cost and least cost of service, and would be prepared to certificate such a line if CAGPL were approved.

The facilities on Westcoast's mainline would be the same as for the Foothills project, as the volumes of gas to be transported are the same.

Westcoast's application is based on fifth year volumes of 500 MMcf/d. If the volumes available from the Mackenzie Delta were reduced from the 2.4 Bcf/d for which Foothills had designed to more realistic volumes of between 800 and 1,200 MMcf/d, Westcoast's throughput would likely be similarly reduced. In that event, the design of the Westcoast facilities would require reconsideration.

3.2.4.2 Geotechnical and Geothermal Design

Frost Heave

Westcoast applied for a certificate with respect to an extension of its mainline northward by 141 miles to connect with the proposed Foothills line at a point approximately seven miles north of the British Columbia-Northwest Territories border. All of this extension, described in the Introduction section of this chapter for the Foothills Group Project and in the Westcoast Facilities Design and Capacity section, would be in the widespread discontinuous permafrost zone. Westcoast indicated that as gas moved through this extension, it would approach ground temperature, which in the Fort Nelson area is 30°F in January.

Westcoast was, however, of the opinion that, based on its experience in operating under similar conditions in the immediate area, additional freezing of the ground, and thus potential frost heaving, would not occur.

In a revised filing submitted in response to the Board's request for further evidence regarding potential frost heave problems, Westcoast calculated that gas flowing temperatures would not be more than three Fahrenheit degrees below freezing and that this would occur only in winter months. It was expected that summer thaw-back would prevent any cumulative freezing and thus any frost heave problem.

Westcoast, in addition to its application to construct the Territories Mainline Extension as part of the Foothills Project, also filed evidence regarding its possible frost heave problem should it receive gas from CAGPL.

The indicated winter flowing temperatures for this situation would be considerably lower than for connection to the Foothills system due to the lower gas receipt temperature, higher pressures and the resulting higher pressure drop. In the fifth operating year and beyond, on an average winter day the gas would be flowing at temperatures below freezing from milepost 50 to milepost 141, and would reach a temperature of 6 Fahrenheit degrees below freezing.

Westcoast was confident that summer melt-back, when the gas flowing temperatures would be approximately 15 Fahrenheit degrees above freezing, would prevent any year-round freezing and thus eliminate frost heave. In the earlier operating years when gas receipt temperatures would be considerably lower, there would be a gas heater installed at the receipt point to raise the flowing temperature to a point where frost heave would not be a design consideration.

Westcoast indicated that no insulation was planned for this line.

Thaw Settlement

Westcoast testified that, based on a search of seismic bore hole logs and other information available to it, it did not believe that it would experience a thaw settlement problem. Westcoast referred to its past experience in building pipelines in the Northwest Territories as support for its position on the matter.

Views of the Board

The Board agrees with the Applicant that frost heave would not be a design consideration should Westcoast connect to the Foothills system.

With respect to the case where Westcoast would connect to the CAGPL system, the Board would require Westcoast to submit data justifying the assumptions on ground temperatures and to submit flow studies establishing the efficacy of the proposed gas heater method of avoiding frost heave problems with the higher pressure drop anticipated with the CAGPL connection.

In view of the fact that the proposed Territories Mainline Extension extends onto the Alberta Plateau and in view of the evidence submitted by CAGPL that thaw settlements of up to 18 feet could be anticipated in this region, the Board has concluded that there is considerable doubt as to the correctness of Westcoast's assessment of thaw settlement. As a condition of any certificate which it might issue, the Board would require Westcoast to give further consideration to potential thaw settlement problems in relation to final design.

3.2.4.3 Stress Analysis and Materials Engineering

After performing a comparative study, Westcoast decided on 30-inch O.D., 0.375-inch wall thickness Grade 70 line pipe for the Territories Mainline Extension, whereas 36-inch O.D., 0.390-inch wall thickness Grade 60 line pipe would be used for looping of the existing mainline. The Territories Mainline Extension pipeline would operate at a maximum operating pressure of 1250 psig, while the maximum operating pressure of the mainline looping would be 936 psig. These maximum operating pressures corresponded to a hoop stress equivalent to 72 per cent of SMYS for both lines.

Except for the calculation of hoop stress, there was no detailed stress analysis in the Westcoast application.

Westcoast chose fracture arrest as the fracture control criterion and stated that "the notch toughness requirements specified for the Territories Mainline Extension and the mainline expansion meet or exceed those values of toughness for the arrest of a pipeline failure". Westcoast specified a minimum CVT fracture toughness value of 48 ft-lbs for any specimen at 25°F. An average fracture toughness value was not specified.

Westcoast believed that the values chosen for the material fracture toughness were based upon the best available information for fracture arrest, but did not quote the theoretical fracture toughness value required for ductile fracture self-arrest. In addition to the CVT fracture toughness, Westcoast adopted a minimum of 60 per cent and an average of 85 per cent shear area of the fracture surface in the standard drop weight tear test specimen as a design measure against brittle fracture propagation.

Westcoast adopted its existing line pipe Specification No. 102, Revision 33; Specification No. 202, Revision 5 for welded flanges, fittings, and scraper barrels; and Specification No. 301, Revision 8 for valves. These Specifications cover the requirements for the manufacture, testing and inspection of line pipe and pipeline components.

Views of the Board

If a certificate were granted, it would be conditioned by the Board to require Westcoast to undertake and submit, for Board approval, a complete stress analysis for the site-specific conditions.

It is the opinion of the Board that pipe of the dimensions and properties specified by Westcoast could be manufactured as a standard product in a number of Canadian mills.

3.2.4.4 Right-of-way

The width of the permanent right-of-way planned to be acquired was stated to be 60 feet, although additional working room of 20 to 25 feet during construction of the pipeline might be required.

Westcoast stated that it had applied for a Crown grant of right-of-way to the Lands Branch, Department of Lands, Forests and Water Resources of the Province of British Columbia for new right-of-way, and that a similar application, also to include additional line rights in existing rights-of-way, would be made to the Department of Indian Affairs and Northern Development.

Westcoast confirmed its awareness of the requirements in respect to the crossings of navigable waters, as well as the provisions of Section 74 of the NEB Act which deals with the taking of lands without the consent of the owner. The majority of Westcoast's existing easements confer the right to construct multiple lines within its existing right-of-way.

Views of the Board

Westcoast, in the past, has complied with requirements and provided proof of its understanding of and cooperation with landowner problems in all right-of-way matters. The Board would, nevertheless, require that Westcoast comply with all of the Board's directions regarding the acquisition of rights-of-way and other lands, including but not necessarily limited to specific directions as to the rights of and notice to all potentially affected property owners to ensure an orderly land an equitable acquisition and settlement program.

3.2.4.5 Communications

To provide the necessary communications facilities for its proposed pipeline additions, Westcoast intended to make use of its existing extensive telecommunications system composed of Company-owned and leased facilities. The Applicant did not propose any major additions or modifications to these facilities.

Westcoast indicated that its present communications system included the following:

(a) four leased full-time party line or selective private telephone channels interconnecting all Company compressor stations, offices, warehouses and other fixed installations throughout the entire operating area;

(b) a two-way radio system, owned by Westcoast, providing mobile radio coverage along the pipeline rights-of-way and contiguous highways throughout the existing pipeline system; and

(c) remote control/telemetry/data acquisition facilities located in all compressor stations processing plants and major sales metering stations, operated under the control of a computerized master station in the gas control centre in Vancouver.

This control/telemetry/data acquisition system would provide the gas control centre with current information regarding volumes into and out of the pipeline system, pressure and line pack conditions, station and unit operating parameters, alarms and status, etc. The control system would also provide for remote starting and stopping of compressor units and stations and for the adjustment of discharge pressure set points, thus allowing the remote, unattended operation of the pipeline.

Views of the Board

The Board accepts Westcoast's proposal to make use of its existing communications system, and agrees that this system would be capable of providing the high level of availability and reliability required for the safe, efficient operation of the pipeline.

3.2.4.6 Construction

Westcoast proposed that the 141-mile Territories Mainline Extension would be constructed during the winters of 1980/81 and 1981/82.

The construction of each section was scheduled to begin in January and be completed by about mid-April.

The construction of three southern loops on the Fort Nelson mainline was proposed for the summer of 1981, and the two northern loops on the Fort Nelson mainline, along with some Fort St. John mainline looping, would be constructed in 1982.

Views of the Board

The Board views the Westcoast project as a conventional type of pipeline project to be built in an area where the Applicant has had considerable experience in the construction of pipelines and the associated compression facilities.

If a certificate were granted it would be conditioned to require the Applicant to file its construction specifications in advance of pipeline construction.

3.2.4.7 Operations and maintenance

The Applicant felt that the additional facilities could be maintained with very little change to its existing operations and maintenance program.

3.2.4.8 Cost of Facilities

Cost Estimating Procedure

In preparing its estimates, Westcoast had drawn on its experience gained over a period of years in the design, construction and operation of pipelines in similar terrain in British Columbia, Yukon and the Northwest Territories. Equipment suppliers and contractors were also consulted in the preparation of the cost estimates.

During cross-examination, Westcoast stated that the pipe prices used in the cost estimates were not pipe quotes but were obtained from a study of standard price listings.

Westcoast proposed that pipe material would be purchased in Canada and that Canadian engineering and construction personnel would be used. It was estimated that the Canadian content for the project would be approximately 96 per cent.

Cost Summary

Westcoast estimated the total cost of the facilities that would be required to transport the Mackenzie Delta gas in late 1982 would be $388.2 million. The following is a summary of these costs based on first quarter 1976 costs escalated to the year of construction:

WESTCOAST

ESCALATED COST OF FACILITIES

	(Millions of Dollars)
Land	2.938
Pipeline Looping	174.278
30-Inch Territories Mainline Extension	130.631
Compressor Station Additions	14.050
Additional Meter Runs	0.082
Fort St. John Mainline Impeller	1.986
Engineering	16.165
Contingencies	19.124
Allowance for Funds Used During Construction	28.931
TOTAL	388.185

The cost estimate for the proposed project can be summarized as follows in respect to materials, labour and other related costs:

WESTCOAST

SUMMARY OF MATERIALS, INSTALLATION AND OTHER RELATED COSTS

	Costs (Millions of Dollars)
Materials	154.3
Labour	167.7
Other Related Costs	66.2
Total Escalated Costs	388.2

Of the materials costs, about $140 million is for line pipe, including taxes, coating and freight charges, and about $12 million for two compressor units.

Installation costs were developed assuming a shared risk contract with provision for an overhead of five per cent and profit allowance of ten per cent.

Westcoast had made no provision in its capital cost estimate for communication facilities between Foothills' last Compressor Station CS-17 and Fort Nelson, British Columbia, but advised that such costs would be covered by the contingency item of the cost estimates.

As pointed out in the Design section of the report, before determining the optimum line size to transport the Mackenzie Delta gas, the Applicant considered several routes for the mainline extension. The estimated costs for the alternative routes varied from $86.4 to $158 million. The route selected by Westcoast had the shortest distance, the lowest capital cost and lowest cost of service.

Alternate Plan to Connect with CAGPL Pipeline

Although Westcoast is a participant in the Foothills Project, at the Board's request it submitted a description of those facilities and capital costs required in the event that the Westcoast system were connected to the CAGPL pipeline north of the Alberta-Northwest Territories border.

Westcoast presented two alternatives for the 141 miles of connecting line, one based upon a 30-inch O.D. pipeline designed to operate at a maximum operating pressure 1,250 psig (identical to that proposed to connect with the Foothills system) and the other based upon a 24-inch O.D. pipeline designed to operate at the same line pressure as CAGPL's proposed maximum operating pressure of 1,680 psig.

Westcoast estimated that the cost of the 30-inch O.D. pipeline would be $164.5 million and the 24-inch O.D. pipeline would be $131.4 million. (These cost estimates do not include a cost estalation for the one-year delay in the CAGPL project.)

Views of the Board

The Board agrees with Westcoast's estimated costs both for the mainline extension in northeastern British Columbia and Northwest Territories and for the loop lines along its entire system from northern to southern British Columbia. In coming to this conclusion, the Board relies on Westcoast's extensive experience in constructing and operating pipelines in difficult terrains varying from highly mountainous to extremely boggy. The Board is confident that this experience and Westcoast's cost records have been fully utilized in the preparation of the estimates.

Westcoast made cost estimates of various route alternatives before selecting its route for connecting its Fort Nelson mainline to the Foothills mainline in the Yukon Territories. The Board agrees with the cost parameters and the results of the study.

The Board is of the opinion that the estimate of material costs of the $154 million is realistic if the project adheres to the construction schedule and the assumed composite escalation factor of eight per cent is correct. The Board also is of the opinion that the construction cost estimates are reasonable provided the construction schedule is adhered to and the assumed inflation factor of eight per cent is correct.

3.2.5 TRUNK LINE (CANADA)

3.2.5.1 Facilities Design and Capacity

Facilities Location

The facilities required to transport the design volume from the Trunk Line (Canada) receipt point at the southern terminus of the Foothills system to the northern terminus of Trunk Line near Zama Lake in Northern Alberta would consist of 81 miles of 42-inch O.D. pipeline.

Projected Gas Volumes

The gas volumes proposed to be transported by the Applicant are as follows:

TRUNK LINE (CANADA)

Operating Year (1 Nov. to 31 Oct.)	Average Flow Rate (MMcf/d)
1982-83	319
1983-84	705
1984-85	1084
1985-86	1457
1986-87	1827

Pipeline Size Selection

Trunk Line (Canada) completed optimization studies of various pipe sizes, grades and operating pressures and selected 42-inch O.D. x 0.469-inch W.T., Grade 70 pipe operating at 1250 psig, because it showed the lowest cost of service for the fifth year gas volumes to be received from Foothills.

In carrying out comparative economic studies, the following pipe and pressure alternatives were also considered:

(a) 36-inch O.D. x 0.540-inch W.T., Grade 70 pipe and a maximum operating pressure (MOP) of 1680 psig;

(b) 42-inch O.D. x 0.540-inch W.T., Grade 70 pipe and 1440 psig MOP; and

(c) 48-inch O.D. x 0.406-inch W.T., Grade 70 pipe and 911 psig MOP.

Each of these alternatives was considered to give a less favourable result than the design selected.

Station Design

For the optimum design, i.e. a 42-inch O.D. x 0.469-inch W.T., Grade 70 pipe operating at a maximum operating pressure of 1250 psig, and a minimum temperature of 25° F, no compression facilities were required.

Use of Trunk Line Facilities and Future Expansion of Trunk Line (Canada)

As outlined in the description of the Foothills Group Project in the Introduction section of this chapter, the facilities required by Trunk Line (Canada) to transport Mackenzie Delta gas volumes were covered under Schedules A, B, C, E and AA facilities.

With respect to Schedule A facilities, consisting of additions required to be made to the existing Trunk Line facilities in order to transport first year northern gas volumes, application has not as yet been made for these facilities because Trunk Line is an operating company with other sources of supply and thus it felt it was difficult to predict at this time exactly what additional facilities would be required.

With regard to Schedule B facilities, consisting of additions to the existing Trunk Line system that would be required for full flow of northern gas, application has not as yet been made for these facilities.

In regard to Schedule C facilities, consisting merely of leasing spare capacity in Trunk Line's existing facilities in order to transport northern gas volumes, no application was made to the Board.

The Schedule E facilities, consisting of a new 81-mile pipeline to be owned, constructed and operated by Trunk Line (Canada), are described in detail in this section of the report and are the subject of the Company's certificate application.

Schedule AA facilities would consist of existing Trunk Line facilities leased to Trunk Line (Canada) if required to complete a continuous 42-inch pipeline across Alberta.

It was proposed that through a combination of the above facilities, a continuous 42-inch pipeline across Alberta operated by Trunk Line (Canada) would exist by 1986/87 assuming 1982 first flow of northern gas.

To the best of its knowledge, Trunk Line (Canada) estimated that the facilities under Schedules A and B would consist of the addition, as required, of approximately 880 miles of mainline, compression totalling approximately 309,000 horsepower and other related facilities to the existing Trunk Line system.

The mainline additions would be constructed of 42-inch O.D. pipe of wall thicknesses varying between 0.375 and 0.469 inches and would be operated at pressures varying between 755 and 1250 psig to match those of the existing system. An exception to this would be the section from Zama Lake to Gold Creek Junction, some 300 miles in length, which would be isolated from the existing adjacent facilities and operated at 1250 psig by the second year of northern gas flow.

Construction of these additional required facilities would commence in the winter of 1980/81 and would be completed by the summer of 1986.

Views of the Board

The Board agrees with the Applicant's choice of 42-inch O.D. x 0.469-inch W.T., Grade 70 pipe with a maximum operating pressure of 1250 psig for fifth year operating volumes of 1,827 MMcf/d for the 81 miles of pipeline which would connect the Foothills pipeline to Trunk Line facilities near Zama Lake, Alberta.

The Applicant satisfied the Board that this pipe selection, when compared to other pipe diameters and pressures, offered the lowest cost of service for the projected fifth year volumes and required no compression facilities. However, the Board believes that the pipeline would be over-designed for the more realistic volumes of 800 to 1,200 MMcf/d from the Delta, and the design would thus need reconsideration.

Because no formal application was made to construct the necessary incremental pipeline facilities from Zama Lake to Empress, the Board is not in a position to comment upon the adequacy of capacity.

The Board's views concerning the proposed leasing of Capacity from Trunk Line are given in section 4.2.3 of the report.

3.2.5.2 Geotechnical and Geothermal Design

Trunk Line (Canada)'s proposed pipeline, extending some 81 miles from Zama Lake to the terminus of the Foothills pipeline seven miles north of the Alberta-Northwest Territories border, would be located in the discontinuous permafrost zone. Since the pipeline would traverse some frozen ground and would be operated at above freezing temperatures, there exists a potential for thaw settlement and buoyancy problems along the proposed route. Of particular concern is a 15-mile segment where the line would cross the Alberta Plateau.

The Applicant stated that the terrain traversed by the pipeline was generally poorly drained and that where thawing of the permafrost occurred, buoyancy control would, in many cases, be more of a concern than thaw settlement. However, Trunk Line (Canada) indicated that areas of deep peat deposits (up to 30 feet in depth) had been encountered during the drilling program and that these areas were of significant concern with respect to potential thaw settlement. The Applicant stated that it would not be possible to define all of the areas where thaw settlement would be a concern until the drilling program for final design was complete; areas of deep peat deposits would be more fully identified during the extensive geotechnical survey to be carried out in conjunction with the clearing operation.

With respect to construction procedures, the Applicant stated that the right-of-way clearing in permafrost areas would be carried out two years in advance of pipeline construction. This would allow the observation of trends in settlement, ponding and changes in drainage patterns.

In areas where surface peat deposits were present, the trench would be excavated to as deep a level as possible with conventional ditching equipment in order to leave the pipe resting on firm soil beneath the peat. A witness for Trunk Line (Canada) suggested that this procedure could be used for peat deposit depths of up to 20 feet.

In areas where deeper peat deposits were identified, the Applicant proposed to use screw anchors designed to restrain both downward motion due to settlement and upward motion due to buoyancy. Trunk Line (Canada) stated that by not using concrete weights to control buoyancy it would reduce the potential for settlement in those areas where settlement rather than buoyancy was a concern.

It would be necessary for the screw anchors to be based in firm soil. The Applicant indicated that screw anchors were normally driven into the ground, but, in areas of deep peat deposits, holes would be drilled to a level below the peat where the soil would be able to hold the screw anchor in place.

With respect to other potential problems of a geotechnical or geothermal nature, the Applicant proposed conventional methods of buoyancy control, such as continuous wire-reinforced concrete coating, concrete weights, screw anchors and increased pipe burial depth, these to be used in areas where the water table would be above the level of the pipeline.

It was indicated by Trunk Line (Canada) that neither seismic activity nor slope stability was considered to be of concern along the proposed pipeline route.

Views of the Board

With regard to the potential for thaw settlement problems along the proposed route, it is clear that Trunk Line (Canada) would need to carry out considerable additional investigation. In the event that a certificate were issued, the Board would attach a condition thereto requiring additional work to be done in association with the finalizing of designs for mitigating the effects of thaw settlement.

The Board is satisfied that, given the general nature of the terrain along the route, no insurmountable difficulties of a geotechnical nature would be encountered.

3.2.5.3 Stress Analysis and Materials Engineering

Stress Analysis

According to Trunk Line (Canada), some studies had been done on pipe stress analysis, and detailed studies would be completed in the final design after it had had an opportunity to investigate possible permafrost degradation.

Materials Engineering

Trunk Line (Canada) stated that failure of gas pipelines could best be prevented by specifying the maximum toughness which would be effective in inhibiting fracture initiation. Calculation of the criteria was based on the application of the Battelle hypothesis. According to this hypothesis, the criterion selected, 40 ft-lbs Charpy V-notch absorbed energy, corresponded to a critical through-wall flaw size of some five inches.

Trunk Line (Canada) adopted the Drop Weight Tear Test requirement of CSA Z245.2 for prevention of propagating brittle fracture.

Trunk Line (Canada) recognized the possibility of a propagating ductile fracture occurring but did not utilize the Battelle or AISI hypotheses to specify a fracture arrest criterion. It was of the opinion that such a criterion was not required, based on a number of considerations such as rarity of the actual occurrence of such fractures, the fact that the mean toughness of the pipe would probably be significantly higher than the minimum specified, and that factors other than material toughness could also cause fracture arrest.

Trunk Line (Canada) did not plan to use crack arrestors as a method of controlling long propagating fractures. It claimed that such devices might do more harm than good since they increased the risk of fracture initiation.

Trunk Line (Canada) stated that it specified only the minimum value of Charpy absorbed energy (40 ft-lbs), which was 10 ft-lbs lower than the minimum absorbed Charpy energy specified by Foothills, and did not specify the average Charpy absorbed energy value. It concluded that it would obtain line pipe with an average Charpy absorbed energy value similar to that specified by Foothills (80 ft-lbs). In answering a question in respect to the differences in operating pressure levels between Trunk Line (Canada) and Foothills, Trunk Line (Canada) agreed that its maximum operating pressure would be 80 per cent of the specified minimum yield strength (SMYS) of the pipe, whereas Foothills proposed a maximum operating pressure of 69 per cent of SMYS. Trunk Line (Canada) pointed out that Foothills would be operating under permafrost conditions and added that Foothills' concern about fracture propagation was to provide a more positive assurance in remote areas.

Views of the Board

In view of the many uncertainties and limitations in the understanding of fracture initiation and propagation, the Board agrees with Trunk Line (Canada) that the most practical approach is to specify the highest toughness that is commercially available for line pipe. The Board views with some concern the Trunk Line (Canada) withdrawal from this philosophy in specifying only 40 ft-lbs minimum CV as against the 50 ft-lbs minimum, 80 ft-lbs mean, which Trunk Line (Canada) agrees is, in fact, commercially available from Canadian producers. If a certificate were issued, it would be conditioned to require the use of pipe having a higher specified toughness requirement than that now proposed by the Applicant.

3.2.5.4 Right-of-way

Trunk Line (Canada) indicated that it proposed to acquire a 60 foot wide permanent right-of-way to accommodate the proposed pipeline, 81 miles in length, plus an additional 60 foot wide temporary working space for the construction period. Lands would not be required for compression or metering facilities. It was stated that the proposed pipeline right-of-way would be generally located in vacant Crown lands, but no contacts had as yet been made with the appropriate authorities or owners. Trunk Line (Canada) undertook to request approvals from the appropriate authorities for the crossing of navigable waters, railways and utilities in due course.

Views of the Board

Trunk Line (Canada) indicated an appreciation of possible right-of-way problems which could arise from pipeline construction in the area of negotiation and acquisition of lands, as well as the need to obtain further regulatory approvals.

The Board would require that Trunk Line (Canada) comply with all of the Board's directions regarding the acquisition of rights-of-way, including but not necessarily limited to specific directions as to the rights of and notice to all potentially affected property owners to ensure an orderly land acquisition and an equitable settlement program.

3.2.5.5 Communications

Trunk Line (Canada) proposed to make use of the existing Trunk Line private line communications system. The Applicant stated that this system consisted of:

(a) voice communications interconnecting the Company head office, district offices, gas control centre, compressor and meter stations and Company vehicles through mobile radio and base station facilities; and

(b) supervisory system communications connecting all compressor and major meter stations to the gas control centre in Calgary.

All operating data related to the proposed pipeline facilities would be transmitted by means of the remote supervisory system to the gas control centre in Calgary, which would be capable of adjusting operating parameters as required, thus making unattended operation possible.

Views of the Board

The Board accepts Trunk Line (Canada)'s proposal to make use of the existing Trunk Line communications system, thus avoiding the unnecessary duplication of facilities. The Board agrees that this system would be capable of providing the high level of availability and reliability required for the safe, efficient operation of the pipeline.

3.2.5.6 Construction

The pipeline has been scheduled for construction during the winter of 1981/82 to take advantage of frozen ground conditions and to minimize disruption of vegetation.

Trunk Line (Canada)'s construction program was based on the following main assumptions:

(a) existing road and railway facilities would be utilized for the transportation requirements of the project;

(b) the construction schedule was based on permits and approvals being received by 1 July 1979;

(c) Trunk Line, under the supervision of Trunk Line (Canada) would maintain close control over the project at all times;

(d) procurement and supply of major materials would be done under the direction of Trunk Line on behalf of and under the control of the Applicant;

(e) the warm water method would be utilized for hydrostatic testing the pipeline during the winter to a pressure corresponding to the specified minimum yield strength

(SMYS) (the contemplated operating pressure of 1250 psig would correspond to 80 per cent of the SMYS); and

(f) the construction schedule assumed a productivity rate of 6,500 feet of pipeline per working day.

Trunk Line (Canada) proposed to control pipeline buoyancy by using screw anchors. CAGPL challenged the use of these devices in deep permafrost unless they were driven through the permafrost into stable soil. Trunk Line (Canada) did not foresee any problem if long stem devices were used but admitted that if any difficulty arose during construction saddle weights could be used as alternative means to control pipeline buoyancy.

Views of the Board

The Board views the Trunk Line (Canada) project as a conventional type of pipeline to be built in an area where the Applicant has had considerable experience in the construction of pipelines and the associated compression facilities.

If a certificate were granted, it would be conditioned to require the Applicant to file its construction specifications in advance of pipeline construction.

3.2.5.7 Operations and Maintenance

Because of the proximity of the Applicant's proposed pipeline to the existing operating system of Trunk Line, Trunk Line (Canada) proposed that its pipeline be operated on its behalf by Trunk Line in order to avoid the unnecessary duplication of facilities and personnel.

3.2.5.8 Cost of Facilities

Cost Summary

The costs of the facilities were estimated to be approximately $94,800,000 (1976 dollars escalated to the year of expenditure, i.e., between 1979 and 1982).

The following table shows the details of the escalated costs of the proposed facilities:

TRUNK LINE (CANADA)

COSTS OF FACILITIES

	(Millions of Dollars)
Land	0.2
Pipeline	67.1
Support Facilities	7.7
Pre-Permit Costs	1.5
Engineering Costs	3.0
Contingency	3.8
Interest During Construction	11.5
TOTAL	94.8

Cost Estimating Procedure

In preparing the preliminary estimate, quantities for the proposed facilities were based upon right-of-way alignment sheets. Material costs were prepared on a first quarter of 1976 basis based on quotations from manufacturers or on actual purchases of similar material in 1976.

Loram International Ltd., a consultant to Trunk Line (Canada), developed a typical spread for installation of 42-inch O.D. x 0.469-inch W.T. pipe under winter conditions.

The costs were developed assuming a shared risk contract and were on a first quarter 1976 basis.

Equipment costs were based on the assumption that new equipment would be supplied by the contractor. The contractor would be allowed equipment rental at the rate of five per cent per month on the capital cost of heavy equipment and eight per cent per month on the balance of the equipment.

To cover the potential errors or omissions in the estimate the Applicant included contingency costs which represented five per cent of the direct costs.

Cost of Materials

Line Pipe Cost

During cross examination, CAGPL asked for comments on various estimates of the cost per ton for 42-inch O.D. pipe. Westcoast had estimated $690 and Foothills $709, while Trunk Line (Canada) estimated $540.

Trunk Line (Canada) for reasons of competitive pricing and confidentiality, stated that it did not wish to disclose its detailed pipe price quotations, but provided an explanation of the manner in which the detailed pipe price quotations were used in the construction estimates.

Pipe price quotations were obtained from the two major Canadian suppliers, IPSCO and Stelco, and based on discussions with the manufacturers and on its own experience, the Applicant selected a price of $540 per ton (f.o.b. Edmonton including tax). To confirm the validity of its assumed prices it then compared its quoted price per ton with actual prices paid for similar 36-inch diameter pipe purchased for northern Alberta in late 1976. This comparison showed that the quoted prices applicable to the first quarter of 1976 were virtually identical with those actually being experienced in the third quarter of 1976.

According to Trunk Line (Canada), one of the prime reasons for the higher prices quoted by Foothills and Westcoast, in the range of $700 per ton, was the heavier wall thickness pipe required by these companies for their respective projects. In addition, their prices apparently reflected lower production rates for the heavier wall thickness pipe, more severe impact toughness requirements and more rigid specifications to allow for low temperature operation. Trunk Line (Canada) pointed out that these requirements added to the cost of producing the pipe, particularly as the wall thickness increased beyond the thickness range commonly used at present.

Installation Costs

The spread costs included an overhead and profit allowance of 18 per cent on labour and consumables. An allowance of five per cent was provided for administrative costs related to camp and catering.

Escalation Factors

The escalation factors used for this pipeline were the same as those used by Foothills in the Cost of Facilities section of the report.

Views of the Board

The Board recognizes that Trunk Line (Canada) has not yet completed its drilling program to identify the areas of permafrost in the deeper peat sections along its proposed route. The results of this program will undoubtedly identify locations where the potential for pipe settlement exists and thus where special measures would be required to prevent settlement exceeding the critical differential settlement for the pipe. Until the studies are completed and the final design is made the total cost of the facilities cannot be accurately established.

Trunk Line (Canada) considered that the design approach, the construction procedures and the costs of its proposed facilities would be more or less the same as for similar construction in southern Canada. The Board does not share this view and believes that it should have included more allowance in its cost estimates to cope with intermittent permafrost and muskeg as did Westcoast in its cost estimates.

The total cost of the facilities (escalated) in terms of materials, installation and other related facilities is summarized as follows:

	Costs (Millions of Dollars)
Materials	40.5
Installation	26.6
Other Related Costs	27.7
Total	94.8

The Board concludes that installation costs could be understated by some 10 per cent and that the total cost of the pipeline could vary from $95 to $105 million.

3.3 FOOTHILLS (YUKON) GROUP PROJECT

3.3.1 Introduction

Foothills (Yukon)

The proposed Foothills (Yukon) pipeline would form part of a natural gas express transmission system designed to transport approximately 2.4 Bcf/d of Prudhoe Bay gas from Alaska to United States markets in the lower 48 states. The other companies involved in this project in Canada are Westcoast and Trunk Line (Canada). The overall length of the project in Canada would be approximately 2,023 miles.

The pipeline systems in Alaska and the lower 48 states which would interconnect with the Foothills (Yukon) project facilities would consist of the Alcan, PGT and Northern Border pipelines. The proposed Alcan facilities would consist of a 48-inch diameter pipeline in Alaska from Prudhoe Bay to the point of connection with the Foothills (Yukon) pipeline at the Alaska-Yukon border; an application was filed before the FPC in respect to these facilities. The PGT pipeline system would connect near Kingsgate with the proposed Westcoast pipeline in southern British Columbia. PGT has applied to the FPC to complete the looping of its existing system by the addition of 36-inch O.D. pipe. The proposed Foothills (Yukon) Saskatchewan section would connect at Monchy with a 42-inch O.D. pipeline proposed by Northern Border to the FPC. The Board is satisfied as to the adequacy of these interconnecting facilities.

Foothills (Yukon) proposed to construct a 512.6-mile, 48-inch diameter pipeline commencing at a point of interconnection with the proposed Alcan pipeline at the Alaska-Yukon border (milepost 0) and following a route across the Yukon Territory generally paralleling that of the Alaska Highway. From the border, the line would proceed in a southerly direction until it reached White River (milepost 44), then it would take a more easterly course. There would be major diversions from the route of the highway between mileposts 172 and 185, in the vicinity of Haines Junction, where the route would be located a maximum distance of approximately four miles north of the highway; between mileposts 240 and 275, in the vicinity of Whitehorse, where the pipeline would be located a maximum distance of approximately nine miles south of the highway; and between mileposts 300 and 330, where the pipeline would be located north of the highway by a maximum distance of approximately ten miles.

At milepost 392, the Foothills (Yukon) pipeline would cross the Yukon-British Columbia border into British Columbia and continue through the Province for approximately 39 miles, as does the Alaska Highway. The line would recross the border into the Yukon at milepost 431. The route of the pipeline would continue to closely parallel that of the highway for a distance of 81.6 miles until it reached milepost 512.6 at the Yukon-British Columbia border, in the vicinity of Watson Lake, Yukon, where the proposed Foothills (Yukon) pipeline would terminate and the Westcoast interconnecting pipeline would commence. (See Map 3-8.)

An alternate routing of the Yukon section was studied that would facilitate the connection of Mackenzie Delta gas via a pipeline paralleling the route of the Dempster Highway, and this is discussed in a later section of this chapter.

In addition to its pipeline facilities in the Yukon Territory, Foothills (Yukon) proposed to construct a 42-inch diameter pipeline to receive the Prudhoe Bay gas from Trunk Line (Canada) at the Alberta-Saskatchewan border, near Empress. From the point of interconnection, the line would proceed southeast for a distance of approximately 160 miles across Saskatchewan to a point near Monchy, just north of the international boundary. The Foothills (Yukon) Saskatchewan facility would connect at this point with the proposed Northern Border system. (See Map 3-8.)

The gas volumes flowing through the Foothills (Yukon) system would originate in the Prudhoe Bay natural gas field in Alaska and be transported through the facilities of Alcan, Foothills (Yukon)'s Yukon section, Westcoast's northern section, and Trunk Line (Canada) to (a) the Westcoast facilities in southern British Columbia for delivery to the PGT system and transportation to western United States markets, and (b) the Foothills (Yukon) Saskatchewan section for delivery to the Northern Border facilities and transportation to markets in the Midwestern and Eastern United States.

Foothills (Yukon) would not own the gas transported through its system, but planned to act as a contract carrier for shippers of this gas. Volumes of gas required for compressor fuel would be supplied to the pipeline by each shipper in proportion to its throughput in the line.

With respect to the provision of gas to Yukon communities and industries along the pipeline route, Foothills (Yukon) indicated that it planned to arrange for this service to be provided, but that this did not form part of the current application.

The northernmost 40.8 miles of the Foothills (Yukon) pipeline, from the Alaska-Yukon border to the first compressor station (FY-1), would be located in the permafrost zone, and the gas would be chilled below 32°F in this section to prevent degradation of the permafrost. In areas where frost heave was of concern, Foothills (Yukon)'s mitigative design measures included the use of insulation and backfill replacement with non-frost-susceptible materials. A gas heater would be installed at Station FY-1 to heat the gas to above-freezing temperatures in order to satisfy both metallurgical and geotechnical considerations. No frost heave mitigative measures were recommended south of this point, but the pipeline was designed for potential thaw settlement problems in this section. The two compressor stations on the Saskatchewan section would require aerial cooling facilities in order to satisfy pipeline temperature constraints.

The design characteristics of the proposed Foothills (Yukon) pipeline are outlined in the following table:

DESIGN CHARACTERISTICS OF
FOOTHILLS (YUKON) PIPE

	O.D. (inches)	Wall Thickness (inches)	CSA Grade	Maximum Allowable Operating Pressure (psig)
Yukon Section				
Chilled Portion	48	0.600	65	1300
Unchilled Portion	48	0.540	70	1260
Saskatchewan Section	42	0.473	70	1260

Foothills (Yukon) would hydrostatically test its pipeline to permit operation at a pressure level equal to 80 per cent of specified minimum yield strength. However, it was proposed that the line be operated at 1075 to 1100 psig for the first operating year (1 October 1981 to 31 December 1982), during which time the pipeline would be monitored to identify areas of potential concern with respect to overstressing due to unmitigated frost heave or thaw settlement. The pressure would be increased to 1260 psig on 1 January 1983. The Saskatchewan section would be operated at the maximum allowable pressure of 1260 psig. The last compressor station, however, would have a discharge pressure of 1440 psig at the Canada-United States border near Monchy.

There would be a total of seven compressor stations on the Yukon section and two compressor stations on the Saskatchewan section of the proposed Foothills (Yukon) pipeline facilities. There would be one metering facility, located at the delivery point at Monchy, Saskatchewan, on the international boundary.

The proposed in-service date of the Foothills (Yukon) pipeline was 1 October 1981. Major pipeline construction would take place on the Yukon section in the summer season of 1979 and the summer and winter seasons of 1980 and 1981. The Saskatchewan section would be constructed in the summers of 1980 and 1981. Three of the seven compressor stations on the Yukon section and one of the two stations on the Saskatchewan section would be required for the first year of operation. The gas heater at Station FY-1 and the meter station at Monchy would also be required for the first flow of gas. The other compressor stations would be added in 1982 in order to accommodate the increased volumes projected for 1 January 1983.

The following table outlines the maximum projected volumes to be transported through the proposed pipeline systems of the Foothills (Yukon) group:

FOOTHILLS (YUKON) GROUP
ULTIMATE PROJECTED THROUGHPUT VOLUMES
(MMcf/d)

	1983
Prudhoe Bay to Alaska-Yukon Border	
Prudhoe Bay Supply	2,400.0
- Fairbanks Delivery	45.0
- Fuel Used	38.7
Delivery to Foothills (Yukon)	2,316.3
Alaska-Yukon Border to Yukon-B.C. Border	
Foothills (Yukon) Receipt	2,316.3
- Fuel Used	27.8
Delivery to Westcoast	2,288.5
Yukon-B.C. Border to B.C.-Alberta Border	
Westcoast Receipt	2,288.5
- Fuel Used	24.5
Delivery to Trunk Line (Canada)	2,264.0
B.C.-Alberta Border to James River	
Trunk Line (Canada) Receipt	2,264.0
- Fuel Used	18.8
Deliveries at James River	
- to Western Leg (29%)	659.0
- to Eastern Leg (71%)	1,586.2
James River to Kingsgate	
Western Leg Receipt	659.0
- Fuel Used	0.3
Delivery to PGT at Kingsgate	658.7
James River to Monchy	
Eastern Leg Receipt	1,586.2
- Fuel in Alberta	7.1
Delivery to Foothills (Yukon) Sask. Section	1,579.1
- Fuel in Saskatchewan	10.2
Delivery to Northern Border at Monchy	1,568.9

The estimated costs of the Yukon and Saskatchewan sections of the Foothills (Yukon) pipeline were $1,309,800,000 and $192,200,000 respectively, for a total estimated cost of $1,502,000,000 (1976 dollars escalated to the year of expenditure).

Westcoast

Westcoast applied to the Board only for those facilities it would require in order to transport initial volumes of Prudhoe Bay gas. These facilities consisted of two new pipeline sections located in the province of British Columbia, plus compression, metering and other related facilities.

One section of the Westcoast pipeline would be located in northern British Columbia and would be constructed of 48-inch diameter pipe. This line, 438.7 miles in length, would commence near Watson Lake, Yukon (milepost 0), at the termination point of the proposed Foothills (Yukon) pipeline. It would proceed in a southeasterly direction across the northeastern part of the Province, generally following the route of the Alaska Highway until approximately milepost 140. At approximately milepost 175, the line would take a more south-southeasterly course and proceed in a direct line to the British Columbia-Alberta border and the point of connection with the proposed Trunk Line (Canada) pipeline at Boundary Lake (milepost 438.7). The proposed pipeline would cross the existing Westcoast mainline at approximately milepost 280, some 35 miles south of Fort Nelson. (See Map 3-8.)

The other section would be located in southeastern British Columbia and would be constructed of 36-inch diameter pipe. The route of this line, approximately 106 miles in length, would generally follow that of the existing ANG pipeline, commencing at the point of interconnection with the proposed Trunk Line (Canada) pipeline near Coleman, Alberta (milepost 0), and proceeding across the southeastern corner of the Province to Kingsgate, British Columbia (milepost 106.1), where there would be a connection with the PGT system. (See Map 3-8.)

Westcoast would transport the Alaskan gas volumes owned by shippers through its proposed system on a contractual basis. Gas volumes required for compressor fuel in the Westcoast pipeline would be supplied by each shipper in proportion to its throughput in the line, and delivery volumes would be adjusted to reflect this.

The northern British Columbia section of the proposed Westcoast pipeline would be constructed of 48-inch diameter, Grade 70 pipe, with wall thicknesses of of 0.540 inches, 0.600 inches and 0.720 inches. The southern British Columbia section would be constructed of 36-inch diameter x 0.406-inch wall thickness, Grade 70 pipe. Both sections of the pipeline were designed to operate at a maximum allowable pressure of 1260 psig. In order to be consistent with Foothills (Yukon), Westcoast planned to operate the northern section at a reduced maximum pressure of 1075 psig during the first operating year. The actual operating pressure of the southern British Columbia section would be about 900 psig, due to the lower volumes handled in this section.

Westcoast would require three compressor stations on its northern section in order to transport initial Alaskan gas volumes. Two meter stations would also be required, one located at the Yukon-British Columbia border on the northern section and one at Kingsgate, British Columbia, on the southern section. Two additional compressor stations would be required on the northern section by the time the maximum projected throughput volumes were reached in January 1983, although these facilities were not being applied for at this time.

In accordance with the proposed in-service date of 1 October 1981, construction of the 48-inch O.D. mainline in northern British Columbia was scheduled to commence in December of 1979 and continue through the winter and summer seasons of 1980 and 1981. The three compressor stations and the meter station on this section were to be constructed in the winters of 1980 and 1981. Construction of the 36-inch O.D. mainline in southern British Columbia would take place in the summer of 1981, with right-of-way preparation work being done in the previous summer. The meter station at Kingsgate was scheduled to be built in the summer of 1981.

The estimated costs of the facilities required by Westcoast to enable it to transport initial volumes of Prudhoe Bay gas were $1,096,000,000 for the northern section and $148,000,000 for the southern section, for a total cost of $1,244,000,000 (1976 dollars escalated to the year of expenditure).

Trunk Line (Canada)

Trunk Line (Canada) applied to the Board for approval to construct and operate those facilities required in the Province of Alberta to transport Prudhoe Bay gas volumes under the Foothills (Yukon) group project.

The pipeline system proposed by Trunk Line (Canada) would commence at the termination point of the northern section of the proposed Westcoast pipeline at the British Columbia-Alberta border near Boundary Lake, Alberta (milepost 0). The 48-inch diameter line would proceed in a generally southeasterly direction from Boundary Lake to Gold Creek Junction, from which point it would follow the existing Trunk Line pipeline right-of-way to James River (milepost 394.9). From James River, a western leg, 36 inches in diameter, would proceed in a southwesterly direction for 176.4 miles. This leg would follow the existing Trunk Line right-of-way for 110 miles and then follow a new route farther west to connect with the southern section of the proposed Westcoast pipeline at the Alberta-British Columbia border near Coleman, Alberta. Also from James River, an eastern leg, 42 inches in diameter, would proceed in a southeasterly direction for 234.7 miles to the point of connection with the proposed Foothills (Yukon) Saskatchewan section at the Alberta-Saskatchewan border near Empress, Alberta. (See Map 3-8.) The total length of the pipeline facilities to be constructed in Alberta by Trunk Line (Canada) would be approximately 806 miles.

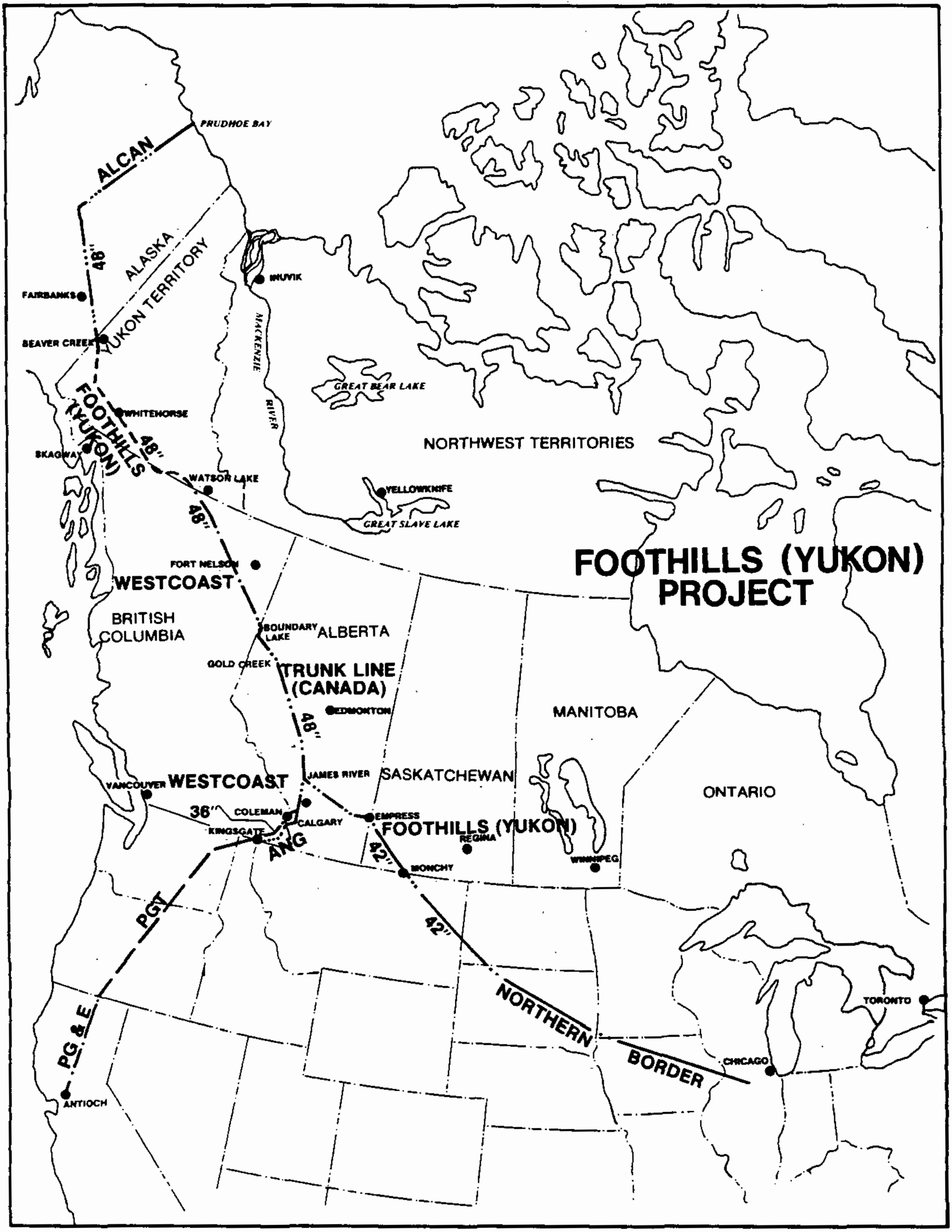
Trunk Line (Canada) would transport the Prudhoe Bay gas volumes for shippers on a contractual basis. Gas volumes required for compressor fuel in the Trunk Line (Canada) pipeline would be provided by each shipper in proportion to its throughput in the line.

The Applicant's proposed pipeline from Boundary Lake to James River would be constructed of 48-inch O.D. x 0.540-inch wall thickness, Grade 70 pipe. The 36-inch O.D. section from James River to Coleman would be 0.405-inch wall thickness, Grade 70 pipe, and the 42-inch O.D. section from James River to Empress would be constructed of 0.473-inch wall thickness, Grade 70 pipe. The entire pipeline was designed to operate at a maximum allowable pressure of 1260 psig. Unlike Foothills (Yukon) and Westcoast on their northern sections, Trunk Line (Canada) proposed to operate its pipeline at this maximum pressure right from start-up, rather than reducing the operating pressure in the first year. Eight compressor stations would be required and three meter stations would be constructed, one at each of Boundary Lake, Coleman and Empress.

Mainline construction was scheduled for the summer seasons of 1980 and 1981 and the winter season of 1981. Four of the eight proposed compressor stations and the three meter stations would be required for the first flow of gas on 1 October 1981. The four additional compressor stations would be constructed during the first year of operation and would be required by 1 January 1983 in order to accommodate the projected increased volumes.

The estimated costs of the proposed Trunk Line (Canada) facilities were $971,600,000 (1976 dollars escalated to the year of expenditure).

MAP 3-8


FOOTHILLS (YUKON)
PROJECT
PRUDHOE BAY
ALCAN
48"
ALASKA
YUKON TERRITORY
FAIRBANKS
BEAVER CREEK
INUVIK
MACKENZIE
RIVER
GREAT BEAR LAKE
FOOTHILLS
(YUKON)
WHITEHORSE
SKAGWAY
NORTHWEST TERRITORIES
WATSON LAKE
YELLOWKNIFE
GREAT SLAVE LAKE
FORT NELSON
WESTCOAST
BRITISH
COLUMBIA
BOUNDARY
LAKE
ALBERTA
GOLD CREEK
TRUNK LINE
(CANADA)
EDMONTON
MANITOBA
JAMES RIVER
SASKATCHEWAN
ONTARIO
VANCOUVER
36"
COLEMAN
CALGARY
EMPRESS
KINGSGATE
ANG
REGINA
42"
MONCHY
WINNIPEG
PGT
NORTHERN
BORDER
TORONTO
CHICAGO
PG & E
ANTIOCH

3.3.2 Alternative Routes

In its original application, Foothills (Yukon) stated that since the Alaska Highway offered a fairly direct route from Fairbanks, Alaska to existing pipeline systems in British Columbia and since this corridor had been utilized from the earliest days of settlement for land transportation and had the additional advantages of many paved and emergency landing strips and a C.N. telecommunications link, alternate routes for the proposed pipeline were not seriously considered.

The Alaska Highway was located to take advantage of relatively easy grades along river valleys, lake shores and mountain passes. For this reason, the proposed pipeline route was generally located within two miles of the highway.

At a later stage of the hearing, the Applicant, in conjunction with Foothills, filed four studies related to alternate methods of connecting Mackenzie Delta and Beaufort Sea gas. It was stressed by the Applicant that these studies were filed for information purposes and were not to be construed as changes in the applications before the Board.

These studies are described in detail in the Foothills Alternate Routes section. Possible alterations to the route of the 48-inch diameter mainline were postulated in Studies 2 and 3.

Study No. 2 postulated a minor route change in the vicinity of Whitehorse in order to facilitate the connection of Delta gas. The 48-inch diameter mainline would be rerouted so that it passed north of Whitehorse instead of south of it, as presently proposed. This rerouting would result in an additional 4.6 miles on the mainline.

The only study which would result in a significant change in the location of the 48-inch diameter mainline was Study No. 3. In order to decrease the length of a possible pipeline to connect the Delta reserves, the 48-inch diameter mainline, instead of following the Alaska Highway from Delta Junction, Alaska to Whitehorse, Yukon, would either proceed cross-country eastward from Delta Junction to the point where the Taylor Highway crosses the border, or along the Alaska Highway to Tetlin and thence along the Taylor Highway to the Alaska-Yukon border. From there, the mainline would proceed along the Boundary Highway to Dawson City and then along the Klondike Highway to Whitehorse, whence it would follow the original route along the Alaska Highway. The 30-inch diameter Dempster Highway pipeline from the Delta would connect with the 48-inch diameter mainline just east of Dawson where the Dempster and Klondike Highways meet.

This rerouting would add either 64.5 or 119.9 miles to the 48-inch diameter mainline, depending on the route chosen, and would shorten the 30-inch diameter Dempster pipeline route by 276.5 miles.

It was pointed out that the alternative routings in Alaska had been investigated by over-flights only. It was felt that either the cross-country route to Delta Junction or the Taylor Highway route to Tetlin Junction could be constructed. The cross-country route would be approximately 55 miles shorter but would require a haul road to be built. The Taylor Highway route would have better access, but the highway would have to be upgraded. Both of the alternative reroutings under Study No. 3

would have the advantage of avoiding the Kluane National Park and the Shakwak Trench.

The costs of rerouting the 48-inch diameter mainline to Dawson from Delta Junction were reported as $340 million for the Canadian portion and $202 million for the Alaska portion, with costs escalated to the year of expenditure. The Alaska portion costs assumed the route would follow the Taylor Highway to Tetlin Junction. A witness for Alcan felt that the cross-country route would be more expensive, but no figures were available to support this view.

Views of the Board

The rerouting of the 48-inch diameter mainline via Dawson offers the prospect of connecting Delta gas at significantly lower cost than a lateral connecting Delta gas to the 48-inch diameter line at Whitehorse, while having relatively little impact on the mainline costs.

The Taylor Highway and the cross-country alternative routings under Study No. 3 were overflown only and were not studied in detail. The Board questions which of these alternatives in Alaska would offer the greatest economic advantage. On one hand, the cross-country route would require only 64.5 miles to be added to the 48-inch diameter line but would additionally require the construction of a haul road. On the other hand, the Taylor Highway alternative would be approximately 55 miles longer than the cross-country route, but could make use of the existing highway, even though this highway would require upgrading.

Further study would be required to determine which of these alternatives would offer the greatest economic advantage.

The rerouting examined under Study No. 3 does avoid the Kluane National Park and the Shakwak Trench but, although following existing highways, is not as accessible as the Alaska Highway route. Nevertheless, the alternative is of major interest to the Board and warrants immediate in-depth study before the Board could be satisfied that the route in the application is the most appropriate from a Canadian public interest point of view.

3.3.3 FOOTHILLS (YUKON)

3.3.3.1 Facilities Design and Capacity

Facilities Location Description

The Applicant applied for the construction of pipelines in the Yukon (including several miles in the Province of British Columbia) and in the Province of Saskatchewan.

(a) **Yukon Section**

The pipeline would consist of approximately 512.6 miles of 48-inch diameter pipe which would start at a point near the Alaska Highway at the Alaska-Yukon boundary, would parallel the Alaska Highway past Whitehorse and would connect with facilities proposed to be constructed by Westcoast near Watson Lake, on the Yukon-British Columbia border.

Three compressor stations would be installed for the first 15 months of operation (1 October 1981 to 31 December 1982) and ultimately seven stations for the year 1983 with an average spacing of 76 miles.

(b) **Saskatchewan Section**

This section of 159.8 miles of 42-inch O.D. pipe would connect, near Empress, Alberta, with proposed 42-inch O.D. pipeline facilities to be owned and operated by Trunk Line (Canada) and near Monchy, Saskatchewan, with facilities to be constructed by Northern Border in the United States.

Foothills (Yukon)'s Saskatchewan facilities would include two compressor stations, one at milepost 159.8 and the other to be installed in 1983 at milepost 38.1. There would also be a gas metering station at the international boundary at Monchy (milepost 159.8).

Both Yukon and Saskatchewan facilities would form an integral part of a natural gas transmission system designed to transport gas produced at Prudhoe Bay to markets in the lower 48 states. This gas would be transported in Alaska by Alcan, in the Yukon by the Applicant, in British Columbia by Westcoast, in Alberta by Trunk Line (Canada) and in Saskatchewan by the Applicant.

While it was not part of its application, Foothills (Yukon) planned to arrange for gas to be provided to Yukon communities and industries along the route of the pipeline and stated that this could be accomplished by having a Canadian gas distribution company arrange to receive the required quantity of the shippers' gas in the Yukon Territory and return an equivalent quantity of Btu's to the same shipper in Alberta.

Summary of Projected Gas Volumes

FOOTHILLS (YUKON)

PEAK DAY SUMMER GAS VOLUMES

(MMcf/d)

Section	**Operating Year** 1	2
Yukon		
Alaska/Yukon Border Receipt	1639.0	2462.6
Fuel in Yukon	14.1	32.7
Yukon/B.C. Border Delivery	1624.9	2429.9
Saskatchewan		
Empress Receipt	1132.3	1676.7
Fuel in Saskatchewan	5.9	12.8
Monchy Delivery	1126.4	1663.9

System Configuration

Pipeline Installation Concept

The design of the pipeline was influenced by the following concepts:

(a) environmental disruption should be minimized and sociological considerations should be emphasized;

(b) capable of operating without hazard to the public or operating maintenance staff;

(c) capable of economically transporting the required quantity of gas;

(d) compatible with the availability of pipe and materials, and current construction techniques;

(e) protected from corrosion; and

(f) provision to be made for pressure testing without environmental damages.

Concepts (c) an (d) were used by the Applicant to select the line size for its pipeline system in Yukon and in Saskatchewan.

Pipe Selection

(a) **Yukon Pipeline**

Foothills (Yukon) carried out an optimization study which compared 42-inch O.D. x 0.54 W.T., Grade 70 pipe designed to a maximum operating pressure (M.O.P.) of 1440 psig, but derated to 1250 psig, with 48-inch O.D. x 0.54 W.T., Grade 70 pipe designed to operate at 1260 psig but derated to the range of 1075 to 1100 psig. An annual load factor of 93.5 per cent was used for both pipe sizes in the study.

Since the original Foothills (Yukon) pipeline was designed to operate at a derated level for metallurgical reasons, the Applicant applied the same concept of deration to the 48-inch O.D. line to make the comparative study. As explained in more detail in the Stress Analysis and Materials Engineering section, the Applicant's plans were to derate its pipeline's operating pressure during the first 15 months only but subsequently to operate at the maximum operating pressure of 1260 psig.

In the comparative study, 38,000 horsepower per station was proposed for the 42-inch diameter line and 29,000 horsepower per station for the 48-inch diameter line. The cost of service was calculated to be 4.70 cents per Mcf per 100 miles for the 42-inch diameter line and 4.54 cents per Mcf per 100 miles for the 48-inch O.D. line size.

The Applicant selected the 48-inch O.D. pipe with 29,000 horsepower compressors because:

- it provided lower cost of service for the second year volume of 2,430 MMcf/d as well as saving compressor fuel; and
- it permitted significant increases in future capacity up to 3.4 Bcf/d, by the addition of compressor stations.

(b) **Saskatchewan Pipeline**

Optimization studies were carried out on 36-inch and 42-inch diameter pipe sizes, the results of which indicated that a 42-inch O.D. x 0.473-inch W.T., Grade 70 pipe operated at 1260 psig provided a cost of service some 13 per cent lower than a 36-inch diameter system for the second year projected gas flows of 1.7 Bcf/d.

Station Design and Spacing

The criteria used to select compressor station size included commercial availability of units, cost of service considerations and pipeline temperature constraints.

(a) **Yukon Section**

Hydraulic studies carried out by the Applicant determined that a total of seven compressor stations spaced at approximately 76 miles would be required in the second year of operation to transport the maximum capacity of about 2.5 Bcf/d receipt volumes at an operating pressure of 1260 psig. Intermediate stations could be installed to accommodate future expansion of the system.

A single unit 29,000 horsepower gas turbine driven centrifugal compressor would be installed at each station and no chilling or aerial cooling facilities would be required. For geotechnical reasons, the gas would be transported in the chilled mode across Alaska and for the first 40.8 miles (to Station FY-1) in Yukon. In order to maintain the gas temperature below 32° F, chilling stations would be installed only in Alaska, and the last chilling station would be located at the Alaska-Yukon border. However, a 90 MMBtu per hour gas heater would be installed at milepost 40.8 to maintain the gas flowing temperature above 32° F, as the Applicant proposed to allow the pipeline to operate in the warm mode from that point on (explained in more detail in the Geotechnical and Geothermal Design section and in the Stress Analysis and Materials Engineering section).

During the first 15 months of operation, it was planned, for metallurgical reasons, to operate the system at a reduced pressure of about 1080 psig instead of the maximum allowable operating pressure of 1260 psig (See Stress Analysis section). Even at the derated pressure of 1080 psig, only three compressor stations would be required for the Applicant to meet the projected volumes of 1.64 Bcf/d. Four additional stations would be installed to provide capacity for the second and subsequent years throughput requirement.

(b) **Saskatchewan Section**

Two compressor stations with aerial coolers were proposed for Saskatchewan, the first one at milepost 38.1 and the second one at the Monchy delivery point at milepost 159.8. A single 29,000 horsepower gas turbine driven centrifugal compressor would be installed at milepost 38.1 and two 29,000 horsepower compressor units, operating in series, would be installed at milepost 159.8.

System Reliability

The Applicant performed a reliability study on the entire Alaska Highway pipeline system, that is from Prudhoe Bay to the 49th parallel. For the purposes of that study, the system was segmented into seven sections as follows: Alaska and Yukon were considered as four sections; northern British Columbia, one section; the 48-inch mainline across Alberta, one section; and the 42-inch delivery lines in southern Alberta and Saskatchewan, one section.

The following assumptions were made for the purposes of the study:

(a) 98 per cent unit availability;

(b) probability of no units being down was 49.3 per cent; one unit down, 35.2 per cent; two units down, 12.2 per cent; and three units down, 2.7 per cent;

(c) weighted average repair time for planned unit maintenance of 8.4 days; and

(d) five units to be serviced simultaneously so that a total of about 59 days would be required annually to service all 35 units on the system.

Foothills (Yukon) concluded that the system could deliver an annual volume of 881 Bcf under conditions of planned and unplanned unit outages. This volume would be slightly in excess of the design annual volume of 876 Bcf.

Seismic Activity

The proposed route for the 48-inch O.D. mainline in the Yukon would pass through an important area of seismic activity and parallel the Shakwak Trench. Since the pipeline would cross that Trench at least twice, special design measures were proposed by the Applicant to counteract seismic acitvity (as explained more fully in the Geotechnical and Geothermal Design section).

Views of the Board

Yukon Section

The Board agrees with the Applicant's choice of 48-inch O.D. x 0.54-inch W.T., Grade 70 pipe for the Yukon section.

The Applicant satisfied the Board that this 48-inch diameter pipe, when operated at the maximum allowable operating pressure of 1260 psig with 29,000 horsepower compressor stations every 76 miles, would provide the lowest cost of service for the planned throughput of 2.4 Bcf/d in the second operating year as compared to a number of other pipe diameters and operating pressures. It has the further advantage that it could be expanded economically to about 3.4 Bcf/d by the addition of further compressor stations at intermediate points.

As explained in the Stress Analysis and Materials Engineering section of this report, because Foothills (Yukon) is concerned about the possibility of pipe over-stressing caused by unmitigated frost heave or thaw settlement, it has planned to reduce the operating pressure of the pipeline from 1260 psig to about 1080 psig for the first fifteen months. During that period, major pipe movement due to frost heave or thaw settlement would be closely monitored and mitigative measures taken.

Due to the present limited knowledge of potential areas for frost heave and thaw settlement along Foothills (Yukon)'s route, the Board concurs with the Applicant that it is prudent to reduce the line operating pressure to about 1080 psig during the first fifteen months of operation. This would allow time to obtain operational history of the line, and apply, where necessary, corrective measures and reduce the risk of line failure.

Based on the Applicant's experience at the end of the 15-month period, the Board would give consideration to increasing the maximum allowable operating pressure to 1260 psig.

Based on current information, the Applicant plans to allow gas flow within its system under the chilled mode up to its first compressor station, FY-1, in Yukon (milepost 40.8), and from that point gas would be maintained above 32°F by means of a heater.

The Board agrees with the concept of chilled gas to prevent permafrost degradation and the use of a heater to assure a flowing temperature above 32°F where it is no longer desired to maintain the integrity of the permafrost. When the Applicant has completed its soils studies, however, they may indicate that the chilled gas cut-off point should be extended beyond 40.8 miles in Yukon, and design modifications may be required. (For more details see Geotechnical Design section of the report.).

The Applicant would be required to submit final design of its compressor stations, including the heaters, for approval of the Board prior to construction.

Foothills (Yukon) has designed its system to meet its annual requirements taking account of the availability of its compressor units. Its system, unlike CAGPL and its partner, Westcoast, cannot meet its average daily requirement with the loss of the critical compressor unit. In the absence of transportation contracts, the Board is unable to say if the system reliability would be adequate to meet the demands of the shippers.

Foothills (Yukon) is proposing large single unit gas turbine driven centrifugal compressor units at each station, as is its partner, Trunk Line (Canada). While it is appreciated that these large single units provide economies as compared to dual units at each station as proposed by Westcoast, they do result in larger losses in throughput in the event of a malfunction. The Board notes that Trunk Line (Canada) has recognized this problem on its portion of the project and has provided for two mobile compressor units which would be used in place of the line units to permit necessary maintenance.

Saskatchewan Section

The Board agrees with the Applicant's choice of 42-inch O.D. x 0.473-inch W.T., Grade 70 pipe for the Saskatchewan section and the Board is prepared to allow a maximum operating pressure of 1260 psig upon the completion of a successful hydrostatic test.

The Applicant has designed this section of pipeline on the same basis as its Yukon section in that it will meet the annual requirements taking account of planned and unplanned outages, but it will not meet the average day requirements with the loss of the critical compressor unit. The Board's comments on reliability of the Yukon section of the pipeline apply equally to the Saskatchewan section.

3.3.3.2 Geotechnical and Geothermal Design

Frost Heave

Extent of Frost Heave

Along the Foothills (Yukon) route, only about 41 miles of the line would be operated at below-freezing temperatures. Of this 41 miles, Foothills (Yukon) testified that only a few miles would pose a serious frost heave problem; the exact estimate relied upon was not clear, but the general indication was that the distance would be about six miles.

The estimate of the length of frost-susceptible route in the Yukon was based on more identifiable information than the estimate made for the Foothills Mackenzie Valley route. Foothills (Yukon) submitted a report containing the results of 82 test holes that were drilled along the northernmost 110 miles of its route in the Yukon.

Foothills (Yukon) had earlier testified that this drilling program had been designed to evaluate thaw settlement which would occur in permafrost terrain, in contrast to frost heaving that would only occur where the soil was unfrozen. The test hole sites had been specifically located in areas that were thought to have the highest thaw settlement potential. When asked if this type of study would not miss areas of frost heave potential, the witness replied, "That could be so from the point of view of drilling in pond areas, but in most drilling investigations we tend to put them on the sides of ponds rather than into the ponds or into real swampy areas... Very few holes were actually put into what I would call real swampy areas." Other than stating that these test holes indicated the type of soils to be found along the route, the witness did not indicate why drilling in frozen areas that were not swampy would allow the use of the resulting data to evaluate the extent of the frost-susceptible terrain.

The Applicant also testified that no attempt had been made to include shallow permafrost terrain in its study of the extent to which frost heaving would be experienced along its route. It agreed that to the extent that sections of shallow permafrost might prove frost-susceptible, the estimates of the mileage of the route susceptible to frost heaving would be in error. However, it was also pointed out that even if the mileage were doubled, the increase in the cost of the project would not be great.

Part of the input into the determination of the miles of frost-susceptible soil along the route was the criteria for frost susceptibility. The Applicant agreed that a soil shown in the CAGPL evidence to have a composition of 62 per cent sand, 23 per cent silt and 15 per cent clay, heaved at significant rates even at overburden pressures up to 10,000 psf and that it would be a frost-susceptible soil. While it was indicated that this would be a soil of the type that was included in its estimate of the length of frost-susceptible terrain, Foothills (Yukon) testified that it would expect this soil to have a very low frost susceptibility.

Frost Heave Design

The evidence on frost heave design was common to Foothills and Foothills (Yukon) and is summarized in the portions of the report regarding the Foothills proposal.

Testimony was given by a witness for Alcan, the company that would build the Alaska portion of the pipeline, that it would also adopt this method but planned to use fine gravel or crushed rock instead of sand for soil replacement.

Views of the Board

The evidence put forward by Foothills (Yukon) with regard to the extent of the potential frost heaving problem is, in the view of the Board, composed of inconsistent and, at times, conflicting information with respect to the terrain involved, questionable concepts as to the nature of frost heaving, and errors in soil classification.

In determining the number of miles of frost-susceptible terrain along the 41 miles of the route that Foothills (Yukon) proposes to operate chilled, the Applicant has used a series of 82 bore holes placed to study thaw settlement and spread over 110 miles of route. Given the original purpose of drilling these holes, it is doubtful that the data obtained would be of much value for frost heave studies.

The Board is also concerned about some aspects of the Applicant's classification of soils as to their frost susceptibility. For example, the Board notes that Foothills (Yukon) proposes to use sand with five to ten per cent silt and clay as non-frost-susceptible bedding and relies upon it to not heave. In view of some of the evidence presented by CAGPL, based on actual test results for a somewhat similar type of soil, the Board questions the Foothills (Yukon) position that its proposed bedding material is not frost-susceptible.

Any certificate which the Board might issue to Foothills (Yukon) would be conditioned to require comprehensive experimental work and study to be carried out at a test site, the results of such work to be used in a thorough analysis of potential frost heave problems and in the final design of mitigative measures.

Thaw Settlement

Extent of Thaw Settlement

Evidence was given that permafrost occurred over the entire length of the Foothills (Yukon) route. In the northernmost 110 miles, the permafrost was said to be widespread discontinuous, while along the remainder of the right-of-way, the permafrost was described as scattered discontinuous. The Applicant gave evidence that thaw settlement of varying magnitudes could be expected at numerous locations along the entire portion of the pipeline that would be operated at temperatures above freezing.

Magnitude of Thaw Settlements

Testimony was given that some areas along the Foothills (Yukon) route had thaw settlement potentials in excess of nine feet. The Applicant indicated that if such areas could not be avoided, special measures might be required.

The Applicant indicated that much more drilling would be required to properly delineate the thaw settlement problem for final design.

Thaw Settlement Predictions

Foothills (Yukon) adopted the methods of thaw settlement prediction put forward by Foothills.

Permissible Values of Thaw Settlement

Foothills (Yukon) adopted the Foothills analysis of permissible thaw settlements. When Foothills (Yukon) amended its application from a 42-inch O.D. pipeline to a 48-inch O.D. pipeline, no further analyses were filed in this regard.

Mitigative Measures

Foothills (Yukon) adopted the mitigative measures put forward by Foothills.

Views of the Board

With regard to Foothills (Yukon)'s assessment of the magnitude and extent of thaw settlement along its route, the Board is of the opinion that the Applicant has not presented adequate information on which to judge the correctness of the assessment, and that considerable additional investigative work would be required before the final design could be completed. However, the Board is of the view that, with additional time, effort and funds, a safe design could be prepared.

With regard to the methods put forward by the Applicant for predicting thaw settlement, the Board believes that the bulk density method of estimating thaw settlement is not adequate for design purposes and that the method requires considerable refinement. The method, as submitted by Foothills (Yukon), yields estimates for which the uncertainty is at times as large as the estimate. At the extreme end of the scale, i.e. for pure ice, the thaw settlement would be under-estimated by in excess of 20 per cent. Test hole logs showing pure or nearly pure ice have been submitted by the Applicant. It is the opinion of the Board that the density of the frozen soil in a thawed and consolidated state must also be known for the bulk density method to be of use.

Buoyancy Control

Foothills (Yukon) adopted the evidence submitted by Foothills with regard to buoyancy control.

Views of the Board

With regard to the Foothills (Yukon) proposals for buoyancy control, it is the view of the Board that the measures proposed are feasible and have been proven through many years of use in other areas.

Permafrost

Extent of Permafrost

Continuous Permafrost

Foothills (Yukon) indicated that none of its line in the Yukon would traverse continuous permafrost terrain. This assessment was based on published information and the results of test hole information and other reports, mainly from the Federal Department of Public Works.

Discontinuous Permafrost

The entire length of the Foothills (Yukon) line would be within the discontinuous permafrost zone in the Yukon.

About 41 miles of the line would be operated at below-freezing temperatures and the remainder operated warm.

Identification of Permafrost

Foothills (Yukon) adopted the evidence of Foothills with respect to permafrost.

Views of the Board

The feasibility of Foothills (Yukon)'s proposed exclusive use of test hole boring to locate the interfaces between thawed and frozen ground over the 41 miles of route in discontinuous permafrost terrain, in which its proposed pipeline would be operated at below-freezing temperatures, is highly uncertain. Since the failure to discover even a few such interfaces could conceivably result in pipeline failure from uncontrolled frost heaving, it is imperative that every effort be made to avoid missing any such locations.

In view of Foothills (Yukon)'s plans regarding the investigation of permafrost terrain in the discontinuous permafrost zone and the large number of test holes that such an investigation would require, and in view of the apparently good results that CAGPL has obtained with the geophysical methods that it has described in its submissions, it is the opinion of the Board that Foothills (Yukon) should reconsider its decision not to use this method. Accepting that geophysical methods are not 100 per cent certain, they would appear to provide a considerable amount of useful information at a reasonable cost.

Slope Stability

Magnitude of Slope Stability Problems

Foothills (Yukon) stated that no detailed analysis of slope stability had been carried out along its route.

It indicated that the most serious slope stability problems were anticipated at river crossings where major landslides could be initiated by erosion of the toe of the slope, and in northerly portions of the route where slopes had high ice contents.

The proposed Foothills (Yukon) route would pass through several areas where significant slope failures had occured in the past. The two major areas that the Applicant indicated were of concern were the Sheep Mountain area and the south end of Kluane Lake.

Submissions from Foothills (Yukon) indicated that, in the Sheep Mountain area, both the Alaska Highway and the Haines-Fairbanks pipeline crossed an ancient failure that originated about a mile from the highway. Foothills (Yukon) indicated that a three-mile wide area centered on the right-of-way would be investigated for potential failures to ensure that a similar slide would not damage the pipeline.

The Applicant said that in the Kluane Lake area, the potential for slides was, "as great as, or greater than, the Sheep Mountain Slide", due to poorly compacted, unconsolidated material. A number of slides had occurred in this area in the past, one of which damaged part of the abandoned Haines-Fairbanks pipeline.

The Applicant indicated that the remaining assessment work would be done in the final design phase.

Measures for Slope Stabilization

In its submissions, Foothills (Yukon) outlined several methods of assuring that the proposed pipeline would not be damaged by slope failures. The principal method proposed would simply be to avoid unstable slopes where this was possible. In the event that stable terrain could not be found, several possible methods could be used to stabilize the slopes. At river crossings, bank armouring, toe loading berms and bank cuts could be used to prevent erosion of the toe of the slope and to reduce the effective slope of the bank. Gravel blankets could be installed to slow melting and encourage consolidation of permafrost slopes. The Applicant indicated that this method would be used to reduce the potential where there were cuts in permafrost. Other methods put forward as possible solutions included burying the pipeline deep enough to avoid damage in the event of a failure and reducing the thermal disturbance by insulating the pipe.

The Applicant indicated that the material presented to the Board was very preliminary and that extensive investigation would be necessary for final design.

Foothills (Yukon) testified that marginally stable slopes would be monitored during operation and, in the event of an imminent slope failure, steps would be taken to protect the pipeline.

Foothills (Yukon) compared its problems with the problems encountered by the owners of the Alyeska pipeline. It testified that in spite of Alyeska's best efforts, some slopes had failed, particularly permafrost slopes in which cuts had been made.

Views of the Board

In view of Foothills (Yukon)'s statements regarding the degree to which it has assessed the potential for slope instability along its route and the stated intention to study a three mile wide area for potential problems, the Board recognizes that a very considerable amount of investigation must be done to enable completion of a full assessment of the slope stability problem.

The assessment of the problem of slope stability and proposals for mitigative measures would have to be part of the final design process subject to Board review.

Drainage and Erosion Control

Foothills (Yukon) indicated that it had not done any work on drainage and erosion control along the proposed route. The Applicant testified that it felt that the work carried out along the Mackenzie Valley route by Foothills was applicable to the Yukon route and for this reason the work was not repeated.

Borrow Materials

The Applicant would require approximately two million cubic yards of borrow pipeline. Requirements for select backfill would account for approximately 0.78 million cubic yards. Requirements for graded material for surfacing, concrete aggregate and for erosion control would amount to 0.659 million cubic yards and the remaining requirements would be for sand-sized material for bedding and padding the pipe.

The Applicant stated that the proposed route would be close to borrow sites and that there would be sufficient quantities of material to satisfy all current and long-term needs. For the most part, borrow requirements could be taken from pits which are already open along the Alaska Highway. The Applicant tabulated 125 of them. For the first half of the route to mile post 215, the pipeline would be, for the most part, within two miles of the highway. On the second half of the proposed route, the pipeline would be up to 12 miles from the highway, although most of it would be within five miles.

The Applicant has not yet identified which borrow sources it would use and thus resource conflicts and depletion of deposits have not been addressed.

Views of the Board

The Applicant does not require large quantities of borrow material. In considering geological conditions of the area, major shortages of material would not appear to be a problem. There are, however, several concerns with respect to availability of specialized materials, competition for material, use of existing borrow pits, transport of meterials and materials handling problems.

Within the Shakwak Trench there are lacustrine silt deposits; they are wide spread having been deposited in the glacial lakes which occupied the valley. Granular deposits are mostly high terraces and alluvial fans at the mouths of hanging valleys. Gravel deposits are abundant; however, many are small and of doubtful quality.

It is the opinion of the Board that the above-mentioned geological conditions, combined with the fact that there will also be a demand for these materials and the use of existing pits for highway construction, may cause a conflict with respect to the mining of these deposits. The Department of Public Works is currently upgrading the Canadian portion of the Alaska Highway and will have significant requirements for borrow materials for road subgrade and surfacing in the next 5 years. Many pits along the highway have already been reserved for highway use. The Board would require that the company demonstrate that there would be no conflicts, or that conflicts could be resolved with respect to operation of pits or demands for materials.

The Applicant may encounter problems with respect to mining and placement of sand bedding and padding material when frozen. If the material is excavated and placed as frozen chunks, it would not provide the soft cushion required to protect the insulated pipe. If the insulation is damaged, its insulation properties would be reduced, aggravating frost heave problems; also, moisture entering the damaged area could accelerate corrosion. The Board would require that the Applicant provide plans to resolve these materials handling problems, should they arise.

River Crossings

Assessment of Problems

Foothills (Yukon) indicated that its assessment of the proposed river crossings was preliminary. Eight major river crossings had been identified, but scour estimates had been prepared for only two of these, the White River and the Donjeck River. It was indicated that many of the river crossings might have to be relocated due to bank instability or other problems along the route leading to these crossings.

Hydrology

Foothills (Yukon) testified that its consultants had proposed a 1,000-year return period for the design of river crossings.

The Applicant testified that while only one or two years of historical flow data were available for the White River, between ten and twenty years of data were available for the other major rivers. Foothills (Yukon) indicated that flood frequency data for ungauged rivers and streams would be obtained using the catchment modeling techniques that were adopted by Foothills for its proposed Mackenzie Valley pipeline.

Scour

Foothills (Yukon) indicated that three methods of scour prediction were being employed and that it was felt that these predictions were accurate to within about two feet. The Applicant stated that further work remained to be done with respect to scour predictions at river crossings and that this would be part of the final design procedure.

Further discussion regarding the methods to be employed by Foothills (Yukon) appears in the discussion of the Foothills project.

Views of the Board

With regard to the Foothills (Yukon) proposals for river crossings, it is evident to the Board that a considerable amount of work remains to be done before any construction could take place. As a condition of any certificate which might be issued to Foothills (Yukon), the Board would require submissions as to the completeness of the assessment of the problems and the adequacy of the crossing designs.

Monitoring

Foothills (Yukon) stated that it adopted the same method of monitoring slopes as were proposed by Foothills for the Mackenzie Valley project.

The only additional item that was mentioned by Foothills (Yukon) was the possible use of seismic monitoring devices. It was indicated that Foothills (Yukon) was considering the installation of two of these devices, one near Compressor Station CY-4 and one near the Alaska-Yukon border.

These aspects of the Foothills (Yukon) pipeline are discussed in more detail in the corresponding section of the report dealing with the Foothills pipeline.

Views of the Board

With regard to monitoring of the propsed pipeline, the Board is not convinced that the plans proposed by Foothills (Yukon) are adequate. While the route of this line would be somewhat more accessible than the Mackenzie Valley route, it would appear that the number of threats from landslides, earthquakes, thaw settlements and river bank failures, as well as frost heave, to the integrity of a pipeline would be greater. It would be prudent for Foothills (Yukon) to employ the very latest methods to ensure, to as great an extent as possible, that natural forces do not cause an unanticipated failure of the pipeline. In the event that a certificate were issued, Foothills (Yukon) would be required to submit a complete monitoring plan to the Board for approval.

Seismic Design

Extent of Problem

Foothills (Yukòn) has submitted that its proposed route includes regions of earthquake risk and crosses a number of faults(1) in the earth's crust. The Applicant indicated that the mapping of these faults was not yet complete, but that the two years remaining before the proposed start of construction would be sufficient for this work to be done.

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(1) A fault is a break or boundary in the earth's crust relative movements, sometimes of several feet, can occur between adjoining portions of the crust.

Design for Seismic Activity

Foothills (Yukon) put forward a number of designs which were based principally on a report by Dr. N.M. Newmark or Urbana, Illinois for CAGPL in 1974, and on the experience of Alyeska.

The Applicants approach to design for the loads and distortions that might occur during an earthquake due to ground motions involved the determination of a temperature differential(1) that would yield equivalent strains in the pipeline and adding these to the strains expected during normal operation. Due to the limited amount of historical seismic data in this area, a safety factor of two would be used in these calculations.

Foothills (Yukon) agreed that the strain calculation would only be valid where the soil around the pipe remained solid and continued to provide support during an earthquake. The Applicant indicated that at least one section of the ground, at the proposed Slims River crossing, had been identified as subject to liquifaction in the event of an earthquake. Foothills stated that no special design had been prepared to prevent pipe movement in the event of seismic activity. It indicated that a special design might not be necessary and that, in the event of

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(1) The temperature differential is the difference between the temperature of the pipe when it was buried and the temperature at which it is operated. If this temperature is too large, excessively high stresses can result due to restrained thermal expansion of the pipe.

liquifaction of the soil during an earthquake, the pipe would probably simply rise to the ground surface due to buoyant forces and would then have to be reburied.

The Applicant indicated that further work would be necessary before the designs were finalized.

Fault Crossing Design

Foothills (Yukon) indicated that it had two options for fault crossing designs; to bury the pipe in a specially designed ditch or to construct the pipe above ground and cover it with a berm. The Applicant indicated that the below ground design was the one that it currently expected to use but that the decision would be left until the fault areas had been defined.

The below ground design would involve burying the pipe in a ditch that would be a minimum of 20 feet wide at the bottom and would have gently sloping sides. The trench would be back filled with small, well rounded gravel or, should there be any concern about the shear characteristics of this material, with something in the nature of crushed plastic.

The Applicant indicated that this ditch design would extend for about 500 feet on either side of the fault.

The Applicant indicated that the fault crossings would be designed to accommodate movements of up to ten feet.

Views of the Board

The Board is uncertain of the efficiency of the proposed design of fault crossings, particularly the design involving a ditch backfilled with gravel. In the event that the Board were to issue a certificate to Foothills (Yukon), it would include a requirement that tests be carried out to demonstrate that such a design would function correctly.

3.3.3.3 Stress Analysis and Materials Engineering

Stress Analysis

Introduction

Foothills (Yukon) noted that much of the stress analysis undertaken for its previously proposed line, as well as for the Foothills 42-inch diameter project, applied also to the Foothills (Yukon) 48-inch diameter pipeline project. This stress analysis presented details on membrane, flexural and bending stresses and strains induced in the pipeline (42-inch x 0.540-inch wall thickness, Grade 70 pipe) by various pre-operational and operational conditions, including internal gas pressure, containment imposed on the pipeline by the surrounding media, temperature differentials, handling and installation, welding, stringing and testing the pipeline. The analysis also dealt with the stresses and deformations induced in the pipeline by such geotechnical influences as frost heave, wash-out, and thaw settlement. From the viewpoint of stress analysis, the principal difference between the Foothills pipeline project and the Foothills (Yukon) 48-inch pipeline project was that the latter passed through an area of significantly higher seismicity.

Analytical Techniques

A non-linear, elasto-plastic analysis was used for the calculation of longitudinal stresses due to seismic loading; these stresses were then converted to equivalent temperature differentials. The difference in seismic activity between the locales of the two projects was indicated by the magnitude of these equivalent temperature differentials, which were approximately 10 Fahrenheit degrees for the Mackenzie Valley and 125 Fahrenheit degrees for the Yukon. These equivalent temperature differentials would contribute to the total which is limited by the design criterion, and hence would directly influence allowable tie-in temperatures.

Two other possible consequences of seismic activity were examined: shear motion at a fault crossing and liquefaction of unstable soil. Where a pipeline crosses a fault at a high angle, seismic activity may impose a transverse shear on the pipe. Foothills (Yukon) tentatively identified at least two fault crossings at the Shakwak Fault. A basic design was developed to accommodate the effect of predicted earth movements within the pipeline stress and strain criteria. Final design would require further evaluation on a site-specific basis.

Liquefaction of unstable soil, with consequent loss of bearing support, was identified as a possibility at one locale, the Slims River Valley. Liquefaction would lead to a physical condition similar to muskeg or swamp, and design procedures appropriate to those conditions would be required. Again, final design details would require site-specific investigations.

When Foothills (Yukon)'s 48-inch diameter x 0.540-inch wall thickness pipe was compared with CAGPL's 48-inch diameter x 0.720-inch wall thickness pipe, Foothills (Yukon) agreed that the pipe with the thinner wall was more flexible and more susceptible to ovalling damage than the thicker wall pipe. Further comparisons were drawn between smaller diameter (42-inch) and larger diameter (48-inch) pipe of the same wall thickness (0.540-inch) with respect to wrinkling and ovalling due to frost heave and due to handling of the pipe. Finally, it was stated that most of the calculations presented in the report, "Some Stress Analysis Aspects of the Foothills Mackenzie Valley Pipeline", were repeated for the Yukon 48-inch, diameter line. Tabular comparisons between the 48-inch diameter and 42-inch diameter line pipe were made with regard to pipe properties, hoop membrane stresses, temperature differentials, radius of curvature, maximum burial depth, anchoring lengths and axial loads.

Experimental Verification

CAGPL questioned whether the Foothills (Yukon) stress analysis had been verified experimentally. Foothills (Yukon) responded that computer results had been compared to experimental results of Berkley Test No. 2 conducted for Alyeska Pipeline Service Co. (Bouwkamp, J.G. and Stephen, R.M., "Large Diameter Pipe Under Combined Loading," ASCE, Vol. 99, No. TE3, Aug. 1973, pp. 521-536) for which full data had been published. The comparison showed that the computed results agreed very well with the experimental data. Foothills (Yukon) considered that this agreement proved the analysis, and therefore did not intend to check it against other tests in the Berkley series.

The chilled and non-chilled Yukon sections would be monitored for vertical movement due to frost heave and thaw settlement during the first 15 months of operation at the derated pressure of **1080 psig**. Monitoring risers would be strategically spaced along the pipeline. In the areas of potential frost heave and thaw settlement, riser spacing of 40 to 50 feet was proposed. The results of the monitoring would be compared to the analytical findings and mitigative measures, such as the application of insulation to non-insulated sections of the pipeline, would be undertaken, if required, before the pipeline was subjected to the maximum operating pressure of 1260 psig on 1 January 1983. Monitoring of the line would continue beyond this date.

Design Criteria

Many of the limitations placed on the state of stress or strain were contained in national codes and regulations. Thus, for example, for buried pipelines, CSA Z-184 stipulates that the maximum hoop stress to which the pipeline can be stressed by the internal pressure is 80 per cent of SMYS. Foothills (Yukon) established some additional limitations on combined membrane and flexural stresses and total strain levels which were based on experience, on observed behaviour of pipeline structures, and on available test data from full-scale tests of pipeline structures.

Foothills (Yukon) provided stress criteria for the handling and installation of line pipe. The following pre-operational and installation conditions were considered: lifting and flexing of pipe, handling of welded pipe sections, lowering of pipe into ditch, field bends and minimum radii of curvatures, burial depths, anchoring lengths of straight pipe and anchoring forces at bent portions of the pipeline.

Special Considerations

A minor difference in the stress analysis of the Foothills (Yukon) project was the adoption of 29 x 10 psi for Young's Modulus of Elasticity versus the 30 x 10 psi utilized in the Foothills project. The change was made because test results on trial pipe showed that 29 x 10 psi more closely approximated the stress-strain curve of the project material. The effect of this change in modulus was illustrated by a specific example in which the maximum temperature differential to meet the design criteria changed from 119 to 123 Fahrenheit degrees.

CAGPL questioned whether Foothills (Yukon) had undertaken a test to confirm the strength of girth welds under seismic loading conditions. Foothills (Yukon) stated that girth weld properties were considered to be related to stress magnitude, and that the source of the stress was irrelevant. It was stated that there was no specific allowance for the possible stress concentration effect of girth welds in the Foothills (Yukon) stress analysis.

Materials Engineering

Introduction

The general approach to materials engineering was similar to that taken for the Foothills pipeline. Differences which arose were a result of the changes in gas composition and in operating temperature.

With respect to the material selection for the mainline pipe, there would be three distinct pipeline sections with different operational conditions: the chilled Yukon section (40.8 miles), the non-chilled Yukon section (471.8 miles), and the Saskatchewan section (159.8 miles). Considering the structural strength and stability requirements of the pipeline, Foothills (Yukon) selected the following material and pipe size parameters:

- Grade 65, 48-inch O.D. x 0.600-inch wall thickness, Cv-100(1) minimum = 50 foot-pounds, Cv-100 average = 80 foot-pounds, for the chilled Yukon section;
- Grade 70, 48-inch O.D. x 0.540-inch wall thickness, Cv-100 minimum = 50 foot-pounds, Cv-100 average = 80 foot-pounds, for the non-chilled Yukon section; and
- Grade 70, 42-inch O.D. x 0.473-inch wall thickness, CvT(2) = 40 foot-pounds, for the Saskatchewan section.

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(1) Cv-100 - The value of absorbed energy corresponding to 100 per cent shear area in the Charpy V-notch impact test.

(2) CvT - The value of absorbed energy at the test temperature in the Charpy V-notch impact test.

Fracture control criteria for the Yukon section were based on the Battelle hypothesis for fracture initiation and fracture propagation. The Saskatchewan section was designed to a crack initiation criterion only.

Fracture Initiation

Foothills (Yukon) adopted the philosophy of primary design against fracture initiation by specifying sufficient pipe toughness to reach the level where failure becomes flow stress dependent. For a particular pipe and operating pressure, the flow stress dependence level may be expressed either in Cv toughness level or critical through-wall crack size(1). For 48-inch diameter pipe of different wall thicknesses, Foothills (Yukon) chose to calculate critical crack sizes. Critical through-wall crack sizes for 48-inch O.D. by 0.600-inch wall thickness, Grade 65; 48-inch O.D. by 0.540-inch wall thickness, Grade 70; and 42-inch O.D. by 0.469-inch wall thickness, Grade 70; all at 1260 psig and Cv of 50 foot-pounds, were as follows: 7.009 inches, 6.126 inches and 5.389 inches, respectively. This was the idealized crack of sharp ends, crack ends normal to the crack surface, and crack length parallel to the pipe axis. This idealized crack was a limiting case; the critical crack length for all real cracks would be the same or longer. These crack lengths were calculated for the operating conditions. The above-

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(1) Critical through-wall crack size may be defined as the maximum axial length of a sharp crack that the pipe can tolerate at the operating pressure without a propagating fracture starting.

quoted critical crack lengths for operating conditions were acceptable to Foothills (Yukon) since they were significantly longer than the defects that would be detected in the mill or in the field.

Brittle Fracture Propagation

Foothills (Yukon) stated that in the pipe with a toughness of 60 per cent minimum and 85 per cent average shear area in the drop weight tear test at a minimum operating temperature of 25°F brittle fracture propagation theoretically could not occur.

Ductile Fracture Propagation

Foothills (Yukon)'s ductile fracture propagation analysis for the Yukon sections, based on the Prudhoe Bay gas composition, showed that fracture propagation would be limited by a fracture toughness of 70 foot-pounds (Cv-100) under the initial operating conditions (1100 psig pressure at 25°F) in the 48-inch diameter, 0.600-inch wall thickness, Grade 65 pipe, and by a fracture toughness of 72 foot-pounds (Cv-100) at 1075 psig pressure and 60°F in 48-inch diameter, 0.540-inch wall thickness, Grade 70 pipe. For the maximum operating pressure of 1260 psig, on the other hand, the corresponding fracture toughness to limit fracture propagation was in the order of 100 foot-pounds for 48-inch O.D., 0.600-inch wall thickness pipe and 102 foot-pounds for 48-inch O.D., 0.540-inch wall thickness pipe.

The Saskatchewan section was designed to a crack initiation criterion only. The decision not to specify a fracture propagation criterion was based on the fact that the pipeline was considered to be conventional and that there were many pipelines in the area which had not, historically, suffered propagating fractures.

Foothills (Yukon) carried out investigations to confirm the gas decompression behaviour for the composition anticipated for Prudhoe Bay gas, at the temperatures applicable, and submitted a report.

Foothills (Yukon) also submitted a statistical study on fracture length predictions. The computer program was based on a probabilistic model. The only means of fracture arrest taken into account was material toughness. On this basis and within the limits of the numerous assumptions made, the study indicated fracture lengths of 80 feet at a 50 per cent probability level and 200 to 280 feet at a 99 per cent probability level. Foothills (Yukon) noted that its statistical method differed from that used in a similar study carried out for CAGPL, but stated that the results would be similar in the 10 per cent to 90 per cent probability range.

Specification of Fracture Toughness

With regard to testing the notch toughness of the heat-affected zone of mill welds, Foothills (Yukon) agreed that useful determinations could be obtained and noted that it was carrying out tests on trial production pipe to satisfy itself that the heat-affected zone did not, in fact, have very low toughness.

The Applicant did not intend to specify a requirement on a manufacturing procedure qualification basis.

Notch toughness requirements for such items as station pipe, small diameter valves, flanges and fittings were established, based on experience, critical crack size calculations and the ASME Boiler and Pressure Vessel Code, Section VIII.

Crack Arresting

Foothills (Yukon) felt that the problem of ductile fracture propagation existed only in the Yukon section and not in the Saskatchewan section.

It stated that there were many different mitigating measures against ductile fracture propagation which could be utilized; for example, reduction of the operating pressure, changing the gas composition, increasing the pipe wall thickness to decrease the stress levels, and, of course, using "devices which arrest cracks". The derated pressures at which Foothills (Yukon) planned to operate for the first 15 months of operation, therefore, would cause shorter propagating fractures than the maximum operating pressure of 1260 psig. With the increase in operating pressure to the maximum value, Foothills (Yukon) estimated there would be a two to three-fold increase in the mean length of any fractures which might occur.

Foothills (Yukon) proposed to monitor the vertical movements of the Yukon section in order to guard against possible fractures and in order to identify areas where appropriate mitigative measures should be taken. This method had been checked at the CAGPL Calgary test site. Based on the results of the Calgary test site geothermal studies, Foothills (Yukon) felt that it would be able, within 15 months, to identify all the areas with inadequate mitigative measures and to take the proper corrective measures before the pipeline pressure was increased. At the maximum operating pressure of 1260 psig, the hoop stress levels in the Foothills (Yukon) pipeline sections would be as follows: in the chilled Yukon section, 77.5 per cent of SMYS; in the non-chilled Yukon section, 80 per cent of SMYS; and in the Saskatchewan section, 79.9 per cent of SMYS.

In addition, Foothills (Yukon) planned to carry out burst tests to verify, firstly, that pipe toughness would be adequate for self-arrest of a crack; secondly, that frozen soil would assist in arresting a ductile fracture in frozen areas; and, thirdly, to test the applicability of concrete weights as crack arrestors. These burst tests would be carried out in northern Alberta prior to construction of the pipeline. If the burst test showed that crack arrestors were required to shorten the propagating length, Foothills (Yukon) would be prepared to install concrete weights every thousand feet in the sections were they would not otherwise be required.

Materials Specifications

Status of Specifications

Foothills (Yukon)'s specifications filed with the Board covered materials, procedures and inspection.

The materials specifications covered most pipeline materials, with the exception of such ancillaries as pressure vessels, aerial coolers and heat exchangers. Foothills (Yukon) stated that specifications for these components could only be drafted in final design. The ASME Boiler and Pressure Vessel Code would provide the basis for unit design, but notch toughness testing in excess of the code requirements would be specified.

Foothills (Yukon)'s materials specifications were based on the appropriate standards of the Canadian Standards Association and incorporated requirements beyond those of CSA. A number of weaknesses were noted in the detailed provisions of the specifications, some of which were brought out in the Board examination of the Applicant's witnesses; for example, lack of notch toughness requirements in the girth welds of mill jointers, the advisability of requiring an automatic welding process for such mill welds, the possibility of an unacceptably-high phosphorus content in fittings, and deficient provisions regarding sampling of heat-treated fittings. Foothills (Yukon) agreed to make the appropriate changes to cover such deficiencies.

Foothills (Yukon) had stated a policy of purchasing Canadian pipe made by standard procedures. The Foothills (Yukon) specification for line pipe did not make provision for this. The Board questioned the acceptability of pipe made from strand cast slabs in the event that conversion to that practice coincided with production of pipe for the project. Foothills (Yukon) stated that strand cast slab for skelp would only be accepted after its suitability had been demonstrated by manufacture of pipe for, and successful installation of, a pipeline by another purchaser. A generally similar view was taken by Foothills (Yukon) with respect to acceptance of cold-expanded spiral weld pipe, in that experience with a mill production expander and extensive investigation and testing of such pipe would be required.

Foothills (Yukon)'s specification for line pipe, P-100, required sampling on a random basis to determine the mechanical properties. The Board pointed out in cross-examination that test data for the trial IPSCO production showed that in all cases where both ends of a pipe, representing the inner and outer wraps of the hot coiled skelp, had been tested, the notch toughness of the two locations differed significantly and consistently. Foothills (Yukon) noted that it had work underway to test the homogeneity of IPSCO pipe and that, if a consistent pattern were established, it would prefer to select on the basis of testing the lower strength end, but would prefer to have a random sample for Charpy testing. The IPSCO homogeneity test showed that the tensile and impact specimens of the spiral welded pipe, manufactured from coiled skelp, should be taken from the end of the pipe representing the trail of coil.

Foothills (Yukon)'s specifications F-400 and F-402 for pipeline and compressor station fittings and flanges outlined in detail the requirement in addition to the CSA Standards Z-184, Z-245.1, and NEB Regulations Respecting Gas Pipelines for the manufacture, inspection and testing of fittings and flanges.

A set of three Foothills (Yukon) specifications (C-800, C-801 and C-802) covered properties, application procedure, and testing of the internal coating of line pipe.

Foothills (Yukon)'s specification T-1000 covered the procedures for field hydrostatic testing of installed pipeline sections in both summer and winter conditions.

Most of the above-mentioned revisions were made in the latest submission of the Foothills (Yukon) contingency standards.

With regard to shipping, handling, stockpiling, etc., of large diameter pipe, the Applicant stated that the matter was under study and noted that Stelco and Canadian National Railway were studying rail shipment procedures. The studies had the ultimate objective of minimizing cost while still maintaining adequate protection for the pipe. Foothills (Yukon) did not anticipate establishing complete shipping specifications until well into the final design phase.

With regard to smaller diameter pipe, Foothills (Yukon) stated that quantities were small and that current practices regarding shipping, handling and stockpiling were adequate.

Field Welding

The procedure specifications (W-700, W-701, and W-710) of Foothills (Yukon) covered field girth welding, field jointer welding, and welding of station and other special piping. The specifications referenced the appropriate provisions of the CSA Gas Pipeline Code (Z-184) and the NEB regulations as basic documents, and elaborated on welding and inspection procedure requirements.

Implementation and Inspection

Specification Q-1100 outlined the Foothills (Yukon) proposed quality control or inspection with respect to organization, activities and responsibilities. It covered all stages from manufacturing plant to field construction.

To improve field welding inspection, Foothills (Yukon) noted that it was aware of the necessity for ensuring greater adherence to laid-down procedures and that its inspectors would be trained prior to going to the field. Foothills (Yukon) stated that the most significant improvement was the change in the organization used by Trunk Line in the past, whereby the field inspectors would be responsible to an inspection department rather than to the production department.

Materials Supply and Availability

Line Pipe

The Applicant stated that line pipe would be produced by Canadian mills. A tabulation of the tonnage of 48-inch diameter pipe required by all Canadian companies participating in the Foothills (Yukon) project originally indicated that the highest demand would occur in 1980 (617,000 tons), which was, according to Foothills (Yukon), only 45 per cent of the yearly pipe mill capacity. In the revised schedule, the peak demand for all companies in 1980 dropped to 597,000 tons, because of pre-purchasing of pipe in 1978 by Foothills (Yukon) and Westcoast. The same document also showed that the main supplier for Foothills (Yukon) would be Stelco, which would produce 361,000 tons of 48-inch diameter pipe and 89,000 tons of 42-inch diameter pipe, while IPSCO would supply 20,000 tons of 48-inch diameter pipe. The cost estimates for Stelco pipe were based on cold-expanded pipe, although Stelco did not demonstrate its ability to meet Foothills (Yukon)'s specifications by cold expansion, because the facility for cold expansion was not yet in operation. Therefore Foothills (Yukon) reserved its technical decision on accepting cold-expanded pipe. Foothills (Yukon) expressed concern regarding cold-expanded pipe, since this would be the first time it had been used for spiral welded pipe. In the event that cold-expanded pipe did not meet its specifications, Foothills (Yukon) would re-examine its position as to whether it was willing to pay higher prices or accept a somewhat higher carbon equivalent than that indicated in the present specification (i.e. a maximum of 50).

Pipeline Components

Foothills (Yukon) had only approximate estimates with respect to how many 48-inch diameter gate and ball valves it would require. It was in contact with many North American valve manufacturers, but had not made any firm commitments. Foothills (Yukon) did not present any evidence with respect to supply and availability of other pipeline components.

Views of the Board

Stress Analysis

The stress analysis conducted by Foothills (Yukon) for pre-operational and operational loading conditions and loading due to buoyancy and geotechnical phenomena covered most situations of single and combined stresses. Established design criteria are reasonable.

Due to the lack of site-specific data on loading due to frost heave and thaw settlement, the Board supports Foothills (Yukon)'s proposal to monitor the movement of the pipeline and undertake mitigative measures, as required. Detailed design of the monitoring system in respect to the measuring instrumentation and procedures, as well as critical values for pipeline movement considering the adopted design criteria, should be established. Furthermore, the mitigative measures should be defined in relation to the field data obtained in the monitoring process.

Materials Engineering

Foothills (Yukon) presented a sound design for the prevention of fracture initiation and brittle fracture propagation. However, the specified inherent materials properties did not provide positive ductile fracture self-arrest. As a measure of safety, Foothills (Yukon) correctly chose to derate the operating pressure. The announced intention to increase the operating pressure after 15 months of operation is a matter of some concern. Of special concern would be the sections of the pipeline located in permafrost terrain planned to operate in chilled and non-chilled conditions. Although the specifications of the line pipe properties could be upgraded, or the operation could be limited to the derated operating pressure, the installation of external crack-arresting devices, such as offset-mass, bolt-on concrete weights might provide adequate limitation of ductile fracture propagation. Installation of such devices would be required on the pipeline section where the potential of ductile fracture propagation exists. Appropriate studies would have to be conducted to determine the length of pipeline requiring installation of such crack-arresting devices and the spacing between these devices. Final ductile fracture control design would have to be tested experimentally under closely simulated field conditions. The Board has noted that Foothills (Yukon) proposes to carry out burst tests to demonstrate ductile fracture arrest with and without crack-arresting devices, and would require that the results of these tests be submitted to the Board in support of an application to operate the Foothills (Yukon) pipeline at the maximum operating pressume of 1260 psig.

Materials Specifications

The materials specifications submitted by Foothills (Yukon) represent standard practice. Detailed specifications for shipping, handling and stockpiling of larger diameter pipe should be completed as part of the final design process.

Materials Supply and Availability

Foothills (Yukon)'s plan to acquire all the line pipe from Canadian mills is supported by the Board. The latest acquisition schedule for line pipe from IPSCO and Stelco for the companies participating in the Foothills (Yukon) project is acceptable to the Board. The installation and testing of expansion facilities at Stelco should be accelerated so that technical acceptance of the cold-expanded line pipe can be made. Early availability of cold-expanded pipe is also required for full-scale tests to be conducted by Foothills (Yukon).

3.3.3.4 Right-of-Way

In the Yukon Territory and British Columbia, Foothills (Yukon) proposed to acquire a permanent right-of-way 90 feet in width with the exception of major river crossings where a working width of 200 feet or possibly more would be required. No evidence was presented on the width of right-of-way required in the Province of Saskatchewan.

Foothills (Yukon) stated that the right-of-way would be cleaned up and restored, as nearly as feasible, to its original conditions.

It was also stated that other necessary authorizations to cross navigable waters, railways and utilities would be obtained from the appropriate authorities.

Views of the Board

Foothills (Yukon) evidenced an understanding and appreciation of right-of-way problems which could arise from pipeline construction, particularly in the areas of clean-up and restoration of right-of-way. Foothills (Yukon) intended to employ competent inspection to ensure that all regulations are complied with.

The Board would require that Foothills (Yukon) comply with all of the Board's directions regarding the acquisition of rights-of-way and other lands, including but not necessarily limited to specific directions as to the rights of and notice to all potentially affected property owners to ensure an orderly land acquisition and an equitable settlement program.

3.3.3.5 Communications

Foothills (Yukon) stated that two alternatives were considered with respect to how its objectives regarding the required communications system could be attained: (a) provision of a dedicated private commercial system operated by Foothills (Yukon) personnel, or (b) leasing, from the public telecommunications carrier, a system which would provide the same levels of reliability and availability that would be built into a private system.

Foothills (Yukon) chose the latter alternative and proposed to lease the communications system required for its Yukon section from C.N. Telecommunications, the common carrier operating in the Yukon. The system required for the Saskatchewan section would be leased from Saskatchewan Telecommunications, the common carrier in that area.

The Applicant stated that the communications system must generally be located parallel to the pipeline right-of-way and as near as was practicable to compressor station sites where the facilities would be used. Foothills (Yukon) considered the proximity of the existing C.N. telecommunications link to its proposed pipeline route as one of the advantages of this route.

Construction Communications System

Foothills (Yukon) pointed out that during construction some temporary communications sites might be required at locations remote from the right-of-way of the pipeline, for example, communications from camp sites not coincident with compressor station sites or from pipe storage and stockpile areas.

The two primary requirements of the construction communications system were as follows:

(a) that it provide communications for pipe-laying and compressor station contractors, consisting of voice communications and Telex service in order to facilitate the expediting of supplies and equipment, to provide administrative control and to ensure personnel safety; and

(b) that it provide communications services for the total length of the pipeline, exclusively for the use of Foothills (Yukon) personnel involved in the construction phase of the pipeline, including private voice communication from the construction camp sites to the area offices.

It was indicated by the Applicant that internal contractor communications would be the responsibility of the individual contractor, and that private commercial mobile radio telephones would be used for this purpose, with the public mobile radio telephone system available as an emergency back-up system.

Foothills (Yukon) stated that its personnel would be provided with a discrete private mobile radio telephone system for the activities along the entire extent of the pipeline right-of-way, and that this mobile equipment would also include the public mobile radio telephone channels available in each area.

Permanent Communications System

Foothills (Yukon) stated that the permanent communications system, or operations and maintenance system, must provide communication services of the highest possible reliability and availability between pipeline installations, such as compressor and meter stations, area offices and the gas control centre, to guarantee the safe, efficient operation of the pipeline. The two primary requirements of this system were as follows:

(a) that it provide the normal administrative traffic requirements and the dispatch of personnel; and

(b) that it provide the medium for a sophisticated supervisory control system that would operate remotely and monitor the performance of the pipeline.

The administrative network would consist of telephone and Telex interconnection between compressor and meter stations, area offices and executive headquarters, and would provide for administrative, maintenance and staff functions.

Pipeline repair and maintenance personnel would make use of mobile radio telephone services to communicate with their respective operating headquarters. This would be a private commercial mobile radio telephone system owned by Foothills (Yukon), with the public mobile radio telephone channels available for emergency back-up.

Telemetry and Supervisory Control System

Foothills (Yukon) stated that the conceptual design of the supervisory control system envisaged that the pipeline would be capable of being operated in a safe, efficient manner from a central control point (i.e. the gas control centre in Whitehorse). This system would permit the remote and unattended operation of compressor stations, meter stations, and their auxiliary equipment and services, providing automatic reaction within pre-set limits. It would also furnish the gas control centre and the area offices with all necessary status, alarm and measurement information to maintain pipeline control, providing for manual over-ride for selected functions such as starting and stopping stations in the case of upset conditions. The Applicant stated that the availability and reliability of this system, therefore, must be extremely high in order to guarantee the full operating safety of the pipeline, since it would be the prime operating tool of the gas controller.

An additional function required of the system was the maintenance information system, which would provide data from the mechanical equipment to a central processor. This central processor would be programmed to perform trend analysis calculations, establish the frequency of maintenance work and predict the nature of equipment failures, thus not only helping in the development of maintenance optimization programs, but also in the determination of the nature of failures. This would allow maintenance and repair personnel to pre-determine their tool and equipment requirements which would, according to the Applicant, significantly minimize the duration of station outages.

Views of the Board

The Board accepts Foothills (Yukon)'s decision to lease the required communications facilities from the existing common carriers operating in the Yukon Territory and in the Province of Saskatchewan. The Board is of the opinion that these communications facilities are capable of providing the high level of availability and reliability required for the safe and efficient operation of the pipeline.

3.3.3.6 Construction

Construction Mode

Foothills (Yukon) proposed that conventional winter and summer pipeline construction techniques would be employed for the construction of the Yukon portion of the pipeline. The Applicant expected to encounter widespread discontinuous permafrost in the western part of Yukon Territory; however, it was felt that the presence of this permafrost would not affect the construction progress nor would the construction activities have any degrading effects on the terrain. Foothills (Yukon) proposed to construct the pipeline in the permafrost areas during the winter months. The Applicant stated that only a limited number of snow roads would be required. It was expected that standard pipeline construction techniques would be employed in other areas where a winter road on the frozen ground would be used for the pipeline construction.

Foothills (Yukon) planned to construct the compressor stations and the meter stations on gravel pads where no natural gravel or granular area existed. Standard construction techniques would be employed for erection of the stations and it was expected that the construction would not be affected by the weather or the Arctic location.

Foothills (Yukon) proposed to construct the Saskatchewan section of the pipeline during two consecutive summers. The terrain was described as relatively flat and semi-arid with no major water crossings. Standard pipeline construction techniques would be used with few obstacles expected.

Construction Techniques

Foothills (Yukon) planned to employ standard pipeline construction techniques as extensively as possible. Winter construction techniques would be employed in muskeg and major permafrost areas. Summer construction would take place in dry soil or granular and rocky terrain areas.

The method of excavation of the pipeline trench would be dependent on the soil conditions. In most areas other than solid rock, the pipeline trench would be excavated with a conventional ditching machine. In rocky terrain, drilling and blasting would be used to break up the bedrock and the ditch excavated with a backhoe.

Foothills proposed to employ standard winter and summer pipeline construction practices for:

- pipe handling, hauling and stringing;
- pipe bending;
- line-up for welding;
- welding;
- protective coating for field joints;

lowering-in and tie-ins;

pipe weighting;

trench bedding and backfill;

gauging and cleanings; and

clean-up and restoration.

Foothills (Yukon) felt that no problems would be encountered in finding granular material required to construct the compressor and meter station sites.

A minimum of access roads would be required since the pipeline would cross the Alaska Highway at numerous locations and access to the pipeline would be gained at these crossing points.

Foothills (Yukon) stated that a minimum of snow roads would be required in the permafrost areas. Standard techniques would be employed to construct the snow roads and where necessary the snow would be either hauled to the area where required or manufactured by artificial means. Most stream crossings would be carried out as part of the pipeline construction spread's activities, where the ditch would be excavated with equipment carried with a normal spread. If special equipment were required to excavate and place the pipeline on the river bottom, a separate crew would be required.

Foothills (Yukon) proposed that one construction camp would be erected for each of the pipeline construction spreads.

Foothills (Yukon) proposed to use water as the test medium and to perform all the pipeline testing during the summer months.

Construction Logistics and Schedule

Foothills (Yukon) stated that since its route would follow and cross the Alaska Highway at numerous locations in the Yukon, the highway would be used as extensively as possible to bring material and equipment to the pipeline right-of-way. The narrow gauge rail system from Skagway to Whitehorse, and also the established air transport systems to Whitehorse, would be used prior to and during the construction phase of the pipeline.

Foothills (Yukon) proposed that material and equipment originating in Vancouver could be shipped north via ocean freighters to the Alaska seaport at Skagway, offloaded and shipped either via the narrow gauge railway or along the highway (the highway between Skagway and Whitehorse is scheduled for completion in the spring of 1978) to Whitehorse. Additional storage facilities would be required at Skagway and also at Whitehorse. The products pipeline between Skagway and Whitehorse would be utilized to ship fuel to storage facilities at Whitehorse. This pipeline, however, would have to be upgraded since it had been operating at its peak capacity during recent winter seasons.

Material and equipment originating in Vancouver would also be shipped along an inland route by using the existing rail system to Fort Nelson and then by road to the Yukon. This route would be used for oversized or heavier equipment which could not be accommodated on the narrow gauge railway from Skagway to Whitehorse. Material transfer facilities would be required at Fort Nelson to accommodate the increased volume of material and equipment.

Material and equipment originating at Edmonton, Calgary or points in Eastern Canada would be moved to the right-of-way by a combination of rail and road.

Foothills (Yukon) felt that with the existence of these transportation facilities, major storage facilities would not be required due to the year-round access along all of the transportation routes. The intermediate storage sites located at transfer points would be surge storage as transport vehicles would be operating on scheduled movements from these sites to the right-of-way stockpiles. The additional requirements at these surge storage sites would involve a relatively small amount of development and capital investment.

Foothills (Yukon) estimated that it would start moving equipment and material to the pipeline right-of-way one month in advance of its being needed and maintain this one-month lead time throughout the construction of the pipeline. Because of the available transportation routes and facilities, it was felt this one-month buffer would be sufficient during the construction of the Yukon portion of the pipeline.

Foothills (Yukon) did not propose to construct any new airstrips and expected to make use of a minimum amount of air support during the construction phase of the pipeline project.

The Saskatchewan portion of the pipeline project would use existing highways, secondary roads and railroads for the transportation of materials and equipment to the pipeline right-of-way. Foothills (Yukon) did not plan to upgrade any of the existing transportation routes. Storage facilities would not be required in the Saskatchewan portion of the pipeline.

Foothills (Yukon) proposed to construct the Yukon portion of the pipeline in sections as follows:

	Milepost	to Milepost	Miles	Construction Season	No. of Spreads
Section 1	0	30	30	Winter, 1981	1
Section 2	30	71.4	41.4	Winter, 1980	1
Section 3	71.4	111.4	40.0	Winter, 1980	1
Section 4	111.4	21.64	105.0	Summer, 1979	2
Section 5	216.4	312.4	96	Summer, 1980	2
Section 6	312.4	415.7	103.3	Summer, 1979	2
Section 7	415.7	512.6	96.9	Summer, 1980	2

Foothills (Yukon) proposed that the hydrostatic testing of all the Yukon sections would be carried out during the summers of 1979, 1980 and 1981.

The Saskatchewan sections of the pipeline would be constructed during two consecutive summers. The first section consisting of 60 miles of pipeline would be constructed during the summer of 1981 with one spread and the second section of 100 miles would be constructed during the summer of 1980, also with one spread.

Views of the Board

The Foothills (Yukon) project is a more standard type of pipeline construction proposal than either that of Foothills or CAGPL in that it is to be constructed in accessible country where permanent roads exist. If, during the course of construction, the Applicant required additional equipment or materials, it would have the advantage of year-round access to the pipeline right-of-way. The pipeline construction can be scheduled during any part of the calendar year in most areas of the proposed project.

The Board has examined the construction program of Foothills (Yukon) and identified some concerns. There are areas where frost heave problems will be identified and require handling in the final design process. When the final design was completed, the contractors would be able to adjust their work forces and equipment to install the required materials for the mitigation of frost heave. Final design would have to be completed well in advance of the work so that the contractors could have the proper equipment available.

3.3.3.7 Operations and Maintenance

Station Operation and Maintenance

Foothills (Yukon) proposed that an operations head office be located in Whitehorse, Yukon which would provide management, administration and operating supervision and engineering to the pipeline area offices outside of the Whitehorse area.

The pipeline operations and maintenance organization would be divided into areas with offices located in Whitehorse, Watson Lake, Teslin, Haines Junction and Beaver Creek. This segmentation of the system would distribute the responsibilities and work loads with reasonable travel distances.

A technical maintenance centre with special equipment and skilled personnel to perform major mechanical and technical maintenance would be established at Whitehorse since it would be reasonably central to the pipeline system and to sources of parts and material.

The compressor stations and meter stations would be designed to provide a fail-safe mode of operation with the intent of operating all stations on an unmanned basis. It was intended that unattended operation would be achieved gradually over the first several years of staff training, system development and on-site experience. A high reliability communications system would be employed to support the remote control concept and to assure maximum safety to personnel working anywhere on the system.

Foothills (Yukon) proposed that the routine maintenance of the compressor stations would be performed by maintenance personnel on routine visits to the station sites. In order to avoid deterioration of equipment and unscheduled station shut-downs, maintenance programs would be developed to schedule inspection and repair of equipment and controls at regular intervals. The maintenance personnel would inspect station alarms and controls and would correct malfunctions in the equipment to ensure maximum reliability of the compressor stations.

Pipeline Surveillance and Maintenance

In permafrost and other sensitive terrain areas, ground travel would be restricted to emergency maintenance during the summer and heavy equipment would not be transported or employed unless absolutely necessary. In the event that some maintenance were necessary to ensure the integrity of the pipeline, helicopter transportation and low ground pressure vehicles would be employed to perform the temporary repairs.

Line patrol would be by aircraft, either helicopter or small fixed-wing. The pipeline patrol program would be supplemented by ground patrol carried out in a small vehicle suitable to the terrain to be patrolled or on foot by specially trained individuals. All patrols would be under the supervision of the district supervisor who would ensure that the frequency and method of the patrols would not be detrimental to the terrain and/or wildlife.

In the event of a major pipeline failure during the summer months, in an environmentally sensitive area such as a permafrost region or muskeg terrain, helicopter transportation would be used to bring in pipe sections, men and equipment for a temporary repair. The pipeline would be temporarily repaired with 24-inch diameter pipe to maintain the system in operation, and during the winter months the temporary 24-inch diameter line would be replaced with permanent 48-inch diameter pipe. Foothills (Yukon) felt that very little loss of throughput would result with the reduced diameter repair line due to the decreased demands on the system during the summer months.

Similar procedures would be followed in the event of a failure at a river crossing during a period of spring break-up when the water level was high and ice flows prevented dredging and placing a new crossing. Foothills (Yukon) proposed that a tow cable would be placed alongside the pipe at each of the river crossings for this purpose. A larger diameter pipe would replace the temporary crossing in the summer months when conditions would be suitable for dredging.

Foothills (Yukon) proposed that the operations and maintenance personnel would be drawn from its parent companies in the south, from other pipeline systems and from towns and communities in the north. Although a staff turnover would be expected in the northern regions of the pipeline, Foothills (Yukon) was confident the turnover would not affect its ability to operate and maintain the pipeline system.

Views of the Board

The Foothills (Yukon) project is accessible year-round by public highways and, to that extent, its operations and maintenance procedures would be traditional. The Board at this time has no comments to make other than that Foothills (Yukon) might have to adjust its operations and maintenance procedures to reflect monitoring requirements which might be imposed as a condition of the Board's approval of the operations and maintenance procedures.

3.3.3.8 Cost of Facilities

Capital Cost Development

Foothills (Yukon) facilities would include 512.6 miles of 48-inch O.D. mainline and seven compressor stations in the Yukon Territory and British Columbia, 159.8 miles of 42-inch O.D. mainline and two compressor stations in the Province of Saskatchewan and the necessary ancillary facilities for both pipeline systems, designed for the receipt of 2.4 Bcf/d by the second operating year.

The estimated cost of the facilities was based on 1976 prices for labour, materials, equipment and supplies as quoted by vendors, manufacturers, contractors and consultants.

The following escalation rates were utilized to convert the 1976 dollar estimate to the year of material purchase or installation.

ESCALATION RATE

COST COMPONENT	(per cent) 1977	1978	1979	1980	1981+
Line Pipe	6.7	6.5	7.0	6.5	6.0
Wages & Salaries	11.3	8.5	8.0	8.0	7.5
Non-residential Construction Materials	7.8	6.5	6.5	6.0	6.0
Construction Machinery and Equipment	6.3	6.0	6.0	6.0	6.0
Land, Freight, Communications, Miscellaneous	7.3	6.0	5.5	5.5	5.5
Compressors, Turbines and Related Equipment	5.2	6.5	6.0	6.0	6.0

The escalation rates for 1977 reflected the anticipated change from the first quarter of 1976 to mid-year 1977. The escalation rates for 1978 reflected the anticipated change from mid-year 1977 to mid-year 1978 and similarly for each successive year.

The contractual arrangements (target-type) for the construction of the mainline would be the same as those proposed in the Foothills application (as outlined in the Foothills Cost of Facilities section).

The estimates of construction costs for the Yukon segment were developed after a limited assessment of the terrain was made and after various route reconnaissances. According to Foothills

(Yukon), the reconnaissances established the optimum route for construction and river crossings. More specific helicopter reconnaissances determined the appropriate river crossings and the environmental impacts. In addition, a drilling reconnaissance program was conducted, particularly at river crossing locations.

Marine Pipeline Construction of Canada Limited determined the labour requirements and also the type of labour, the labour rates, as well as the equipment, miscellaneous materials, supplies and fuel requirements for the originally proposed 42-inch diameter line across Yukon and Canuck Engineering Ltd. was requested by the Applicant to review Marine Pipeline's original cost in estimates.

Foothills (Yukon), with the assistance of Marine Pipeline, updated the 42-inch diameter pipeline costs to develop costs for the 48-inch diameter pipeline system now applied for and developed the additional equipment and personnel required for the installation of 48-inch diameter x 0.54 W.T., Grade 70 pipe.

Labour rates for pipeline construction were based on 1971 rates from the Pipeline Contractors' Guide. Salaries were estimated on an 84-hour work week including overtime premiums and related benefit costs.

Construction equipment costs were estimated on the basis of the Applicant renting the equipment either from the contractor or from other suppliers at the rates contained in the Contractors' 1976 Equipment Rental Guide. The equipment ownership costs were estimated on new replacement value and salvage value.

Foothills (Yukon) had surveyed the pipeline construction industry in Canada and determined there would be no equipment shortages.

Cost Summary

The escalated costs of facilities designed to carry an ultimate throughput of approximately 2.4 Bcf/d of Prudhoe Bay gas by the second operating year were $1,310 million for the Yukon section and $192 million for the Saskatchewan section for a total of $1,502 million.

The following is a summary of the escalated construction costs of the total facilities:

FOOTHILLS (YUKON)

ESCALATED COST OF FACILITIES

(Millions of Dollars)

DIRECT COSTS	YUKON SECTION	SASKATCHEWAN SECTION
Land and Land Rights	2.0	1.0
Pipeline	650.5	104.6
Compressor Stations	92.0	35.4
Support Facilities	146.2	
Operations and Maintenance	22.6	3.8
Meter Stations		3.9
Communications	5.6	0.7
INDIRECT COSTS		
Pre-Permit	15.8	2.5
Head Office and Pre-Operation	35.2	5.6
Engineering	36.8	6.0
Contingency	45.9	7.5
Allowance for Funds Used During Construction	257.2	21.2
TOTAL	$1,309.8	$192.2
GRAND TOTAL	$1,502.0	

Major Direct and Indirect Cost Categories

Basically, the major items of the Cost Table were developed on the same basis as shown in the Foothills Cost of Facilities section of the report.

Installation Costs

The Applicant stated that the Marine Pipeline estimate filed in support of the originally proposed Foothills (Yukon) 42-inch diameter system, and the Canuck report which accompanied that estimate, were used to estimate the costs of the proposed 48-inch diameter system. Adjustments to manpower and equipment lists were made to reflect the proposed larger diameter pipe.

The original mainline installation cost in the Yukon, estimated to be $64.62 per foot (in unescalated dollars) for the 42-inch diameter line, was increased by about 19 per cent to $77.31 (unescalated) for the newly proposed 48-inch diameter pipeline facilities.

CAGPL argued that the installation cost of the 48-inch diameter Alcan pipeline would be in the order of $159 per foot and requested an explanation as to why Alcan's installation costs were more than double those used by the Applicant. Foothills (Yukon) commented briefly on the difference by alleging that two countries were involved with different union agreements, with different productivities, and the terrain was possibly different.

In answer to CAGPL as to whether the installation cost increase of 19 per cent was representative of the difference in installation costs between a 42-inch and 48-inch pipeline generally, the Applicant stated that this figure was arrived at by going back to the estimates and labour requirements which were upgraded to the degree felt appropriate for the 48-inch pipe.

The Applicant provided $384,000 for a special ditch design in the seismic sensitive area of the Shakwak Trench.

Adjustments

Adjustments were made to the estimated cost of the 48-inch diameter line as a result of cross-examination on the 42-inch diameter Foothills (Yukon) application during January 1977. These adjustments were summarized as follows:

(a) under cross-examination on the 42-inch diameter case, it was determined that an amount of $3,512,000 had been omitted from camp costs and this sum was added to the 48-inch diameter case;

(b) cross-examination relating to the Shakwak Fault revealed that two valves were required and an amount of $270,000 was added to the 48-inch diameter costs;

(c) since the chilling point cut-off was changed from 110 miles in the 42-inch case to 40.8 miles for the 48-inch case, the frost heave costs were decreased by $498,000 to account for the reduction in insulation; and

(d) also during cross-examination, it was brought to the Applicant's attention that its hydrostatic testing costs were not adequate, and after further study Foothills (Yukon) determined that it should increase the estimate for hydrostatic tests by about $4 million.

The Applicant's 48-inch O.D. x 0.540 W.T. pipe requirements for its Yukon pipeline were assumed to be 208,000 tons in 1979 and 173,000 tons in 1980 but it planned to pre-purchase 137,000 tons of pipe in 1978 to avoid the pipe demand crest in 1980.

The Applicant did not plan to purchase pipe construction equipment but would rent it from the construction contractors or from third parties.

Logistics Costs

In the 48-inch diameter cost estimate, both the tonnage moved and the application of the logistics costs were determined by Foothills (Yukon) staff. CAGPL stated that a logistics cost report prepared by Trimac Consulting Services Ltd. indicated costs $5 million lower than those prepared by the Applicant. Foothills (Yukon) stated that its logistics costs would be revised, if necessary, after a study was made of the Trimac report.

Cost Penalty of Operating at 1,080 psig

Foothills (Yukon) estimated, that if it was not certain that the pipeline could be operated at 1,260 psig after the initial 15-month period of operating at the derated pressure of 1,080 psig, 2,000 fracture arrestors could be installed as a corrective measure. The use of concrete weights as crack arrestors would add another $3 million to the estimated cost of the project.

Views of the Board

The Board considers that the Applicant has not had sufficient time to make the necessary terrain analysis and to finalize its design in respect to frost heave and thaw settlement control in the Yukon section.

As discussed in the Facilities Design section of the report, it is possible, once the Applicant's soil studies are completed, that the chilled cut-off point may be extended beyond 40.8 miles in Yukon; that more suitable methods may be required to prevent frost heave or to protect pipe movement caused by thaw settlement; and that installation of chilling equipment may be required in the Yukon to keep the gas temperature below 32°F.

The Board has made a preliminary estimate of the costs involved to account for the above frost heave and thaw settlement controls. It assumed that the length of the frost heave controls would be extended to milepost 82.4, that is, at the location of the intermediate station proposed for future gas expansion. Since the Applicant did not take into account thaw settlement control the Board assumed that about 70 miles of thaw settlement control would be required. In its study, it assumed that the length of the frost heave and thaw settlement controls could extend to 152 miles and assumed an average additional cost of $2 million per mile. The $2 million per mile additional cost to the estimated construction cost of $2.55 million a mile gives a total of $4.55 million per mile compared with $5.69 million per mile for CAGPL and $4.78 million per mile estimated by Alcan.

The following table illustrates the potential degree of cost under-estimation as estimated by the Board.

ESTIMATED COSTS WITH FROST HEAVE RE-DESIGN

	Costs (Millions of Dollars)
Frost Heave Controls Estimated by Staff	305
Applicant's Estimated Cost	1,502
Total Estimated Costs	1,807

The Board believes, therefore, that the estimated costs are somewhat under-estimated in Yukon and could increase by some 20 per cent depending upon the final design in the permafrost areas. It considers the costs for the Saskatchewan section of the pipeline to be generally acceptable.

3.3.4 WESTCOAST

3.3.4.1 Facilities Design and Capacity

As part of the Foothills (Yukon) project, Westcoast proposed to construct two segments, one in northeastern British Columbia and the other in southeastern British Columbia.

Northern British Columbia Section

Facilities Location Description

The northern British Columbia pipeline would consist of approximately 439 miles of 48-inch O.D., generally of 0.540 W.T., Grade 70 pipe to operate at 1,260 psig (80 per cent of SMYS) connecting with the proposed facilities of Foothills (Yukon) at a point on the Yukon-British Columbia border near Watson Lake, Yukon Territory and with proposed facilities of Trunk Line (Canada) on the Alberta-British Columbia border near Boundary Lake.

Summary of Projected Gas Volumes

The following table outlines the peak day summer gas volumes proposed for transmission through the Westcoast northern British Columbia pipeline.

WESTCOAST

PEAK DAY SUMMER GAS VOLUMES

(MMcf/d)

Section	Operation year 1	2
Northern British Columbia		
Watson Lake Receipt	1624.9	2429.9
Fuel	15.9	32.9
Boundary Lake Delivery	1609.0	2397.0

System Configuration

The routing of the proposed mainline in northern British Columbia was determined by considering the following:

(a) expected environmental impact;

(b) existence of seismic cut lines and winter roads;

(c) anticipated location and accessibility of compressor stations;

(d) existence of the Alaska Highway, its future development and other kinds of infrastructure;

(e) location of Westcoast's existing pipeline facilities;

(f) proposed hydro power development on the Liard River; and

(g) total mileage of pipeline.

Westcoast had held discussions with the Federal Department of Public Works regarding the long-term planning for further development of the Alaska Highway system. Although the Department of Public Works plans were very preliminary, there was only a remote chance that the proposed pipeline route would be affected by proposals to relocate several sections of the highway in the future.

Westcoast indicated that there might be hydropower development on the Liard River in the late 1990's and dams could affect the proposed mainline between mileposts 17 and 148. The mainline would cross potential water reservoirs created by dams in at least four locations. To avoid pipeline buoyancy problems at these locations, Westcoast proposed to employ weighted heavy wall 48-inch O.D. x 0.72 W.T., Grade 70 pipe during the construction of the line for a distance of about 34 miles.

Westcoast proposed to employ, for a distance of about 25 miles, 48-inch O.D. x 0.60 W.T., Grade 70 pipe where the pipeline would cross deep muskeg.

Pipe Size

The pipe size was selected as 48-inch diameter to be consistent with that of other segments of the Foothills (Yukon) project.

Station Design and Capacity

Westcoast proposed to install five compressor stations at spacings of 76 miles. Three stations would be installed in 1981 and the other two in 1982. Compression of 48,000 horsepower (dual 24,000 horsepower gas turbine driven centrifugal compressors) would be installed at each station.

In selecting compressor size and station spacing the Applicant used the following criteria:

(a) to install a unit with a capacity of 105 per cent of the summer peak day flow; and,

(b) to achieve capacity of about 3.2 Bcf/d in the future by the addition of intermediate stations.

Westcoast's reasons for installing five per cent additional capacity were to allow for changes in transmission factors, to take account of transient flow conditions within the system, and to compensate for the loss of turbine horsepower due to seasonal fluctuations in ambient temperature.

System Reliability

The Applicant performed reliability studies to predict the operation of its northern British Columbia line in the year 1982. The computer studies determined the system throughputs in the event of a particular compressor unit or station failure while maintaining a minimum delivery pressure of 1,260 psig at the discharge of Station A-5 near Boundary Lake.

With a shut-down of the most critical unit, Westcoast's system could deliver about 2,258 MMcf/d to Trunk Line (Canada) during the summer season. Since the average day flow requirement for the summer season would be 2,255 MMcf/d, the system would not suffer any loss in throughput on an average day under these conditions.

Westcoast found no technical reasons to prevent the operation of its northern British Columbia pipeline at the design pressure of 1,260 psig during the first 15 months of operation; nonetheless, as a matter of consistency with the proposed operation of Foothills (Yukon) Westcoast proposed to operate its mainline system at the reduced pressure level of about 1,080 psig during this 15-month period. At this reduced pressure the

Applicant would still be able to transport its projected gas volume of 1.6 Bcf/d.

At the maximum operating pressure of 1,260 psig, the relationship between operating pressure and specified minimum yield strength for the 48-inch O.D. line was as follows:

(a) in the flooded area at the future dam sites in northern British Columbia, Class 2 area 48-inch O.D. x 0.72 W.T., Grade 70 pipe would be hydrostatically tested to 100 per cent of the yield pressure but would be operated at 60 per cent of the yield pressure;

(b) in the muskeg area, Class 1 area, 48-inch O.D. x 0.60 W.T., Grade 70 pipe would be tested with air to 90 per cent of the yield pressure but would be operated at 72 per cent of the yield pressure;

(c) in the farmland or dry land area, Class 1 area, 48-inch O.D. x 0.54 W.T., Grade 70 pipe would be hydrostatically tested to 100 per cent of the yield pressure but would be operated at 80 per cent of the yield pressure.

Southern British Columbia Section

Facilities Location Description

The southern British Columbia pipeline would consist of approximately 106.1 miles of 36-inch O.D. x 0.405 W.T., Grade 70 pipe connecting with proposed facilities of Trunk Line (Canada) near Coleman, Alberta and would connect on the international boundary near Kingsgate, British Columbia with the facilities of PGT.

Summary of Projected Gas Volumes

The following table outlines the peak day summer gas volumes proposed for transmission through the Westcoast southern British Columbia pipeline:

WESTCOAST

PEAK DAY SUMMER GAS VOLUMES

(MMcf/d)

Section	Operating Year 1	Operating Year 2
Southern British Columbia		
Coleman Receipt	472.0	689.3
Kingsgate Delivery	472.0	689.3

System Configuration

The routing of the proposed line in southern British Columbia was determined by considering the following:

(a) expected environmental impact;

(b) location of the existing pipeline right-of-way of Alberta Natural Gas; and

(c) total mileage of the pipeline.

During the cross-examination, Westcoast's policy witness admitted that the southern British Columbia link was a duplication of the existing ANG pipeline. He stated that, in the adversary circumstances, the Applicant could not ask its competitor (ANG) to design this segment of the pipeline in southern British Columbia. In addition, the policy witness stated that Westcoast had not changed its philosophy of making use of existing facilities and it would not run past an existing facility without very good reason, but under the circumstances the only recourse Westcoast had was to file with the Board a complete application, i.e., including the southern segment from Coleman to Kingsgate, British Columbia.

Westcoast's pipeline system would parallel ANG's pipeline and cross it at 15 locations to gain a more favourable location.

In addition, the proposed pipeline would pass through two provincial parks in the Province of British Columbia. Westcoast admitted during cross-examination that the British Columbia government might not be receptive to another right-of-way through provincial lands in southern British Columbia.

Pipe Size

The Applicant stated that no studies were made from an economic point of view on the line size proposed in southern British Columbia. The selection of line size was based on the size requested by the prospective purchaser in the United States, of the Alaska natural gas.

Station Design and Capacity

No compressor stations were proposed for this section of line. If the line's operating pressure were increased to 1,260 psig from the proposed 900 psig, the throughput capacity of 0.69 Bcf/d would increase to about 1.3 Bcf/d.

Views of the Board

Northern British Columbia Section

The Board agrees with the Applicant's choice of 48-inch O.D. x 0.54-inch W.T., Grade 70 pipe for the northern British Columbia section.

The Applicant satisfied the Board that this 48-inch diameter pipe when operated at the maximum allowable operating pressure of 1,260 psig with 48,000 (twin 24,000 units) horsepower compressors every 76 miles, would provide the lowest cost of service for the planned throughput of 2.4 Bcf/d in the second operating year.

The Board's view is based on Trunk Line (Canada)'s study which proved that 48-inch O.D. x 0.54 W.T., Grade 70 pipe planned to be operated at 1,260 psig and 76-mile compressor station spacing was the optimal design. Westcoast made no study to justify its line size but adopted the rationale of its partners for line sizing.

The Board agrees with Westcoast's intention to operate its pipeline at the reduced pressure of 1,080 psig rather than the design pressure of 1,260 psig for the first fifteen months. This reduced pressure will provide a measure of security during the start-up period and allow monitoring of pipeline movements. Based on the Applicant's experience, at the end of the 15-month period, the Board will give consideration to increasing the maximum allowable operating pressure to 1,260 psig.

Westcoast designed its pipeline so that with the loss of the critical compressor unit, it can deliver its average day throughput. This degree of reliability is similar to that proposed by CAGPL whereas the other participants in the Foothills

(Yukon) project, i.e. Foothills (Yukon) and Trunk Line (Canada) have designed their systems to meet an annual requirement after taking account of both planned and unplanned outages but not to meet the average daily level of throughput on any one day with the loss of a critical unit. In the absence of any firm transportation contracts, the Board is unable to say which degree of reliability would be required for the system.

Westcoast has provided for two single unit gas turbine driven compressor units at each compressor station rather than one larger single unit. The double unit station is more costly than a single unit station but it reduces the loss in throughput with the loss of a compressor unit and allows for planned maintenance. The Board agrees with Westcoast's design particularly as its system is more remote and more difficult to reach than the facilities of the other participants in the Foothills (Yukon) project.

Southern British Columbia Section

The Board believes that a new pipeline system through southeastern British Columbia would be a duplication of an existing system which would result in a greater environmental impact than would an expansion of the existing system.

ANG is a member of the CAGPL project and has applied for facilities to transport similar volumes of gas in connection with that application. In the event that the Board were to certificate the Foothills (Yukon) project, consideration should be given to the apparent advantages of approval of the ANG application in lieu of the southern British Columbia section of the Westcoast application.

3.3.4.2 Geotechnical and Geothermal Design

Frost Heave

Westcoast testified that it believed that it would not experience any difficulties due to frost heaving. This belief was based on its flowing temperature calculations which indicated that, while the winter flowing temperature is a bit below freezing, the summer flowing temperatures are well above freezing. Westcoast was confident that any frost heave that occurred during the winter would be mitigated through melting during the summer.

In evaluating the flowing temperature of the originally proposed 42-inch diameter pipeline, Westcoast had employed what is known as the Schorre equation. Westcoast testified that this equation contained an error, and that a different, and correct, equation had been employed in calculating the flowing temperatures in the case of the now proposed 48-inch diameter pipeline.

In cross-examination, Westcoast stated that it relied on the warm operation of its proposed pipeline in summer to melt any ice that might have formed during the winter. It also indicated that it relied on certain values of the average summer soil temperature, in particular, a summer soil temperature of 53° F to ensure operation at above-freezing temperatures. Westcoast indicated that it was confident that the summer soil temperatures would reach this level even though both Foothills (Yukon) and

CAGPL used considerably lower summer soil temperatures in adjoining regions.

Westcoast's application shows that the same summer soil temperature was used in the preparation of flow studies for the proposed southern British Columbia pipeline.

Thaw Settlement

Westcoast testified that permafrost occurred in scattered peat bogs along its proposed route. It was indicated that these permafrost areas generally were not frozen to a great depth and that, in the majority of cases, the permafrost could be completely excavated and the pipe placed on the stable soil beneath it. In areas of deeper permafrost Westcoast indicated that the pipe would be weighted for neutral buoyancy and the permafrost permitted to melt. The Applicant testified that this procedure had worked well in the past and it was confident that it would work equally well in the case of a 48-inch diameter pipeline.

Seismic Design

Westcoast indicated that it considered its proposed pipeline to be safe as proposed for seismic events with a return period in excess of 1000 years.

Terrain Evaluation

Westcoast testified that its terrain analysis was based, primarily, on a fly-over of the proposed route in February of 1977, a month during which there was little or no snow, and on data available through the interpretation of seismic shot hole logs. It was indicated that these logs generally confirmed the results of the aerial reconnaisance.

River Crossings

Westcoast testified that there would be several significant river crossings along its proposed route.

Views of the Board

With regard to the Westcoast terrain analysis, the Board is of the opinion that additional work would be required by Westcoast before its designs could be finalized.

Westcoast did not satisfy the Board that frost heave would not be a problem along the applicants proposed pipeline. Accordingly, as a condition of any certificate which might be issued, Westcoast would be required to satisfy the Board that significant frost heaving would not occur.

With regard to thaw settlement, the Board is satisfied that, if Westcoast's terrain assessment confirms its current information on this subject, the measures proposed by Westcoast to mitigate the effects of thaw settlement are adequate.

With regard to such matters of a geotechnical nature as slope stability, river crossings and pipeline monitoring, the Applicant would be required to satisfy the Board as to the adequacy of the final design in these areas.

3.3.4.3 Stress Analysis and Materials Engineering

Stress Analysis

Introduction

Westcoast did not submit a documented stress analysis study. It considered that a stress analysis for the different loading situations of the pipeline was not required because of estimated low seismic loading, its intention to remove permafrost beneath the pipeline and its construction method of weighting the pipeline for zero buoyancy in muskeg areas.

Reference was made to seismicity and Westcoast estimated that areas where the 48-inch diameter mainline was located would experience maximum earthquakes of three per cent acceleration of gravity, based on a 100-year return period. The area of the proposed pipeline was described as having an expected return period of between 500 and 1000 years for an earthquake shock of ten per cent acceleration of gravity. Even allowing for a factor of uncertainty of two, which would change the three per cent of gravity (100-year return period) to six per cent, Westcoast claimed that it was well below the ten per cent gravity acceleration commonly believed to cause damage to ordinary structures. A pipeline was considered by Westcoast to be stronger than an ordinary structure. In addition, the proposed pipeline would not cross any known geological faults. Therefore, Westcoast did not feel it was necessary to conduct an earthquake load analysis.

Based on Westcoast's field observations and experience, permafrost conditions on the mainline were expected to be of the lens variety, having an active layer some 18 inches deep and a maximum lens thickness of three to four feet. Since the pipeline trench for the 48-inch diameter mainline would provide a minimum of 30 inches of pipeline cover, it was expected that the pipeline would be resting on firm soil beneath the permafrost. For this reason and because the pipeline would be operated in a warm mode, Westcoast did not expect any overloading of the pipeline due to frost heave or thaw settlement and therefore did not perform any free span stability calculation.

Westcoast expressed confidence in its experience in building and operating lines as large as 36 inches in diameter in the same geographical area. For the construction of the 48-inch diameter pipeline, Westcoast would follow the methodology proven by its extensive, satisfactory experience with winter construction in muskeg terrain. An essential element in this technique was to minimize restraint, thus allowing the pipeline freedom to move, either up or down, in service. This had resulted in pipelines being buoyant for lengths up to 100 feet, but still operating satisfactorily.

Westcoast did not feel that it was essential at this time to conduct a stress analysis for any of the external forces; the only calculation it performed was a computation of the hoop stress due to the internal pressure.

Design and Test Criteria

Since Westcoast performed only the hoop stress calculation, it required only one design criterion with respect to limiting stress, which was stated in the CSA Standard Z184 to be 80 per cent of SMYS for testing with water and 72 per cent of SMYS for testing with air. This criterion would apply except in areas where Westcoast expected the mainline to be inundated by the water from reservoirs created by river dams to be constructed by B.C. Hydro in the future.

Westcoast intended to test the 48-inch diameter, 0.540-inch, 0.600-inch and 0.720-inch wall thickness pipeline sections situated on solid ground to 100 per cent of SMYS, using water as the pressurizing medium. All of the 0.600-inch wall thickness pipe which was in muskeg terrain would be tested with air to 95 per cent of SMYS. All of the 36-inch diameter pipe was to be tested with water to 100 per cent of SMYS.

Materials Engineering

Introduction

Westcoast stated that, for the northern section, it would be using 48-inch diameter pipe with three different wall thicknesses (0.540-inch, 0.600-inch, 0.720-inch) of Grade 70, all with the same fracture toughness at 25°F (Cv minimum of 50ft-lbs and Cv average of 80 ft-lbs). Required shear area for the drop weight tear test at 25°F was a minimum of 60 per cent and an average of 85 per cent. In the southern section, Westcoast proposed 106 miles of 36-inch diameter, 0.405-inch wall thickness, Grade 70 pipe, with the same fracture toughness requirements as the 48-inch diameter pipe.

Westcoast adopted fracture arrest as its fracture control criterion. The Applicant claimed that the specified fracture toughness was thought to be the highest available in project quantities from Canadian mills, while approaching those values of toughness predicted for the arrest of propagating ductile fractures by the experiments conducted at the Battelle Memorial Institute and the American Iron and Steel Institute.

Crack Arresting

Although Westcoast did not consider that derating of the operating pressure during the first 15 months of operation would be required for technical reasons, it decided to select an operating pressure of 1080 psig to be consistent with that of Foothills (Yukon).

Westcoast's fracture control approach and specified fracture toughness based on the Battelle Hypothesis were comparable with those of Foothills (Yukon). Ductile fracture arrest relied on high fracture toughness and fracture-arresting ability of natural crack arrestors such as valves, fittings and heavy wall pipe in river and road crossings. Also, concrete weights would be attached to the line in the reservoir and muskeg areas. Westcoast did not plan to install special concrete weights for the purposes of ductile fracture arrest.

Westcoast had not performed any formal burst tests to demonstrate the performance of concrete weights as crack arrestors on a 48-inch diameter pipe. However, Westcoast did observe fracture arrest under the concrete weights in field failures on its existing pipelines. Furthermore, Westcoast would be participating with Foothills (Yukon) in future burst tests.

Materials Specifications

In revision 36 of Westcoast Specification 102, the chemical composition as determined by a check analysis, was substantially revised from the previous composition applicable to the 42-inch diameter project, as reflected in a carbon content of 0.10 per cent maximum and a manganese content of 0.80 per cent maximum. The maximum carbon equivalent would not exceed 0.50 per cent, as determined by a check analysis.

Full transition curve was required for 20 per cent of the heats rather that the 10 per cent commonly specified for impact toughness testing.

Material Supply and Availability

Foothills (Yukon) co-ordinated the line pipe requirements for all three participating companies. From its acquisition schedule, it would follow that the total 48-inch diameter tonnage requirement of 336,000 tons for Westcoast would be supplied by the Stelco Stelform mill at Welland and the 36-inch diameter tonnage requirement of 45,000 tons would be obtained from the Stelco pipe mill at Camrose over the time period 1978 to 1981.

As Westcoast planned to install valves at regular intervals of 20 miles, this would mean a substantial demand for large diameter valves, and Westcoast doubted whether these would be purchased in Canada.

Views of the Board

Stress Analysis

Considering the benefits to be derived for carrying out a stress analysis and ready availability of applicable computer programs, it is the view of the Board, that a project of this dimension should be supported by a detailed stress analysis based on site-specific input data. All applicable external loads should be considered in the analysis and resulting stresses and strains compared to established design criteria. If a certificate were granted, it wold be conditioned to require the Applicant to submit such an analysis to the Board for consideration as part of final design approval.

Materials Engineering

The selection of line pipe dimensions and steel properties for the mainline as well as for the pipeline components was adequate. In view of Westcoast's proposed route containing areas of difficult accessibility, and/or unstable soil conditions, the Board believes that Westcoast should carry out a burst test of its proposed pipe to ascertain the possible need for crack-arresting devices.

As suggested during the hearing, Westcoast's participation in a burst test proposed by Foothills (Yukon) would be satisfactory to the Board.

Materials Specifications

The Applicant would be required to submit final and project specific specifications covering in detail properties, dimensions, manufacture, testing and inspection of line pipe and pipeline components. In these specifications, special attention should be given to all types and phases of welding and inspection of welds.

Supply and Availability

There are no evident problems with the supply of line pipe. Westcoast's plan to acquire line pipe from Stelco over a period of four years, in co-ordination with Foothills (Yukon) and Trunk Line (Canada), is acceptable to the Board.

3.3.4.4 Right-of-Way

In northeastern British Columbia, Westcoast stated that the widths of the proposed rights-of-way would be approximately 70 feet (for summer construction) or 100 feet (for winter construction) while it claimed that it would be able to construct its pipeline in southeastern British Columbia within a 60-foot wide right-of-way. In the latter area, it was planned to generally parallel the existing right-of-way of Alberta Natural.

Westcoast stated that it had applied to the Lands Branch, Department of Lands, Forests and Water Resources of the Province of British Columbia for a Crown grant for the required rights-of-way.

Westcoast also confirmed its awareness of the requirements in respect of the crossings of navigable waters, as well as the crossings of railways, highways and other utilities.

It was confirmed that the provisions of section 74 of the NEB Act, which deals with the taking of lands without the consent of the owner, would be adhered to.

Views of the Board

Westcoast, in the past, has complied with the requirements and provided proof of its understanding of and cooperation with landowners in problem areas relating to right-of-way matters and has been highly successful in negotiating for rights-of-way.

The Board would, nevertheless, require that Westcoast comply with all of the Board's directions regarding the acquisition of rights-of-way and other lands, including but not necessarily limited to specific directions as to the rights of and notice to all potentially affected property owners to ensure an orderly land acqusition and an equitable settlement program.

3.3.4.5 Communications

To provide the necessary communications facilities for its proposed pipeline, Westcoast intended to make use of its existing extensive telecommunications system composed of Company-owned and leased facilities. It indicated that modest additions or modifications would be made to these facilities in order to accommodate the requirements of the proposed additional pipeline facilities.

The Applicant indicated that the present communications system included the following:

(a) four leased full-time party line or selective private telephone channels interconnecting all Company compressor stations, offices, warehouses and other fixed installations throughout the entire operating area;

(b) a two-way radio system, owned by Westcoast, providing mobile radio coverage along the pipeline rights-of-way and contiguous highways throughout the existing pipeline system; and

(c) remote control/telemetry/data acquisition facilities located in all compressor stations, processing plants and major sales metering stations, operated under the control of a computerized master station in the gas control centre in Vancouver.

This control/telemetry/data acquisition system would provide the gas control centre with current information regarding volumes into and out of the pipeline system, pressure and line pack conditions, station and unit operating parameters, alarms and status, etc. The control system would also provide for remote starting and stopping of compressor units and stations and for the adjustment of discharge pressure set points, thus allowing the remote, unattended operation of the pipeline.

Views of the Board

The Board accepts Westcoast's proposal to make use of its existing communications system, with minor additions or modifications, thus avoiding the unnecessary duplication of facilities. The Board agrees that this system is capable of providing the high level of availability and reliability required for the safe, efficient operation of the pipeline.

3.3.4.6 Construction

Northern British Columbia

Westcoast proposed to construct approximately 438.7 miles of 48-inch diameter pipeline from a location near Watson Lake, Yukon, to the Alberta-British Columbia border near Boundary Lake. The Applicant proposed to start construction of the pipeline during the winter of 1979-80, and complete the system by September of 1981. The construction program would be a continuous two-year program with construction activities ceasing only during break-up and freeze-up in the two-year period. The Applicant proposed the employment of two construction spreads during the four construction seasons, and during the 1980-81 winter season, one spread would be devoted solely to river crossing construction.

Westcoast expected to encounter only permafrost of the lense variety, having an active layer of some 18 inches in depth and a maximum lense thickness of three to four feet. The Applicant proposed to provide a minimum of 30 inches of pipeline cover and expected that the pipeline would be on firm soil beneath the permafrost.

Westcoast proposed that standard winter and summer pipeline construction techniques would be used for the construction of the pipeline and also for the construction of the compressor stations and meter stations.

Westcoast proposed that existing highways and railways would be used to transport material and equipment to the north. Permanent or temporary access roads would be used to gain access to the pipeline right-of-way.

Southern British Columbia

Westcoast proposed to construct the 106 miles of 36-inch O.D. pipeline from the British Columbia-Alberta border to the British Columbia-United States border paralleling the existing ANG pipeline right-of-way. The proposed pipeline would be constructed during two consecutive summer construction seasons. Standard pipeline construction practices would be employed.

Views of the Board

Northern British Columbia

The Board feels that the Westcoast project would be a standard type of pipeline project constructed in an area where the Applicant has had considerable experience in construction of pipeline and compression facilities. If, during the course of construction, the Applicant requires additional equipment or materials, it has the advantage of access to the pipeline from existing permanent roads and railroads.

However, if a certificate were issued, it would be conditioned to require the Applicant to file its construction specifications for approval of the Board in advance of any pipeline construction.

Southern British Columbia

The Board is satisfied that Westcoast could build the pipeline facilities as proposed in southern British Columbia, but notes that the route would parallel that of the pipeline presently being operated by ANG, an Applicant in these proceedings for competing facilities within its own right-of-way. In the absence of other compelling reasons, the Board would question the wisdom of certificating Westcoast, in light of the operating experience of ANG in this area.

3.3.4.7 Operations and Maintenance

Northern British Columbia

Westcoast proposed that an operations head office would be established in its present Vancouver office, with a permanent staff increase of approximately fifteen per cent.

It was proposed that minor modifications to its existing operating, communications and maintenance facilities would be required for the proposed system. Compressor stations and sales metering facilities would be equipped with remote control, telemetry and data acquisition facilities operated under the control of its Vancouver office.

Westcoast proposed to establish an operations and maintenance base at Watson Lake which would contain some equipment for pipeline maintenance.

Southern British Columbia

The Applicant proposed to operate the pipeline in the same manner as its existing pipelines in British Columbia. The pipeline would be managed and controlled from the existing head office in Vancouver.

Views of the Board

The Board is satisfied that the proposed operations and maintenance procedures projected by the Applicant are satisfactory; however, if a certificate were granted, a condition would be included requiring the Applicant to submit its operations and maintenance plans for review and approval by the Board.

3.3.4.8 Cost of Facilities

Capital Cost Development

Westcoast proposed facilities that would be required for a gas flow of 1.6 Bcf/d in the operating year 1981-82. Applications for future facilities would be submitted when the need could be more accurately established.

Westcoast's cost estimates were based on its experience gained in the design, construction and operation of pipelines in similar terrain in British Columbia, the Yukon and Northwest Territories.

The estimated cost of the facilities was based on 1976 prices for labour, materials, equipment and supplies as quoted by vendors, manufacturers and contractors.

Westcoast utilized a composite escalation rate of eight per cent to convert the 1976 estimate to the year of material purchase or installation. According to Westcoast, it reviewed estimates made by others and decided this percentage was adequate.

Construction equipment costs were estimated based upon the Applicant renting the equipment either from the contractor or from a third party. The provision for the rental of equipment was based on ten per cent of equipment replacement cost and expressed in dollars per month for the duration of the rental.

The estimate of the cost of the 48-inch diameter mainline was based on the original cost submitted for the 42-inch diameter mainline. These costs were adjusted to reflect the larger diameter.

Westcoast developed a computer program to prepare its definitive cost estimate for installation of facilities. Project requirements were subdivided into 28 tasks to which were assigned various numbers of personnel and equipment costs. Project costs were then estimated taking into account the current labour rates, equipment rates, and costs of expendables, etc.

Westcoast anticipated that the proposed pipeline would be constructed under a target-type contract. Under this type of contract the Applicant and the contractor would share the normal risks associated with pipeline construction, with the contractor receiving a profit of approximately ten per cent and an additional five per cent for office overhead costs.

Cost Summary

The following is a summary of the escalated construction costs for the facilities required in 1981-82.

WESTCOAST

ESCALATED COSTS OF FACILITIES

(Millions of Dollars)

Direct Costs	**Northern B.C.**	**Southern B.C.**
Land and Land Rights	$ 2.994	$ 2.244
Pipeline	783.607	117.331
Compressor Stations	51.325	
Meter Stations	4.407	3.349
Communication and Telecontrol	3.253	

Indirect Costs

Engineering	41.011	6.295
Contingency	55.625	8.073
Allowance for Funds Used During Construction	153.462	10.496
TOTAL	$1,095.684	$147.788
GRAND TOTAL	$1,243.472	

Major Direct and Indirect Costs Categories

(a) **Land**

Land costs included the purchase in fee simple of lands for permanent facilities. Land rights included the lease of an easement for the right-of-way, the lease of lands for temporary facilities during the construction period and the associated acquisition costs.

Land costs were based on the following assumptions:

(1) in northern British Columbia, a 70-foot right-or-way for summer construction, and a 100-foot right-of-way for winter construction. The extra right-of-way footage would be required for snow disposal; and

(2) in southern British Columbia, a 60 foot right-of-way would be required for the 36-inch O.D. pipeline.

(b) **Pipeline**

This category included the cost of all pipe, including taxes, internal-external pipe coatings and the installation of the pipeline, including river crossings, road and railway crossings, swamp weights, rock ditching, field radiography and miscellaneous construction. This category also included the costs associated with testing and start-up of the pipeline.

The following table illustrates Westcoast's pipe tonnage required for its mainlines, the price per ton of pipe and the pipe cost including freight, tax and internal coating costs.

WESTCOAST

BREAKDOWN OF ESTIMATED PIPE COST

Pipe Requirement	Pipe Size	Pipe Wall Thickness	Grade	Pipe Price (1)	Provincial Tax	Pipe Cost (2)
(tons)	(inches)	(inches)		($ per ton)	($ per ton)	($ per ton)
283,000	48	0.540	70	693.00	48.51	834.17
28,000	48	0.600	65	697.75	48.84	839.25
25,000	48	0.720	70	708.75	49.61	851.02
39,000	36	0.405	70	650.00	51.88	792.99
6,000	36	0.540	70	650.00	51.88	792.99

Notes:

(1) Pipe prices were Stelco's quotes.

(2) The pipe cost included an average freight cost of $86.41 per ton to construction sites.

Westcoast did not include any cost allowance to build access roads to its 36-inch diameter southern British Columbia line because it assumed that ANG's existing roads could be used, subject to mutual agreement between the two companies.

Westcoast was cross-examined on discrepancies between its estimated capital cost and cost of service and those of ANG for a similar segment (but operated at a lower pressure of 911 psig).

Westcoast's estimated capital cost was $147 million compared with ANG's estimate of $74 million.

At Westcoast's request, Finning Tractor and Equipment Co. Ltd. in Vancouver, British Columbia made a survey of the backhoes required for the construction of the Westcoast project. The survey results indicated that sufficient backhoes would be available in Canada to carry out the construction.

(c) **Compressor Stations**

Compressor costs were based on quotes from different manufacturers of gas turbine driven centrifugal compressor units. Westcoast had not committed its purchases of compressors but the Canadian content would vary from about 58 to 81 per cent depending upon the manufacturer selected.

(d) **Meter Station**

The meter station costs included permanent materials, equipment and installation costs.

(e) **Communications and Telecontrol System**

This cost included items such as microwave repeaters, microwave terminals, microwave spurs, upgrading of existing communications, telecontrol facilities and installation of the above equipment.

(f) **Engineering**

Engineering costs were estimated to be about five per cent of the total direct costs for the pipeline, communications and telecontrol system and meter stations, and two and one-half per cent of the compressor station costs.

(g) **Contingency**

The contingency was assumed to be six per cent of the total cost for the pipeline and ten per cent of the other items shown in direct costs and engineering.

Views of the Board

The Board agrees with Westcoast's design and does not consider that any abnormal construction problems will occur. In coming to this conclusion, it relies on Westcoast's experience in constructing and operating pipelines in these areas. The Board is confident that the experience and cost records of Westcoast have been fully utilized in the preparation of the estimates.

The cost estimates for this pipeline are summarized as follows:

	Costs (Millions of Dollars)
Materials	531.5
Construction Costs	431.7
Other Related Costs	280.3
Total Costs	1,243.5

The largest material item is the line pipe which is $425.3 million and includes known transportation costs to the site. The pipe costs were obtained by the Applicant from quotes from the manufacturers. The Board is of the opinion that the pipe costs should be realistic if the project adheres to the construction schedule and the assumed escalation factor of eight per cent is correct.

The second largest material item is the compressor units, the costs of which were obtained by the Applicant from quotes from the manufacturers and include known transportation costs to the site. If the project adheres to its construction schedule and the escalation factor is correct, these prices should be realistic.

The Applicant proposed target-type contractual arrangements for the construction of its pipeline facilities. On this basis, the Applicant and conractor would mutually agree on the equipment and labour costs which are reflected in the most part by the estimate plus a profit. Under such a contract, there would be an incentive for the contractor to maximize his profit by meeting or improving upon his construction schedules. The Board is of the opinion that the construction costs would not be exceeded, provided the construction schedule is adhered to and the assumed inflation factor of eight per cent is correct.

The Board is therefore prepared to accept as reasonable the Applicant's estimate of cost of $1,243.5 million for this project.

3.3.5 TRUNK LINE (CANADA)

3.3.5.1 Facilities Design and Capacity

Facilities Location Description

Trunk Line (Canada) proposed to construct 395 miles of 48-inch O.D. pipeline from the terminus of Westcoasts's 48-inch O.D. pipeline near Boundary Lake to James River; 235 miles of 42-inch O.D. line from James River to Empress to connect with the Foothills (Yukon) 42-inch O.D. pipeline in Saskatchewan and 176 miles of 36-inch O.D. delivery line from James River to Coleman to connect with Westcoast's 36-inch O.D. southern British Columbia pipeline. It would also construct eight compressor stations and three measurement stations within Alberta.

Summary of Projected Gas Volume

The following table outlines the average day summer gas volumes proposed to be transported in the Trunk Line (Canada) system:

TRUNK LINE (CANADA)

AVERAGE DAY SUMMER GAS VOLUMES

(MMcf/d)

Section	Operating Year	
	1981-82 (15 months)	1983
MAINLINE		
Boundary Lake Receipt	1,509.2	2,255.4
Fuel	9.4	19.2
James River Delivery	1,499.8	2,236.2
WESTERN DELIVERY		
James River Receipt	442.0	659.0
Fuel	-	0.3
Coleman Delivery	442.0	658.7
EASTERN DELIVERY		
James River Receipt	1,057.8	1,577.2
Fuel	3.1	7.0
Empress Delivery	1,054.7	1,570.0

System Configuration

Pipeline Routing

The proposed pipeline was selected, based on the following criteria:

(a) the shortest distance from the Westcoast interconnection to the existing Trunk Line right-of-way at Gold Creek;

(b) the location of existing Trunk Line pipeline facilities downstream from Gold Creek;

(c) economic analysis of land acquisition, pipeline construction, operation and maintenance; and

(d) minimization of negative environmental and social impacts.

Mainline Pipe Selection

The Applicant made an economic study of four cases to justify the 48-inch O.D. line size and the 1,260 psig operating pressure selected. The following is a summary of the results of the study:

TRUNK LINE (CANADA)

COMPARATIVE LINE SIZES AND RELATED

COST OF SERVICE FOR 2.3 Bcf/d

Pipe Specifications Diameter (inches)	Grade	Wall Thickness (inches)	Maximum Operating Pressure (psig)	Cost of Service (¢/Mcf/100 miles)
42	70	0.473	1260	2.45
42	70	0.63	1680	2.45
48	70	0.54	1260	2.30
48	70	0.72	1680	2.67

The 48-inch O.D. x 0.54 W.T., Grade 70 pipe at a maximum operating pressure of 1260 psig with 32,700 horsepower compressor units was selected because it would provide the lowest cost of service for the projected flows of 2.3 Bcf/d. The optimum volume for a 48-inch diameter pipeline operating at 1260 psig was calculated to be in the neighbourhood of 2.8 to 3.0 Bcf/d with intermediate stations in the 76-mile spacing.

Eastern Delivery Line to Empress

Similarly, the Applicant carried out another economic study of two cases to determine the optimum line size from James River to Empress, the results of which are summarized for the projected throughput of 1.6 Bcf/d.

TRUNK LINE (CANADA)

COMPARATIVE LINE SIZES AND RELATED

COST OF SERVICE FOR 1.6 Bcf/d

Pipe Specifications			Maximum	
		Wall	Operating	
Diameter		Thickness	Pressure	Cost of Service
(inches)	Grade	(inches)	(psig)	(¢/Mcf/100 miles)
42	70	0.473	1260	2.53
48	70	0.540	1260	2.79

The 42-inch O.D. x 0.473-inch W.T., Grade 70 pipe at a maximum operating pressure of 1260 psig with 32,700 horsepower compressor units was selected because of the calculated lower cost of service.

Western Delivery Line to Coleman

The Applicant also stated that, based on an economic study, the pipe selected for the James River to Coleman line was 36-inch O.D. x 0.405-inch W.T., Grade 70 pipe to be operated at 1260 psig on the basis of the lowest cost of service for the projected flows of 0.66 Bcf/d.

Station Design and Capacity

(a) Mainline:

Trunk Line (Canada) proposed five compressor stations, three to be installed in 1981 and the other two in 1982. The stations would be located every 76 miles and would have 32,700 horsepower compressor units.

To select the unit size and spacing between compressor stations, the Applicant considered the following criteria in an economic analysis:

(a) gas compressor equipment must be commercially available;

(b) selected units must be proven technology;

(c) the reliability and mechanical availability must be high; and

(d) gas compression units must be designed for set temperature conditions.

In addition, all compressor stations except Compressor Station No. 8 were designed with aerial cooling to prevent cascading temperature effects. These would be sized with the following criteria:

(a) the gas would be cooled to 80° F when ambient air temperature is about 65° F; and

(b) with a maximum gas pressure drop of 5 pounds per square inch through the cooling unit.

(b) Western Delivery Line:

One 4,000 horsepower compressor station was proposed at the James River Junction.

CAGPL questioned the lack of provision for a heater on the pipeline to Coleman because it believed temperature conditions would be similar to or lower than the corresponding CAGPL pipeline which did require a heater. The Applicant stated that no heater was required because the minimum gas flowing temperature would not be lower than 25°F.

(c) Eastern Delivery Line:

Two compressor stations of 32,700 horsepower gas turbine driven centrifugal compressor units (single) with aerial cooling were proposed for the eastern section from James River to Empress, Alberta with an average spacing of 78 miles. The criteria selected for the unit sizes were the same as those shown for the mainline.

System Reliability

The Applicant performed system reliability studies under most critical operating conditions, that is, average summer day with a flow of 2.3 Bcf/d. Those studies indicated that, on an annual basis, with all units operating at about 59 per cent of the time, one unit down about 12.4 per cent, two units down about 0.76 per cent, and under planned maintenance conditions, where mobile compressor units would replace units under overhaul, about 28.0 per cent of the time, the expected deliverability to Empress and to Coleman on an annual basis would be approximately 843 Bcf whereas the required delivery on an annual basis is 817 Bcf. Therefore, the system would have an excess annual capability even with planned and unplanned outages.

To provide planned maintenance on the gas turbine units the Applicant proposed to keep at critical locations along its system two 16,000 horsepower mobile compressor units which would be temporarily installed within seven days to replace the gas turbine units out of service.

Trunk Line (Canada) proposed to operate its system at the maximum operating pressure of 1260 psig which corresponded to 80 per cent of the pipe yield pressure. Unlike Foothills (Yukon), it found no technical reasons to prevent the operation of the pipeline at the design pressure of 1260 psig during the first 15 months of operation. To move the initial quantity of gas (1.5 Bcf/d) through the Trunk Line (Canada) system, the compressor stations would need to be operated at only 1183 psig.

If the pipeline system were operating at the reduced pressure level of 1080 psig, the projected throughput of 1.5 Bcf/d could still be met but the fuel consumption would increase by 11 per cent over the fuel requirements at 1183 psig which would increase the fuel cost by $502,000 per year.

During cross-examination, the Applicant stated that the stress levels to which this pipeline would be exposed, would be no higher than for any other pipeline operating at 80 per cent of the yield pressure in conventional areas. In addition, Trunk Line (Canada) felt that it could move quickly to make any necessary pipeline repair as pipeline accessibility would not be as great a problem as in Yukon or in British Columbia.

Views of the Board

The Trunk Line (Canada) system would form part of an integral system to move gas from Prudhoe Bay to the United States customers.

The Board agrees with the 48-inch O.D. line size selection from the connecting point to the Westcoast system at Boundary Lake to the bifurcation point at James River. The pipeline planned to be operated at 1260 psig provides the lowest cost of service at the projected gas throughput of 2.3 Bcf/d.

Similarly the Board concurs in the selection of the line sizes of 42-inch O.D. and 36-inch O.D. respectively for the James River to Empress and James River to Coleman sections.

The Board would be prepared to allow Trunk Line (Canada) to operate its system at the maximum allowable operating pressure of 1260 psig upon commencement of operations, if the metallurgical requirements for the 48-inch and 36-inch diameter pipe recommended by the Board were met (as explained in the Stress

Analysis and Materials Engineering section of the Report) and if it achieved a satisfactory hydrostatic test.

The Applicant has designed its pipeline system to meet annual requirements taking account of planned and unplanned compressor unit outages. In the event of a compressor unit outage at the most critical location, it cannot meet its average day requirements.

This design is similar in degree of reliability to that of Foothills (Yukon) but is less reliable than that of Westcoast, which can meet the average daily requirement with a compressor unit failure.

Trunk Line (Canada), in the same manner as Foothills (Yukon), has proposed large single unit gas turbine driven centrifugal compressors at each station to provide economies as compared to dual units. It has recognized the vulnerability of its pipeline to loss in throughput when taking a unit out of service for maintenance purposes. It has thus provided for two mobile compressor units which can be installed anywhere in the pipeline within seven days. In this regard, it has provided more security than Foothills (Yukon). In the absence of throughput agreements which would clarify whether firm capability must be provided to meet throughputs on a daily basis or only on an annual basis, the Board cannot assess the adequacy of the planned degree of reliability.

3.3.5.2 Geotechnical and Geothermal Design

Trunk Line (Canada) stated in its application that the majority of its proposed pipeline facilities would be constructed immediately adjacent to Trunk Line's existing pipeline right-of-way, and thus the geotechnical considerations were well known by its parent company. As the proposed pipeline route would be located south of the permafrost zone, frost heave and thaw settlement would not be problems.

The Applicant proposed to use conventional measures for buoyancy control in areas where the pipeline would cross rivers, streams, muskeg, peat swamps or areas where the water table was close to the ground level. These measures included the use of continuous wire-reinforced concrete coating, bolt-on or saddle-type concrete weights, screw anchors, or increased pipe burial depth.

With respect to differential settlement due to erosion or compaction of the soil supporting the pipe, the Applicant stated that measures to control this problem were covered in the construction procedures, which consisted, in the most part, of standard Trunk Line procedures.

Views of the Board

It is the opinion of the Board that Trunk Line (Canada) would not encounter any serious problems of a geotechnical or geothermal nature that could not be handled by standard procedures currently used by Trunk Line in pipeline construction throughout the Province of Alberta.

However, as the application did not treat geotechnical design in detail with regard to such subjects as slope stability, river engineering and pipeline monitoring, should a certificate be issued, the Applicant would be required to satisfy the Board as to the adequacy of the final design in these areas.

3.3.5.3 Stress Analysis and Materials Engineering

Stress Analysis

Trunk Line (Canada) stated that it designed its mainline to allow for the potential problems of line stability which might arise as a result of buoyancy, differential settlement and temperature differentials, but it did not submit any evidence on stress analysis dealing with external forces. The only evident design criterion was the limitation imposed on the hoop stress by the CSA Standard Z-184. Trunk Line (Canada) expressed its intention to operate all sections of its pipeline at the maximum allowable pressure from the commencement of operation, although the other companies participating in the Foothills (Yukon) project would be operating their northern sections at reduced pressures.

Materials Engineering

Introduction

The proposed facilities would be constructed in a variety of terrain from muskeg and prairie regions to foothills and mountains. Taking into account terrain and projected flow capacities, Trunk Line (Canada) specified Grade 70 for all line pipe and a fracture toughness of 40 ft-lbs CVT minimum for the

48-inch O.D. x 0.540-inch wall thickness and for the 42-inch O.D. x 0.473-inch wall thickness pipe, and 30 ft-lbs CVT minimum for the 36-inch O.D. x 0.405-inch wall thickness pipe, at a minimum operating temperature of 25°F. The yield strength requirement of Trunk Line (Canada) was comparable with those of the other two companies, but the minimum fracture toughness was lower than that of Foothills (Yukon) or Westcoast; there was no requirement for the average fracture toughness in Trunk Line (Canada)'s specifications.

Fracture Initiation

Trunk Line (Canada) believed that prevention of failure of the mainline could best be achieved by specifying the maximum toughness which would be effective in inhibiting fracture initiation. Using the Battelle hypothesis for fracture initiation, Trunk Line (Canada) obtained a critical through-wall crack size of 5.5 inches for the 42-inch O.D. x 0.473-inch wall thickness pipe and for the 48-inch O.D. x 0.540-inch wall thickness pipe, both Grade 70 operating at a pressure of 1260 psig and having a CVT fracture toughness value of 40 ft-lbs. This critical crack length was compared to the corresponding value obtained by Foothills (Yukon) for its 48-inch pipeline design and it was established that, due to the lower minimum fracture toughness requirement, Trunk Line (Canada) obtained a shorter critical crack size (i.e. 5.5 inches for Trunk Line (Canada) as compared to 6.1 inches for Foothills (Yukon)). Trunk Line (Canada) stated that this critical crack size of 5.5 inches was approximately two times larger than what was considered an acceptable minimum and that further increase in toughness beyond the specified level of 40 ft-lbs would have little effect on the critical flaw size of failure.

Valves, flanges, fittings and other components were also designed against fracture initiation. These components usually operate at lower applied stresses. Trunk Line (Canada) specified, for all pipeline components, a minimum Charpy V-notch level of 20 ft-lbs (average of three specimens) at the minimum operating temperature for all levels of material strength. Comparative critical defect size calculations for a fracture toughness of 20 ft-lbs gave critical through-wall defect sizes from approximately 3.5 inches for flanges to more than seven inches for fittings and valves.

Crack Arresting

Trunk Line (Canada) tried to justify its decision not to design against ductile fracture propagation by giving an explanation of why there were relatively few occurrences of long ductile fractures: only a small percentage of pipelines operate at the maximum allowable operating pressure and the minimum temperature; pipe properties are better than the minimum requirements; fracture toughness properties may be sufficient to arrest propagating fractures, even though they were not specifically required; the critical crack orientation might not be favourable for the formation of a propagating fracture; and certain pipeline appurtenances might act as natural crack arrestors. Trunk Line (Canada) believed that a Charpy V-notch energy of 72 ft-lbs was required for a ductile fracture arrest.

Specifying pipe with a minimum fracture toughness of 40 ft-lbs would provide a certain percentage of pipe that would be of the 72 ft-lbs level. Trunk Line (Canada) estimated that the length of a ductile fracture would be anywhere from 20 feet up to 1000 feet. If the Battelle Hypothesis for ductile fracture arrest were applied to the Foothills design parameters and the Trunk Line (Canada) design parameters for 48-inch O.D. pipe, the length of fracture for Trunk Line (Canada) would be longer. Although the fracture could be longer, the outage time might be shorter due to Trunk Line (Canada)'s ability to move in rapidly and make repairs to the line. Trunk Line (Canada) thought that the time required to repair a 600-foot failure in Alberta could compare with the time required to repair a 100-foot failure in the Yukon. This ability of Trunk Line (Canada) to act quickly in the case of an emergency was attributed to the favourable terrain, climatic and access conditions along the Alberta route.

In addition, Trunk Line (Canada) submitted a "Fracture Length Prediction Study" in which the maximum length of self-arresting fractures (300 feet) and the average length of fractures arrested at natural crack arrestors (390 to 450 feet) were calculated. Natural crack arrestors were defined, for the purpose of this statistical analysis, in terms of probability of arrest as follows: sections of heavy wall pipe, valve and fitting assemblies and anchor weights were assumed to have a 100 per cent probability of arrest; field girth welds were considered to have a 12.5 per cent probability of arrest; mill double joints and field bends were not considered in this analysis.

Trunk Line (Canada) had discussed the possibility of installing anchor weights as crack arrestors in areas where access was difficult or where fractures of 1000 feet could occur, but it did not include crack arrestors in the proposed design.

Trunk Line (Canada) did not consider reduction of the operating pressure necessary and intended to operate at the maximum pressure of 1260 psig.

Materials Specifications

Status

The materials specifications of the former Alaska Highway 42-inch pipeline project were adopted by Trunk Line (Canada) for the Alaska Highway 48-inch pipeline project. Since the 48-inch O.D. pipeline project used line pipe of different dimensions, specifications for 48-inch O.D. and 36-inch O.D. pipe were not complete. Also, the sample specifications for the pipeline components of the previous application were adopted by the new application, although they were not directly applicable to the 48-inch O.D. pipeline components.

For the 48-inch pipeline project, Trunk Line (Canada) also adopted Trunk Line's Specification P-2 for double submerged arc high strength, large diameter gas transmission line pipe and Specification V-1 for pipeline and compressor station valves.

Trunk Line (Canada) specified procedures for field welding, allowing for a manual shielded metal-arc process using coated electrodes, a semi-automatic gas metal-arc process and shielded metal-arc process, or a fully-automatic gas metal-arc process. General guidelines were given for pre-heating before welding.

Implementation and Inspection

For the plate, line pipe and components inspection, Trunk Line (Canada) decided for third party inspection at the manufacturers' facilities. Specifications P-2 and V-1 also contained requirements for non-destructive testing based on CSA Standard Z-184 and ASTM Standards E71, E94, E109, E125, E138 and E186, with some additional requirements for information on testing equipment, methods of calibration and operators' qualifications.

Materials Supply and Availability

Trunk Line (Canada) expressed its intention to purchase all line pipe from Canadian suppliers. According to the co-ordinated Foothills (Yukon) line pipe acquisition schedule, all of the Trunk Line (Canada) line pipe would be purchased in 1980 and 1981 from Stelco and IPSCO. Except for 20,000 tons to be purchased by Foothills (Yukon), Trunk Line (Canada) would be the only member of the Foothills (Yukon) Group who would be a major buyer of IPSCO large diameter pipe (250,000 tons). It was Stelco's intention to supply cold expanded 48-inch O.D. spiral welded pipe to all participating companies, including Trunk Line (Canada). Trunk Line (Canada) stated that 42-inch O.D. and 36-inch O.D. pipe from Stelco would be longitudinally welded and cold expanded.

Evidence submitted by Trunk Line (Canada) indicated that large diameter valves and fittings and small diameter valves, fittings and pipe would be more than 90 per cent Canadian content.

Views of the Board

Stress Analysis

Although Trunk Line (Canada)'s section was the most southern section of the 48-inch O.D. mainline and was, therefore, situated in a more moderate environment than the Foothills (Yukon) and Westcoast 48-inch O.D. sections, it is the opinion of the Board that a stress analysis is also required for the Trunk Line (Canada) section before approval of the final design.

Materials Engineering

The fracture toughness specified by Trunk Line (Canada) is considered adequate to prevent brittle fracture propagation and just sufficient to inhibit fracture initiation. Lack of design against ductile fracture propagation and inadequate inherent or external protection against such propagation are considered a risk to the integrity of the pipeline. The absence of the specification for the average fracture toughness value is viewed with concern by the Board. Upgrading of the fracture toughness to the level specified by Westcoast is considered necessary, and generally any certificate issued would be so conditioned.

Materials Specifications

In general, the submitted materials specifications are considered acceptable for pipeline construction. The Board would require that materials specifications in their final form be submitted to it for approval.

Supply and Availability

The schedule of proposed line pipe acquisition prepared by Foothills (Yukon) making provisions also for Trunk Line (Canada) is, in general, acceptable to the Board. It was noted that line pipe deliveries to Trunk Line (Canada) were scheduled for the second half of the construction period (1980 and 1981). However, the proposed delivery dates should not cause undue restraint on the line pipe availability.

3.3.5.4 Right-of-way

Trunk Line (Canada) adduced evidence that it proposed to acquire a completely new permanent right-of-way with a width of 60 feet; however, during construction an additional temporary working space of 40 to 60 feet wide would be required. It was confirmed that the right-of-way in certain areas would parallel existing rights-of-way of Trunk Line with the intent to possibly utilize portions of existing right-of-way for working space. Existing roads of Trunk Line would also be utilized during construction.

Trunk Line (Canada) indicated that it proposed to negotiate for multi-pipeline rights unless limitations to one line of pipe were imposed upon it in expropriation proceedings.

Views of the Board

Trunk Line (Canada) indicated an appreciation of possible right-of-way problems which could arise particularly in the area of negotiation and acquisition of lands. It also showed its awareness of utilizing, where possible, the 'corridor concept'.

The Board would require that Trunk Line (Canada) comply with all of the Board's directions regarding the acquisition of rights-of-way and other lands, including but not necessarily limited to specific directions as to the rights of and notice to all potentially affected property owners to ensure an orderly land acquisition and an equitable settlement program.

3.3.5.5 Communications

Trunk Line (Canada) proposed to make use of the existing Trunk Line private line communications system. The Applicant stated that this system consisted of:

(a) voice communications interconnecting the Company head office, district offices, gas control centre, compressor and meter stations and Company vehicles through mobile radio and base station facilities; and

(b) supervisory system communications connecting all compressor and major meter stations to the gas control centre in Calgary.

All operating data related to the proposed pipeline would be transmitted by means of the remote supervisory system to the gas control centre in Calgary, which would be capable of adjusting operating parameters as required, thus making unattended operation possible.

Views of the Board

The Board accepts Trunk Line (Canada)'s proposal to make use of the existing Trunk Line communications system, thus avoiding the unnecessary duplication of facilities. The Board agrees that this system is capable of providing the high level of availability and reliability required for the safe, efficient operation of the pipeline.

3.3.5.6 Construction

Trunk Line (Canada) proposed to construct some portions of the pipeline during the winter to take advantage of frozen ground conditions and to minimize vegetation disruption. The construction of the pipeline and related facilities would start in the winter of 1978-79 and continue through until the summer of 1982 in order to receive the maximum throughput volume from Prudhoe Bay in 1983. The Applicant proposed to employ standard winter and summer pipeline construction practices. Considerable experience in pipeline construction had been gained in northern Alberta by Trunk Line, and contingencies for down-time caused by poor weather and cold temperatures have been included in the Applicant's schedule.

Existing rail, highway and road systems would be used for the transportation requirements of the project. The material and equipment transportation would be scheduled in conjunction with the other participants in the Foothills (Yukon) Group Project so that the existing transportation facilities would be more effectively utilized.

Views of the Board

The Board feels that the Trunk Line (Canada) project would be a standard type of pipeline constructed in an area where the Applicant has had considerable experience in the construction of pipelines and pipeline compression facilities.

However, if a certificate were issued, it would be conditioned to require the Applicant to file its construction specifications with the Board for review and approval in advance of any pipeline construction.

3.3.5.7 Operations and Maintenance

Because of the proximity of the Applicant's proposed pipeline to the existing operating system of Trunk Line, Trunk Line (Canada) proposed that its pipeline would be operated by Trunk Line and thus avoid unnecessary duplication of facilities and personnel.

Views of the Board

The Board is satisfied that the Applicant's proposed operations and maintenance procedures are satisfactory; however, if a certificate were issued it would be conditioned to require review and approval by the Board. The Board would consider further any Service Contract agreement with respect to operations and maintenance at the final design approval stage.

3.3.5.8 Cost of Facilities

Capital Cost Development

The Trunk Line (Canada) system would include 395 miles of 48-inch O.D. mainline from Boundary Lake to James River, 235 miles of 42-inch O.D. delivery line from James River to Empress, 176 miles of 36-inch O.D. delivery line from James River to Coleman and four compressor stations (total of 147,000 horsepower) for a design throughput of 1.5 Bcf/d. To increase the throughput to 2.3 Bcf/d in January 1983, four additional compressor stations totalling 118,000 horsepower would be installed. Two mobile compressor units of 16,000 horsepower each are included in these totals.

The estimated cost of facilities was based on 1976 prices for labour, materials, equipment and supplies as quoted by vendors, manufacturers, contractors and consultants. The first quarter 1976 cost estimates were escalated to the appropriate year of material purchase or installation in accordance with the Applicant's construction schedules.

The following escalation rates were utilized to convert the 1976 dollar estimate to the year of material purchase or installation:

TRUNK LINE (CANADA)

ESCALATION RATE

(per cent)

	First Quarter 1976 to Mid 1976	1977	1978	1979	1980
Line Pipe	0.7	6.0	6.5	7.0	6.5
Wages and Salaries	1.2	10.0	8.5	8.0	8.0
Non-residential Construction Materials	1.7	6.0	6.5	6.5	6.0
Construction Machinery and Equipment	-0.2	6.5	6.0	6.0	6.0
Land, Freight, Communications and Miscellaneous	1.2	6.0	6.0	5.5	5.5
Compressor, Turbines, etc.	-0.8	6.0	6.5	6.0	6.0

The escalation rates for 1977 included the anticipated change in costs from mid-year 1976 to mid-year 1977 and in a similar manner for each successive year.

The Applicant would prefer to use competitive bid, fixed price contracts rather than target-type contracts because the design and construction of the pipeline were well defined and it did not warrant shared risk or target-type contracts.

The pipeline construction cost estimates were made by Loram International Ltd., a consultant to Trunk Line (Canada), who developed costs for a typical spread installing 48-inch, 42-inch and 36-inch O.D. pipe under winter and summer conditions. These costs included related daily spread operating costs for consumables, labour and equipment. Pipeline equipment costs were based on the assumption that new equipment would be supplied by the contractor. Equipment rentals were based on a monthly rate of five per cent of the capital cost of the heavy equipment and eight per cent on the balance of the equipment.

The spread costs also included an overhead and profit allowance of 18 per cent on labour and consumables. An allowance of five per cent was provided for administrative costs related to camp and catering.

The compressor station equipment costs were estimated (as of the first quarter of 1976) from manufacturers' quotations on the major items of equipment in accordance with Trunk Line (Canada)'s specifications. This accounted for approximately 90 per cent of the material cost of a typical single unit, aerial-cooled station. The remaining equipment costs were developed by reviewing equipment costs from previously constructed stations and escalating these costs to the first quarter 1976.

Compressor station installation cost estimates were prepared by Brown & Root Ltd. In addition to the four per cent overall engineering allowance, an additional sum of eight per cent of total material costs was added to cover such items as drafting, inspection, soils and concrete testing, radiography permits and licences.

Cost Summary

The escalated cost of facilities designed to carry an ultimate throughput of approximately 2.3 Bcf/d of Prudhoe Bay gas by the second operating year (1983) was $971.6 million.

The following is a summary of the escalated construction costs of the total facilities:

TRUNK LINE (CANADA)

ESCALATED COSTS OF FACILITIES

(Millions of Dollars)

Direct Costs	
Land and Land Rights	7.665
Pipeline	620.412
Compressor Station	129.824
Support Facilities	35.186
Division and District	3.360
Meter Station	6.657
Communication Facilities	0.242
Indirect Costs	
Pre-Permit Costs	1.100
Engineering and Overhead	32.134
Contingency	40.167
Allowance for Funds Used During Construction	94.900
TOTAL COST	971.647

Major Direct and Indirect Cost Categories

The major direct and indirect cost categories were estimated on the same basis as shown in the Foothills (Yukon) Cost of Facilities section of the report.

Land and Land Rights

The 48-inch diameter pipeline would be installed in a separate 60-foot right-of-way purchased by Trunk Line (Canada). The right-of-way, from Bow Creek to James River, would be beside the existing Trunk Line right-of-way except in areas where the terrain would cause it to diverge. Similarly the 42-inch diameter section of the system from James River to Empress, and the 36-inch diameter section from James River to Coleman, would also be installed in a separate 60-foot Trunk Line (Canada) right-of-way adjacent to the existing Trunk Line right-of-way.

The Trunk Line right-of-way would be used only during the construction stage for placing the spoil from the ditch. Roads along the existing Trunk Line right-of-way and access thereto would be shared during the operation phase.

Installation Cost

The installation costs were prepared with the assistance of Loram International Ltd., who had estimated the costs for the 42-inch diameter Foothills project and for the originally proposed 42-inch diameter Foothills (Yukon) pipeline.

Pipe Cost

Trunk Line (Canada) did not disclose its detailed pipe price quotations but provided an explanation of the method by which the quotations were applied to the construction cost estimates. Pipe prices were obtained from the two major Canadian pipe suppliers and, based on these quotations, the following pipe prices, f.o.b. Edmonton, including tax, were developed.

TRUNK LINE (CANADA)

ESTIMATED PIPE PRICE

Pipe Requirements (tons)	Pipe Size (inches)	Pipe Wall Thickness (inches)	Grade	Pipe Price ($/ton)
68,000	36	0.405	70	545
127,000	42	0.473	70	545
276,000	48	0.540	70	760

Views of the Board

Trunk Line (Canada), through its parent company, has many years of experience in the construction and operation of pipelines in the Province of Alberta and the Board is confident that this experience is reflected in the Applicant's cost estimates.

The Applicant has based its construction cost estimate on a target-type contract basis but, based on its experience, would prefer to sign firm bid contracts. In any event, in this conventional area of Alberta where less uncertainties are foreseen than in Yukon and in northern British Columbia, either type of contractual arrangement would be satisfactory. The Board is of the opinion that the labour costs shown in the estimate will be achieved provided the construction schedules are adhered to and the rates of inflation used for labour are correct.

The Board is, therefore, prepared to accept as reasonable the estimated cost of $972 million increased by about two per cent

($20 million) to cover design changes to the 48-inch O.D. and 36-inch O.D. line pipe specifications.

3.4 ALTERNATIVE SYSTEMS OF TRANSPORTATION

CAGPL discussed the following alternative systems of transportation which involved transportation modes other than, or in addition to, the transmission of natural gas in its gaseous state by the proposed pipeline:

(a) Electrical Generation and Transmission - Natural gas would be converted into direct current electricity and transported from the gas producing areas via High Voltage Direct Current (HVDC) transmission lines to delivery points in southern Canada and the United States where it would be converted to alternating current for distribution.

(b) Dense-phase Pipeline - Natural gas from the producers' gas plants would be converted to its dense phase and transported via a dense-phase pipeline to a southern delivery point where it would be regasified and transported to final markets by pipeline.

(c) Methanol Pipeline - Natural gas from the production plants would be converted to methanol and transported in liquid form via pipeline to an eastern destination where it would be converted to SNG.

(d) LNG (Liquefied Natural Gas) Railway - Natural gas would be liquefied in the plant area, loaded into LNG rail cars and transported to Trout River, Northwest Territories, via railway, where it would be regasified for transportation via pipeline to the market destination.

(e) LNG Monorail - This system would be generally similar to that for the railway except that the LNG would be shipped to Trout River, Northwest Territories, on an elevated guide-way, using magnetic levitation to support the traction and trailer vehicles.

(f) LNG Tanker - Natural gas would be transported by a chilled gaseous-phase pipeline to a deep-water port, to be developed at Babbage Bight, Yukon Territory, where it would be liquefied and loaded into LNG tankers, shipped to ports on the east and west coasts, unloaded and regasified for distribution through pipelines.

(g) LNG Submarines - This system would be the same as the LNG tanker except that no gas would go west because of the shallow waters along that route.

(h) LNG Airplane - The natural gas would be liquefied in the plant areas and loaded into pods which could be attached to airplanes and flown to a regasification plant in the south, where the pods would be detached and the LNG regasified and distributed through pipelines.

(i) LNG Helifloat - This system would operate like the LNG airplane system.

After examining the studies done by CAGPL, Foothills decided to analyze only those alternatives which would allow the use, expansion and associated economies of existing pipeline systems, which would not suffer from unduly high energy consumption within the system, and finally which would not require an excessive period of time to develop the required technical expertise.

The three alternatives studied by Foothills were:

(a) Dense-phase Pipeline

(b) LNG Railway

(c) LNG Airplane.

Both Applicants examined the alternatives and compared them with their proposed natural gas pipeline systems on the basis of the following criteria:

1. Level of Technical Expertise - The following major points were examined with regard to technology: amount of research and development that had been conducted, amount of direct operating experience, together with an examination of the additional effort and time required to develop a system for operation in the Canadian Arctic.

2. Operating Performance - The ability of each system to achieve and maintain a high level of service continuity was examined, since throughput reliability was considered essential.

3. System Efficiency and Marketable Energy - The overall efficiency of the process and transportation components of each system was estimated on the basis of:

$$\text{Efficiency (\%)} = \frac{\text{Net Energy Delivered} \times 100}{\text{Gross Energy Input}}$$

The quantity of marketable energy available was calculated by subtracting the processing and transportation losses from the gross energy input.

4. Cost Estimates and System Tariffs - The landed cost of energy for each system was estimated by accounting for the total capital, annual operating, and financial costs of all components of each system, and the net energy delivered by each total system.

5. Financing - The total financing requirements of each system were reviewed together with an assessment of the ability to raise capital for each system.

6. Environmental Impact - These aspects of the various systems were evaluated on the basis of a comparison with the proposed natural gas pipeline system.

7. Socio-economic Effects - These aspects of the various systems were evaluated on the basis of a comparison with the proposed natural gas pipeline system.

CAGPL pointed out that, in all comparisons between the natural gas pipeline system and other proposed systems, the pipeline was superior with respect to all items, such as costs, environmental protection, efficiency, operating reliability and known technology.

During cross-examination, CAGPL ranked the various alternatives with respect to the factors used in analyzing those alternatives.

Considering the current level of technical confidence alone, the ranking was:

High	-	natural gas pipeline
		methanol pipeline
		HVDC electrical system
Medium	-	LNG railroad
Low	-	LNG airplane
		LNG helifloat
		LNG monorail
		LNG submarine
		ING tanker
		Mr. Bradley's proposed conveyor system

For operating aspects, the ranking was:

High	-	natural gas pipeline
		methanol pipeline
Medium	-	HVDC electrical system
		LNG aircraft
		LNG monorail
		LNG railroad
		LNG submarine
		LNG tanker
Low	-	dense-phase pipeline
		LNG helifloat
		Mr. Bradley's proposal

With respect to environmental factors, the LNG railway would have the greatest potential impact and the pipeline the least.

In regard to system efficiencies, the rankings were:

Ranking	Overall Efficiency (%)
natural gas pipeline	90.0
dense-phase pipeline	86.1
LNG railway	82.2
LNG tanker	80.6
LNG airplane	77.4
methanol pipeline	48.2
HVDC transmission	30.1

The rankings and estimates for capital costs were:

Ranking	1974 Estimates of Capital Costs ($ Billion)
natural gas pipeline	8
methanol pipeline	12
LNG tanker	12
LNG airplane	12
dense-phase pipeline	12
LNG railway	16
HVDC transmission	19

The rankings and estimates for annual operating costs were:

Ranking	1974 Estimates of Annual Operating Costs ($ Million/yr.)
natural gas pipeline	146
dense-phase pipeline	278
methanol pipeline	435
LNG airplane	536
LNG railway	724
HVDC transmission	818
LNG tanker	857

One way in which a railroad would be superior to a pipeline would be the capability of the former to haul a wide range of products in both directions. CAGPL pointed out that the railway would be advantageous only if the volume of freight to be carried were sufficient to keep the unit cost of transportation at an economic level. It was pointed out that if the quantity of haul was not sufficient, then the economic burden of the railroad would either have to be carried by the users, through exorbitant rates, or by subsidy.

CAGPL did not conduct a full study of potential railroad haul prospects, but while admitting that there existed a potential need for movement of large quantities of freight into and out of the north, stated that, upon initial examination, it appeared that transportation to the west coast through the Yukon and down to Skagway via existing railroad systems might well be less expensive. Furthermore, CAGPL pointed out that the rail mode was not economic for natural gas, since just the incremental costs of liquefaction, haul and regasification, without assessing any railroad fixed costs against the gas haul, would exceed the full cost of pipeline transportation. Accordingly, either the gas would be forced to bear an even greater burden by also absorbing fixed railroad costs, or the shipment of gas by rail would do nothing to help the feasibility of the railway.

The major reason for the natural gas pipeline being rated superior to other methods of transportation was the energy losses and increased costs associated with changing the natural gas to another form (such as electricity, methanol, dense phase, or LNG) for each of the alternative systems. As an example of this, it was pointed out that with the HVDC system, the energy delivered would be only about 40 per cent of the energy input.

Mr. R.A. Bradley intervened on his own behalf and presented his proposal for a liquefaction plant and conveyor belt delivery system. Mr. Bradley claimed that the dense-phase plants studied by the Applicants would produce LNG at a substantial cost saving over their proposed LNG plants.

Mr. Bradley's proposed liquefaction system was based on a plant built in Cleveland, Ohio, and its operation was described by Dr. D.A. Katz in the "Handbook of Natural Gas Engineering". Foothills agreed that this plant could work, but it was felt the system was very inefficient due to the great deal of recycling required, and therefore actual costs would greatly exceed those reported by Mr. Bradley. Also, CAGPL pointed out that this system could be feasible only in the vicinity of a city where large quantities of low pressure gas could be used in a distribution system.

Another major obstacle to Mr. Bradley's proposal, according to the Applicants, was the need for a large number of bridges to be constructed in conjunction with the conveyor system. It was felt that these costs, coupled with the other costs of liquefaction and related regasifying plants, would also make this proposal uneconomic.

Views of the Board

The Board agrees with the assessment of the relative attractiveness of a natural gas pipeline compared with alternative systems of transportation and concludes that a pipeline system is superior to any of the alternatives studied for the movement of natural gas from the discovery areas in Prudhoe Bay and the Mackenzie Delta to the projected market areas.

CHAPTER 4

CONTRACTUAL, FINANCIAL AND ECONOMIC MATTERS

CONTRACTS

4.1 INTRODUCTION

This part of Chapter 4 examines the various issues before the Board with respect to contracts: contracts between producers of gas in the Mackenzie Delta and at Prudhoe Bay with prospective shippers of the gas, contracts between the shippers and the Applicants to move the gas, and contracts between the shippers and prospective customers in the identified markets. Additionally, the terms and conditions of the proposed lease for the use of Alberta Gas Trunk Line facilities are examined.

Executed contracts which reflect that sufficient volumes of gas supplies are committed to the pipeline and will be sold in markets are important cornerstones in examining the financeability of a pipeline project. The status of the contracts, and in particular supply contracts, was therefore a matter of considerable interest and importance to the Board throughout the hearing.

4.2.1 SUPPLY CONTRACTS

Introduction

Matters of gas supply and evidence in the form of gas supply contracts between shippers and producers, to establish that gas is available and will be committed to a pipeline in sufficient volume for a pipeline to be operated, contribute substantially to the Board's determination of whether a pipeline proposal will be economically feasible and therefore financeable.

The Board heard evidence from Applicants, prospective shippers, and producers on the status of gas supply (purchase) contracts for both Mackenzie Delta and Prudhoe Bay gas. During the course of the hearing, it was apparent that contracts for gas supplies in the Mackenzie Delta were being renegotiated, and that most contracts for Prudhoe Bay supplies had been terminated as a result of the Federal Power Commission decision of 31 December 1975 to disallow rate base treatment for gas advance payments to Alaska producers made after 27 December 1973. The various parties undertook to file, and some did file, with the Board those renegotiated contracts which were executed during the hearing.

In the case of Delta gas, the 1975 NEB Report on Natural Gas Supply and Requirements clearly reflected that established reserves in Canada were not sufficient to provide an exportable surplus, and indeed no application for an export licence was actively before the Board with respect to such gas.

Nevertheless, at the time of the commencement of the hearing in April 1976, virtually all of the Delta gas had been committed under contracts to shippers to United States markets. A condition of these contracts did, however, provide for the payment by the buyers of advances in the form of loans to the producers, which money did contribute to the level of exploration activity. Nevertheless, it should have been apparent to all parties during the hearing that all of the established Delta reserves would be required to meet Canadian demand, and therefore it was necessary for those volumes of Delta gas contracted for export to the United States market to be freed from such contracts and to be made available to Canadian buyers. Accordingly, various contracts for the purchase of Delta gas were under renegotiation at the same time as the hearing was taking place.

Although many of the prospective shippers of Prudhoe Bay gas had terminated or cancelled their contracts with Alaska producers, they indicated that they nevertheless intended to purchase Alaska gas. The major impediment to recontracting for the gas appeared to be the development of a unitization agreement by the producers of the Prudhoe Bay field, approval of the agreement by authorities in the State of Alaska, determination by Alaska of royalty provisions, and the establishment of a field price for Alaska gas.

Mackenzie Delta Supply Contracts

Evidence in the final stages of the hearing showed that only some 2.6 Tcf of the proved Delta reserves had been dedicated by a producer, Imperial, to a Canadian market, TransCanada. Negotiations were taking place for the dedication of an additional 2.2 Tcf to TransCanada, and 0.6 Tcf to Westcoast. Mobil's 0.4 Tcf remained uncommitted. With respect to the gas volumes which remained under the control of the producers and to any future additions to the gas reserves, evidence indicated that any volumes declared surplus to Canadian requirements would be offered by the producers first to the shipper-buyers who had originally contracted for gas supplies for United States markets, namely Alberta and Southern, Natural Gas Pipeline Company of America, Pacific Lighting Gas Development Company, and Michigan Wisconsin Pipe Line Company.

Imperial Oil Limited and Imperial Oil Enterprises Limited

Imperial testified that it had contracts with TransCanada, Natural Gas Pipe and Michigan Wisconsin. An amendment to the agreements between Imperial and Natural Gas Pipe and Michigan Wisconsin, dated 10 February 1977 and filed with the Board on 25 April 1977, allowed, upon notice, the automatic release back to Imperial of the 2nd and 4th Tcf of Imperial's reserves, otherwise committed to those companies, allowing Imperial to sell the gas to a Canadian buyer to meet Canadian requirements.

By a letter dated 26 April 1977, and filed with the Board on

4 May 1977, Imperial advised Natural Gas Pipe, Michigan Wisconsin and TransCanada that its initial recoverable reserves in the Delta totalled 3.27 Tcf. This letter served to provide notice to the contract parties that these reserves were required for the Canadian market. The effect of these amendments was to permit the dedication to Canadian markets of the first 5 Tcf of gas Imperial might find.

Under its gas supply contract with TransCanada, dated 4 January 1975, only some 1.4 Tcf of the first 4 Tcf of gas found by Imperial would have been allocated to TransCanada based upon the allocation formula in that contract. With the freeing of the 2nd and 4th Tcf of gas by Natural Gas Pipe and Michigan Wisconsin, Imperial stated that it would allocate a total of 2.6 Tcf to TransCanada under a contract clause giving Imperial the right to increase the quantity of gas allocated to TransCanada. Imperial considered that such gas would be "automatically sold under the contract terms".

Imperial's contract with TransCanada included a commodity value pricing provision as well as a minimum floor price of 35¢/MMBtu adjusted for changes in the Consumer Price Index since November 1974. The commodity value price is based upon the volume-weighted average price of crude oil delivered to Toronto refineries plus the premium value, if any, of gas over petroleum fuels less the transportation cost from the Delta to Toronto. The contract also provides for a take-or-pay condition whereby TransCanada must take, or pay for, 85 per cent of the daily contract rate (1:7300 of dedicated reserves) and 95 per cent of the annual deliverable volume, determined by a formula.

The Board heard testimony during the course of the hearing from witnesses of Westcoast and Imperial of contacts between these two companies in the matter of a possible sale by Imperial to Westcoast of uncommitted gas reserves in the Delta. The Board had difficulty, however, in assessing the seriousness of these two parties in this matter, and a witness for Westcoast stated in late 1976 that Westcoast had not pursued the contacts actively because, among other things, Imperial was not in a position to add any new commitments. Westcoast stated that its primary concern, if it contracted for Delta gas, was the ability to recover all of its costs, including the field cost of gas, the cost of transportation, and its rate of return. Westcoast filed on 16 May 1977, at the request of the Board, an exchange of correspondence with Imperial comprising six letters covering the period 10 November 1976 to 15 April 1977. Imperial's first offer of gas to Westcoast is contained in a letter dated 17 March 1977, in which it offered 0.6 Tcf to Westcoast, but conditioned the offer that the gas be sold only in the Canadian market. Westcoast testified on 11 May 1977 that this condition was unacceptable.

The amendments of 10 February 1977 to Imperial's contracts with Natural Gas Pipe and Michigan Wisconsin did not alter the terms of the gas purchase contracts, dated 13 February 1976 and 19 May 1976 respectively, with respect to the dedication to them of the 6th and subsequent even-numbered Tcf of gas Imperial might find in the Delta. In addition, the letter amendment committed the 13th and 15th Tcf that Imperial might find to these buyers, thus 8 Tcf of the first 16 Tcf of gas Imperial might find remain committed to Natural Gas Pipe (4 Tcf) and Michigan Tcf Wisconsin (4 Tcf).

Should Imperial make substantial new discoveries of natural gas in its Mackenzie Delta acreage, over and above its identified recoverable reserves of 3.27 Tcf, the reserves which remain committed to Natural Gas Pipe and Michigan Wisconsin (commencing with the 6th Tcf found) could be tied up for a considerable time by the three parties. Examination of the contracts with the two United States buyers centred upon the issue of releasing gas back to Imperial if it is required in Canada. The witness for Natural Gas Pipe stated he was not expecting to get any gas from the Delta.

Gulf Oil Canada Limited

Gulf concluded gas purchase contracts with Alberta and Southern and Pacific Lighting Gas Development Company on 6 December 1972, under which Gulf had dedicated essentially all of the gas it might find in the Delta, up to 4 Tcf, equally between the two companies. PLGD is a California company, a subsidiary of Pacific Lighting Corporation, and its objective is the acquisition and transportation of natural gas for delivery to the Southern California Gas Company, another subsidiary of Pacific

Lighting Corporation. Alberta and Southern is a Canadian company whose objectives are the acquisition and export of Canadian natural gas for delivery to Pacific Gas and Electric Company for markets in California. Thus all of Gulf's reserves were initially dedicated to the export market.

Witnesses for both Gulf and PLGD testified that the contract between their companies would be amended in accordance with a letter dated 16 August 1976 from Gulf to PLGD by which PLGD would give up its right to any of Gulf's gas which would be committed to the Canadian market, in exchange for retaining a preferred right to purchase one-half of any of Gulf's gas, up to 2 Tcf, determined by Canadian regulatory bodies to be exportable.

Gulf testified that it had notified both TransCanada and Westcoast that the reserves formerly committed to PLGD were now available for use in the Canadian market, and that negotiations were taking place with TransCanada.

Both Gulf and Alberta and Southern testified in October 1976 that the contract between them was being renegotiated. There had previously been some difference of opinion between the parties to the contract as to whether Alberta and Southern could resell gas purchased under its Delta contract for consumption in Canada. Alberta and Southern testified that one of its objectives in the renegotiations was to ensure that, if the gas were required in Canada, it would be made available without delay. Gulf indicated it concurred in this objective. Natural Gas of California, the eventual purchaser of Delta gas purchased by Alberta and

Southern, acknowledged that there was not a surplus of gas in Canada available for export to the United States.

Under the contract between Gulf and Alberta and Southern, each of the parties to the contract was to decide when it would make an application for the necessary authorizations. Alberta and Southern testified that, at that time, it did not intend to apply for export authorization for Delta gas. Gulf stated that under its interpretation of the contract, it could not compel Alberta and Southern to make an application for an export licence.

Once an application for an export licence had been made, and if it were refused, then the contract provided for a further 18-month period before either party could unilaterally terminate the contract. Where there was a partial approval of the export application, the volumes which were denied would revert to Gulf immediately.

Gulf and Alberta and Southern had not formally amended their contracts at the time the hearing closed, although both parties had indicated their intentions to do so. Gulf testified that it hoped this would be done by mid-June 1977. Gulf also stated that it was engaged in negotiations with TransCanada covering the total Parsons Lake production, with expectations of concluding the contract with TransCanada by 1 September 1977.

Evidence tendered by Gulf indicated that its estimate of recoverable reserves (proved plus probable) of its main discoveries, Parsons Lake and YaYa, totalled some 2.0149 Tcf, of which its share was 75 per cent, or 1.5111 Tcf. Alberta and Southern disagreed with this estimate, stating that in its opinion, the reserves in Parsons Lake and YaYa totalled only 1.6106 Tcf, with Gulf's share, therefore, 1.207 Tcf. Regardless of the accuracy of the two estimates, Gulf testified that it considered that it had reserves of at least 1.22 Tcf of Delta gas which could be contracted to TransCanada.

Mobil Oil Canada Ltd.

The 25 per cent of reserves in Parsons Lake and YaYa gas fields not owned by Gulf are owned by Mobil Canada Ltd. These reserves were estimated by Gulf to be 0.5038 Tcf, and by Alberta and Southern 0.403 Tcf. Mobil did not present witnesses to testify on the possible sale of this gas to potential buyers. In a letter dated 16 November 1976 filed with the Board by Westcoast on 16 May 1977, Mobil stated that it did not regard its reserves to be immediately contractable because of economic uncertainties concerning the terms and conditions of Federal land regulations and transportation costs.

Shell Canada Resources Limited and Shell Explorer Limited

Shell Canada Resources Limited ("Shell Resources") is a wholly-owned subsidiary of Shell Canada Limited ("Shell") and Shell Explorer Limited ("Shell Explorer") is a wholly-owned subsidiary of Shell Oil Limited, the United States affiliate of the Royal Dutch Shell organization. Their reserves in the

Mackenzie Delta are shared on a 50/50 basis between Shell Resources and Shell Explorer. The reserves of Shell Resources were assigned to it by Shell on 14 April 1977.

The Shell partners (Shell Resources and Shell Explorer) had assigned 9 of the first 12 Tcf of gas they might find in the Mackenzie Delta to Alberta and Southern under a financing and gas purchase right agreement dated 23 August 1973. They retained control over the 6th, 9th, and 10th Tcf they might find and in October 1976, the Shell partners stated they were negotiating to sell these potential volumes to TransCanada. Under the terms of its agreement, Alberta and Southern had provided the Shell partners with interest-free loans which, as of 31 December 1976, totalled some $39 million to Shell Explorer, and $2 million to Shell.

The three parties amended their 23 August 1973 agreement on 1 January 1977 under a settlement and modification agreement, under which Shell Explorer and Shell agreed to repay their respective loans over a period extending to 23 July 1983, and by which Alberta and Southern gave up its right to purchase gas as provided in the purchase right agreement. The parties also agreed that, under certain conditions, Alberta and Southern would retain the right to purchase, for export from Canada, such gas as the Shell partners might find in the Delta if the gas were not required for consumption in Canada.

The Shell partners estimated their current reserves in the Delta to be 0.973 Tcf proved and probable. Alberta and Southern testified that it estimated the reserves to total 0.799 Tcf.

On 3 May 1977, TransCanada testified that it hoped to be able to commence negotiations with the Shell partners as soon as the latter were free from their contractual obligations with Alberta and Southern. On 4 May 1977, the Shell partners testified that they had commenced negotiations with TransCanada, and tabled as evidence a TransCanada letter dated 3 May 1977 in which the two parties agreed to commence negotiations to conclude a gas purchase contract. Major items to be resolved were price and the economics of production of the Niglintgak Field. Both parties hoped to conclude the contract by mid-year.

Alaska-Prudhoe Bay

Columbia, Northern Natural and Panhandle Eastern gave evidence on their gas purchase contracts for Prudhoe Bay gas.

Columbia testified that it had gas purchase contracts with Sohio and BP Alaska Inc. and Northern Natural testified that it had a gas purchase contract with BP Alaska Inc. None of these contracts was affected by the FPC decision disallowing rate base treatment of advance payments.

Panhandle Eastern's gas purchase contract with Atlantic Richfield was affected by the FPC decision and Atlantic Richfield returned the advances made by Panhandle Eastern with interest. Rather than terminate the agreement, however, the parties agreed that it should continue in effect with the exception of Panhandle Eastern's obligation to make advance payments. Several gas purchase contracts were terminated due to the FPC decision. These included Atlantic Richfield's contracts with PLGD and Texas Eastern, and Exxon's contracts with Northern Natural, PG&E and Michigan Wisconsin. Each of the former buyers under these contracts provided witnesses to give evidence. Each former buyer expected to purchase essentially the same share of the working interest which it formerly had under contract, but testimony indicated that new contracts would not likely be signed until after the unitization agreement and operating plan had been approved by the State of Alaska, and after the field price and royalty provisions had been determined. CAGPL testified that the State of Alaska had commenced hearings into these matters on 1 April 1977 and that the Director, Division of Minerals, Energy Management Department of the State had indicated that he would recommend approval of the unitization agreements.

Views of the Board

It is a matter of concern to the Board that, despite the widely publicized assessment of Canada's natural gas supply and future requirements contained in the Board's report of April 1975, virtually all of the discovered reserves of the Mackenzie Delta were still dedicated to shippers to United States markets in April 1977. In this regard, the Board notes that the holders of the largest acreage in the Delta (Imperial, Shell and Gulf) provided substantial input to the Board's 1974 hearing that preceded the release of its April 1975 Gas Supply and Requirements Report; and thus were fully aware of Canada's need for frontier gas supplies. The Board's concern about the lack of gas purchase contracts was clearly expressed on a number of occasions during the hearing.

Pacific Gas Lighting Development Company was the first company to agree, on 1 September 1976, to release its gas rights to permit the dedication of that gas to Canadian markets, and the Board finds its willingness to have done so an example that unfortunately was not followed by other shippers. The Board believes that generally the producers and shippers have been somewhat dilatory in the renegotiation of contracts.

The Board notes that only 2.6 Tcf of Mackenzie Delta gas has so far been dedicated to the Canadian market, being a portion of Imperial's 3.27 Tcf proven reserves committed to TransCanada. The Board also notes the testimony that negotiations are continuing between TransCanada and the other two large Delta acreage holders, Gulf and Shell, which may ultimately lead to the commitment of approximately 4.8 Tcf to TransCanada (2.6 Tcf from Imperial, 1.2 Tcf from Gulf, and 1 Tcf from Shell). However, the apparent reluctance of the producers and Westcoast to negotiate a contract for Delta gas is of concern to the Board, particularly in light of Westcoast's application for a certificate for a pipeline connection with a capacity of 500 MMcf/d. The only other significant Delta gas reserves identified in the testimony as proven and not committed are 0.6 Tcf from Imperial and 0.4 Tcf from Mobil. The Board notes that Imperial has offered its gas to Westcoast under conditions Westcoast stated it cannot accept, while Mobil apparently is not prepared to sell its gas at the present time.

The situation with respect to gas purchase contracts for Prudhoe Bay gas, throughout much of the hearing, was not dissimilar to that for Delta gas, in that most of the original gas purchase contracts between producers and shippers were terminated due to the decision of the Federal Power Commission of 31 December 1975. The Board, however, notes the testimony of the various shippers that it is their intention to conclude new contracts with Prudhoe Bay producers once unitization plans and certain other State of Alaska regulatory procedures have been completed, and notes that such procedures were in the process of completion at the time the hearing closed. While the lack of definite gas purchase contracts and gas transportation contracts is of concern to the Board, the Board understands the circumstances which gave rise to this situation, and concludes that appropriate gas purchase contracts are likely to be negotiated in the near future to commit Prudhoe Bay gas to United States markets in volumes sufficient to support a throughput of 2.0 Bcf/d.

4.2.2 TRANSPORTATION AND SALES CONTRACTS

Introduction

The Board normally requires an applicant to file fully-executed contracts covering the transmission and sale of natural gas to be shipped through a pipeline; however, prior to the commencement of this hearing, the Board decided, pursuant to rule 3(2), to modify the requirements of the Rules of Practice and Procedure to the extent that it would be satisfied, in this regard, with the filing of pro forma contractual arrangements.

Transportation Contracts

No executed transportation contracts between the Applicants and shippers were filed with the Board for the hearing, and, before such contracts would likely be negotiated, a number of essential contractual matters such as tariffs and determination of throughput volumes would require resolution.

The types of pro forma transportation contracts envisaged by the various Applicants formed part of their submissions on the form and content of tariffs and these are discussed in a subsequent section of this report.

Sales Contracts

No executed gas sales contracts between shippers and purchasers of Canadian gas had been filed with the Board by the time the hearing closed. The only volume of Mackenzie Delta gas committed to Canadian markets was 2.6 Tcf committed by Imperial for sale to TransCanada. TransCanada will include this gas as a component of its total supply to serve existing customers, and no specific sales contracts would likely be negotiated for this gas.

No executed gas sales contracts were filed in respect of gas to be sold in United States markets by United States shippers. However, in view of the major shortages of natural gas in that country, there appears to be little doubt about the capacity of the United States market to absorb the volumes of Alaskan gas proposed to be shipped.

4.2.3 TRUNK LINE - TRUNK LINE (CANADA) LEASE

Trunk Line (Canada) is a company incorporated under the laws of the Dominion of Canada, with Head Office at the City of Calgary, in the Province of Alberta. It is a wholly owned subsidiary of Trunk Line, and is a designated subsidiary as defined in Trunk Line Trust Deeds.

As a part of the Foothills project, Trunk Line (Canada) applied to the Board for a certificate of public convenience and necessity to construct a line from a point seven miles north of the Northwest Territories-Alberta border for a distance of 81 miles southward into Alberta near Zama Lake (Schedule "E" facilities). It was proposed that the Mackenzie Delta - Beaufort Basin gas would be transmitted across Alberta from Zama Lake to Empress in a combination of facilities of Trunk Line (Canada) and Trunk Line. No application was filed for these additional Trunk Line (Canada) facilities.

Trunk Line, a company operating wholly within the Province of Alberta with respect to the transmission of natural gas, made a submission to the Board in support of the applications of Foothills and Trunk Line (Canada) for the movement of northern gas to markets in Eastern Canada.

It was proposed that initially northern volumes would traverse Alberta from Zama Lake to Empress in a combination of facilities of Trunk Line (Canada) and Trunk Line. The Trunk Line (Canada) facilities, when they are applied for, are to be constructed by that company, but are to be owned and operated by Trunk Line. These facilities (Schedule "A" and "B" facilities) would be leased by Trunk Line to Trunk Line (Canada), with an option to purchase being included as a term of the lease. Trunk Line would operate and maintain these facilities. (See section 3.2.1 of the report entitled FOOTHILLS PROJECT - Introduction, for a description of schedules). The Applicant undertook that it would own and put in service a continuous 42-inch diameter line with its own right-of-way within five years of the commencement of the flow of northern gas. Trunk Line undertook that it would provide Trunk Line (Canada) with the use of spare capacity in the facilities Trunk Line currently operates and the facilities it would construct between the present and the first flow of northern gas for the movement of Alberta gas. Trunk Line also undertook that, after the five-year period, to the extent that northern volumes exceeded the capacity of the Trunk Line (Canada) system, it would make available spare capacity in Trunk Line facilities as required for the movement of the full design volume of the Foothills project. (Schedule "C" facilities). Trunk Line also undertook to lease to Trunk Line (Canada) at the end of the five-year period, facilities that it owned to complete the continuous 42-inch diameter line (Schedule "AA" facilities). These facilities would be required in a few places where new facilities for northern gas (Schedules "A", "B", and "E" facilities) had not been constructed by the end of the five-year period.

The proposed arrangement also contemplated the continued control of Trunk Line (Canada) by Trunk Line and, as noted, involved considerable complexity as well as overlap in regulatory control between federal and provincial agencies.

All facilities to be built prior to the year of first northern flow, other than the facilities currently being applied for by Trunk Line (Canada), i.e., the Schedule "E" facilities between the Northwest Territories and Zama Lake, would be subject to and authorized by Alberta regulatory authorities and constructed by Trunk Line for Alberta volumes. Some of these facilities might form part of the facilities in which spare capacity is to be leased to Trunk Line (Canada) (Schedule "C" facilities).

Both during the period of projected volume buildup and after the proposed continuous 42-inch diameter line was completed after five years of northern gas flow, spare capacity would be leased by Trunk Line (Canada) from Trunk Line (Schedule "C" facilities).

It was admitted during cross-examination that this arrangement could not necessarily be distinguished from a transportation contract agreement and that no rights of exclusive possession to any portion of the line capacity were purported to be granted. Capacity to be made available would be determined by Trunk Line and only to the extent not required for Alberta volumes.

Both during the build-up period and after the completion of the continuous 42-inch diameter line, northern origin and Alberta origin gas would be commingled. Trunk Line (Canada) would lease spare capacity in Trunk Line facilities (Schedule "C" facilities) and it was contemplated Trunk Line would also move Alberta origin gas through Trunk Line (Canada), Schedule "A", "B" and "AA" facilities, particularly in the northwest area of Alberta, when spare capacity was available. Such commingling would require complicated cost allocation procedures. Certain cost allocations would also be necessary with respect to the facilities leased where certain facilities, such as compressor stations and communications facilities, would be common and where operations and maintenance expenditures would be common. It was proposed to divide the system into 19 sections for cost purposes, with section boundaries adjusted by Trunk Line as a matter of its judgment.

As indicated, Trunk Line (Canada) is currently a wholly-owned subsidiary of Trunk Line and is a "designated subsidiary" within the meaning of that term in the Trunk Line Trust Deeds, and would be subject to the obligations with respect to existing and future debt issues of its parent. These obligations and charges on its property would continue even after exercise of the option to purchase under the terms of the draft lease agreement. It was not clear how the mechanics of the exercise of the option would operate. There was some suggestion by Trunk Line that the option could be exercised at the direction of the Board.

While it was proposed that Trunk Line (Canada), would eventually have a certain number of independent directors, it was clear, however, that Trunk Line (Canada) would at all times be controlled in an operational sense by Trunk Line and decisions would not be made independently in the event of an outage including throughput reduction decisions. Directors could be removed by Trunk Line, as that company would continue to control Trunk Line (Canada).

The terms of the contract under which Trunk Line (Canada) would acquire the necessary right-of-way were not finalized.

Views of the Board

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 Board does not look with favour on the arrangement proposed by Trunk Line (Canada) and Trunk Line for the movement of Mackenzie Delta - Beaufort Basin gas to markets in Eastern Canada. 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 involve the movement on an indefinite basis of natural gas from the north through a system not regulated by this Board. Additionally, there is unresolved doubt as to the power of Trunk Line under its governing statute to enter into such an arrangement. The Board has noted that certain facilities required to move northern gas, including facilities to be built subsequent to the date of the current application, would be constructed on application to other regulatory authorities even though, as stated by witnesses for the Applicant, little of such capacity would be needed in the future for Alberta gas. The Board also notes that the proposed Schedule "C" facilities do not provide any assured capacity or any assured priority for movement of northern gas through the Trunk Line system nor would there by any supervision of such facilities by this Board.

It would be preferred if a system were designed by the Applicant to accommodate all volumes of northern gas that could be expected over a reasonable build-up period without use of transmission facilities of some other company. Such facilities (including the right-of-way) moving gas from the northern territories should be exclusively under the Board's jurisdiction.

In the Board's view, in the circumstances of this case, the transportation of northern gas to southern markets should at all times 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. The Board would examine the proposed terms of such arrangement at the appropriate time in the future.

FINANCIAL MATTERS

4.3.1 INTRODUCTION

The participants in each of the three pipeline projects, CAGPL Group, Foothills Group and Foothills (Yukon) Group, proposed to raise significant sums of money from the Canadian, United States and international capital markets during the period 1978-1982. The totals of the proposals of the three projects to raise external funds, for construction in Canada, were as follows:

	($Millions)
CAGPL Group (1)	7510
Foothills Group (2)	4020
Foothills (Yukon) Group (3)	3502

(1) Includes CAGPL and ANG

(2) Includes Foothills, Trunk Line (Canada) and Westcoast

(3) Includes Foothills (Yukon), Trunk Line (Canada) and Westcoast

In addition to the above sums, each of the Groups recognized the contingency that it might have to raise further additional money should its project, if approved, subsequently incur cost overruns. Accordingly, CAGPL, Foothills and Foothills (Yukon) provided for the possibility of having to raise additional amounts of capital as follows:

	($Millions)
CAGPL	1870
Foothills	510
Foothills (Yukon)	264

At the same time as these fund-raising operations were being undertaken, the companies completing

(a) the Alaska portion of the lines;

(b) the pipelines to be built in the United States; and

(c) the extensions to Canadian gas transmission lines,

would be raising funds in capital markets. Depending on which project was approved this would require amounts approximating the following to be raised:

	($Millions)
CAGPL Group (1)	3984
Foothills Group (2)	743
Foothills (Yukon) Group (3)	5668

(1) Includes Alaskan Arctic, Northern Border, PGT, PG&E, and TransCanada

(2) Includes TransCanada

(3) Includes Alcan, Northern Border, PGT and PG&E

The sum of these future requirements from the capital markets represents one of the largest projects ever financed through conventional market sources.

4.3.1.1 Method of Financing

In the Foothills Group and Foothills (Yukon) Group applications it is intended that the operating companies, Westcoast and, through its parent company, Trunk Line (Canada) would finance their own expenditures. The portions of the pipeline systems to be constructed by the Foothills and Foothills (Yukon) companies would be backed by a financing plan based on the concept of a construction project financing. In the case of CAGPL its financing plan was structured as construction project financing while Alberta Natural would finance its own expenditure.

A construction project financing may be defined as follows:

> "A new company is formed to finance, construct, own and operate a project".
>
> "A vehicle is created, namely the pipeline company and some credit is conveyed to it indirectly by parties associated with it as distinguished from direct applications of credit from several parties."

CAGPL, Foothills and Foothills (Yukon) each indicated that, given the capacity of the existing sponsors of each project, the construction project method of financing was the only viable method at the present time.

4.3.1.2 Viability of the Projects

The viability of the financing plans of each of the Applicants was dependent on a number of approvals and authorizations being in place prior to the negotiation of financing.

In presenting their draft financial plans, the financial advisors to the Applicants indicated that they had made certain assumptions, and these assumptions would probably require confirmation prior to the project being considered financeable. Among these were:

(a) that the Governments of Canada and the United States would each decide that the project was in the national interest of its country;

(b) that there would be sufficient reserves of gas and sufficient demand for that gas at the projected cost; and

(c) that the project would be proven, eventually, to be technically and economically feasible.

The Applicants have stated that, should the Board grant a certificate subject to conditions, that would in itself represent a demonstration that the project was viable and that the Board believed that all significant problems either had been overcome or were capable of resolution. In short, each Applicant was certain that things would fall into place if the Board were to issue a certificate subject to certain conditions and the governments were to decide that the project was in the national interest. It can be said that the financing plans put forward by the Applicants were entirely conceptual. In general terms, none of the Applicants attempted to show evidence of firm commitments from investors or formal negotiations of terms and conditions. Nor were financial projections made by the Applicants related to the terms of proposed contracts for the sale and transportation of natural gas. Accordingly, all evidence put forward relating to these matters was limited to each of the Applicants advising the Board what its financial advisors considered would be both practical and appropriate for a project of this nature. The Applicants indicated that they hoped to receive a certificate subject to certain conditions, one of which would be a subsequent proof of financing.

4.3.1.3 Similarity of Proposals

In structuring its overall financial plan and in selecting the rate-making and accounting principles that it wished to use, each Applicant, not unreasonably, selected those principles which would facilitate the raising of these very large amounts of capital. The selection of these principles was to a large extent, dictated by the following:

(a) the need to generate amounts of shipper/consumer-contributed capital as quickly as possible;

(b) the need to ensure that the pricing of gas to the ultimate consumer in the inital years is economic;

(c) the need to ensure overall income flow, particularly in the initial years of the project, sufficient to generate the cash to repay debt principal and debt interest; and

(d) the need to ensure the completion and continued operation of the pipeline.

These requirements led the Applicants to take an innovative approach towards rate-making and accounting principles. While the Applicants asserted that they had always been guided by (a) the accounting principle of matching costs and revenues and (b) the regulatory principle of maintaining equity between classes and generations of customers, they acknowledged that at times their method of accomplishing these objectives might have been innovative. The Applicants contended, however, that because of the mammoth capital costs involved in moving frontier gas to the market, such innovation was required.

Because of these innovations, certain of the rate-making or accounting principles requiring approval are either common to each of the applications or had relatively minor differences. Among these matters were:

(a) the requirement for a full cost of service tariff with an "all events" clause;

(b) the need for shippers to be allowed by their regulatory authorities to include their investments in the project company in their rate bases during the pre-operating phase of the project;

(c) the need for depreciation rates to be set to ensure the recovery of the capital cost of the pipeline over a period of time which would approximate the life of the long-term debt;

(d) the need for the accounting principle of normalization of income taxes to be approved so that income taxes might be charged as a cost of service item on this basis; and

(e) the need for assurances to be given to long-term lenders of the certainty of repayment of funds advanced by them in the event of:

   (1) failure to complete the line;

   (2) a major interruption of service during the operation of the line; and

   (3) abandonment of the line in the period prior to the repayment of the initial long-term debt obligation.

(f) the need to assure lenders of the flow of funds if the pipeline were completed but the flow of gas was, for some reason, delayed.

With regard to (e) above, the Applicants differ. Each of the Applicants viewed the "all events" tariff as being the first part of the required assurance to the long-term lenders of the certainty of the repayment of funds advanced by them. The Applicants all realized however that the "all events" tariff per se would not be sufficient to assure long-term lenders as to the adequacy of the security of their funds. The Applicants differed in their proposals to give the long-term lenders the required security as follows:

CAGPL would supplement the "all events" tariff with tracking, with a guarantee from each of the Federal Governments which, under the situation hypothesized above, would assure the flow of funds to the long-term lenders.

Foothills (Yukon) proposed to assure the lenders of the flow of funds by having an automatic tracking mechanism which would enable the costs incurred by shippers under the "all events" tariff to be passed through to the ultimate consumer. Foothills (Yukon) considered that under these circumstances, government backstopping would not be needed. However, it recognized that investors might still require backstopping by the United States Government or others. Foothills proposed that its shareholder group would guarantee completion of the line or repayment of debt to the long-term lenders. Foothills, while proposing an "all events" tariff, did not indicate how it proposed to obtain protection for its shippers against the financial impact of the "all events" clause. Foothills also advised that, should private sector financing not be possible, it would recommend that a Crown Corporation build all or part of the line.

The above items may be more fully described as follows:

Full Cost of Service Tariff with an "All Events" Clause

A full cost of service tariff was defined by CAGPL as follows:

> "Under the regulatory concept of a cost of service form of rate or rate schedule, those receiving service under the rate schedule are required to pay, in the aggregate, an amount equal to the serving company's costs of providing service, rather than a fixed rate or amount which would aim to result in payments of approximately those costs. Under the cost of service form of rate, the total of all costs of providing the service is borne by the customers, in proportion to contracted or received services."

In addition to the full cost of service tariff each Applicant included an overriding clause in its tariff which required shippers to pay the tariff even if the Applicant was unable to accept the gas for transportation - "the all events concept".

Rate Basing of Shipper Investments

Sponsors of CAGPL which are regulated companies indicated that suitable arrangements must be made for the recovery of the carrying costs of their equity investment in the Company. It was also indicated that United States shippers on the Alcan project would require similar treatment. In these cases such requirement would be met by these companies being permitted by their regulatory bodies to include their investment in the successful

Applicant in their rate base during the period of construction and, therefore, to earn their allowed rate of return on that investment.

Linking of Depreciation to Debt Repayment

Each of the Applicants selected a four per cent rate of depreciation for its pipeline facilities. This was based on a number of factors, including the expected life of proposed transportation contracts, the amount of gas reserves and the expected physical life of the pipeline. An additional factor leading to the selection of this rate was the need for each Applicant to have an assured flow of funds over the period of time that it planned to repay its initial borrowings of long-term debt.

Deferred Income Taxes

Each Applicant indicated that it required the approval of the Board to use the accounting principle of deferred income taxes. Each Applicant argued that this approval was merited on theoretical accounting grounds, in that it provided a proper matching of costs and revenues. The Applicants also indicated that deferred income taxes formed an integral part of their financing plans and that the funds that the use of that accounting principle would permit them to obtain were required to repay short term debt. In the case of CAGPL an amount in excess of $1.4 billion of cash would be raised by this means in the early years of operation. Such capital is in addition to the initial capital requirements set out at the start of this section.

Government Guarantees/Automatic Tracking of Costs

Each of the Applicants presented evidence to indicate that potential long-term lenders to its project would require guarantees of repayment of debt principal and debt interest from a credit-worthy party. For each Applicant it was indicated that the existing group of sponsors would not be perceived by the potential lenders as being able to offer satisfactory unconditional guarantees of the repayment of debt principal and interest. Accordingly, a mechanism would be required by which those lenders could be assured, in "all events", of the certainty of the recovery of their investment. The first level of assurance to the lenders would be provided by the "all events" tariff, itself a form of tracking. However, it was recognized that this would not be sufficient to assure the lenders of the recovery of their investment in all events. Accordingly, each Applicant supplemented this tariff provision by additional assurances. In the case of CAGPL it was proposed that these assurances would be obtained by government backstopping under which the Governments of the United States and Canada would commit, under certain circumstances, to insure the long-term lenders against loss of funds. The proposal of Foothills (Yukon) would accomplish the same end by obtaining, from the appropriate regulatory bodies, the ability to flow the costs of such debt through to the ultimate consumers of gas. The exact methodology by which this would be done was not placed on the record by Foothills (Yukon). Foothills (Yukon) recognized that if this could not be done, it would require government backstopping by the United States Government. Foothills did not provide for additional assurances except that in the construction period the shareholders would guarantee the recovery of debt to the long-term lenders.

Date of Commencement of Tariff

A sub-issue of the "all events" clause in the tariff is the date of commencement of the tariff. Each of the Applicants recognized that there could be a period of time between the date on which the first flow of gas was intended to commence and the date when the first flow of gas actually commenced. The Applicants indicated that if there were a substantial delay between these two dates, the financial burden on them would be intolerable. The Applicants sought to overcome this by providing for the tariff to commence at the date the pipeline was certificated as being ready to receive gas (CAGPL) or having the tariff, or equivalent, commence on a "date certain" after the start of the construction of the project, irrespective of the stage of completion of the construction of the pipeline (Foothills (Yukon) and Foothills).

4.3.1.4 Basis of Financial Projections

Each Applicant's financial plan and supporting pro forma financial statements depicted a project of a finite term and structure. Future expansion of initial facilities which might arise from discovery and dedication of further reserves in later years was not considered. In addition, it should be noted that the basis of the financial statements presented is likely to be different from that which will occur when the projects are in operation. The financial projections filed with the Board were based on assumptions regarding gas reserves, gas transportation contracts and the ultimate deliverability of gas which relate more to the proposed capacity of the pipeline rather than to gas reserves already discovered.

4.3.1.5 Views of the Board

The Board recognizes that the financial plans and proposed form and content of the tariffs submitted by the Applicants are part of an innovative response to a unique and difficult financing task. The Board also notes the representations by the Applicants that, to assist in financing the project, a policy should be expressed as to the approval of an "all events" tariff. The Board accepts that the tariff should, to the greatest extent possible consistent with good accounting principles and sound regulatory principles, facilitate financing in the private sector, and thereby reduce or possibly eliminate any requirement for government backstopping. This would be the principal factor governing any approvals the Board might give to the innovative approaches taken by the Applicants.

The Board recognizes that, on the evidence before it, none of the projects could be financed without the implementation of an "all events" clause in the tariff. Based upon the facts before it, the Board accepts, subject to the filing of evidence that the same clause has been approved by the appropriate United States and Canadian regulatory authorities in all applicable jurisdictions, the principle of the "all events" tariff and its embodiment in the form and content of the tariff to be approved upon application, subject, of course, to the provisions of Part IV of the Act.

The Board, however, does not consider approvals of any of the innovative approaches taken by the Applicants necessarily to set a precedent for future rate cases relating to other companies who operate in more conventional areas. The Board notes that the views expressed by it are limited to the circumstances of this particular case, and particularly, that these are expressed relating to a Part III application for a Certificate of Public Convenience and Necessity and concern basically the achievement of financeability by the project. These views do not necessarily represent a decision in a Part IV rate case which should probably follow these proceedings if a certificate were issued. The Board also notes that under the full cost of service "all events" tariff,the Board would still retain the right of disallowance of improperly or imprudently incurred expenditures, with regard to items in the rate base as well as to cost of service items.

4.3.2 CAGPL

4.3.2.1 Financing

Capital Requirements

CAGPL's financial plan and projected sources of funds may be summarized as follows:

	Plan of February 1977 ($ millions)	
Basic Commitments:		
Equity Investors - Canada	820	
- United States	1,050	
Institutional Bond Purchasers in Canada	400	
Institutional Bond Purchasers in United States	2,000	
Canadian Bank for Term Loans	700	
United States Banks for Term Loans	460	
Foreign Supplier Credits	900	
		6,330
Standby Commitments:		
To Backstop Public and Other Subsequent Bond Offers:		
United States and Canadian Banks	345	
Banks in the International Market	805	
Total Backstop Commitments		1,150
Total Estimated Funds Required		7,480
To provide Reserve for Cost Overruns or Cash Shortfalls from Operations:		
Equity Investors or Others for Subscription of Shares or Subordinated Debentures	625	
Canadian Banks	75	
Banks in the International Market (including Canadian & United States Banks)	1,170	
Total Reserve Commitments		1,870
Total Commitments		9,350

Canadian/United States Source of Investment Funds

Equity

CAGPL stated in its written evidence that its plan provided the opportunity for Canadian investors to purchase the majority ownership of the Company's common shares and that Canadian investment, if forthcoming, would be taken in preference to United States investment. The Applicant's subsequent testimony indicated, however, that based on a total requirement of $1,870 million, it was the Applicant's intention to place $1,050 million with United States companies and $820 million with Canadian investors. CAGPL testified that if more Canadian investment was forthcoming, it would be taken in preference to United States investment. The Applicant held the view that further Canadian commitments would be forthcoming if and when the project was certificated but future funds would be drawn from wherever available, according to requirements. CAGPL considered that ownership of its equity was somewhat irrelevant, since its operations would be under Canadian regulatory control.

The Applicant tabled a study discussing various methods of achieving Canadian control, in the event of a deficiency in the percentage of Canadian equity ownership. Possible methods included separate classes of common shares carrying the right to elect a majority of directors; the issue of subordinated debentures to United States investors as opposed to common shares, and the possibility of requiring United States investors to sell their shares to Canadians, following pipeline completion. CAGPL had not seriously considered these methods as its original position on majority ownership had remained unchanged. The Applicant also presented evidence to indicate that United States shippers and sponsors agreed that control could, if required by the Board, be left with Canadian shareholders.

Debt

CAGPL stated that its financial plan would provide for substantial participation in its debt financing by Canadian institutions and the Canadian public. The Applicant intended to raise $2,450 million from the issue of first mortgage bonds in the United States and $900 million of the same type of debt in Canada, a total of $3,350 million. CAGPL considered that it would not be possible to raise additional funds, in significant amounts, in Canada.

Capital Structure

Debt/Equity Mix

The Applicant proposed that equity investors would commit 25 per cent of the basic funds of $7,480 million ($1,870 million) and 33 1/3 per cent of the funds related to the reserve commitments of $1,870 million ($625 million). CAGPL felt that the 25 per cent basic equity component was the minimum amount of equity needed in the capital structure.

The Applicant stated that it had considered the convertible debentures included in the proposed financing plan as equity funds. CAGPL's advisors also believed that a maximum of one-fifth of the equity component could be in fixed rate investments such as convertible debentures or preferred shares.

The Applicant's pro forma financial statements (Base Case) indicated that, excluding retained earnings and treating convertible debentures as equity, the proportion of equity in the capital structure was higher than 25 per cent in each year. The proportion of equity funds was high in the early years due to the receipt of equity funds prior to the draw-down of long-term debt. The proportion would fall to a low of 25.6 per cent in 1982 and then would increase to 59 per cent in 1988 as a result of the accumulation of retained earnings and the repayment of debt.

One of CAGPL's witnesses stated that the increase in equity ratio was irrelevant since it arose only from the fact that the project was considered "static". He believed that once the project became a going concern, it would develop in the light of future discoveries and dedications and would draw more funds at a 75/25 ratio. This witness agreed that the equity proportion depicted by the pro forma financial statements was "more expensive" than the 75/25 capital ratio mentioned in the financing plan.

Capital Market Capacity

Debt Requirements

CAGPL stated in written evidence that it had a requirement for $5,610 million (including escalation) of debt financing. The Applicant felt that there would be adequate capacity in capital markets to support this level of financing, given that the funds would be raised over a number of years.

CAGPL anticipated potential further financing requirements if the project sustained cost overruns. Total debt reserve commitments for this purpose were $1,245 million. Project commencement delays or re-routing would cause additional funding requirements.

Debt Availability

CAGPL presented three formal studies relating to capital market capacity. These were prepared in 1974 and covered the Canadian, the United States and international capital markets. These studies supported the written evidence of the Applicant to the effect that sufficient funds would be available from the various sources to finance the project, given that it extended over a number of years and that the project would not have an adverse effect on economic performance, particularly in Canada. The three studies were based on economic models and projections developed by Wood Gundy Limited (Canadian market) and Morgan Stanley & Co. (United States and international markets).

In addition, a study was prepared by its Canadian banking advisors, in 1974, which supported the statement that the Canadian banks had the capability to provide term loans to the project in the amounts proposed by CAGPL. A further study, undertaken in 1976 by the Royal Bank of Canada, was also filed and this study reinforced the view that Canadian banks could finance the bank loan requirements of the project.

The key assumptions used in these studies related to the economic feasibility of the project, an adequate demand for the gas, regulatory approval of the "all events" tariff, undoubted security for long-term lenders (government backstopping), attractive rates of interest and support from the government for the project being in the national interest.

In the case of the Canadian debt market, the financial advisors developed a projection involving rapid economic growth and high employment. This was not intended to be a "most likely" case but was chosen because it would weight the case to some extent against CAGPL due to the capital markets being more heavily used in this type of economic situation. The United States capital market study was based both on economic modelling and on the independent judgments of Morgan Stanley & Co. based on its experience of Canadian and United States financial markets and enterprises.

It was the Applicant's strong contention that the existence of a withholding tax on interest payments to non-residents was a deterrent to foreign investment in Canada, and its financing plan assumed that no withholding tax on interest would apply on debt issued outside Canada. CAGPL agreed that this assumption was inconsistent with the current law regarding withholding tax on foreign debt but felt that the current law could be extended and changed to make all of the project debt free from withholding tax. It was stated by the Applicant that United States and foreign investors would expect an extension of the current exemption from withholding tax.

With respect to a possible bond rating, CAGPL felt that it might obtain a Baa rating and that this rating would be sufficient to attract the funds required. However, one of the studies presented by the Applicant stated that a single A rating would maximize available contributions, and could result in additional funds of about $250 million being available to the project. CAGPL stated in its evidence that bond ratings would not play an important part in the assessment of its project by United States life insurance companies as these organizations did not necessarily follow the rating of the leading rating agencies. A witness for CAGPL conceded that there was no certainty of obtaining a bond rating in view of the absence of a track record by the Applicant but stated that it would be important to try to obtain the rating.

Debt Terms of Borrowings

CAGPL stated in written evidence that long-term debt would be drawn down to the extent possible on a basis which would allow a period of amortization approaching the life of the proposed transportation contracts. Subsequently, the Applicant conceded that the proposed mix of long, medium and short term debt was based on the recommendations of its advisors who felt that this was what the Applicant could obtain and it represented a balance between what was appropriate and desirable and what was available.

CAGPL agreed that, overall, the proposed "mix" represented a higher reliance on short to medium term debt that would be typical for the financing of a pipeline. The Applicant confirmed that, if it were possible to obtain more long-term debt, it would do so.

Use of Available Debt Markets

CAGPL's financial plan drew upon various sources of debt finance within the market capacity stated in its evidence. Proposed short and long-term debt financing was $1,600 million in the Canadian market, $2,910 million in the United States market, and $1,100 million in the international market including supplier credits. The Applicant indicated that only limited additional financing from Canadian markets could be anticipated as capacity constraints were close to being reached. However, CAGPL considered that there was a considerable amount of excess capacity remaining in the United States market.

Practicality of Obtaining Debt Commitments

To the close of the record, CAGPL had not received any specific commitments from potential lenders to the project. The Applicant argued that, if a certificate subject to certain conditions were issued by the Board, commitments could then be negotiated. The point was raised that, while there might be technical capacity in the market, a more important consideration might be the willingness of the lenders to participate in the project. CAGPL was confident that lenders would be willing to commit the funds needed, if government backstopping were obtained.

Cost of Capital

Cost of Debt

CAGPL set out assumed terms and conditions attaching to its various debt securities in its written evidence. It stated that the estimated interest rates, commitment fees, amortization and sinking fund requirements reflected mid-1976 conditions and not future projections. A witness for the Applicant stated that probably in virtually every market in the world, lower rates would now be achievable than those included in the Applicant's financing plan. The Applicant stated that, provided its lenders had undoubted security, it would expect to have to pay the market rates prevailing at the time of issue of its securities. Witnesses for the Applicant also contended that it was impossible to foretell what actual rates would be in future years, or even one year hence.

CAGPL's position that lenders must be given undoubted security was extensively supported by testimony given by its witnesses. It was stated that lenders and equity holders would be subjected to certain business risks which might arise from shipper bankruptcy or non-marketability of gas. All investors would face normal business risks except those arising from extended interruption of service or abandonment of the line; these risks would be backstopped by the governments according to the Applicant's plan.

Equity Requirements

CAGPL stated that its requirements for equity capital were $1,870 million. A 25 per cent overrun commitment had been provided for, which would require extra equity capital of $625 million.

The Applicant stated that its equity investors would be drawn from companies shipping and marketing gas and from companies in related fields. Other investors could include producers, the Canada Development Corporation and the general public. CAGPL's sponsors placed on the public record certain conditions precedent which must be met before they would invest in the project. These were as follows:

that the necessary regulatory approvals were received for the facilities and tariff;

that financing arrangements were established on a satisfactory basis;

that gas supply was satisfactory; and

that suitable arrangements were made for the recovery of the carrying costs of the equity investment.

The Applicant stated it would be in a strong position to obtain equity participation on issuance of a certificate subject to certain conditions.

Equity Investment

CAGPL advised the Board that it expected to obtain equity investments from companies currently operating in the gas transmission and distribution industries, from the producers, from the Canada Development Corporation and from the general public. The Applicant filed letters of intent from sponsoring companies. These showed an equity investor list as follows:

Equity Investment

($ million)

Eastern Canadian Shippers and Distributors	Equity	Overrun
TransCanada	200	72
Union	50	18
Consumers'	50	18
Northern and Central	24.2	8.7
Greater Winnipeg	10.5	3.8
Gaz Metropolitan	15.3	5.5
	350	126
Shippers and Distributors of United States Originating Gas		
Northern Natural		
Michigan Wisconsin		
Panhandle Eastern		
Texas Eastern		
Columbia		
Natural Gas Pipe		
Pacific Interstate	n.b.	No breakdown between the companies was provided.
Pacific Gas & Electric		
Pacific Gas Transmission		
Alberta Natural		
	1,050	405
Producers		
Gulf	50	18
Imperial	50	18
Shell	50	18
	150	54
Convertible Debentures		
Canada Development Corporation	100	-
Canadian Public	100	-
	200	-
Grand Total(1)	$1,750	$585

(1) In evidence filed later, CAGPL indicated that it would require additional equity of $120 million and would also provide for additional overrun funds of $40 million. The source of this investment was not indicated.

All sponsors put on the public record certain conditions precedent which must be met before they would invest in the project. These are set out in the previous section.

In addition, the Canada Development Corporation would require the following additional conditions precedent:

adequate provision for cost overruns;

representation on the Board of CAGPL; and

Canadian control and management of CAGPL in the private sector.

Equity Return

In its written evidence, CAGPL contended that equity investors must be satisfied that the prospective return on their investment would be commensurate with the risks which they would bear and with their alternative investment opportunities.

Equity investor decisions would be based on a number of factors:

the proposed rate of return;

the financial and business risks;

the length of the initial period during which no cash return would be received;

the rate of accumulation of retained earnings; and

the marketability and value of the investment.

In addition, the potential of being able to "rate base" the investment and the desire to obtain supplies of gas from the Applicant's system could also provide a significant inducement to regulated companies to invest.

The financial plan presented by CAGPL assumed a rate of return on equity of 15 per cent for illustrative purposes. The Applicant had not yet determined what rate of return would be required on common equity, but a return sufficient to attract investors would be required. The Applicant proposed to file a suggested rate of return on equity at the time of proof of financing assuming it were granted a certificate subject to certain conditions. A witness for CAGPL requested that the Board give an indication of an appropriate rate at such time as it might grant a certificate subject to certain conditions.
The Applicant presented little evidence concerning the extent of risk facing equity investors. A witness for the Applicant agreed that the business risks would be low once commercial operations were under way.

Risks of Foreign Exchange Exposure

The Applicant generally assumed, for the purposes of its financing plan, that United States and Canadian dollars would be at par throughout the life of the project.

Upon request, the Applicant filed an exhibit analyzing the effects of a 5 per cent depreciation of the Canadian dollar prior to financing and construction, and the effects of a 10 per cent depreciation of the Canadian dollar commencing in July 1982.

Based on this exhibit, the Applicant indicated that a 5 per cent depreciation of the Canadian dollar, prior to commencement, would increase capital costs of the project by $134 million, and would increase funds required from United States capital market by $50 million. The other sensitivity case (United States and Canadian dollars at par until mid-1982 and then 10 per cent depreciation of the Canadian dollar) indicated that United States dollar revenue, from tariffs, would offset increased United States debt service costs.

Security Arrangements

The Applicant stated that three fundamental security requirements would be necessary to satisfy long-term lenders:

First, lenders must be satisfied with respect to the economic and technical feasibility of the project.

Second, lenders would require protection against certain basic risks:

that the project would be completed, even if costs exceeded those originally projected (or, if not completed, the total debt of the project would be repaid in full);

that the project, once completed, would generate operating revenue to meet its expenses and service its debt; and that, if for any reason, including force majeure, the project operations were interrupted, suspended or terminated, its debt obligations would continue to be serviced either through continued receipt of revenue, or otherwise. These assurances must take the form of binding contractual obligations.

Third, and most important, lenders would have to be convinced that the entities providing these assurances would have the financial strength to carry them out.

Based on these requirements, specific arrangements would include:

pre-commitment of funds;

assurance of revenues by means of transportation contracts with transmission and distribution companies whose gas would be shipped over the line;

an "all events" tariff which provided that a failure to deliver gas to the shippers would not relieve shippers of their obligations to make payments to the project sufficient to cover its operating costs and service its outstanding debt;

ultimate backstopping by the Federal governments of Canada and the United States in the event that those parties obligated to complete the project did not have the financial strength to honour their obligations; and

ultimate backstopping by the federal governments of Canada and the United States in the event that those parties obligated to pay the tariff were unable to meet their obligations.

The Applicant included the pre-commitment of actual and stand-by funds in an amount necessary to complete the project at its estimated cost of $7,480 million, and stated that it intended to obtain further commitment of 25 per cent of the total cost of the project ($1,870 million) to provide funds in the event of cost overruns or cash shortfalls. The Applicant's witnesses testified that the 25 per cent reserve commitment was not to be considered to relate to the potential magnitude of the cost overruns or shortfalls.

The Applicant believed that its proposed full cost of service tariff including the "all events" clause would provide lenders with the necessary assurance regarding payment of debt principal and interest during normal operations, provided that the parties signing tranportation contracts were adjudged creditworthy.

The Applicant contended that the "all events" feature of its tariff would ensure the continued receipt of revenues, even in the event of an interruption of service. The Applicant, however, recognized that under its "all events" tariff, and in the event of extended interruption, an intolerable financial burden would be placed on all of its shippers.

The Applicant considered that this burden on the shippers might be relieved by the use of a "tracking" mechanism whereby the debt costs of the project would ultimately be collected from the consumer regardless of the volume of gas being delivered.

This was felt to be a method of protecting the shippers from the consequences of having to continue payments under the tariff during a period in which the shippers received no value for such payments. Such a mechanism, assuming that the actual consumers were able to provide all funds necessary in the event of prolonged interruption, would provide ultimate backstopping to the project. However, the Applicant recognized that the establishment of such procedures would be very time-consuming and was not sure that all necessary approvals and legislation could be secured within a reasonable period of time or that all the state authorities would necessarily give their approvals. In the light of such circumstances, CAGPL believed that backstopping by the two federal governments represented the only practical way of achieving both the assurance of completion of the pipeline which it considered would be required by lenders, and the assurance of the flow of funds in the case of prolonged service interruptions. This backstopping would also cover circumstances of abandonment of the line before completion and subsequent repayment of outstanding debt.

The Applicant's financial witnesses stated that they felt that funds would not be advanced to the project unless "undoubted security" could be demonstrated by the Applicant. They indicated during cross-examination that, in their opinion, the only practical way of providing such undoubted security would be by obtaining commitments from the two federal governments.

4.3.2.2 Accounting and Rate Making

Accounting for Income Taxes

CAGPL stated that in accounting for income taxes, it had selected the accounting principle of normalized income taxes ("deferred income taxes").

The Applicant presented three major arguments in support of its selection of this method. Firstly, it stated that the use of deferred taxes would confer "significant economic benefit on the project" in that substantial amounts of "cost free" capital would be acquired in the initial operating years of the project. Secondly, it felt that this principle would properly meet the accounting objective of matching costs and revenues, and thirdly, over the life of the project, this method would cost the consumers less than the taxes payable method.

CAGPL stated that the accounting profession generally favoured the deferred income tax method, and that, outside the regulatory environment, the use of taxes payable was almost non-existent. It considered that there was significant regulatory precedent supporting the use of deferred income taxes and that this tax treatment would be of significant benefit to its financing plan. The Applicant agreed, however, that the taxes payable method of accounting for income taxes was acceptable for utilities under the current requirements of the Canadian Institute of Chartered Accountants ("CICA"). CAGPL considered that this method did not present the economic benefits to its project that the deferred income tax method would present.

Depreciation

CAGPL selected a method of depreciating its gas plant in service which would result in equal amounts being charged annually against earnings over the expected life of the project. This method would result in the capital costs being charged to earnings over a period which approximately matched the period of time of the initial transportation contracts, thus, in the Applicant's opinion, resulting in a proper allocation of costs. CAGPL argued that its choice of depreciation method was in accordance with regulatory precedents. The Applicant stated that among the factors influencing its choice of rates were:

- the length of the proposed gas purchase contracts;
- probable gas reserves;
- rates used by other pipeline companies; and
- the estimated physical life of the pipeline.

The Applicant stated that it had not selected the unit of production method as that method would give an uneven charge in early years and seriously reduce the Applicant's cash flow at that time. The Applicant argued that there was insufficient data available to ascertain fully either the physical or the economic life of the pipeline at this time. While the physical life of the pipeline might be in excess of the period selected for depreciation, it believed that due to the present level of proven reserves, it would be inappropriate to depreciate solely on the basis of physical life.

Allowance for Funds Used During Construction

Debt Interest

The Applicant requested that it be allowed to capitalize an imputed interest cost related to debt funds used during the construction period. The Applicant believed that this method had precedent in the regulatory environment and was widely used by non-regulated businesses. It argued that not to do so would be to fail to account properly for the overall cost of the assets.

Equity Return

CAGPL also proposed to capitalize the imputed cost of equity related to funds used during the construction period. It argued that this should be done because it was the only method by which a return could be given to equity holders during the period of construction. It stated that shareholders would normally expect to obtain a capital appreciation of their shares but that this would not be possible during the construction period. Accordingly, the Applicant sought to offset this inability to generate capital returns by capitalizing the imputed return and placing it in the rate base. CAGPL believed that this had regulatory precedent and was provided for in the Board's code of accounts and it proposed to achieve this by applying the weighted average cost of equity to the rate base at the end of each month and transferring the accumulated amounts into the rate base every six months.

Deferral and Capitalization of Return in Initial Service Phase

The Applicant proposed that, for the first four years or until the pipeline operated at full capacity, the rate of return be reduced by the percentage of unused capacity, and that this reduction be capitalized and placed in the rate base. CAGPL agreed that the selection of the four years was partially arbitrary but stated that this was the maximum period of time which was expected to lapse prior to the full capacity of the line being used. It argued that the charging of all costs in the initial years of service would result in an excessive charge to early consumers. The Applicant believed that a better matching of costs and revenues would be achieved by capitalizing such costs during the initial period of service and charging them to consumers over the life of the pipeline.

No evidence was presented by CAGPL as to regulatory precedent for this proposal. However, it argued that this was not inconsistent with the start-up of new facilities in a non-regulated buiness where full costs of new facilities would not necessarily be charged to customers until the facilities were in full commercial operation.

Depreciation Reduction in Initial Service Phase

CAGPL chose to reduce its depreciation costs in the first four years using the same method as that proposed for the phasing of the rate of return. In the case of the reduction in the depreciation charge, however, the reduction in cost would not be capitalized but rather the use of "phasing" would result in the spreading out of the depreciation charge over a somewhat longer period than the initially planned 25 years. CAGPL presented similar arguments to support this phasing as those given for the phasing of the rate of return.

Accelerated Depreciation

The Applicant proposed to charge, in any one year, an amount in its accounts of up to 50 per cent of the depreciation charge for that year if insufficient funds were available for the repayment of debt principal. This tariff provision was intended to give lenders greater assurance concerning the ability of the Company to repay borrowed funds. CAGPL agreed that this method was not directly in accordance with the Board's uniform accounting regulations concerning depreciation, but stated that it considered that this proposal would be in accordance with generally accepted accounting principles as it would still permit an orderly charge to be made for depreciation against earnings over the life of the project. The Applicant pointed out that this proposal would not increase the depreciation charge over the life of the pipeline but would simply accelerate the timing of such charges in the financial statements.

The Applicant agreed that there was no regulatory precedent for this method.

Compounding of AFUDC

The Applicant proposed to charge the allowance for funds used during construction, both interest and equity, into its rate base every six months. Thus, in making its calculations, it would, after the first six months, be calculating the allowance on the total capital cost to date including the already capitalized allowance. CAGPL agreed that this proposal did not have regulatory precedent but considered it justifiable in view of the very long period of construction.

4.3.2.3 Tariff Matters

"All Events" Tariff

CAGPL requested a full cost of service tariff with an "all events" clause. It considered that this would be fair to shippers as they would only pay the actual costs incurred by the Applicant plus its allowed rate of return. CAGPL adduced evidence to indicate that its shippers had agreed to the form of tariff proposed by it. This agreement, however, was subject, in all cases, to the shippers being granted relief by their regulatory bodies from the impact of the "all events" clause. The Applicant stated that it believed there were regulatory precedents for a full cost of service tariff in both Canada and the United States. However, it did not adduce evidence concerning regulatory precedents for the "all events" clause. Concern was expressed as to whether the Applicant would exercise proper control over expenditures if this clause were approved. The Applicant considered that the Board's right of disallowance of costs would protect future customers.

CAGPL stated that the "all events" clause was intended to assure it of sufficient revenues to pay ongoing costs even if there were an extended period of interruption of service. The Applicant agreed that this was innovative in the regulatory environment, but stated that it felt the clause to be necessary to assure the lenders as to the security of their investments.

Mcf-Mile Method of Cost Allocation

CAGPL requested that the Board approve its method of cost allocation which was that known as the Mcf-mile method. The Applicant stated that this method had extensive precedent in the natural gas transmission industry and that it was appropriate because it most properly took into account the integrated nature of its operations. CAGPL argued that its system would be interdependent between the two sources of gas supply, each bringing with it certain benefits and certain risks. Because of this factor, the Applicant considered that the Mcf-mile method of cost allocation would be the most appropriate method of sharing these benefits and risks.

The Applicant further stated that it considered that any segmentation or zoning method of cost allocation would be an inappropriate method of cost allocation. It agreed that a form of segmentation occurred because of the division of various jurisdictions caused by national boundaries. The Applicant considered that any inequities caused by the rolling in of all segment costs for allocation between all shippers, were less than those which would occur if the line were split into segments for purposes of cost allocation. CAGPL contended that the allocation of common costs to individual segments of the line was an artificial exercise which would result in an improper allocation of costs.

The Province of Ontario expressed concern as to the possible over-sizing of the Cross Delta leg of the system, and whether the proposed method of sharing costs between Canadian and United States shippers would result in a benefit being conferred on the United States shippers.

Triggering of the Tariff

The Applicant proposed that the tariff would commence on the date that the pipeline was certificated as being ready to receive gas. The Applicant agreed that this would cause shippers to pay the tariff even though gas was not flowing and possibly never would flow through the pipeline. The Applicant considered that this feature was really an extension of the "all events" clause, and was part of the overall protection that would be required by lenders.

Effect of Failure to Receive 100 per cent of Tendered Quantity of Gas

The Applicant recommended the inclusion of a provision in its tariff which would deny it a full return on equity investment and related income taxes for service performed for a given shipper, if the company accepts from the shipper in any billing month a volume of gas less than 80 per cent of the quantity of gas tendered by the shipper pursuant to the shipper's transportation service agreement. Thus, if the level of service fell to 85 per cent of volumes tendered, no penalty would result; but if the level fell to 75 per cent the transporter would fail to collect 25 per cent of the otherwise chargeable return on equity and related income taxes. In either event, the shipper would be permitted make-up transportation in subsequent billing months; if the monthly receipt deficiency were such as not to trigger the penalty provision (i.e., less than 20 per cent), the make-up transportation would be performed at a reduced charge if a charge were applicable at all. The Applicant cited no precedent or theoretical support for this request. However, the Applicant did state that it considered that this provision would assist it in assuring equity holders as to its ability to earn the allowed rate of return. The Applicant was also unable to give any reason for the selection of the 80 per cent level for the drop-off of charges, except to state that it considered that this would be a reasonable level at which the charges should begin to abate. In its recommendation to the President, the Federal Power Commission recommended that 90 per cent should be used as the level at which the penalty provision would be triggered rather than the 80 per cent proposed by the Applicants before it.

4.3.2.4 Views of the Board

Financing Matters

While the Board recognizes that domestic and foreign capital markets have shown continuing growth trends, this project has massive debt requirements, and moreover, must compete with other energy-related and major capital projects for available funds. The Board considers that, despite the theoretical evidence for the ready availability of funds, proposed debt funding levels represent an upper level for project financing, particularly in the Canadian market.

Overall, however, the Board considers that the Applicant has demonstrated that the capacity of the capital markets in Canada and the United States appears to be adequate to provide the proposed funds.

The Board believes that if the withholding tax continued to exist, the costs associated with the project would rise. On the other hand, the existence of the withholding tax would not seriously reduce the capacity of the financial market. The Board considers that, although the Applicant's foreign debt would probably not qualify for withholding tax exemption under the current law, the issue is not important in these proceedings. The Board concurs with the Applicant's view that the government might "assist" the project by exempting it from such withholding tax.

The Board believes that it is not possible to determine at the present time whether a bond rating would be assigned to the project. The Board notes that the obtaining of a bond rating and its level would probably be dependent on the inclusion of government backstopping. Since the Applicant proposed to raise $500 million through public debt issues in Canada, and these issues were to be offered prior to the first gas flow, the Board feels that there may be some difficulty in marketing these issues if no bond rating is available. The Board also believes that the ability to obtain a bond rating prior to first gas flow represents an important goal for the Applicant, and that the Applicant should be asked to obtain such a rating as part of the proof of financing should a certificate with conditions attached be granted.

The Board believes that CAGPL's proposed debt/equity mix is resonable but more definite views must await the demonstration of proof of financing.

The 75/25 per cent ratio selected by the Applicant is understood to have been based on the minimum equity commitment that long-term lenders would require. In this light, the Board also considers it logical that the required proportion of equity would increase as the project took on more risk due to cost overruns or cash shortfalls. There is no question that the debt/equity ratio shown on the pro forma financial statements becomes progressively more expensive over the projected life of the project in terms of overall rate of return, and consequently, tariff. The Board is concerned that the equity component of 59 per cent in 1988 is too high, particularly when the tax component associated with the use of equity is included. Some means of maintaining a more balanced capital structure in the later years of the project appears to be desirable.

The Board believes that the most important consideration when examining the mix of short, medium and long-term debt, is its compatibility with the proposed operations of the project. It agrees with the Applicant's contention that debt should be, as far as possible, repaid during the life of the proposed transportation contracts. However, the Board notes that the transportation contracts are not "in place", and that the adequacy of reserves in the Mackenzie Delta/Beaufort Sea area to support long-term transportation contracts is currently questionable. Given the unavailability of "hard" operating projections, it is not possible to assess the compatibility of the aggregate borrowing terms in relation to proposed transportation contracts.

The Board notes that the planned mix of debt maturities is not typical of pipeline financing and has obviously been greatly influenced by the availability of debt funds in the marketplace. The Board would prefer to wait for proof of financing before commenting on this matter.

The Board considers as valid the Applicant's contention that the pre-commitment of funds would give lenders additional confidence as to completion. The Board recognizes the necessity for providing funds or commitments of not less than 25 per cent of the cost of the project to take care of the situation if cost overruns should occur. The Board is of the opinion that this would constitute a necessary inducement to long-term lenders.

Given that the Applicant can have no assurance that public issues would be subscribed for as planned, and that these funds are not capable of pre-commitment, the Board feels that it is necessary for such public issues to be replaced by firm contingency commitments from other sources. The Board particularly notes that the stand-by amounts provided in respect of bond offers ($1,150 million) would be an integral part of the $7,480 million which the Applicant felt it must have pre-committed.

The Board considers it fundamental to the financeability of the project that the Applicant's future revenues be assured by the existence of long-term transportation contracts with shippers. Without such contracts, the project would surely be incapable of financing. The Board feels that the concept of an "all events" tariff is fundamental to the Applicant's financing plan in terms of security arrangements for lenders, and that the Applicant's contention, that undoubted security, however such security is defined, would be required before funds could be committed, is valid.

The Board notes that the cost of debt used in the projected financial statements was illustrative only. The Board realizes that the cost of debt can only be determined upon completion of definitive financial negotiations. The Board observes that, if the project were to be granted an "all events" tariff, and if government backstopping were in place, then the risks facing lenders would be no more and could be less than those typical of a pipeline company. Under these circumstances, higher than normal debt costs should not occur.

The Board believes, from the evidence presented, that it would be unlikely that Canadian investors would own the majority of the equity. The Applicant's objective of majority ownership by Canadians was unsupported by tangible evidence of how it would be achieved. The Applicant's contention, that further equity investment from Canada might be forthcoming following certification, could be valid; however, the Board feels it is not possible at this time to assess this assertion. The Board does not find this satisfactory, as it considers that the provision for majority Canadian voting control should be a sine qua non of the financing plan.

The Board recognizes that it is difficult at this time, to assess the risks facing the equity investor, since those risks could vary significantly depending on the final resolution of the security arrangements. If these are resolved as proposed by the Applicant, the Board would not consider the illustrative return on equity used by the Applicant to be unduly high. However, the Board cannot make a definitive ruling on this point in the absence of contracts and a definitive financial plan. In additon the Board notes the lack of information concerning possible government guarantees or government backstopping in such matters as completion, major interruption or abandonment of the pipeline before the repayment of the initial borrowings of long-term debt.

In summary the Board believes that the CAGPL project could be financed but the demonstration that it could be financed would have to await the submission of proof of financing.

The views of the Board on backstopping of the CAGPL project by the Canadian government are included in its Reasons for Decision in Chapter 1 of the report.

Accounting and Tariff Matters

The Board notes that the tariff was endorsed by proposed Canadian and United States shippers, subject to their being able to flow-through the effect of the "all events" clause included in the tariff. The Board also observes that the Mackenzie Delta producers, who would be most affected by the tariff if the present pricing system remains in effect, have endorsed the form and content of the CAGPL tariff.

While the Board recognizes that CAGPL would have liked approval of the form and content of its tariff, including the specific wording of the tariff, the Board notes CAGPL's acceptance of the fact that, while desirable, this was not practicable in this hearing. The Board, therefore, has dealt only with major matters of principle raised in the tariff.

The Board notes that the CICA recommends the normalization of income taxes for virtually all profit-oriented enterprises but does make an exception for regulated companies where a regulatory agency endorses the taxes payable method. Because of the economic benefit to the project of the cash generated in the early years through tax normalization, the need for the Applicant to reduce its already major requirements from the capital markets and the fact that the accounting principle of deferred income taxes is generally accepted, the Board considers that the Applicant should be permitted to charge income taxes in its cost of service on a normalized basis.

The Board considers that the depreciation method and rate selected involves the exercise of judgment concerning the probable physical and economic life of the pipeline. While the Board concurs with the Applicant that its selected method of depreciation is in accordance with generally accepted accounting principles and has regulatory precedent, the Board questions the appropriateness of the Applicant's rate of depreciation of four per cent as it appears probable that, while this rate may be appropriate for Alaska reserves, it is questionable whether it can be justified for Delta reserves. The Board believes that the rate of depreciation cannot definitely be determined in the absence of contracts for both the sale and transportation of Alaska and Mackenzie Delta gas.

The Board believes there is validity in the Applicant's argument concerning the accounting principles relating to the capitalization and compounding of interest on debt during a construction period, and the existence of regulatory precedent for this matter. The Board believes, however, that it would be more appropriate if it were to allow the capitalization of interest costs actually incurred, rather than on the basis proposed by CAGPL.

The Applicant sought to include return on equity in its AFUDC and to compound that return. The Board agrees that the granting of a return on equity has occurred in the regulatory environment in the past and this could be considered acceptable provided there was reasonable assurance that the amounts so capitalized would be recovered from consumers in future years. (Under the commodity value concept now followed in Canada the Board notes with respect to Mackenzie Delta gas, that it would be the Canadian producers who would bear this cost through reduced net back prices at the wellhead). The Board notes, in any event, that the Applicant has no direct cost relating to this imputed return and would, during the construction period, build up its retained earnings by means of entries in its books of account which would not be directly supported by substance.

The Board realizes that equity investors will wish to be compensated for their investment and that the investment of large sums of equity, without such investments generating any return over a long period of time, may not be an attractive proposition. However, the Board notes that witnesses for the sponsoring companies indicated that they were not primarily motivated by a desire to obtain a high return on investment. In any event, the Board believes that, rather than compensating for this matter by capitalizing an imputed return to the equity holder, it might be preferable for the return to be dealt with either by those companies being allowed to rate base their investment in the Applicant or by allowing a higher return when operations commenced to reflect that no return was allowed during the construction period. All of the United States sponsors and most of the Canadian sponsors are regulated companies which have indicated that they will seek relief in their own jurisdiction for their investment in the Applicant's project. To approve a return on equity in CAGPL could, therefore, result in a double return to these investors. The Board notes that Canadian producers and other non-regulated investors would have no similar benefit available to them. Until this situation is clarified in the various jurisdictions which will have to rule on the matter, the Board is refraining from expressing an opinion on this matter.

The Applicant requested that it be authorized to defer its depreciation charges in the early years of operation until a throughput of 4.5 Bcf/d was achieved.

The Board believes that the Applicant's desire to smooth the impact of costs and avoid placing an undue burden on early customers is reasonable. The Board considers that there is regulatory support for the theory that initial customers should not pay for capital costs which were obviously incurred for the benefit of later customers.

The Board concurs with the Applicant that the unit cost of transportation in the initial years of operation should be in line with that which will prevail when the pipeline is operating at close to full capacity. Accordingly, the Board is prepared to accept the principle proposed by the Applicant that the depreciation charge be phased. The Board notes that the volumes of gas deliverability set out in the Applicant's No Expansion Case appear more probable of achievement than those set out in its Base Case. Accordingly, the ultimate capacity of the No

Expansion Case of 3.25 Bcf/d should be used for the phasing calculation.

The Applicant sought to defer and capitalize its return in the initial service phase in circumstances similar to its proposed deferral of depreciation charges.

The Board believes that the phasing of the rate of return and subsequent capitalization thereof is simply a logical extension of the Applicant's proposal to capitalize the imputed cost of debt and return on equity in the period of construction. In either case, the Applicant sought to ensure a return to its equity holders in excess of that which would be obtained through normal operations. The Board considers that the arguments stated for and against the capitalization of equity return in the construction period have equal weight in this case.

Although the Board accepts the principle of phasing costs in the initial years of operation, it believes that its decision in relation to this matter, inasmuch as it concerns the rate of return, should parallel its decision concerning the allowance for funds used during construction. Accordingly, while the Board approves the phasing of the rate of return, to the capacity level of the No Expansion Case, it considers, at this time, that only the interest portion should be capitalized.

The Applicant sought to increase its depreciation rate by up to 50 per cent, in the early years of operation, if cash flow was inadequate to cover repayment of debt principal.

The Board believes, that the need for this has not been adequately demonstrated and that a decision on this point should be deferred until proof of financing is submitted.

The Applicant requested a full cost of service tariff with an "all events" clause. The Board notes that it has accepted full cost of service tariffs in the past. The Board considers that an endorsement of these matters in no way precludes the right of the Board to disallow expenditures improperly or imprudently incurred. The Board recognizes that, on the evidence before it, the project is probably not financeable without the inclusion of the "all events" clause in the tariff. Subject to the filing of evidence that the same clause has been approved by the appropriate United States and Canadian regulatory authorities in all applicable jurisdictions, the Board accepts the principle of the "all events" tariff.

The Applicant proposed an Mcf-mile method of allocation of costs for its entire system. Evidence adduced during the hearing indicated that the greatest risk of cost overruns, and the highest transportation costs per mile, would be on the segment of the pipeline from the Alaskan border to Tununuk Junction. The Applicant's proposal would, in the opinion of the Board, result in a higher cost to Canadian shippers than that which would occur if the segments of the line from the Delta and from Alaska were treated as separate segments for costing purposes. The Board wishes to express concern about this issue; however, the Board believes that this matter should more properly be dealt with in a subsequent Part IV proceeding which would follow if the application were approved.

The Applicant proposed that it commence billing customers from the date that leave to open the pipeline is granted.

The Board accepts the Applicant's contention that lenders to the project will require assurances as to the flow of funds in the period that may elapse between certification of the line and the flow of gas. In such a situation there would be a serious burden upon the Canadian shipper with regard to the initial cost of operation of the pipeline. The positon concerning both commercial and government insurance during the period has not yet been made clear by the Applicant. The Board considers that the record is quite clear that none of the potential shippers could bear the costs associated with a long delay between the qranting of leave to open and the commencement of gas flow for a very long period. Accordingly, the Board considers that, while it approves this provision, such approval would only be of assistance to the Applicant if its shippers were permitted to flow these costs through to consumers.

The Applicant proposed that, when it could not accept gas tendered for delivery, the "all events" tariff should be modified and the return on equity reduced if deliveries fell to a level of 80 per cent or less of the tendered volumes.

The Board notes that the Applicant considered that the acceptance of this proposal would assist in assuring equity holders as to the continuing flow of revenues. The Board believes that although the proposal has merit in principle, the setting of the level at 90 per cent of the tendered volumes would be more appropriate.

4.3.2A ALBERTA NATURAL GAS

4.3.2A.1 Financing

Capital Requirements

Alberta Natural proposed to raise $74.3 million for the construction of new facilities as follows:

	$Millions
Issue of First Mortgage Pipeline Bonds	30.0
Generated from Internal Sources	44.3
Total	74.3

Cost and Nature of Debt

Alberta Natural stated that it had not determined whether the bonds would be placed privately or offered publicly, this decision would be made based on conditions at the time of financing. The Applicant, in preparing pro forma financial statements, assumed an interest rate of 10.5 per cent for the bonds.

Internally Generated Funds

Alberta Natural stated that it would generate the $44 million from depreciation and the deferment of income taxes. It subsequently filed an exhibit which gave pro forma financial statements for its pipeline and liquids extraction businesses for the years 1976-1986. These statements showed that there would be sufficient cash generated by the pipeline and liquids extraction businesses in the years 1976-1982 to fund the $44 million, except that $8 million would be borrowed in 1981 and repaid in 1982.

Government Backstopping

Alberta Natural stated it was not seeking government backstopping in respect of completion of its segment of the project.

Rate of Return

Alberta Natural stated that it had used a rate of return of 13 per cent on common equity for illustrative purposes in its pro forma financial statements. This was the rate that it was currently earning on its pipeline operations.

Equity

Alberta Natural stated that it did not propose to make any further issues of common stock. This would ensure that Canadian ownership of its shares would remain unchanged at 55 per cent with the balance being owned by Pacific Gas Transmission Company.

4.3.2A.2 Accounting and Rate Making

As set out in the introduction, many of the accounting policies put forward by Alberta Natural are common with those put forward by other Applicants. To save repetition, the Board considers it appropriate that the arguments put forward concerning these policies and the Board's views thereon, should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to the application of CAGPL and are to be found in that section:

Accounting for Income Taxes;

Allowance for Funds Used During Construction; and

Deferral of Return in Initial Service Phase.

This section deals with the accounting matter set out below where the policy proposed by the Applicant differs from that of CAGPL:

Depreciation.

Alberta Natural proposed that it recover, through its tariff, depreciation charges based upon net plant in service using either the unit of throughput method or the straight line remaining life method, whichever yielded the higher rate. It stated that its present practice was to charge its two existing customers on the unit of throughput basis and that it proposed to adopt the same method for the new facilities. Alberta Natural had assumed that the export licence for Alaska gas would be for a period of approximately twenty years, and it agreed that this method would be based on a period of time which would be shorter than the physical life of the facilities.

4.3.2A.3 Tariff Matters

As set out in the introduction, many of the proposals concerning the selection of the tariff put forward by Alberta Natural are common with those put forward by other Applicants. To save repetition, the Board considers it appropriate that the arguments put forward concerning the proposals and the Board's views thereon should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to CAGPL and are to be found in that section:

All Events Tariff; and

Effect of Failure to Receive 100 per cent of Tendered Quantity of Gas.

This section deals with the tariff matter set out below where the policy proposed by the Applicant differs from that of CAGPL:

Cost Allocation.

Alberta Natural proposes, where appropriate, to allocate the cost of the new facilities on an incremental basis. All new plant will be segregated and regarded as being for the account of the shippers of Alaska gas. Depreciation, property taxes, return and income taxes related thereto would be charged to the account of those shippers. All other costs of service, with the exception of compressor costs, would be allocated between shippers of Alaska gas and shippers of gas from other sources on the basis of daily contract quantities; compressor costs would be allocated on the basis of daily contract quantities and shippers' assigned share of compressor capital costs. Alberta Natural stated that it believed the incremental method of cost allocation to be more equitable to its existing shippers. On the other hand it felt that its proposal would give the new shippers an opportunity to ship Alaska gas at a lower cost than they would incur if they were to build their own pipeline.

4.3.2A.4 Views of the Board

Financing Matters

The Board is satisfied that Alberta Natural has demonstrated the ability to finance the expansion of its facilities by the proposed mixture of debt and internally generated funds.

Accounting and Tariff Matters

In light of the fact that Alberta Natural presently uses the unit of throughput method to calculate depreciation charges, the Board believes that the Applicant's proposal to continue this practice for its new facilities is reasonable. In addition the method proposed by Alberta Natural has the merit of reducing depreciation expense during the initial service phase, when volumes are building up. However, the Board reserves its position at this time on the method proposed by Alberta Natural.

The Board accepts in principle Alberta Natural's arguments concerning equity amongst shippers. However, the Board believes that the method of cost allocation would more suitably be dealt with in a Part IV hearing.

4.3.3 FOOTHILLS GROUP

4.3.3.1 Introduction

The overall financial plan of the Foothills Group, the evidence related to the capacity of the capital markets to deal with the financing requirements of that plan, and the viability of the Group's financial plan are all dealt with in Section 4.3.3. Sections 4.3.3A, 4.3.3B and 4.3.3C deal with financing matters relating to the individual financing plans of Foothills, Trunk Line (Canada) and Westcoast respectively.

4.3.3.2 Combined Capital Requirements

The Group's combined capital requirements for the Foothills project are set out below. All numbers are in millions of dollars.

Foothills Group
Combined Capital Requirements[1]
($ millions)

	1978	1979	1980	1981	1982	1983	1984	1985	Total Basic Requirements	Est. Contingency Requirements[2]	Total Est. Requirements
Foothills/Delta											
Canadian Banks	--	--	110	250	60	--	--	--	420	255	675
United States Banks	--	--	--	185	45	--	--	--	230	135	365
Canadian Long Term Debt	--	--	150	280	295	--	--	--	725	120	845
United States Long Term Debt	--	--	175	185	185	--	--	--	545	140	685
Canadian Preferred Stock	--	90	107	--	--	--	--	--	197	40	237
Canadian Common Stock	25	155	213	25	25	--	--	--	443	130	573
TOTAL	25	245	755	925	610	--	--	--	2,560	820	3,380
Trunk Line											
Canadian Banks	--	--	40	80	--	--	--	--	120	400	520
Canadian Long Term Debt	--	50	50	75	75	75	60	60	445	--	445
United States Long Term Debt	--	60	--	--	75	50	--	--	185	--	185
Canadian Preferred Stock	60	--	--	--	50	50	--	--	160	--	160
TOTAL	60	110	90	155	200	175	60	60	910	400	1,310
Westcoast											
Canadian Long Term Debt	--	100	50	--	--	150	--	--	300	--	300
United States First Mortgage Bonds	--	--	--	--	250	--	--	--	250	--	250
TOTAL	--	100	50	--	250	150	--	--	550	--	550
GRAND TOTAL	85	455	895	1080	1060	325	60	60	4020	1220	5240

(1) Does not include bank interim financing, which is provided on a revolving credit basis.

(2) Contingency requirements include both amounts to cover cost overruns and amounts to backstop public issues of securities.

4.3.3.3 Capital Market Capacity

The Foothills Group presented studies on the Canadian and United States capital markets and the Canadian and United States banking systems which supported their contention that there was sufficient capacity within these systems to fund the financial requirements of their project. The studies reviewed the current situation in the capital markets and projected historical trends.

The Applicants' overall summary of the market capacity did not take into account the international market, i.e. outside Canada and the United States, or the use of supplier credits. It was stated that these areas should be viewed as sources of possible additional funding in the event of major cost overruns.

With regard to the United States capital market, the continued exemption of interest payments from Canadian withholding taxes was assumed.

In all cases, it was indicated that the ability of the Foothills Group to raise funds would be contingent upon the lenders perceiving that they had undoubted security of the payments of loan principal and interest. This was defined as insuring the lenders against all known risks, and also assuring them an adequate return on their investment.

Overall, the financial advisors were satisfied that the requirements of the project were within the limits of the capacities of the capital market.

4.3.3.4 Viability of Project

In written evidence it was stated that the following assumptions were made in preparing the plan:

- at the time of financing, proven and probable reserves of gas, as determined by independent consultants, would be available;
- prospective customers will be able to sell gas at prices which will enable them to sign Foothills transportation contracts;
- gas transportation revenues will be provided by full cost of service contracts lasting at least until the final maturity of the debt arranged under the financing plan; and
- transportation contracts will contain a provision for Foothills' customers to pay the tariff in all events.

Several witnesses for the Foothills Group testified that they had not tried to satisfy themselves as to whether the project was economically feasible. A witness agreed that the financing plan must be feasible on the assumptions made in its preparation but felt that the assumptions had yet to be proven.

A witness agreed that the prospective shareholders would not invest if they did not feel confident about the economics of the project.

At a much later stage in the hearing, after the main evidence on the Foothills financing plan had been given, further evidence was adduced on the viability of the project which is reviewed at the end of the evidentiary section.

4.3.3A FOOTHILLS

4.3.3A.1 Financing

Summary of Capital Requirements

Summary of Capital Requirements

($ millions)

	1978	1979	1980	1981	1982	Total Basic Require-ments	Est. Contingency Require-ments	Total Est. Require-ments
Canadian Banks	--	--	110	250	60	420	255	675
United States Banks	--	--	--	185	45	230	135	365
Canadian Long Term Debt	--	--	150	280	295	725	120	845
United States Long Term Debt	--	--	175	185	185	545	140	685
Canadian Preferred Stock	--	90	107	--	--	197	40	237
Canadian Common Stock	25	155	213	25	25	443	130	573
TOTAL	25	245	755	925	610	2,560	820	3,380

Canadian/U.S. Investment

Foothills stated in its written evidence that it was an important objective and assumption of its financing plan that all equity would be owned by Canadians. During cross-examination a witness for the Applicant defined "Canadians" as companies that were not controlled outside of Canada.

Foothills envisaged that 20 per cent of its equity would be provided by Trunk Line, 20 per cent by Westcoast, and 60 per cent by stockholders who had yet to be determined.

In written evidence, the Applicant stated that it proposed to arrange, to the maximum extent, the placement of its debt requirements in Canadian markets. This was partly in recognition of the fact that the Applicant would not deliver, directly, any gas outside Canada and, accordingly, might not have any foreign sources of revenue. Foothills considered that it was important, within the constraints of the Canadian capital market, to arrange as much debt finance as was feasible in Canada.

Debt/Equity Mix

The Applicant intended to finance its project with 75 per cent debt and 25 per cent equity. The 3:1 debt/equity ratio was felt to be an appropriate balance in achieving the objective of arranging funds at the lowest cost practicable. If project costs exceeded basic estimates and further financing was required, this debt/equity ratio would be maintained up to the Applicant's overrun factor of 20 per cent.

Foothills would draw down substantially all of its equity funds before it commenced to draw down its debt requirements. The pro forma financial statements presented by it indicated a high proportion of equity capitalization during construction, such proportion falling gradually to 28 per cent of capitalization in 1982. Thereafter, the equity proportion would increase over a period of years to 48 per cent by 1991.

A witness testified that a "normal" debt/equity ratio for a utility would be approximately 60 per cent debt to 40 per cent equity. A further witness believed that the increase in equity component, through time, arose from a consideration of a static project which repaid its debt and accumulated retained earnings. The witness felt that, since the Board would regulate the utility on an ongoing basis, a safeguard existed in that the Board might, if it considered the actual capital structure of the utility to be inappropriate, determine the capital structure appropriate to the utility.

Debt Term

The Applicant sought to raise its debt financing from United States and Canadian banks and long-term lenders. First mortgage bonds and unsecured debentures would constitute approximately 66 per cent of debt requirements, the balance would be bank financing. First mortgage bonds and unsecured debentures would carry a term of 20 years from completion of construction and a 100 per cent sinking fund would commence in 1984. Canadian term bank loans would be amortized over a six-year period from 1984, and United States term bank loans over a four-year period from the same date.

Foothills presented no evidence indicating that the terms of its various borrowings had been considered in the light of the proposed economic life of its project or the length of the proposed transportation contracts.

Cost of Debt

The Applicant ascribed cost rates to each of the debt issues set out in its financial plan. Assumptions regarding rates were made taking into account current market conditions and reasonable projections of future conditions. A witness confirmed that the Applicant's plan assumed that United States lenders would not be subject to Canadian withholding taxes. The witness felt confident that either the current withholding tax provisions would be extended beyond 1978, or the Applicant's project would be specifically exempted from Canadian withholding taxes. However, the witness agreed that were such an exemption not granted, the cost of the United States debt would increase.

A witness for the Applicant testified that the rate used for bank financing in Canada was an average over the period of the financing and was not based on any assumed relationship with a prime rate. A further witness believed that the amounts sought from United States banks, although not outside the range of what those banks could accommodate, was on the "high side" and he believed that normally, the longer the term, the higher would be the rate charged by the bank. The banks also might require a slight premium in view of the size of the required borrowing.

One of the Applicant's financial advisors testified that it would seek a group of shareholders who were sufficiently credit-worthy to allow the Applicant to obtain a bond rating of Baa. The witness stated that Foothills might not necessarily expect to have a bond rating before a "proof of financing" phase but that, when the financial package was in place, the financial advisors would be able to evaluate it and obtain a rating letter.

A witness believed that United States lenders might be able to charge a slight premium in respect of borrowings by Canadians in view of the "Canadian basket" restrictions of those lenders. This restriction prevents United States life insurance companies from investing more than a specified percentage of their admitted assets in Canadian companies.

Debt Commitments

The Applicant's financial advisors testified that no commitments, conditional or otherwise, had been received from prospective long-term lenders.

Equity Components of Capitalization

The Applicant sought to raise a total of $640 million for equity financing. This would comprise $393 million for common shares to be issued to sponsoring shareholders, $50 million for common shares to be issued to the public and $197 million for first preferred shares to be issued to sponsoring shareholders. Sponsoring shareholders would be obligated to purchase approximately $1 principal amount of preferred shares for each $2 subscription for common equity. The preferred shares would be redeemed on the basis of a 5 per cent annual purchase fund commencing in 1984.

Cost of Equity

In written evidence, the Applicant stated that its rate of return on equity should be sufficient to compensate shareholders for the risks they would assume and, also, be competitive with rates earned on other alternative investments. It believed that further factors in the determination of an appropriate rate would be the consideration of the period of time through which investors would wait before receiving dividends and the timing and amounts of such dividend flows. The Applicant used a rate of return on common equity, for illustrative purposes, of 15 per cent. The Applicant stated that it was not applying to the Board for a 15 per cent rate of return but would request approval of a specific rate at a later date.

The Applicant proposed that its preferred shares would carry a dividend rate of 10 per cent.

During cross-examination, it was shown that an equity investor would receive a composite return on his investment in common and preferred equity of less than 15 per cent. Taking into account that common equity would earn only 10 per cent during construction, that preferred shares would earn no return during construction and that an equity investor would be required to purchase preferred shares, the composite return to 1991 might be of the order of 12 per cent. A witness for the Applicant believed that such a return would be low in light of the risks facing an equity investor.

A witness for the Applicant confirmed that the question of what a reasonable return on equity might be, had not, at the time of the hearing, been addressed.

Equity Commitments

The Applicant proposed that 40 per cent of its equity financing would be provided by Trunk Line and Westcoast. The balance of 60 per cent would be sought from other potential investors who might include the following:

Canadian natural gas transmission and distribution companies;

Canadian gas producers in the Beaufort Basin;

Canadian industrial and transportation corporations;

Canadian investing institutions; and

Federal and Provincial crown corporations or agencies.

During cross-examination a witness for the Applicant confirmed that it had not yet assigned any amount of money in whole or in part to groups, sub-groups or individuals in respect of the remaining 60 per cent equity requirement. The witness further confirmed that, as an advisor, he had not had any discussions with any of the potential shareholders (other than Trunk Line and Westcoast) in Foothills.

A witness indicated that as a result of negotiations between potential shareholders, the percentage ownership of common shares by Trunk Line and/or Westcoast might conceivably be reduced.

While the Applicant's financial advisors stated that it would not be a condition of the financing plan that a shipper would be obligated to become an equity holder in the company, it was assumed that shippers would take such participation. Specifically, the witness stated that the Applicant assumed that TransCanada would be a potential equity investor. This witness believed that there were sufficient Canadian industrial companies or Crown Corporations who might be investors for the Applicant's plan to be feasible but confirmed that while the advisors had considered the capacity of potential investors to lend funds, they had not considered the willingness of such potential investors to invest.

Crown Corporation

A policy witness testified during cross-examination that Foothills would seek to finance the project in the private sector. If it could not obtain private financing, exclusive of government quarantees of the security of lenders, it would conclude that the project could not be financed by the private sector. The Applicant would then consider approaching the government with a suggestion that a Crown Corporation might build all or part of the Applicant's project north of the 60th parallel. The witness confirmed that Foothills would only seek assistance from a Crown Corporation in the event that it was unable to finance its project independently. It would not seek assistance in the event of an "after the fact bail-out".

The witness further stated that, in view of the fact that a Crown Corporation would not be collecting taxes and would, presumably, finance all expenditures by debt then, if a Crown Corporation were to build the project at a capital cost figure similar to that shown in the Applicant's proposal, the cost of service might be 25 per cent less than that in the proposal. Alternatively, a Crown Corporation could incur capital costs of up to 34 per cent in excess of the estimates filed by the Applicant, and still maintain the cost of service projected by Foothills.

Credit Support

Requirements

The Applicant's financial plan stated that credit support would have to be sufficient to ensure that:

- the project was completed and placed in service;
- revenues were adequate to meet all financial obligations including interest and sinking fund payments on the outstanding debt and to provide an adequate return on equity; and

interruptions in service, including force majeure interruptions, would not jeopardize the ability of the project to meet its obligations.

The types of credit support proposed by Foothills included the following:

- pre-commitment of funds;
- an "open-ended" shareholder agreement;
- full cost of service tariff with an "all events" clause with shippers;
- gas storage and business interruption insurance in the event of service breakdown; and
- acceleration of debt repayments.

During cross-examination a witness confirmed that the Applicant's financial advisors had been specifically instructed that a financial plan predicated upon a Canadian government guarantee was unacceptable to the Applicant.

Pre-Commitment of Funds

Foothills stated that it would seek firm commitments from both equity and debt holders to provide the funds necessary to:

- complete the project at its projected basic cost;
- provide for cost overruns to the extent of about 20 per cent of total initial cost; and
- provide backstop financing for the proposed $310 million of public financing.

The Applicant further proposed that cost overruns, requiring expenditures above the 20 per cent to be overcommitted, would be borne by the sponsoring group or other parties with an interest in the completion of the project.

Since the Applicant recognized that it would be unable to obtain pre-commitment of cost overrun funds from public investors, it proposed to seek a 26 per cent overrun commitment from all institutional first mortgage bond investors. United States and Canadian bank investors would commit to a 20 per cent overrun factor as would the equity sponsors. Taken together, an overall 20 per cent factor of over-commitment would be achieved. In order to backstop the proposed public issues of first mortgage bonds ($160 million) and unsecured debentures ($100 million), the Applicant proposed to seek additional commitments from Canadian and United States banks, pro rata those banks' commitments to provide basic financing. The proposed public issue of common shares of $50 million would be backstopped by the equity sponsors.

The Applicant would thus seek to pre-commit $2250 million for basic project costs, $510 million for cost overruns and $310 million to backstop public issues. Any drawdowns of funds under the additional commitments to cover increased costs would be effected on a pro rata basis to ensure the maintenance of the 75/25 debt/equity ratio.

A Canadian banking advisor confirmed that the backstopping commitments with regard to the public debt issues would be on the security of firm undertakings of parties satisfactory to the banks to refund the securities within three years. The witness agreed that, at the present time, the proposed shareholder group was the party which would ultimately backstop this borrowing. A further witness believed it extremely unlikely that such public issues could not be marketed over a three-year period.

Shareholder Agreement

Foothills proposed that cost overruns requiring expenditures in excess of the funds drawn down on the additional commitments (20 per cent) would be borne by the sponsoring group or other parties with an interest in the completion of the project. It presented no evidence as to who the "other parties" might be but, during cross-examination, its witnesses described many of the proposed features of the shareholder agreement which would commit shareholders to complete the project on an "open-ended" basis.

The proposed shareholder agreement would require the commitment, on a pro rata basis, for basic funds, 20 per cent overrun and additional funds in the event of a default of one of the other shareholders. Such additional funds would be provided in accordance with a "step up" clause in the shareholder agreement. Such a clause might require each of the remaining shareholders to contribute an additional amount of, say, a minimum of 10 per cent and a maximum of 20 per cent of their respective original investments. Any shareholder leaving the shareholder group under a penalty situation would forfeit its equity investment. Members of the shareholder group would be totally obligated to complete the project, whatever the overrun.

The witness envisaged that, after the 20 per cent overrun funds had been used, a situation of flexibility might arise where shareholders might negotiate amongst themselves as to further funding. In this situation, the witness felt that there would be an incentive for shareholders to continue funding on a pro rata basis in order to avoid a dilution factor. The witness also visualized the possibility of including a "penalty dilution" factor in the shareholder agreement which would operate in the event that a shareholder did not increase his investment according to his pro rata share.

The witness believed that the provisions outlined above, i.e. risk of loss of investment in the event of leaving the shareholder group and dilution or penalty dilution should a shareholder refuse to increase his investment, would cause prospective investors to closely consider the terms of their own trust indentures and their own abilities to continue funding in the event of overruns. The witness believed that this was important in order to prevent "weak" prospective shareholders from joining the shareholder group and subsequently finding themselves unable to fulfil their commitments. He further believed that the reverse of this situation, i.e. additional accretion to investment in the event of another shareholder dropping out, would encourage the "strong" shareholder to become part of the agreement.

Shareholders would not be released from their obligation under the shareholder agreement until such time as lenders' conditions regarding completion had been satisfied. Completion might be defined in terms of a "time certain", a dollar amount certain or a percentage performance over a period of time. In the latter case, this period of time might be, say, three months or three years, depending on negotiations.

A witness for the Applicant believed that shareholders would not sign the shareholder agreement without also negotiating an agreement with producers to provide cash flow in the event of a force majeure failure to produce gas.

A witness stated that he believed that the shareholder agreement would also be subject to considerable negotiation on the part of long-term lenders. Lenders would examine the agreement and the credit-worthiness of the parties behind it. Were they to consider that the shareholder group did not have sufficient credit capacity, then the lenders might choose to lend less than the amount sought by Foothills. In that event, the witness believed that Foothills might have no project, or possibly only half of a project with someone else, possibly a Crown Corporation, completing the project.

A witness for the Applicant stated that if the shareholders, at any point, considered that the project had become uneconomic, they would have the option to abandon it. In this event, the shareholders would be liable to repay the outstanding debt obligation to the lenders.

Tariffs

The Applicant proposed that its gas transportation revenues would be derived from full cost of service contracts extending at least until the final maturity of its project debt. Such contracts would operate in all events including force majeure interruptions or reduced throughputs.

A witness for the Applicant explained that in the event of service interruption or throughput being reduced to below 80 per cent of the projected levels, the tariff would be abated to the extent of the rate of return on common equity and related income taxes.

A witness for Foothills testified that it had made no efforts, as far as he was aware, to quantify the payments which would be required from TransCanada or Westcoast in the event of total interruption of service.

During cross-examination, a policy witness for the Applicant stated that its financial plan did not contemplate that shippers would be obligated to commence tariff payments or payments in lieu of tariffs on a date certain. He stated that the Applicant's financial advisors believed that such a provision would be attractive to potential lenders but did not feel that it was essential to the financing plan. The tariff would not commence until all three participants (Foothills, Trunk Line (Canada) and Westcoast) had completed their facilities.

A witness testified that, in the event that shippers were required to continue payments during a major interruption of service, and sought to pass on such costs to their customers, there could, in view of the commodity value pricing concept, be a risk of non-recovery. The witness believed that it might not be possible to obtain regulatory approval in Canada to pass such costs on to the consumer regardless of its effects on city-gate prices and, consequently, believed that this concept would be unworkable in Canada.

Gas Storage and Business Interruption Insurance

During cross-examination, a policy witness for the Applicant testified that the Foothills project would have gas storage facilities sufficient to provide at least ten days of gas supply in the event of an interruption of service. Shippers would thus obtain gas in return for their tariff payments until such time as the stored gas was exhausted.

Foothills proposed to arrange for interruption insurance to be effective from the fifteenth day through to the ninetieth day of interruption. A witness indicated that he considered that the only possible exposure of the shippers, during a period of interruption, would be between the tenth day and the fifteenth day, and that would only be if storage was inadequate to cover this period. This witness believed that it might be possible to modify the Applicant's proposed insurance coverage in order to cover this period, although he recognized that a higher premium would result.

A further witness for the Applicant testified that he believed that the longest outage of a gas transmission line that had ever taken place in Canada was for two or three days.

Foothills presented no evidence as to how shippers might be protected in the event that an interruption were to continue beyond ninety days. However, a policy witness for Foothills believed it inconceivable that an interruption could continue for such a period since he believed that the worst breakdown could be repaired within three weeks.

Acceleration of Debt Repayment

During cross-examination, a witness confirmed that lenders would require provisions in the trust indentures to allow for the acceleration of debt repayment in the event that reserves proved to be inadequate for economic production over the full period of debt repayment.

Government Guarantees

A witness for the Applicant confirmed that the financial advisors were instructed that a financial plan predicated upon a Canadian government guarantee would be unacceptable because, on the face of it, it would not be a financial plan and would merely show that the project was uneconomic. The witness felt that if the project were to have a government guarantee as part of its "credit support package", it would be able to borrow anything, as long as the government itself was in a position to repay the money.

4.3.3A.2 Accounting and Rate Making

As set out in the introduction, many of the accounting policies put forward by CAGPL, Foothills and Foothills (Yukon) are common to each project. To save repetition, the Board considers it appropriate that the arguments put forward concerning these policies and the Board's views thereon, should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to the application of CAGPL and are to be found in that section:

Accounting for Income Taxes;

Depreciation; and

Depreciation Reduction in Initial Service Phase.

This section deals with the accounting matters set out below where either the policies proposed by the Applicant differ from those of CAGPL or Foothills (Yukon), or those policies are not consistent between the companies sponsoring the Foothills project:

Allowance for Funds Used During Construction; and

Deferral of Return in Initial Service Phase.

Allowance for Funds Used During Construction

The Applicant has requested that it be allowed to capitalize an imputed cost related to funds used during construction. The rate proposed by the Applicant was based on the following costs: debt - actual rate incurred; preferred stock - zero; common stock - at an anticipated bank interest rate of 10 per cent.

Deferral of Return in Initial Service Phase

The Applicant has not included in its application a proposal to reduce its rate of return by the percentage of unutilized capacity during the initial service phase.

4.3.3A.3 Tariff Matters

As set out in the introduction, many of the proposals concerning the selection of tariff principles put forward by Foothills are common to each project. To save repetition, the Board considers it appropriate that the arguments put forward concerning the proposals and the Board's views thereon should only be set out once. Accordingly, the following policy is dealt with in the discussion relating to CAGPL and is to be found in that section:

All Events Tariff.

This section deals with the tariff matters set out below where either the policies proposed by the Applicant differ from those of CAGPL or those policies are not consistent between the companies sponsoring the Foothills Group project:

Effect of Failure to Receive 100 per cent of Tendered Quantity of Gas; and

Commencement of Tariff.

Effect of Failure to Receive 100 per cent of Tendered Quantity of Gas

The Applicant recommended the inclusion of a provision in its tariff which would deny it a full return on equity investment and related income taxes for service performed for a given shipper, if the transporter accepts from the shipper in any billing month a volume of gas less than 80 per cent of the quantity of gas tendered by the shipper pursuant to the shipper's transportation service agreement. Thus, if the level of service fell to 85 per cent of volumes tendered, no penalty would result; but if the level fell to 75 per cent, the transporter would fail to collect 25 per cent of the otherwise chargeable return on equity and income taxes. In either event, the shipper would be permitted make-up transportation in subsequent billing months; if the monthly receipt deficiency were such as not to trigger the penalty provision (i.e., less than 20 per cent), the make-up transportation would be performed at a reduced charge if a charge were applicable at all.

In the event of a failure in the Westcoast or Trunk Line system, it proposed to collect its full cost of service, including its allowed rate of return. The Applicant stated that in the event of an interruption, it could offer its customers some protection by the provision of storage facilities which would provide an emergency service of 1 Bcf/day for ten days, and that it might negotiate loss of business insurance after 15 to 20 days.

Commencement of Tariff

The Applicant proposed to include in its tariff a clause whereby payments under the tariff would commence on a date certain which would be set at a specific date after the start of construction. Foothills stated that it had not decided on a date certain, nor had it discussed such a clause with potential shippers. It anticipated, however, that should it fail to put the line in service by 1 November 1981, it might continue to capitalize AFUDC for a period of four to five months before requiring its shippers to commence payments. It was not certain whether, in view of the abatement clause, the operation of this clause would require shippers to pay a full cost of service including the return.

4.3.3A.4 Views of the Board

At a later stage in the hearing, the financial advisors to Foothills testified that on the evidence on reserves and deliverability then before the Board, the economics of the project had not been proved. Accordingly, they felt that at the time of the hearing and until such time as the economics could be proved, the Foothills Group project was not financeable.

Foothills, in written argument, stated "Foothills respectfully request the Board to hold the application for a certificate of public convenience and necessity for the Maple

Leaf project in abeyance until such time as the date upon which Canadian markets will require Mackenzie Delta gas can be forecast with greater certainty than is now the case". Trunk Line also submitted that a route up the Mackenzie Valley should be deferred.

The Board notes the request of Foothills that it defer any decision concerning the Foothills application. The Board also notes the advice of Foothills financial advisors that the Foothills project is, on the evidence currently before the Board, not capable of being financed at this time.

The Board concurs with the Applicants' advisors that the Foothills project is not economically viable at this time, accordingly the Board considers it unnecessary to comment further on the financial details of Foothills.

4.3.3B TRUNK LINE (CANADA)

4.3.3B.1 Financing

Foreword

The Board finds that many of the concepts and assumptions used by the Applicant in the formulation of its financial plan in respect of the Foothills Group project are similar, in all material respects, to those used by it in the preparation of its plan in respect of the Foothills (Yukon) Group project. As a consequence, the Board declines to discuss such aspects in detail and has restricted its summation of the evidence and its views to those areas which it finds to be significantly different from the Applicant's proposal in respect of the Foothills (Yukon) Group project. Accordingly, the Board has limited itself to a discussion of the risks facing the Applicant as a result of its proposed participation in the Foothills Group project.

Summary of Capital Requirements

Summary of Capital Requirements

($ millions)

	1978	1979	1980	1981	1982	1983	1984	1985	Total Basic Require-ments	Est. Contingency Require-ments	Total Est. Require-ments
Canadian Banks	--	--	40	80	--	--	--	--	120	400	520
Canadian Long Term Debt	--	50	50	75	75	75	60	60	445	--	445
United States Long Term Debt	--	60	--	--	75	50	--	--	185	--	185
Canadian Pre-ferred Stock	60	--	--	--	50	50	--	--	160	--	160
TOTAL	60	110	90	155	200	175	60	60	910	400	1,310

Evidence

The Applicant proposed to draw its funds from its parent company, Trunk Line.

Trunk Line proposed not to seek precommitment of the funds necessary for its participation in the Foothills project. A witness stated that Trunk Line was well regarded, its securities had been well received by investors in North American capital markets for almost 20 years, and that, accordingly, pre-commitment was not required.

During cross-examination, a witness confirmed that the sponsor/shareholders group of the Foothills Group would undertake to complete the line, regardless of the ultimate cost.

Testimony given regarding details of the proposed shareholder agreement of the Foothills Group indicated that a sponsor/shareholder would be obligated to the extent of its share of 120 per cent of estimated costs and also a minimum of 10 per cent of its original investment in the event that another shareholder defaulted. A sponsor/shareholder would also assume an "open-ended" obligation to complete the Foothills facilities, whatever the cost.

During cross-examination, a witness testified that a sponsor/shareholder would thus have a contingent obligation of a minimum of 4.9 times his original investment when one included his obligations to the debt-holders of Foothills. The Foothills Group financing plan provides for an investment by Trunk Line in Foothills preferred and common equity of $118 million. The factor of 4.9 times original investment would result in Trunk Line assuming a minimum contingent obligation of $578 million - $153 million for direct equity investment and $425 million with regard to the amounts to be committed by long-term lenders.

Pro forma financial statements filed by Trunk Line indicated that, as at 31 December 1976, its capitalization approximated $720 million and its common equity $240 million. In respect of the Foothills project, Trunk Line would seek to raise $985 million to finance facilities to be constructed by itself and by Trunk Line (Canada) and for its investment in Foothills. It would also assume a contingent obligation to the debt-holders of Foothills of $425 million.

A witness for Trunk Line testified that it would not seek to include its investment in Foothills in its rate base. Trunk Line would continue to be liable, according to the shareholder agreement, until such time as lenders requirements regarding completion were met.

4.3.3B.2 Accounting and Rate Making

As set out in the introduction, many of the accounting policies put forward by CAGPL, Foothills and Foothills (Yukon) are common to each project. To save repetition, the Board considers it appropriate that the arguments put forward concerning these policies and the Board's views thereon, should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to the application of CAGPL, and are to be found in that section:

Deferral of Return in Initial Service Phase; and

Allowance for Funds Used During Construction.

This section deals with the accounting matters set out below where either the policies proposed by the Applicant differ from those of the other projects, or those policies are not consistent between the companies sponsoring the Foothills Group project:

Accounting for Income Taxes; and

Depreciation.

Accounting for Income Taxes

The Applicant proposed to account for income taxes on a taxes payable basis in respect of its 81-mile pipeline to connect Delta gas with the Trunk Line system. The Applicant stated that the requirement to normalize for cash flow purposes was absent in its particular circumstances, and that it had been guided by the need to get Canadian gas into Canadian markets at the lowest cost possible.

Depreciation

The Applicant proposed to depreciate its gas plant in service using a straight line rate of two and one half per cent per annum on the opening balance of depreciable plant in service. The Applicant stated that although the rate to be used by Foothills upstream would be four per cent based on estimated 25 year contracts, it had chosen the two and one half per cent rate in order to bring Canadian gas into Canadian markets as cheaply as possible.

4.3.3B.3 Tariff Matters

As set out in the introduction, many of the proposals concerning the selection of tariff principles put forward by the Applicants are common to each project. To save repetition, the Board considers it appropriate that the arguments put forward concerning the proposals and the Board's views thereon should only be set out once. Accordingly, the following policy is dealt with in the discussion relating to CAGPL and is to be found in that section:

All Events Tariff.

This section deals with the tariff matters set out below where either the policies proposed by the Applicant differ from those of CAGPL or Foothills (Yukon) or those policies are not consistent between the companies sponsoring the Foothills project:

Lease of Capacity and Facilities from Trunk Line.

Lease of Capacity and Facilities from Trunk Line

The Applicant proposed to receive Delta gas at a point seven miles north of the 60th parallel, and to transport it 81 miles south to Zama Lake in its own facilities. From Zama Lake it would transport the gas through facilities which it proposed to lease from Trunk Line.

Under the terms of the lease, Trunk Line would lease to Trunk Line (Canada) certain facilities and unused capacity in Schedule C facilities.

The proposed method of allocation of costs between the two companies would require the implementation of complicated cost allocation procedures. Among the calculations to be made would be:

Trunk Line's mainline from Zama Lake to Empress is to be split into 19 sections, costs would have to be allocated to each of these sections and then allocated between the two companies;

the ascertainment of the cost of incremental facilities to transport Delta gas; and

the use of various percentages to allocate the following costs: operation and maintenance; depreciation; property taxes; income taxes;and return.

The details of the proposed lease and the Board's views thereon are set out in Section 4.2.3.

4.3.3B.4 Views of the Board

The Board's views on the Trunk Line-Trunk Line (Canada) lease are contained in the earlier section of the report dealing with contracts.

The Board notes the request of Foothills that it defer any decision concerning the application. The Board also notes the advice of Foothills financial advisors that the Foothills project is, on the evidence currently before the Board, not capable of being financed at this time.

The Board concurs with the Applicants' advisors that the Foothills project is not economically viable at this time. Accordingly, the Board considers it unnecessary to comment further on the financial details of the Trunk Line (Canada) portion of the project.

4.3.3C WESTCOAST

4.3.3C.1 Financing

Foreword

The Board finds that many of the concepts and assumptions used by the Applicant in the formulation of its financial plan in respect of the Foothills project are similar, in all material respects, to those used by it in the preparation of its plan in respect of the Foothills (Yukon) project. As a consequence, the Board declines to discuss such aspects in detail and has restricted its summation of the evidence and its views to those areas which it finds to be significantly different from the Applicant's proposal in respect of the Foothills (Yukon) project. Accordingly, the Board has limited itself to a discussion of the risks facing the Applicant as a result of its proposed participation in the Foothills project.

Summary of Capital Requirements

Summary of Capital Requirements

($ millions)

	1979	1980	1981	1982	1983	Total Basic Require-ments	Est. Contingency Require-ments	Total Est. Require-ments
Canadian Long Term Debt	100	50	--	--	150	300	--	300
United States First Mortgage Bonds	--	--	--	250	--	250	--	250
TOTAL	100	50	--	250	150	550	--	550

Evidence

The Applicant proposed not to seek precommitment of the funds necessary for its participation in the Foothills project.

During cross-examination, a witness confirmed that the sponsor/shareholder group of Foothills would undertake to complete the line, regardless of the ultimate cost.

Testimony given regarding details of the proposed shareholder agreement of Foothills indicated that a sponsor/shareholder would be obligated to the extent of its share of 120 per cent of estimated costs and also a minimum of 10 per cent of its original investment in the event that another shareholder defaulted. A sponsor/shareholder would also assume an "open-ended" obligation to complete the Foothills facilities, whatever the cost.

During cross-examination, a witness testified that a sponsor/shareholder would thus have a contingent obligation of a minimum of 4.9 times his original investment when one included his obligations to debtholders of Foothills. The Foothills financing plan provides for an investment by the Applicant in Foothills preferred and common equity of $118 million. The factor of 4.9 times original investment would result in the Applicant assuming a minimum contingent obligation of $578 million - $153 million for direct equity investment and $425 million with regard to the amounts to be committed by long-term lenders.

The pro forma financial statements filed by the Applicant indicated that, as at 31 December 1976, its capitalization approximated $566 million and its common equity $265 million.

A witness for the Applicant testified that it would not seek to include its investment in Foothills in its rate base. Westcoast would continue to be liable, according to the shareholder agreement, until such time as lenders requirements regarding completion were met.

A witness confirmed that the Applicant had examined the risks which might arise from the shareholder agreement and that Westcoast was willing to take such risks. A financial advisor for Westcoast felt that, although prospective lenders would examine the contingent risks under the shareholder agreement, it would not prevent lenders from advancing funds.

4.3.3C.2 Accounting and Rate Making

As set out in the introduction, many of the accounting policies put forward by the Applicants are common to each project. To save repetition, the Board considers it appropriate that the arguments put forward concerning these policies and the Board's views thereon, should only be set out once. Accordingly, the following policy is dealt with in the discussion relating to the application of CAGPL, and is to be found in that section:

Deferral of Return in Initial Service Phase.

This section deals with the accounting matters set out below where either the policies proposed by the Applicant differ from those of CAGPL or Foothills (Yukon), or those policies are not consistent between the companies sponsoring the Foothills Group project:

Accounting for Income Taxes;

Allowance for Funds Used During Construction; and

Depreciation.

Accounting Policies

In respect of the transportation cf Delta gas only, the Applicant has prepared pro forma financial statements drawn up on a basis consistent with that presently used by the Applicant. The Applicant has used the following accounting practices:

income taxes have been included in cost of service on a flow-through basis;

an allowance for funds used during construction has been capitalized at a rate of 10 per cent per annum; and depreciation has been charged to cost of service using rates in use by the Applicant at the time of application, and prior to a request for increased rates of depreciation subsequently made to the Board.

4.3.3C.3 Tariff Matters

This section deals with the tariff matters set out below where either the policies proposed by Westcoast differ from those of CAGPL or Foothills (Yukon) or those policies are not consistent between the companies sponsoring the Foothills Group project:

Tariff Matters; and

Commencement of Tariff.

Tariff Matters

Westcoast has made no application in respect of a tariff for Delta gas. Westcoast has suggested that either it purchase the gas in the Delta, which would then become another source of extra-provincial gas to it, or that, should British Columbia consumers purchase the gas, it would devise a tariff whereby common facilities would be shared on a rolled-in basis, and those facilities solely used for Delta gas would be charged to Delta users.

Commencement of Tariff

Westcoast has made no request for a date certain upon which to commence a pre-operational contract with shippers. It stated that it had not contemplated such an agreement since it proposed to be a purchaser of Delta gas. Should it only be a shipper, it stated that the project was small enough in relationship to Westcoast as a whole, and the volumes minor enough not to raise any problems.

4.3.3C.4 Views of the Board

The Board notes the request of Foothills that it defer any decision concerning the Foothills Application. The Board also notes the advice of Foothills financial advisors that the Foothills project is, on the evidence currently before the Board, not capable of being financed at this time.

The Board concurs with the Applicants' advisors that the Foothills project is not economically viable at this time. Accordingly the Board considers it unnecessary to comment further on the financial details of the Westcoast portion of the project.

4.3.4 FOOTHILLS (YUKON) GROUP

4.3.4.1 Introduction

The overall financial plan of the Foothills (Yukon) Group and the evidence related to the capacity of the capital markets to deal with the financing requirements of that plan are dealt with in Section 4.3.4. Sections 4.3.4A, 4.3.4B and 4.3.4C deal with financing matters relating to the individual financing plans of Foothills (Yukon), Trunk Line (Canada) and Westcoast respectively.

4.3.4.2 Combined Capital Requirements

The Group's combined capital requirements for the Foothills (Yukon) project are set out below. All numbers are in millions of dollars.

Foothills (Yukon) Project: Combined Capital Requirements

(for the Canadian portion of the Alaska Highway System 48" diameter line)

($ millions)

	1978	1979	1980	1981	1982	1983	Total Basic Requirements	Estimated Contingency Requirements	Total Estimated Requirements
Foothills (Yukon)									
Canadian Banks	-	85	170	70	-	-	325	65	390
Canadian Long Term Debt	-	70	70	60	-	-	200	40	240
United States Long Term Debt	-	70	330	75	-	-	475	95	570
United States Preferred Stock	88	117	-	-	-	-	205	41	246
Canadian Common Stock	80	60	-	-	-	-	140	28	168
Total	168	402	570	205	-	-	1,345	269	1,614
Trunk Line									
Canadian Banks	-	-	85	75	-	-	160	400	560
Canadian Long Term Debt	50	55	70	70	-	-	245	-	245
United States Long Term Debt	-	125	150	150	-	-	425	-	425
Canadian Preferred Stock	60	-	75	-	-	-	135	-	135
Canadian Common Stock	-	55	-	60	-	-	115	-	115
Total	110	235	380	355	-	-	1,080	400	1,480
Westcoast									
Canadian Banks	20	(20)	60	180	(160)	(63)	17	223	240
Canadian Long Term Debt	-	60	150	100	-	-	310	-	310
United States Long Term Debt	100	140	80	150	120	-	590	-	590
Canadian Preferred Stock	-	75	75	-	-	-	150	-	150
Canadian Common Stock	-	50	100	-	-	-	150	-	150
Total	120	305	465	430	(40)	(63)	1,217	223	1,440
Less Duplication									
Trunk Line	40	30					70	14	84
Westcoast	40	30					70	14	84
	80	60					140	28	168
Grand Total	318	882	1,415	990	(40)	(63)	3,502	864	4,366
Canadian Funds							1,807		
United States Funds							1,695		
							3,502		

4.3.4.3 Capital Market Capacity

The Applicants presented studies on the Canadian and United States capital markets and the Canadian and United States banking systems, which supported their contention that there was sufficient capacity within these systems to support the financial requirements of their project. The studies reviewed the current situation in the capital markets and projected historical trends.

The Applicants' overall summary of the market capacity did not take into account the international market, i.e. outside Canada and the United States, or the use of supplier credits. The Applicants stated that these areas should be viewed as possible sources of additional funding in the event of major cost overruns.

With regard to the United States capital market, the continued exemption of interest payments from Canadian withholding taxes was assumed.

In all cases, it was indicated that the ability of the Applicants to raise funds would be contingent upon the lenders perceiving that they had undoubted security of the payments of debt principal and interest. This was defined as assuring the lenders against all known risks, and also assuring them of an adequate return on their investment. Overall, the financial advisors were satisfied that the requirements of the project were within the limits of the capacity of the capital markets.

4.3.4A FOOTHILLS (YUKON)

4.3.4A.1 Financing

Summary of Capital Requirements

The Applicant filed the following capital requirements summary.

Summary of Capital Requirements

($ millions)

	1978	1979	1980	1981	Total Basic Require-ments	Estimated Contingency Require-ments	Total Estimated Require-ments
Canadian Banks	--	85	170	70	325	65	390
Canadian Long Term Debt	--	70	70	60	200	40	240
United States Long Term Debt	--	70	330	75	475	95	570
United States Preferred Stock	88	117	--	--	205	41	246
Canadian Common Stock	80	60	--	--	140	28	168
Total	168	402	570	205	1,345	269	1,614

Canadian and United States Investment

Foothills (Yukon) proposed to issue its common shares to its Canadian sponsors, Trunk Line and Westcoast. One hundred per cent voting control of the Applicant would be in the hands of these two companies. Non-voting preferred shares would be issued to United States shippers of Alaska gas.

First mortgage bonds and bank borrowings in Canada would constitute slightly over half of the total debt requirements. The balance would be raised by the issue of first mortgage bonds in the United States.

Debt/Equity Mix

Foothills (Yukon) proposed to raise its external financing in a ratio approximately 75 per cent debt to 25 per cent equity. This ratio would be maintained in the event that project costs exceeded basic estimates and further financing was required.

The Applicant would draw substantially all of its equity funds before it commenced to draw down its debt requirements. Accordingly, the pro forma financial statements presented by the Applicant indicated a high proportion of equity during construction, gradually falling to 29 per cent of capitalization in 1981. The pro forma financial statements indicated that the equity proportion of capitalization would not fall below 29 per cent and would gradually increase to 57 percent by 1991.

A witness testified that a "normal" debt/equity ratio for a utility would be approximately 60 per cent debt to 40 per cent equity. A further witness believed that the increase in equity component, through time, arose from considering a "static" project which repaid its debt and accumulated retained earnings. This witness believed that the consideration of a finite case would necessarily lead to such a situation. However, the witness believed that a safeguard existed to ensure that the Applicant's capitalization and rate of return did not become inappropriate in that the Board might determine an appropriate capital structure for the utility.

Debt Term

The Applicants financial plan indicated an intention to raise approximately 50 per cent of its total funds requirement in the form of twenty-year first mortgage bonds. A further 25 per cent of financing would be provided by bank term loans to be amortized over seven years.

The Applicant presented no evidence indicating that the terms of its various borrowings had been considered in the light of the proposed economic life of its project or the length of the proposed transportation contracts.

Cost of Debt

Foothills (Yukon) had ascribed cost rates to each of the debt issues set out in its financial plan.

It was confirmed during cross-examination that the Applicant's financial advisors had assumed, for the purposes of preparing their financial plans, that United States lenders would not be subject to Canadian withholding tax. A witness said that the advisors had had discussions to ascertain the probability of the present Canadian withholding tax provisions being extended beyond 1978. The witness felt confident that either these provisions would be extended or the project would be specifically exempted from Canadian withholding tax. The witness agreed that were such an exemption not to be granted, the cost of the United States debt would increase.

Debt Commitments

The Applicant's financial advisors testified that no commitments, conditional or otherwise, had been received from prospective long-term lenders. A witness did, however, confirm that discussions in principle had been held with several large institutional investors in the United States. Similar discussions had not taken place in Canada.

Equity Components of Capitalization

The Applicant proposed to raise 59 per cent of its equity in the form of non-voting preferred shares to be issued to United States shippers of Alaska gas. These shares would be redeemable, on the basis of an eighteen-year purchase fund, and cumulative as to dividends. Dividends would not be paid until such time as the project was completed.

In its Recommendation to the President the Federal Power Commission in the United States stated that it had no intention of forcing United States shippers to accept non-voting stock if such shippers considered that stock to be inferior to ordinary equity.

The balance of equity investment would be in the form of common shares issued to the Canadian sponsors, Trunk Line and Westcoast.

Cost of Equity

Foothills (Yukon) would seek a 10 per cent rate of dividend on its preferred share issues. These dividends would be cumulative from the date of issue and would be paid following completion of the pipeline.

The Applicant did not formally propose a rate of return on common equity but had assumed an illustrative rate of 16 per cent for the purpose of preparing its pro forma financial statements.

During cross-examination, a witness for Trunk Line (Canada) indicated that he believed that there was some validity in the argument that, if a project were guaranteed by the United States government, investors would, in fact, be investing in a "sure thing". In such circumstances, he believed that it may be argued that the investor might only be entitled to a rate similar to that which he might earn on a government bond.

Equity Commitments

During cross-examination, a witness stated that one reason United States shippers would not be considered by lenders to be sufficiently strong to support the Foothills (Yukon) project, without tracking or backstopping, would be the relative commitment on the part of such shippers. The witness recognized that United States shippers were generally much larger than their Canadian counterparts but believed that they had a greater number of projects in which to invest and, as a consequence, would not make such a relatively high commitment of their resources as might Canadian shippers to, say, a Mackenzie Valley project.

The Applicant presented no evidence regarding firm, or even conditional, commitments on the part of United States shippers to invest in its project.

Credit Support

Requirements

In written evidence, Foothills (Yukon) stated that lenders would require borrowers to meet debt service in all events including:

- failure to complete;
- prolonged interruption of service; and
- abandonment.

The types of credit support proposed by the Applicant arising from direct evidence and cross-examination included the following features:

pre-commitment of funds;

full cost of service tariff, with an "all events" clause;

tracking of costs from shippers to consumers;

contingent government backstopping; and

acceleration of debt repayment.

Pre-Commitment of Funds

In direct evidence, Foothills (Yukon) stated that it would seek to pre-commit funds in the amount estimated to be sufficient to complete its facilities. These commitments would be obtained prior to the commencement of construction. It also intended to make arrangements with debt and equity holders to provide funds necessary for cost overruns should they occur. In this regard, it would seek to obtain additional commitments from debt and equity holders to provide for cost overruns of up to 20 per cent. Accordingly, it would seek the pre-commitment of $1,345 million to finance basic requirements and a further $269 million as estimated contingency requirements to provide for possible cost overruns.

A witness for the Applicant confirmed during cross-examination that it would be a condition of the United States banks' involvement in the Foothills (Yukon) project that the project company would obtain pre-commitment of funds prior to construction.

Tariffs

As its basic credit support, Foothills (Yukon) proposed to seek an "all events" full cost of service tariff with the United States shippers of natural gas. It recognized that, until such time as the project was completed and gas began to flow, provisions of the United States Natural Gas Act would preclude a tariff, as such. As a consequence, it proposed to obtain contractual agreements with the United States shippers obligating them to make tariff-like payments, commencing no later than a "date certain", irrespective of completion status. The Applicant believed that such a "date certain" might be set at four years after the commencement of construction. However, during cross-examination, the Applicant testified that the actual date would depend upon negotiations with lenders.

Tracking

Foothills (Yukon) stated in direct evidence, and confirmed during cross-examination, that the shippers would not be regarded by the lenders as having sufficient financial strength to continue the tariffs under all events. The Applicant proposed that the United States shippers obligated under the tariff would "track" their costs to the ultimate consumers of Alaskan gas. The Applicant considered that the broad-based financial support provided by the ultimate consumers would be the basic credit support for the project. It proposed that the shippers would be able to track all their costs in all circumstances including non-completion, interruption or abandonment.

With regard to the proposed tracking mechanism, a witness for Foothills (Yukon) stated that he had been informed that several necessary actions to assure members of the project undisputed financial access to the end users of natural gas could not be obtained without an amendment to the Natural Gas Act altering the powers of the Federal Power Commission. This witness believed, therefore, that congressional action would be required before lenders would invest in the project. A further witness believed that it was impossible to foretell whether such approvals might be delayed or not. This witness also confirmed that prospective lenders would wish to be assured that the proposed tracking mechanism could not be altered by subsequent regulation.

Backstopping

The Applicant's primary proposal was that the basic credit support would be a "perfect tracking" mechanism. The contingent backstopping by government or others represented a "fall back" position and would only be used if perfect tracking were not feasible or the tracking mechanism available to the project was considered inadequate by lenders.

Foothills (Yukon) proposed that, in the event that investors would require additional credit support for certain defined risks, such support might be in the form of contingent backstopping from the United States government, producers of Prudhoe Bay natural gas, or both. Such financial support would be in the form of a guarantee, in the event of cost overruns in excess of estimated and pre-committed amounts, or an insurance or guarantee designed to cover the shippers' tariff and contractual obligations in the following events:

- non-completion;
- extended interruption; and
- extended reduction of service below a certain percentage of the contractual level.

In the case of an extended reduction of service, the program would cover a percentage of the shippers' tariff obligations determined by the reduction in service.

Foothills (Yukon) envisaged that the government program would contain a feature similar to business interruption insurance to cover the circumstances of extended interruption or reduction of service, and that such support would be dropped at such point that the facilities again provided service at levels at which the tariffs became supportive. In the event that the project was abandoned due to non-completion or extended interruption, the government would either service or purchase the underlying securities. During cross-examination, a witness for the Applicant confirmed that Prudhoe Bay producers had testified that they would not be part of a backstopping agreement to the Foothills (Yukon) project. The witness, however, said that he held some hopes that, if the Applicant's project were certificated, the producers might agree to become participants.

Foothills (Yukon) believed it impossible to know precisely what credit support would be required until such time as the United States Federal Power Commission formulated a position on the regulatory structure that it might recommend in respect to the system. It further believed that the final decision as to whether financial support should come from the consuming public in the form of tracking or from the tax-paying public in the form of a guarantee or an insurance program was one that properly should be made in the regulatory and political arenas.

With regard to the amount of government backstopping which might be arranged, a witness for the Applicant believed that the government backstopping agreement would have to be "open ended" in order for it to have any real effect in terms of lender confidence. The witness believed that the United States government should have the choice of selecting to terminate the project rather than continuing to fund it in the event it was considered uneconomic. Under these circumstances, the government would have the choice as to whether it paid off the debt in a lump sum or repaid it according to the original agreements.

A witness testified that he believed that an essentially non-viable project could be converted into a viable one simply by virtue of United States government backstopping.

Uniformity between Applicants

During cross-examination, a witness for Foothills (Yukon) stated that a fundamental aspect of the proposed credit support would be its uniformity with that proposed for other participants in the Foothills (Yukon) project. The witness felt this was important in order to avoid competition in the financial markets in the event that bonds of one participant were to have credit support feature materially different from those of other participants.

4.3.4A.2 Accounting and Rate Making

As set out in the introduction, many of the accounting policies put forward by CAGPL, Foothills and Foothills (Yukon) are common to each project. To save repetition, the Board considers it appropriate that the arguments put forward concerning these policies and the Board's views thereon, should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to the application of CAGPL and are to be found in that section:

Accounting for Income Taxes;

Depreciation; and

Allowance for Funds used During Construction.

This section deals with the accounting matters set out below where either the policies proposed by the Applicant differ from those of CAGPL or Foothills, or these policies are not consistent between the companies sponsoring the Foothills (Yukon) project.

Depreciation Reduction in Initial Service Phase; and

Deferral of Return in Initial Service Phase.

Depreciation Reduction in Initial Service Phase

Foothills (Yukon) did not propose to reduce depreciation charged in cost of service during the initial service phase before volumes had built up.

The Applicant stated that its United States partner, Northwest Pipeline, had determined that it would not be advantageous to reduce depreciation in the initial service phase. However, should other shippers require such a reduction, Foothills (Yukon) would consider its institution.

Deferral of Return in Initial Service Phase

Foothills (Yukon) did not include in its application a proposal to reduce its rate of return by the portion of unutilized capacity during the initial service phase. The

Applicant stated that, in the opinion of its United States partner, Northwest Pipeline, such phasing would not be advantageous. However, it also stated that should other shippers insist upon phasing mechanism, it would consider its adoption.

4.3.4A.3 Tariff Matters

As set out in the introduction, many of the proposals concerning the selection of tariff matters put forward by Foothills (Yukon) are common to each project. To save repetition, the Board considers it appropriate that the arguments put forward concerning the proposals and the Board's views thereon should only be set out once. Accordingly, the following policy is dealt with in the discussion relating to the application of CAGPL and is to be found in that section:

"All Events" Tariff.

This section deals with the tariff matters set out below whether either the policies proposed by Foothills (Yukon) differ from those of CAGPL or those policies are not consistent between the companies sponsoring the Foothills (Yukon) project:

Effect of Failure to Receive 100 per cent of Tendered Quantity of Gas; and

Date of Commencement of Tariff.

Effect of Failure to Receive 100 per cent of Tendered Quantity of Gas

The Applicant recommended the inclusion of a provision in its tariff which would deny it a full return on equity investment and related income taxes for service performed for a given shipper, if the company accepts from the shipper in any billing month a volume of gas less than 80 per cent of the quantity of gas tendered by the shipper pursuant to the shipper's transportation service agreement. Thus, if the level of service fell to 85 per cent of volumes tendered, no penalty would result; but if the level fell to 75 per cent the transporter would fail to collect 25 per cent of the otherwise chargeable return on equity and income taxes. In either event, the shipper would be permitted make-up transportation in subsequent billing months; if the monthly receipt deficiency were such as not to trigger the penalty provision (i.e. less than 20 per cent), the make-up transportation would be performed at a reduced charge if a charge were applicable at all.

The Applicant stated that while the sponsor companies (viz. Westcoast or Trunk Line) could assume the responsibility for their affiliate (Foothills (Yukon)), the affiliate could not accept responsibility for its sponsor companies. Hence, when the failure arose in Foothills (Yukon), all Canadian companies would be subject to a reduction in return and related income taxes. On the other hand, should failure occur in either the Westcoast or Trunk Line (Canada) systems, both Foothills (Yukon) and the technically non-interrupting company would continue to receive full cost of service. The Applicant justified this on the grounds that it would be unfair for the investors of either Westcoast or Trunk Line (Canada) to have liability for a fault on the other's line.

Date of Commencement of Tariff

Foothills (Yukon) proposed that its tariff would not commence until gas commenced to flow. Should the gas commence to flow on or around the planned date of 1 October 1981, no problems were envisaged. However, the Applicant suggested that in the absence of government guarantees, the bondholders, and in certain circumstances the equity holders, would require protection against the following events occurring:

Abandonment of Project

Should the project be abandoned, the shippers would enter into an agreement to pay an "all events" tariff excluding a return on equity.

Failure to Complete a Section by Parties Other Than Foothills (Yukon), Trunk Line (Canada) and Westcoast

The shippers would enter into an agreement that, should parties other than Foothills (Yukon), Trunk Line (Canada) and Westcoast fail to complete a section, they would pay all ongoing costs incurred by the Canadian companies plus a return on equity. The following dates which would trigger these payments by the shippers were suggested by Foothills (Yukon):

the date of completion of the portions of the system constructed by Foothills (Yukon), Trunk Line (Canada) and Westcoast: or

a date, say, four years after commencement of construction of the project or one year from the quoted start up date.

The Applicant also indicated that existing United States legislation would need to be amended to permit the shippers to track the costs to the ultimate consumers.

4.3.4A.4 Views of the Board

Financing Matters

The Board notes that the Applicants intend to draw most of their funds from the Canadian capital market rather than the United States. The Board notes that, in particular, the Applicants will make significant use of the short and medium term bank loan market in Canada. The Board considers that, in assessing the capacity of the market, the Applicants' advisors relied heavily upon the expectation of a continuation of current trends in the capital markets. The Applicants indicated that their advisors had made certain assumptions regarding the adequacy of gas reserves, the economic pricing of gas and the obtaining of undoubted security for lenders. On the basis of these assumptions, it was considered that the project would be viable and able to obtain funds.

The Board notes that the advisors to the Applicants indicated that the funding of the project was dependent upon the lenders having undoubted security of the repayment of their funds, and it would appear that this would be the major constraint on the ability of the Applicants to raise funds, rather than the capital market constraints.

The Board does not take issue with the Applicant's proposals regarding its planned "mix" of Canadian and United States investment. The Board has considered the possible risks which might arise from substantial revaluations of the United States dollar vis-à-vis the Canadian dollar and its potential impact on debt service costs. Since the Applicant proposes to ship United States gas to United States markets, the Board considers that the resulting United States dollar income would adequately cover such a risk.

Whereas the Board does not consider the Applicant's proposals to raise its equity financing as between United States and Canadian investors inappropriate, it does express concern regarding the achievability of the Applicant's proposals. These concerns are discussed under the section "Equity Financing". The Board notes that, in the event that United States shippers which are providing the main credit support of the project, were to require a measure of participation in the management of the project, the Applicant might not achieve the goal of having all of its voting shares owned by its Canadian sponsors.

The Board notes that all Applicants in this hearing, who intend to finance projects on a construction project basis, would do so by external financing in the ratio of 75 per cent debt to

25 per cent equity. The Board believes this reflects the probable views of prospective lenders in that they would require a minimum 25 per cent equity investment at all times. In view of this, the Board concludes that Foothills (Yukon)'s proposal to seek external financing in a ratio of 75 per cent to 25 per cent is reasonable and appropriate. The Board expresses concern as to the Applicant's proposal that funds required to finance cost overruns would be drawn in a similar ratio. The Board considers that, were cost overrun funds required, financial markets would necessarily consider the project "more risky" and might insist upon a higher proportion of equity in subsequent financing.

The Board has particularly considered the increase in the equity proportion of the capital structure during the operating phase as depicted by the Applicant's pro forma financial statements. While this reflects the situation in which the pipeline is not expanded, the Board believes that the cost of equity and associated income taxes can place an undue burden on shippers if the equity component in the capital structure is too high.

The Board expresses concern that Foothills (Yukon) made no effort to demonstrate the compatibility of its proposed debt terms with its future operations. The Board believes that the mix of debt terms can only be assessed in the light of future operations and, particularly, the terms of gas transportation contracts.

The Board stresses that it would expect Foothills (Yukon), if certificated, to demonstrate clearly the compatibility of its proposed terms of financing with its transportation contracts and operations.

The Board does not take issue with the costs ascribed to its debt securities by the Applicant.

The Board considers the Applicant's assumptions regarding future Canadian withholding taxes to be reasonable. Foothills (Yukon) proposed to raise no short term debt in the United States and, consequently, the major concern would be whether the current provisions regarding the exemption of long-term debt securities would be "rolled over".

The Board notes that Foothills (Yukon) presented no evidence regarding the possibility of seeking a bond rating or whether such a bond rating might be available to it. The Board recognizes that Foothills (Yukon) does not propose to issue any securities to the public. Accordingly, the Board believes that a formal rating or rating letter may not have the same importance that it might, were public investment sought. However, the Board feels that some institutional investors might be interested in an independent rating of the Applicant's credit and, as a consequence, would expect Foothills (Yukon) to seek a rating if certificated.

The Board has some concern as to the Applicant's proposed issue of preferred shares to United States shippers. Foothills (Yukon) proposes that the "pure" equity participation in its project would be limited to 10 per cent of the proposed total financing and that its Canadian sponsors would own all the voting shares of Foothills (Yukon). It proposed that United States shippers would provide 15 per cent of the financing by subscribing to non-convertible, redeemable, non-voting preferred shares carrying a cumulative 10 per cent rate of dividend.

The Board considers that the terms and conditions attaching to the preferred shares to be issued to United States shippers will be subject to substantial negotiation by both prospective lenders and the shippers themselves. The Board notes that the financial advisors to CAGPL testified that long-term lenders would not allow a significant portion of the equity component to be in fixed rate obligations such as convertible debentures or preferred shares. However, the Board recognizes that, in the case of Foothills (Yukon), such preferred shares are to be issued to parties directly associated with the project. The United States shippers would be obligated under the proposed tariffs and the Board feels that lenders might consider such investment differently than if the funds were to be advanced by public investors. Despite this factor, the Board believes that lenders would probably seek to restrict the preferred dividend rights and redemption provisions attaching to these shares. The Board is concerned that, in this event, the preferred shares might become unattractive to the shippers. The Board also notes the views expressed by the FPC on this subject.

The Board recognizes that United States shippers of Alaska gas will be deeply committed to the Foothills (Yukon) project, and as a consequence, may feel forced to make substantial investments. However, the Board feels that the Applicant may have overlooked, or seriously misjudged, the likelihood that such investors might require an opportunity to particpate actively in the project. The Board also believes that lenders may require significant modifications to the privileges attaching to the proposed preferred share issues. The Board feels that, in the event that preferred dividend and redemption privileges were modified downward, there would be an even greater likelihood that United States shippers would demand a measure of active participation.

The Board particularly notes the inclusion by Foothills (Yukon) of redeemable preferred shares in its equity component. The Board feels that, conceptually, the use of redeemable preferred shares might allow the Applicant to maintain the proportions of debt and equity in its capitalization within "normal" limits.

The Board has previously commented on its concern regarding the proposed investment by United States shippers. In view of these concerns, the Board feels that the 10 per cent dividend rate ascribed to the Applicant's preferred shares is questionable. The Board has previously suggested that the

Applicant might reconsider its proposed equity financing and considers that the dividend rate attaching to possible preferred shares might be a part of such reassessment.

The Board notes that Foothills (Yukon) has not proposed a rate of return on common equity but, rather, has assumed a rate for the purposes of preparing its pro forma financial statements. The Board believes that the most important factor in assessing the reasonableness of a return on common equity is the relationship of that return with the risk of investment. The Board further believes that such risks can only be reasonably assessed when the exact nature and extent of the credit support arrangements are finally determined. As a consequence, the Board declines to comment specifically at this time on the rates selected by the Applicant.

The Board feels that the pre-commitment of funds in respect of a project-financed company represents a fundamental measure of security for lenders. Given that a project-financed company does not have an established credit history, the Board views it as unlikely that lenders would advance funds unless they could be assured that the project would be completed and its objectives realized. The Board considers that, without the pre-commitment of funds, Foothills (Yukon) would be subject to the vagaries of the market-place and could experience extreme difficulty in raising financing in adverse economic conditions or if difficulties were experienced in its project. The Board considers it fundamental that the Applicant should seek pre-commitment of funds in an amount necessary to complete its project including provision for possible cost overruns.

The Board believes that for a project-financed company, having no past credit history, transportation contracts, and supporting tariffs, related to its operations would represent the primary credit support in the eyes of lenders. The Board further believes that, at least until such time as the project company may have built up its own financial resources, lenders would require the tariffs to be based on a full cost of service and to be operable in all events. The project company itself, in the early years of operation, simply could not stand the financial strain of scheduled debt repayments and other costs in the event of project abandonment, service interruption or serious reduction of throughput. Consequently, the Board does not doubt the Applicant's need to obligate its shippers under full cost of service, "all events" tariffs, either in the pre-completion phase or during the early years of operation.

The Board believes that the real question in considering credit support arrangements for a project of this nature is "Who will finally foot the bill?". The Applicant proposes that United States shippers obligated under the tariff or pre-tariff agreements would pass on all costs, in all events, to the ultimate consumers of gas. The Applicant's "fall back" position is that as an alternative, or possibly in addition, the United States government and, ultimately, the United States taxpayers, would backstop the project.

The Board's other primary consideration is whether the proposed arrangements would work and be satisfactory to prospective lenders. The Board's view is that, conceptually, the credit support features outlined by Foothills (Yukon) would be satisfactory to lenders. The Board feels that, were the Applicant granted undisputed financial access to either the consumers of Alaska gas or the United States taxpayers, or both, it might realistically claim adequate credit support for its project.

Foothills (Yukon) has clearly stated that its proposal is to seek a perfect tracking mechanism as the primary credit support for its project. The Board finds that although the Applicant has outlined, albeit in a very broad manner, how such a mechanism might operate, it has in no way demonstrated or even attempted to demonstrate the practical feasibility of its proposal. Foothills (Yukon) stated clearly that it recognized that congressional and regulatory action would be required in the United States before its proposal might.be implemented. It stated clearly that it had no idea whether these actions might be forthcoming or how long they might take to implement. Furthermore, the Applicant stated that it sought to ensure that such a regulatory mechanism, if implemented, could not be "upset" by future regulatory action. The Board thus finds itself examining an almost flawless concept presented totally without factual support.

It is clear that whether financial support for the system should come from the consuming public in the form of tracking, or from the taxpaying public in the form of a government guarantee, is one primarily for the United States interests to decide. In summary the Board believes that the Foothills (Yukon) project could be financed but that the demonstration that it could be financed would have to await the submission of proof of financing.

Accounting and Tariff Matters

The Board believes that a mechanism whereby the early costs were smoothed so as to avoid placing an undue burden on early customers is a question to be resolved when transportation contracts are in place and the views of shippers can be ascertained.

The Board's views on the effect on the Applicant of a failure to receive 100 per cent of tendered gas have been expressed in the Section of the CAGPL summary on this topic. In addition, the Board cannot accept the Applicant's arguments for a full return in the event of failure in other Canadian segments of the line. It is the Board's view that the Foothills (Yukon) pipeline system represents a single project, and that the risks inherent in the project should be shared equally by all members.

The Board observes that the Applicant did not file an example of a pre-tariff agreement, upon which it could be examined. While the Board agrees that a pre-tariff agreement as outlined by Foothills (Yukon) would ensure the Applicant an adequate flow of funds prior to the commencement of the tariff, the Board notes that the Applicant was unable to adduce evidence which would suggest that such an agreement could be obtained and enforced. The Board would require approval of such a contract at the proof of financing stage and would require any changed proposal to be approved by the Board. The Board would condition any certificate issued to this effect.

The Board's views on the ownership and control of the Foothills (Yukon) project are expressed in its Reasons for Decision.

4.3.4B TRUNK LINE (CANADA)

4.3.4B.1 Financing

Foreword

The Board finds that a number of the concepts and assumptions adopted by Trunk Line (Canada) and its financial plan are broadly comparable to those used by Foothills (Yukon) in the preparation of that company's financial plan. Where the Board has previously commented on such concepts and assumptions, and considers such comments applicable to the Applicant, it refrains from repeating its discussions and observations. Accordingly, the Board does not specifically comment on the Applicant's proposals regarding Canadian and United States sources of financing, terms and cost of debt, cost of equity, or the basic credit support to be derived from its participation in the Foothills (Yukon) project.

The Board further notes that Trunk Line (Canada) has presented no evidence concerning market capacity issues for its proposed financing but, rather, has relied on the evidence presented by the advisors to Foothills (Yukon) regarding total market capacities for the financing requirements of the overall Foothills (Yukon) project. Accordingly, the Board does not discuss market capacity issues with regard to the Applicant. Trunk Line (Canada) is to be financed 100 per cent by Trunk Line, its parent company.

Summary of Capital Requirements

Summary of Capital Requirements

($ millions)

	1978	1979	1980	1981	Total Basic Require-ments	Estimated Contingency Require-ments	Total Estimated Require-ments
Canadian Banks	--	--	85	75	160	400	560
Canadian Long Term Debt	50	55	70	70	245	-	245
United States Long Term Debt	--	125	150	150	425	-	425
Canadian Preferred Stock	60	--	75	--	135	-	135
Canadian Common Stock	--	55	--	60	115	-	115
TOTAL	110	235	380	355	1,080	400	1,480

Debt/Equity Mix of Financing

The Applicant proposed that its financing would be raised in a ratio of 78 per cent debt, 12 per cent preferred shares and 10 per cent common shares.

As at 31 December 1976, Trunk Line's capitalization consisted of approximately 47 per cent debt, 20 per cent preferred shares and 33 per cent common equity. The Applicant presented a number of analyses indicating factors such as coverage for interest and preferred dividends, bond indenture restrictions and capitalization ratios showing the effects of raising the required funds. A witness for the Applicant stated that he was satisfied that the financing plan was consistent with, and met the requirements of, the parent company's existing trust indentures.

Credit Support

Requirements

A witness for Trunk Line (Canada) believed that the ability to finance its plan depended, amongst other things, on the existence of satisfactory contractual arrangements providing for the payment to the company of sums sufficient to service the debt and equity raised to finance the project.

The Applicant proposed that the financing requirements for its project would be provided by internally generated funds, supplemented by new financing. The financial support for the obligations to be issued would flow from revenues on current rate base, cost of service contracts with present and future customers, and revenues from the proposed new facilities. Cost of service contracts for the new facilities would extend beyond the final maturity of debt incurred to finance them and would be operable in all events.

Shippers would be obligated under the tariff in the same manner as that described in respect of Foothills (Yukon), and the "tracking" or government guarantee alternatives would operate in a similar manner, regardless of which participant incurred the costs. A witness believed it fundamental that the credit support available to investors in each of the individual participants in the Foothills (Yukon) project should be comparable in order to avoid a competitive financial market situation.

Pre-Commitment of Funds

Trunk Line (Canada) would not seek the pre-commitment of its external financing requirements.

In written evidence, a witness stated that he considered pre-commitment unnecessary in view of Trunk Line's history in various financial markets. He further stated, however, that he considered Trunk Line (Canada)'s financial plan sufficiently flexible to embody the concept of pre-commitment of funds should this be required by lenders or shippers.

During cross-examination, this witness explained that, were pre-commitment required, the Applicant would convert its proposed debenture issues into first mortgage bonds and would seek to pre-place all its long-term debt. Bank term loans would be pre-committed, preferred shares would be converted into "term preferreds" and financing would be arranged with Canadian banks.

Despite the fact that it would not seek pre-commitment, the Applicant proposed to conclude arrangements with Canadian chartered banks to provide up to $400 million as a backstop to its proposed public issues or private placements of securities. These monies would be in the form of bridge financing in the event of a delay in bringing a proposed issue of securities to market. Trunk Line (Canada) anticipated that such loans would be repaid from proceeds from issues of securities. A witness for the Applicant believed that the possibility of such securities not ultimately being sold was minimal.

Risks Facing Applicant

A witness testified during cross-examination that, until such time as all Canadian participants (Foothills (Yukon), Trunk Line (Canada) and Westcoast)) were to complete their facilities related to the Alaska Highway project, all Canadian participants would have their equity "at risk". At such time as all Canadian participants completed their facilities, the planned credit support arrangements for the Foothills (Yukon) project would provide for the recovery of equity return of the Canadian participants from the United States shippers and, ultimately, from the United States consumers. In the event that the Applicant completed its facilities, regardless of the completion status of all other participants, it would be entitled to recover all its debt service costs through tariff or pre-tariff agreements with United States shippers. If the Applicant did not achieve completion prior to the "date certain", it would be entitled to recovery of its debt service costs from United States shippers from that date. In all cases, preferred share service costs would be treated similarly to debt service costs.

A witness for Trunk Line (Canada) testified that it would give lenders unlimited, unconditional assurances to complete its segment of the Foothills (Yukon) project and would give the same assurances in relation to its participation in Foothills (Yukon). Another witness confirmed that, in the event that Trunk Line (Canada) failed to complete its facilities on a timely basis, due to the inability to raise funds, the Applicant would be liable to compensate the other parties for any losses suffered by its failure to complete.

4.3.4B.2 Accounting and Rate Making

As set out in the introduction, many of the accounting policies put forward by Trunk Line (Canada) are common to each application. To save repetition, the Board considers it appropriate that the arguments put forward concerning these policies and the Board's views thereon, should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to the application of CAGPL and are to be found in that section:

Accounting for Income Taxes;

Depreciation; and

Allowance for Funds Used During Construction.

The following policies are dealt with in the discussion relating to the application of Foothills (Yukon):

Depreciation Reduction in Initial Service Phase; and

Deferral of Return in Initial Service Phase

4.3.4B.3 Tariff Matters

As set out in the introduction, many of the proposals concerning the selection of tariff matters put forward by Trunk Line (Canada) are common to each application. To save repetition, the Board considers it appropriate that the arguments put forward concerning the policies and the Board's views thereon should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to the application of CAGPL and are to be found in that section:

All Events Tariff; and

Date of Commencement of Tariff.

This section deals with the tariff matters set out below where either the policies proposed by the Applicant differ from those of CAGPL or Foothills or those policies are not consistent between the companies sponsoring the Foothills (Yukon) application:

Effect of Failure to Receive 100 per cent of Tendered Quantity of Gas; and

Cost Allocation.

Effect of Failure to Receive 100 Per Cent of Tendered Quantity of Gas

The Applicant contended that if it were unable to deliver gas, due to reasons of failure within its own system only, its charges to shippers should not reduce unless it would fail to deliver 80 per cent of the volume of gas nominated by the shipper then there would be a reduction of the return on common equity and related income taxes. Should, however, the Applicant be unable to deliver gas due to reasons of failure in systems other than its own or those of Foothills (Yukon), the Applicant proposed to collect its full cost of service and return from its customers.

Cost Allocation

Trunk Line (Canada) proposed that it pay a service charge to Trunk Line. This service charge would result from an allocation of administrative and general expense to Trunk Line (Canada) based on the relationship of Trunk Line's administrative and general expense to total operating expense of Trunk Line, applied to direct pipeline and compression charges incurred by Trunk Line relating to facilities constructed by it for Alaska gas. The Applicant stated that the administrative and general expenses of Trunk Line excluded any expense incurred in respect of non-jurisdictional (pipeline) matters and that the total operating expense included the expenses of the gathering lines.

4.3.4B.4 Views of the Board

Financing Matters

The capital structure of the proposed financing is considerably more debt-oriented than Trunk Line's present capitalization. The Board recognizes that the relatively high equity ratio in Trunk Line's capital structure at the present time might enable it to raise a proportionately higher amount of debt than it might were it more highly levered. However, the Board feels that prospective lenders, when examining the proposed capital structure of new financing, will look first to the risk aspects of the proposed project and the planned credit support arrangements. Financial advisors to Foothills (Yukon) have testified to the importance of credit support arrangements for each participant in the Foothills (Yukon) project being similar. In view of the support arrangements outlined for the system, the Board considers it likely that, were such credit support arrangements "in place", prospective lenders to Trunk Line might view the proposed capital structure appropriate.

The Board does, however, believe that, for investors to place reliance on the credit support planned for the overall Foothills (Yukon) project, it might be necessary for Trunk Line to demonstrate a link between, say, a dollar invested in Trunk Line for the purposes of the Foothills (Yukon) project, and a dollar actually spent on that project and for no other purpose. Accordingly, the Board feels that Trunk Line may need to issue separate classes of securities specifically identified through trust indentures and otherwise with its participation in the Foothills (Yukon) project.

The Board feels that the Applicant's proposal not to seek pre-commitment of funds, in an amount sufficient to place its facilities in service, represents a serious weakness in its financial plan. The Board notes the confidence of Trunk Line and its advisors in its corporate credit and financial history but feels that other important factors must be considered. The Applicant proposed to raise in excess of $1 billion with regard to its participation in the Foothills (Yukon) project. The Board considers that prospective lenders would be unlikely to advance this magnitude of funds without having received adequate assurance that the project would be completed. The Board views the pre-commitment of funds as a fundamental first level assurance of completion. Without pre-commitment, the Applicant could not be assured that funds would be available to it as and when required.

The Board notes the potential liability of the Applicant in the event that it failed to complete its facilities due to an inability to raise its required financing. The Board has also considered the possible impact on the overall Foothills (Yukon) project in the event that Trunk Line (Canada) fails to complete its facilities.

Were the Board to certify the Applicant's project, it would expect the Applicant to seek the pre-commitment of external financing in an amount at least sufficient to complete the proposed facilities at their projected basic cost.

The Board considers that the risks facing Trunk Line (Canada) and Trunk Line can only be properly assessed at such time as the actual credit support arrangements are known. However, the Board notes the circumstances under which Trunk Line would forfeit its equity investment in Foothills (Yukon) and would be unable to recover the equity invested in Trunk Line (Canada)'s proposed facilities. The Board also notes Trunk Line's categoric assurances to complete its subsidiary's facilities and those of Foothills (Yukon) and its obligations in the event of non-completion due to failure to obtain financing.

The Board feels that, were the Applicant assured that the cost overruns of Foothills (Yukon) would not exceed 20 per cent, its own overruns would not exceed a similar factor and its financing were assured by pre-commitment, the potential risks in the event of non-completion would probably be acceptable to lenders.

Tariff Matters

The Board's views on the effect on the Applicant of a failure to receive 100 per cent of tendered gas have been expressed in the section of the CAGPL summary on this topic. In addition, the Board cannot accept the Applicant's arguments for a full return in the event of failure in another section on the line. It is the Board's view that the Foothills (Yukon) pipeline system represents a single project, and that risks inherent in the project should be shared equally by all members.

The Board believes that the Applicant's proposal on cost allocation should be more properly examined during a Part IV rate hearing

4.3.4C WESTCOAST

4.3.4C.1 Financing

Foreword

The Board refrains from detailed comments on many areas of the Applicant's financial plan for the reasons given previously with regard to the financial plan of Trunk Line (Canada) i.e. similarity of concepts and assumptions of Foothills (Yukon).

The Board further finds that the Applicant's financial plan resembles that of Trunk Line in many important areas and notes that much of the evidence given during cross-examination was similar to that given on behalf of Trunk Line, Accordingly, the Board has limited its discussion of the Applicant's financial plan to the Applicant's proposals concerning the debt/equity mix and the pre-commitment of funds.

Summary of Capital Requirements

Summary of Capital Requirements
($ millions)

	1978	1979	1980	1981	1982	1983	Total Basic Requirements	Estimated Contingency Requirements	Total Estimated Requirements
Canadian Banks	20	(20)	60	180	(160)	(63)	17	223	240
Canadian Long Term Debt	-	60	150	100	-	-	310	-	310
United States Long Term Debt	100	140	80	150	120	-	590	-	590
Canadian Preferred Stock	-	75	75	-	-	-	150	-	150
Canadian Common Stock	-	50	100	-	-	-	150	-	150
Total	120	305	465	430	(40)	(63)	1,217	223	1,440

Debt/Equity Mix of Financing

Westcoast proposed raising its basic funds requirements in a ratio of 75 per cent debt, 12 1/2 per cent preferred shares, and 12 1/2 per cent common shares.

Westcoast had a forecast capital structure, as at 31 December

1976 of approximately 47 per cent common equity, 7 per cent preferred shares and 46 per cent debt.

The Applicant stated that its proposed financing had been designed to meet all the issuance tests set out in its Deed of Trust and Mortgage relating to its existing bond issues.

Pre-Commitment of Funds

Westcoast did not propose to seek the pre-commitment of its required external financing; it presented no evidence to indicate how pre-commitment might be accomplished were it required by lenders, shippers or the Board.

The Applicant did not propose to seek any form of commitment from banks or others to backstop proposed public issues of financing or potential cost overruns.

4.3.4C.2 Accounting and Rate Making

As set out in the Introduction, many of the accounting policies put forward by Westcoast are common to each application. To save repetition, the Board considers it appropriate that the arguments put forward concerning these policies and the Board's views thereon, should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to the application of CAGPL and are to be found in that section:

Accounting for Income Taxes;

Depreciation; and

Allowance for Funds used During Construction.

The following policies are dealt with in the discussion relating to Foothills (Yukon) and are to be found in that section:

Depreciation Reduction in Initial Service Phase; and

Deferral of Return in Initial Service Phase,

4.3.4C.3 Tariff Matters

As set out in the Introduction, many of the proposals concerning the selection of tariff put forward by Westcoast are common to each application. To save repetition, the Board considers it appropriate that the arguments put forward concerning the policies and the Board's views thereon should only be set out once. Accordingly, the following policies are dealt with in the discussion relating to the application of CAGPL, and are to be found in that section:

Date of Commencement of Tariff; and

"All Events" Tariff.

The following policy is dealt with in the discussion relating to Trunk Line (Canada):

Effect of Failure to Receive 100 per cent of Tendered Quantity of Gas.

This section deals with the tariff matters set out below where either the policies proposed by Westcoast differ from those of CAGPL or those policies are not consistent between the companies sponsoring the Foothills (Yukon) application:

Cost Allocation.

Westcoast does not propose to incorporate a subsidiary to construct and operate its section of the facilities. This has given rise to the following anomalies:

Deferred Income Taxes

The Applicant proposed to follow normalization for its new facilities, whilst continuing to flow through taxes on its traditional facilities.

Funds

The Applicant stated that it would be able to allocate funds borrowed under its corporate credit between new and traditional facilities.

Administrative and General Expense

The Applicant proposed to allocate its corporate administrative and general expense to its new and traditional facilities on the basis of operating and maintenance expense incurred on its new and traditional facilities.

4.3.4C.4 Views of the Board

Financing Matters

The Board does not specifically take issue with Westcoast's proposals regarding the debt/equity mix of new external financing. The Board does, however, question the overall ability of the Applicant to raise its proposed financing in view of the working capital deficits depicted by its pro forma financial statements. The Board notes that the pro forma financial statements presented by Westcoast show a working capital deficiency for each year of construction and thereafter until 1987. In 1983, the Applicant projects a deficiency of $80 million.

The Board recognizes that a working capital deficiency, does not, of itself, necessarily indicate a serious financial problem for a utility but feels that prospective lenders might closely examine the extent and trend of the deficiency indicated. In the circumstances, the Board feels that prospective lenders may require either a higher proportion of equity financing or stringent restrictions as to the payment of preferred and common share dividends.

The Board feels, for reasons similar to those discussed in respect of Trunk Line (Canada), that the lack of pre-commitment of funds represents a serious weakness in Westcoast's financial plan. The Board also feels that the Applicant's projected working capital deficiencies and their potential effect on lender confidence is yet a further reason to seek pre-commitment.

The Board further notes that Westcoast has not proposed to seek any form of backstopping whatsoever for possible cost overruns or delays in marketing public issues of securities.

Were the Board to certificate the Applicant's project, it would expect it to seek the pre-commitment of external financing in an amount at least sufficient to complete its project at its estimated cost, and to backstop all proposed public issues of securities.

Accounting and Tariff Matters

The Board notes the practical difficulties involved in financing, constructing and operating two sets of facilities within a single corporate entity. In particular, the Board believes that it is virtually impossible to track a dollar invested in a company to its ultimate investment. Insofar as the detailed allocation of costs and funds invested are concerned, the Board believes that such items which give rise to many problems of allocation should more properly be the subject of a Part IV rate hearing.

4.3.5 COMPARATIVE COSTS OF TRANSPORTATION

CAGPL, Foothills and Foothills (Yukon) presented extensive evidence to support their various calculations of the 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 might have been low due to optimistic estimates of construction costs and scheduling.

The Board has set out in Table 4-1 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 cost overruns set forth in the following section of the Board's report.

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. 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.

Appendix 4-1 provides additional supporting data in respect of the figures used in Table 4-1.

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	1987 Vol.	1987 ¢/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.

Views of the Board

There was considerable 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.

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 would 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 re-routing 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/d from the Delta and 2.0 Bcf/d from Alaska, the cost of transmission of Delta gas to Empress, taking into account the preliminary nature of the estimates for the Dempster link, appears to be approximately the same for the Foothills (Yukon) and the CAGPL projects.

4.3.6 RISK OF COST OVERRUNS

4.3.6.1 Introduction

On 24 March 1977 the Board requested that each Applicant prepare an assessment of the probability of the cost overruns for its proposals and the dollar values associated with the different probability levels.

This request was met by 25 April 1977 and the submitted evidence was tested under cross-examination. A summary of the submitted evidence is given in this section of the report. Much of the evidence in other phases of the hearing however dealt, often at great length, with areas where uncertainties existed and where potential cost overruns could occur. Also the validity of the subjective estimates that are inherent in the design of any major project were probed and tested throughout the hearing process. Hence the section of the report dealing with the Views of the Board with regard to the risk of cost overruns is based not only on the evidence presented directly in response to the Board's request of 24 March 1977 but also on the voluminous submissions and testimony given in other phases of the hearing process.

4.3.6.2 CAGPL Project

In the analysis CAGPL submitted in response to the Board's request, it restricted itself to examination of the risk of cost overruns associated with the unescalated direct costs of materials and construction as filed for its No Expansion Case. Cost overruns due to an incorrect estimate of inflation, regulatory or other delays not related to construction, or higher than estimated indirect costs were not considered.

CAGPL divided the material requirements into a number of categories, and assessed the uncertainties associated with the estimates of quantities and unescalated costs in each category. CAGPL also assessed time-related risks associated with the procurement and delivery of materials and equipment for the project and with the actual construction of the pipeline, including estimated costs of various contingency plans to overcome possible difficulties. Consideration was also given to certain "intangible" factors.

To arrive at an overall risk assessment, CAGPL used probability theory to combine the estimated cost distributions of each of the direct cost categories with the cost distributions related to those associated with the contingency plans and "intangible" factors. The resultant distribution indicated that the expected value of the direct costs of the CAGPL No Expansion Case would be \$4.5 billion (compared to filed costs of \$4.33 billion) with a range that extended from about \$4.1 billion to \$4.9 billion.

CAGPL, however, excluded the risk of cost overruns due to variation in estimated rates of price escalation. While CAGPL admitted that escalation had been the single biggest cause of cost overruns in the 1970-75 period, it believed that since escalation uncertainty was common to all proposed projects, it was better excluded from the study.

With regard to the sensitivity of project costs to assumed escalation rates, CAGPL stated that a one per cent increase in the average escalation rate would increase the project cost by 4.4 per cent and that the Board was in the best position to determine to what extent sensitivity assumptions should be applied.

In its assessment of cost overruns CAGPL made the following further key assumptions:

regulatory and other governmental decisions would be made and approvals received in a time frame which would permit the necessary activities to proceed and the necessary expenditures to be incurred in a timely manner in 1978 to achieve a 1982/1983 completion date;

government agency field inspection, monitoring, and design and other approvals would not adversely affect construction activities, schedule and cost; and

a project agreement with no-strike provisions would be developed for that part of the project north of the 60th parallel, including all unions working on or for the CAGPL project excluding truckers and railroad workers delivering materials to the staging sites at Hay River, Enterprise, Fort Simpson and Axe Point.

With regard to the first assumption CAGPL stated that if approvals were not obtained in a timely manner, it was conceivable that a year could be lost at the front end of the construction schedule.

Concerning the second assumption dealing with government inspection and monitoring, CAGPL testified that it was of paramount importance that procedures be developed before construction began and that communication and working relationships between government bodies and project managers be established. This was of such importance that if an additional six months or a year were required prior to construction to develop effective procedures, then CAGPL felt the time should be used to ensure effective management control of the project, properly co-ordinated with the controlling agencies or governments.

The third assumption, that of a no-strike contract north of the 60th parallel, was stated by CAGPL to be virtually mandatory because of the severe impact that a protracted strike in the portion of the project north of the 60th parallel would have on scheduling and costs.

4.3.6.3 Foothills Project

The Foothills Group presented evidence in response to the Board request of 24 March 1977 for an assessment of the probability of cost overruns and the dollar value associated with the different levels of probability. This evidence contained a cost overrun study of both the Foothills and Foothills (Yukon) projects.

The basic approach of this evidence was to divide the filed construction plan into seven categories, and to assess the probabilities of cost overruns in each category due to (a) uncertainties in the capital cost estimate, and (b) uncertainties in the escalation rates. These probability distributions were then combined to give an assessment of the probability of a cost overrun for the project as a whole.

To determine the possible variations in costs for each of the seven categories, judgment factors were used that ranged from minus ten per cent to plus 30 per cent.

To determine the possible range in escalation rates, the study assumed as a lower limit the long-term average annual growth rate from 1961 to 1975 as derived from Statistics Canada's CANSIM price indicator series. The upper bound was assumed to be the short-term annual growth rate for the 1971 to 1975 period.

The result of this analysis was that the combination of escalation rate uncertainties and real cost estimation uncertainties could result in a cost overrun of 58 per cent of the filed escalated cost for the Foothills project.

The study also considered the case where the Foothills project was constructed as scheduled but gas plant construction was delayed, resulting in a one year's delay in gas being available to the pipeline. In this event, the projected cost overruns could reach 76 per cent of filed escalated costs.

4.3.6.4 Foothills (Yukon) Project

Foothills (Yukon) presented evidence in response to the Board request of 24 March 1977 for an assessment of the probability of cost overruns and the dollar value associated with the different levels of probability. The basic approach of this evidence was described in the preceding section dealing with the Foothills project.

The results of the study were that, excluding escalation uncertainties, the estimating uncertainties in the capital cost could result in actual costs ranging from 95 per cent to 112 per cent of the filed cost. Considering escalation uncertainties alone, the cost of the project could range from 92 to 123 per cent of the filed cost. Combining these two areas of uncertainty the study concluded the cost of the Foothills (Yukon) project could range from eight per cent below to 25 per cent above filed costs.

The study then examined four potential delay situations for the Foothills (Yukon) project as set out in the following table. Under cross-examination it was stated that these delay situations were not determined on a probabilistic basis but were chosen on the basis of potential delays identified in the Resources Planning Associates study filed as an exhibit at the hearing.

Under the "worst" case scenario, which is the third case in the table which assumed commencement of the project would be delayed by six months and construction would begin an additional six months later, cost of the project could overrun by as much as 45 per cent of the filed cost according to the study.

Potential Delay Situations Affecting

The Foothills (Yukon) Project*

"What If" Situation	**Start Delay to Project**	**Start Delay for Construction**	**In Service Date**
Base Case	nil	nil	1 November 1981
1.**	nil	6 months	1 July 1982
2.**	6 months	nil	1 July 1982
3.**	6 months	6 months	1 January 1983
4***	nil	nil	1 November 1982

* From Exhibit No. FH(Y)-114-52

** Derived from Exhibit No. N-PD-842 with adjustment to suit the current schedule for the Foothills (Yukon) project.

*** A situation which could arise if the gas plant completion is delayed one year because the critical barging window is missed.

4.3.6.5 Views of the Board

Introduction

In assessing the risk of cost overruns for the CAGPL and Foothills (Yukon) projects the Board has looked at the reasonableness of the real (1976 $) costs, the reasonableness of the projection of these real costs into future dollars and the potential cost overruns due to delay in project completion or the overcoming of difficulties that might otherwise result in delay.

It must be borne in mind that both projects are very complex and expensive engineering undertakings. Successful completion within the predicted cost and time schedules depends not only on the validity of the estimated quantities and costs of the required goods and services necessary to construct the pipeline but also on timely completion of a large number of interrelated tasks.

The remoteness of the construction location, the restricted construction seasons for parts of the projects, and the adverse weather conditions under which much of the work will have to be carried out, put fairly restrictive limits on the deviations from the planned construction schedule which can be tolerated without causing a significant delay in completion of the project or substantial unplanned cost overruns to overcome a potential completion delay.

The magnitude of the projects and their technical complexity make some degree of deviation from the proposals as filed virtually certain.

Additionally, both projects face a risk of cost overruns resulting from a number of elements not within their direct control such as the rate of inflation, regulatory restrictions to minimize environmental and socio-economic impacts, foreign exchange fluctuations, and strikes or other difficulties affecting key suppliers or segments of the transportation sector.

Faced with these and other factors that could significantly alter the cost and completion timeframe of any major project, the Board does not claim to be able to forecast the actual completion date and cost of any of the projects. Rather, based on the evidence (often conflicting), the Board has endeavoured to estimate the most reasonable range of cost overruns.

CAGPL Project

In assessing the real (1976 $) costs that **CAGPL** filed with the Board, it is the opinion of the Board that direct material costs have been reasonably estimated. However, in the area of installation costs, it is the view of the Board that labour costs for the portion of the project north of the 60th parallel could well exceed CAGPL's estimate. It is felt that higher than projected wage demands could be made because of higher Alaska wage rates, the premium that might be demanded for a no-strike contract for the project north of the 60th parallel and the pressures on segments of the skilled labour market that an undertaking of this magnitude would exert.

Real costs could also exceed filed costs because of CAGPL's assumption of parity between the United States and Canadian dollar, whereas the present value of the Canadian dollar is about five per cent below that of the United States dollar. The effect of a lower valued Canadian dollar is to increase the cost of imported goods and services and the cost of servicing debt denominated in United States dollars, or other foreign currency. To the extent United States or foreign currency borrowings are used to purchase Canadian goods and services when the Canadian dollar has a lower value, a lesser amount of foreign currencies than estimated by CAGPL may have to be raised. The project, as explained in the section of this report dealing with the macroeconomic impact of the project, will tend to increase the value of the Canadian dollar. On balance, the Board believes that an increase in the cost of the project in Canadian dollars over that filed by CAGPL is likely because of a lower-valued Canadian dollar, although the magnitude of this increased cost will not be large in terms of the total project cost.

Real costs are likely to exceed costs as filed for other reasons as well, including:

actions required to meet the various conditions that can reasonably be expected to be attached to any certificate which the Board might issue;

changes in final design to incorporate site-specific information; and unforeseen technical difficulties particularly in the region north of the 60th parallel.

CAGPL projected the real (1976 $) costs into the future through the use of 'escalation' or 'inflation' rates for each of eight major cost component categories. While the Board does not anticipate that future inflation rates will be at the very high levels of the past few years, it believes that CAGPL's estimates of escalation rates are too low.

Delay in completion of the project could result in a large cost overrun in real or escalated terms. CAGPL testified that it could not foresee any circumstances where it would be more economic to prolong the project schedule rather than to incur additional expenditure to maintain the schedule. To prevent any such delay in project completion, CAGPL submitted to the Board a series of contingency plans to overcome any foreseeable difficulty, generally at some additional cost.

The Board, however, does not share CAGPL's confidence in this regard. The Board believes that there is risk that delay in project completion could occur because of the following factors, some of which were excluded from the CAGPL analysis:

- conditions attached to a certificate of public convenience and necessity;
- lower than expected construction productivity due to technical, weather or labour problems, particularly in the region north of the 60th parallel; and
- approvals required to implement contingency plans.

The Board believes there is a moderate to high probability of a delay ranging from eight months to one year in the completion of the CAGPL project.

In summary, the Board believes that, all factors considered if the pipeline proposed by CAGPL is built, a cost overrun in the range of 20 to 35 per cent is not unlikely.

The Board, in making the foregoing estimate, has endeavoured to take into account all the known factors which could be quantified and which could 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.

Foothills Project

The review of the financing of the Foothills project, contained in a preceding section of this chapter, indicated that, according to Foothills financial advisors, the project could not be financed at this time on the basis of reserves already discovered. Furthermore, Foothills in its argument asked that the project be deferred until the mid-1980's. For these reasons there is no point in the Board expressing any views on the risk of cost overruns.

Foothills (Yukon) Project

The Board believes that the real (1976 $) cost of the Foothills (Yukon) project is somewhat understated due to significant underestimation of the cost of building the portion of the pipeline in the Yukon Territory.

The Board believes there is a risk of additional real cost overruns due to:

actions required to meet the various conditions that can reasonably be expected to be attached to any certificate which the Board might issue;

final design changes based on site-specific data;

technical and weather difficulties (although the risk in this area is assessed to be lower for the Foothills (Yukon) system than for CAGPL due to the proximity of the Foothills (Yukon) right-of-way to an established year-round transportation corridor); and

a decline in the value of the Canadian dollar in terms of foreign currencies, as was discussed in more detail in the preceding section dealing with the risk of cost overruns of the CAGPL project (the magnitude of this cost increase is expected to be small due to the proposed high Canadian content of the Foothills (Yukon) project).

The Board believes that there is a real likelihood of at least a one-year delay in the completion of the project in relation to the construction timetable as filed, which would cause a cost overrun. It is felt that this delay will result from the completion of necessary pre-construction activities including:

final design (including collecting of needed site-specific data);

obtaining financing and approval thereof; and

actions required to meet the various conditions that can reasonably be expected to be attached to any certificate that might be issued.

Even if pre-construction activities for the Canadian section could be completed on time, it is highly unlikely that construction on the Canadian portion of the Alaska Highway project would commence prior to the substantial completion of pre-construction activities for the United States portion of the pipeline. Otherwise the Canadian section could be completed but not usable because of non-completion of the United States portion of the line.

In summary, the Board believes that if the Foothills (Yukon) project should be certificated and constructed, a cost overrun in the range of 20 to 30 per cent is not unlikely.

The Board, in making the foregoing estimate, has endeavoured to take into account all the known factors which could be quantified and could 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.

4.4.1 INTRODUCTION TO ECONOMIC ASSESSMENTS

This part of Chapter 4 deals with the evidence concerning matters of economic assessment of the pipeline proposals, and with the Board's appraisal of them.

The first section deals with the question of whether the proposed projects might significantly disrupt the Canadian macro-economy. The main concerns at the macro-economic level are whether such large projects could cause undue inflation, increases in Canadian interest rates, significant changes in the foreign exchange rate, unwanted shifts in investment patterns or other difficulties in the Canadian economy.

The following section considers the potential impact of the projects upon Canadian industry, in more detail than is considered in the macro-economic analysis. The Applicants gave evidence concerning the probable Canadian content of their projects and the possible potential for industrial benefits to Canada. The assessment of the Board concentrates upon the potential for industry benefits and it highlights several areas where industrial benefits could be significant. These include project management and construction, engineering expertise, the production of specialized compression equipment, the production of certain valves and fittings, and the production of pipe. In addition, the degree to which the projects are likely to use Canadian industry in general is assessed.

The following section examines the estimated net economic benefits to Canada from the proposed projects. Cost benefit analysis attempts to measure the net economic benefits which might follow from implementation of any of the projects. While these estimates of net economic benefits are for Canadian society at large, the analysis does not include as costs or as benefits difficult-to-quantify factors such as costs or benefits related to environmental or social impacts. Nor does the analysis explicitly include possible benefits from such considerations as the provision of security of energy supply to Canada. However, the Board views the cost benefit analysis as providing an important test of a project's economic worth to Canada, because if estimated net economic benefits are not positive then there would have to be other persuasive factors of a beneficial nature if a project is to be viewed as being in the public interest. The Board regards the cost benefit analysis based upon the existing established reserves of 5.1 Tcf in the Delta as being the basic test of whether the proposed projects which plan to transmit Delta gas are likely to provide net economic benefits to Canada.

Finally consideration is given to whether the production of Delta natural gas is likely to be commercially viable to the producers. This matter is considered to be important because under existing natural gas pricing policy in Canada, it is the gas producers who receive residual prices, or plant gate netbacks, for their gas based upon prices established by the government in the market-place and from these market prices are deducted transmission costs from plant gate to market. Furthermore, the test whether Delta gas can be produced profitably indicates whether it is worthwhile to develop and connect these reserves.

Each of the above areas of economic assessment needs to be considered for an overall economic appraisal of the projects. Furthermore, these analyses must be considered along with the regional socio-economic appraisal which appears in Chapter 5.

4.4.2 MACROECONOMIC IMPACT

4.4.2.1 Introduction

In response to its request to the Applicants to provide macroeconomic impact studies of their proposed projects, the Board received submissions from CAGPL, Foothills and Foothills (Yukon). In addition, John F. Helliwell made a submission to the Board as an intervenor. The macroeconomic impact aspects of his intervention and of the Applicants' submissions are summarized in the following sections.

4.4.2.2 Methodology

There is a standard methodology underlying any analysis of the macroeconomic impact of a pipeline. Initially, a model of the Canadian economy is selected to generate a likely path, or paths, for the Canadian economy for the future, assuming that a frontier gas pipeline would not be constructed. Since this projection (called a control solution) is a possible path for the economy, the supply and demand for all goods and services, including energy, is balanced in each time period.

The model is then "shocked" by introducing the direct effects of pipeline construction and operation on a number of sectors of the Canadian economy. The construction of a pipeline directly affects certain sectors of the economy such as investment, financial, labour, and foreign exchange markets. The operation of a pipeline bringing gas to Canadian markets from the Mackenzie Delta impacts the Canadian energy supply and demand balance assumed in the control solution. Delta gas is either used to replace imported energy, or is exported,[1] or leads to a displacement of other domestic energy supplies. Various assumptions can be made in this regard and the use of alternative sets of assumptions could yield different results.

The "shocked" solution of the model including the pipeline, when compared to the control solution, indicates the effects that construction and operation of a pipeline would have on various sectors of the economy. In addition to the direct effects, the pipeline would have a number of induced or secondary effects. For example, any foreign borrowings to finance the construction of a pipeline, by generating a surplus in the balance of payments over the control solution value, will tend to increase the value of the Canadian dollar and may discourage the export of commodities completely unrelated to the construction of the pipeline. It is only with the help of a macroeconomic model that the multitude of these effects can be assessed.

What these models, however, are not designed to do, (at least those models so far used in the context of an analysis of any of the pipeline projects) is shed any light on the stresses and strains on the individual sectors (at the level of very fine industrial detail) or regions of the economy. Macroeconomic analysis provided in this section thus considers only the aggregate economic impacts at the national level.

4.4.2.3 CAGPL Analysis

CAGPL submitted to the Board an assessment of the macroeconomic impact of an Arctic gas pipeline based on its proposal. The initial study was prepared in November 1974 and was subsequently updated in December 1976 to take into account the 1976 revisions to the capital cost estimates and the delay in the proposed start of the operation of the pipeline from 1979 to 1981. The change of initial throughput to 1982 announced during the hearing was not incorporated. The initial study and the update both used the TRACE Mark III R model of the Canadian economy.

The CAGPL study of November 1974 considered alternative cases and noted that the results from these various cases were not very different. As a result, CAGPL decided to consider in its updated analysis of December 1976 only one of the many possible cases that had been analysed previously. The case analysed was a low unemployment control solution coupled with the assumption that there would be no displacement of other domestic energy investment. CAGPL concluded that the updated results were not significantly different from the results of its earlier analysis.

The main results of the TRACE analysis of the CAGPL proposal were summarized for CAGPL in the direct testimony of Dr. J.L. Carr. The principal findings of the CAGPL study are described below.

The value of the Canadian dollar appreciated modestly during both the construction and operation phases of the pipeline with the maximum appreciation being less than 1.8 per cent in any one year during the period. Interest rates, wages and prices showed decreases which were minimal. None of these variables changed by more than one per cent during any particular year. Real GNP and consumer expenditures showed increases - again by less than one per cent in each case during any particular year. Total employment, including direct pipeline employment and induced employment, increased during most of the period, the peak being an increase of 33,000 man-years in 1980.

Dr. Carr concluded that the changes in macroeconomic variables resulting from construction and operation of the pipeline, according to the CAGPL proposal, were small compared with the order of magnitude of these variables in the economy as a whole.

Table 4-2 has been prepared from the data provided in the evidence of Dr. Carr for CAGPL. An explanation of the major items in this table is provided below.

(i) Investment

Given the assumption of near full employment of labour in the control solution underlying the CAGPL analysis, the increase in investment in the pipeline sector was offset by decreases in investment in other sectors, mainly residential construction. However, the total effect on investment, including that in the pipeline sector, was positive.

(ii) Exports

The revenues from the transmission of Alaska gas to the United States increased export earnings during the operation phase. There were negative induced effects on other exports during the construction and operation periods because of the appreciation of the Canadian dollar. The net effect on total real exports was negative during the construction phase and positive during the operation phase.

(iii) Imports

A portion of pipeline construction material was imported. Interest and dividend payments by CAGPL to foreigners also entered the import content of the pipeline. Imports of energy, however, were displaced. Higher incomes generated by the pipeline and an appreciating Canadian dollar induced other imports. The net effect on total real imports was positive during both the construction and operation phases of the pipeline.

TABLE 4-2: Evidence from CAGPL Submission

Major Impacts of the Pipeline on the Canadian Economy

(Percentage changes unless otherwise indicated:

Two-Year Averages)

	1978-79	1980-81	1982-83	1984-85	1986-87
Real Investment					
(Total)*	3.91	4.83	1.17	.55	1.41
Induced Effects	-.54	-.59	-.63	-.29	1.01
Real Exports					
(Total)*	-.12	-.34	.27	.45	.63
Induced Effects	-.12	-.41	-.54	-.57	-.44
Real Imports					
(Total)*	1.31	1.84	1.08	1.17	1.06
Real GNP (Total)*	.43	.41	.18	.12	.31
Induced Effects	-.11	-.21	-.22	-.21	-.03
Change in Exchange Rate					
(Cdn$/US$)	-.004	-.011	-.013	-.018	-.018
GNP Price Index	-.34	-.37	-.13	-.63	-.90
Average Hourly					
Wage Rate	-.36	-.41	-.13	-.69	-.85

*The "Total" impacts include both the direct and induced effects of a pipeline.

Source: Exhibit No. N-AG-3-152, Appendix B, Tables 9-11, pages 5-7.

(iv) Total Real GNP and Consumer Expenditure

The direct effect of the construction and operation of the pipeline tended to increase real GNP. However, negative induced effects on investment and exports and positive induced effects on imports tended to offset somewhat the direct positive effects of the pipeline. With higher total GNP, consumption expenditures increased.

(v) Balance of Payments and Exchange Rate

The construction and operation of the pipeline altered the supply of and demand for foreign exchange and thus affected the exchange rate since the analysis assumed an exchange rate which is flexible. In addition to the impact of the pipeline on the current account, discussed above, foreign financing of the pipeline (net of debt retirement) generated a balance of payments surplus. Furthermore, there were induced changes in capital flows. The net result of all these changes was to appreciate the value of the Canadian dollar, during both the construction and operation phases of the pipeline.

(vi) Prices, Wages and Interest Rates

Since the pipeline project is very capital intensive compared to the average capital intensity of Canadian industry, labour productivity in this project was high. This, along with the appreciation of the Canadian dollar, tended to reduce the domestic rate of inflation.

The sum of these effects was stronger than the positive effect on prices generated by higher demands for domestic goods and services due to the pipeline. A decrease in the rate of inflation decreased the nominal rate of interest because of the assumption in the model that there existed a significant relationship between the two. The average hourly wage has also decreased for the same reason.

(vii) Employment

During the construction phase of the pipeline, employment in the economy increased, reaching a maximum of 33,000 man-years in 1980. However, there was a decrease in employment of about 6,000 man-years in the year 1984. This was because of the negative induced effects on real GNP (discussed above). By 1987, employment was again up by 16,000 man years.

4.4.2.4 Foothills Analysis

The macroeconomic impact of the Foothills Group project was prepared using the Mark IV D version of the TRACE model. This study included investments in the pipe line project by Foothills, Westcoast, Trunk Line, Trunk Line (Canada), and TCPL. Westcoast, Trunk Line and Trunk Line (Canada) adopted the impact statement submitted by Foothills. Foothills considered only one case for its study in which the assumptions were that the economy would be slack in the period to 1987, having an unemployment rate of approximately six per cent by 1984, and that Delta gas would displace imported energy.

Table 4-3 lists the values of the impact on major economic variables according to the Foothills Group proposal. The principal findings of this study are described below.

The overall effect of the project was small. However, during a forecast period to 1987 characterized by a high unemployment rate, the effect was in the right direction since it increased real GNP (but never by more than 0.9 per cent) and decreased unemployment. Interest rates, wages and prices showed increases during the construction phase and decreases during the operation phase of the pipeline. In all cases these changes were minimal. None of these variables changed by more than 1.8 per cent in any one year. The value of the Canadian dollar also showed minimal changes: a small depreciation during the construction phase and an appreciation during the operation phase of the pipeline. The change in the exchange rate was never more than one per cent in any one particular year.

The direction of most of the induced effects of the Foothills Group proposal as shown in its evidence was the same as for the CAGPL proposal. Therefore, the previous discussion for CAGPL concerning exports, imports, total real GNP and consumer expenditures, prices, wages and interest rates, and employment is also applicable to the Foothills analysis. The direction was different in two areas. First, during the construction phase, the value of the Canadian dollar depreciated in the Foothills analysis. The reason for this was that Foothills' foreign borrowings were relatively small for the construction of the pipeline. This also meant that Foothills did not show negative induced effects on exports during the construction phase of the pipeline. Secondly, induced investment in the Foothills study was positive. The assumed unemployed resources provided slack in the economy so that the construction of a pipeline did not require any significant diversion of productive factors from other investments. Also, differences between the two versions of TRACE were responsible for this result.

Table 4-3: Evidence from Foothills Submission

Major Impacts of the Pipeline on the Canadian Economy

(Differences from control solution; billions of 1971 dollars unless otherwise stated)

	1978	1980	1982	1984	1986
Total Direct Effect					
on GNP	.225	.681	.849	.604	.794
Total Induced Effect					
on GNP	.125	.399	.531	.226	.566
Investment	.065	.229	.324	.166	.177
Exports	0	.010	.020	.030	.040
Imports	.020	.110	.293	.540	.521
Total Effect on GNP*	.350	1.070	1.200	.730	1.360
Per cent change in GNP	.28	.77	.89	.48	.75
Per cent change in in GNP Price Index	.07	.37	.28	-.06	-1.55
Per cent change in Wage Rate	.05	.33	.32	-.40	-1.43
Per cent change in Unemployment Rate (%)	-.09	-.20	-.21	-.06	-.04
Change in Long-term Bond Rate (%)	.02	.08	.06	-.13	-.33
Change in Exchange Rate (Cdn$/US$)	0	.01	.01	.01	-.01

* The numbers are those as revised by Foothills; they do not reflect the sum of the detailed figures shown as these were not revised. The total impact includes both the direct and induced effects of a pipeline.

Source: Exhibit No. N-FH-5-5-1, Figures 5A-34, 5A-35, pages 5A-130, 5A-132.

4.4.2.5 Foothills (Yukon) Analysis

Using the same model as Foothills (TRACE Mark IV D), Foothills (Yukon) studied the macroeconomic impact of its originally proposed 42-inch diameter pipeline. Westcoast, Trunk Line and Trunk Line (Canada) adopted the impact statement submitted by Foothills (Yukon). Foothills (Yukon) did not do a study of this nature for its 48-inch diameter pipeline because it argued that the cost variance of the 48-inch diameter line from the original proposal was small and therefore the impact would be similar in magnitude to that estimated for the original proposal. The control solution for this study was essentially the same as for the Foothills study. Table 4-4 presents the main effects of the Foothills (Yukon) Group proposal on the Canadian economy. The principal findings of this study are described below.

The overall effect of the project was small. However, during the period which was characterized by a high unemployment rate, real GNP increased during both the construction and operation phases of the pipeline, but never by more than 0.7 per cent in any one year. The total induced effect on real GNP was negative during the operation phase, principally because of increased imports which came about as a result of the appreciation of the Canadian dollar.

Employment increased during the construction phase but decreased slightly during the operation phase because of the negative induced effect on GNP. These changes were, however, insignificant as the biggest change in employment was 0.22 per cent recorded for the year 1980, the period of the highest level of construction expenditures.

The value of the Canadian dollar depreciated during most of the construction phase because of higher imports and appreciated during the operation phase because of the foreign exchange earnings from the transmission of Alaska gas. The change in the exchange rate in any direction was always less than one cent.

The effects on wages, prices and interest rates were mixed, but again very small in all cases, never reaching the one per cent mark.

Table 4-4: Evidence from Foothills (Yukon) Submission

Major Impacts of the Pipeline on the Canadian Economy

(Differences from control solution: billions of 1971 dollars unless otherwise stated)

	1978	1980	1982	1984	1986
Total Direct Effect on GNP	.05	.50	.35	.23	.22
Total Induced Effect on GNP	-.04	.46	-.15	-.08	-.10
Investment	0	.18	.01	-.04	-.02
Exports	0	.01	-.01	-.01	-.02
Imports	.04	-.02	.23	.17	.20
Total Effect on GNP*	0	.97	.18	.13	.09
Per cent change in GNP	0	.70	.11	.07	.05
Per cent change in GNP Price Index	-.08	.27	-.17	-.37	-.54
Per cent change in Wage Rate	-.06	.23	-.10	-.30	-.48
Per cent change in Manyears of Employment	0	.22	.02	0	-.02
Change in Long-term Bond Rate (%)	.01	.05	-.02	-.08	-.12
Change in Exchange Rate (Cdn$/US$)	-.002	.008	-.007	-.007	-.009

* The "Total" impact includes both the direct and induced effects of a pipeline.

Source: Exhibit No. FH(Y)-114-31, Figures 6C-16, 6C-17, pages 6C-67 and 6C-69.

4.4.2.6 John F. Helliwell Analysis

In his macroeconomic evidence, Dr. Helliwell simulated fixed exchange rate versions of four econometric models (CANDIDE, RDX2, TRACE Mark IV C and TRACE Mark III R) assuming the same set of shocks. These shocks amounted to an increase in real government expenditure of one per cent of real GNE in each of four consecutive years. Dr. Helliwell used these experiments to compare the dynamics of the four models with a view to estimating how the choice of model might affect the estimated impacts.

Since the size of the shock selected was about the same as estimated Canadian construction costs for CAGPL, Dr. Helliwell used the results to illustrate the economic effects of the construction phase of an Arctic pipeline. His principal conclusion was that any of the models he used for assessment (with the partial exception of TRACE IV C) showed induced increases in real GNP during construction and decreases thereafter. He expressed the opinion that, except under very unlikely circumstances, there could not be a case made that such a construction project provided benefit to stable economic growth. On the other hand, he argued that the macroeconomic disturbance created by a construction project of the size of an Arctic pipeline would not be unmanageably large, and, while of substantial size, should not be the main basis on which approval was granted or denied.

Dr. Helliwell simulated the operation phase of the pipeline using only the RDX2 model. He found that there would be some induced effects on the economy in general and balance of payments and exchange rate in particular.

Dr. Helliwell's overall conclusion was that the macroeconomic evidence, in its present limited state, did not provide a strong basis for either approving or rejecting any of the projects.

4.4.2.7 Views of the Board

Introduction

The Board has reviewed the evidence presented by the Applicants and John F. Helliwell concerning the possible macroeconomic impacts from constructing and operating a frontier pipeline. Before discussing the details of the Board's view of the probable impacts, it may be stated that generally speaking, the Board has found that the likely macroeconomic impacts stemming from any of the three proposals could be absorbed by the Canadian economy, without undue problems, given responsive policy on the part of Governments.

The estimation of possible macroeconomic effects of a frontier pipeline depends crucially upon the numerous assumptions underlying the analysis and upon the particular structure of the econometric model chosen for this purpose. In both these respects the Applicants' analyses differ from one another. The Board has undertaken its own macroeconomic impact analysis of the evidence both to verify the analysis made by each of the Applicants and to compare one with the other on the same basis by standardizing the treatment of the pipeline proposals.

The Board's analysis has been conducted using the CANDIDE 1.2M model, the latest version of the CANDIDE model released by the Economic Council of Canada. The principal reason for selecting this model for the Board's analysis was that CANDIDE is the most detailed of all the available Canadian models. It thus provides the potential to examine the effects of a frontier pipeline at a level of industrial detail which has not been undertaken before.

The Board has examined the likely macroeconomic impacts of a frontier pipeline under conditions of both an assumed fixed exchange rate and an assumed floating exchange rate. The reasons for this are twofold. First, the current Canadian exchange rate policy is not a strictly flexible exchange rate policy. Secondly, the Canadian economy in the past has seen both a fixed and a flexible exchange rate system and the possibility of Canada going back to adopting a fixed exchange rate system in the future cannot be completely ruled out. Thus, the Board decided not to ignore any potential macroeconomic impacts which could take place under either of the alternative exchange rate systems.

As a guideline to the underlying simulations considered by the Board, the Board's econometric methodology and major assumptions are outlined briefly in the following section. Then the Board's views concerning the evidence of CAGPL, Foothills and

Foothills (Yukon) are set forth in the three following sections. In the final section, a summary and conclusions are presented, treating each of the major areas of macroeconomic impact.

Methodology

The Board's econometric analysis takes its methodology from that submitted by the Applicants, although as required, adaptations were made. A control solution[2] of the CANDIDE 1.2M model[3] was prepared for the period 1977-85, with the underlying assumption that no frontier gas pipeline was constructed.

This control solution[4] incorporated, for the year 1978, an unemployment rate of 7.6 per cent, a growth rate of real GNE of six per cent, and a six per cent rate of inflation. After 1978 each of these variables was forecast to decline in value so that by 1985 the unemployment rate was 4.6 per cent, the real GNE growth rate was 4.3 per cent, and the rate of inflation was 5.5 per cent.

The details of the Board's approach to the introduction of pipeline investment and operation into the CANDIDE model to obtain the shocked solution are outlined in the Appendix. The data were taken from the various submissions of the Applicants.

Following the approach used by the Applicants, the Board considered differences in the levels of the various variables of the model between the control solution and the shocked solution to be estimates of the possible macroeconomic impacts of the pipeline.

CAGPL

CAGPL prepared estimates of the macroeconomic impacts of its proposal only for its Base Case, which assumed initial throughput in 1981 and a throughput of 2.25 Bcf/d of Mackenzie Delta gas. To make the estimates comparable with those of CAGPL, the Board has also used CAGPL's Base Case for its own macroeconomic impact studies, assuming the same start-up date. However, it is the Board's view that CAGPL's No Expansion Case, which assumed the same start-up date but a throughput of 1.25 Bcf/d, is a more realistic one since the estimates of the total reserves of gas available in the Mackenzie Delta are only 5.1 Tcf.

CAGPL Base Case

Tables 4-5 and 4-6 show the principal results of the Board's macroeconomic impact analysis of the CAGPL Base Case proposal. These estimates are used as references in discussing the effects on the main sectors of the economy, and in comparing those with CAGPL's estimates discussed above.

Real GNP and its Components

It is the Board's view that the implementation of the CAGPL proposal would probably increase real GNP in each of the years of construction and operation of the pipeline, to 1985. The maximum effect would occur in 1980, the period of peak pipeline construction expenditures. These probable beneficial increases in real GNP are estimated by the Board to be higher than in the CAGPL simulations, because of the following factors:

(a) The Board assumed that unemployment, although declining, will still remain fairly high over most of the construction period. The assumption made in CAGPL's control solution for its updated study was for fairly full employment of labour.

(b) The induced investment estimated by CAGPL was negative, even though the simulation showed that the pipeline project would increase real GNP, reduce the rate of inflation, and decrease interest rates. The Board views such a combination of effects as unlikely. The Board's simulations, under both fixed and flexible exchange rates, show induced investment as positive.[5]

This overall positive induced effect on investment in the Board's estimates can be broken down into four categories, namely; housing, non-residential construction, machinery and equipment, and inventories. In the Board's view, under a flexible exchange rate, all these sectors except inventories would show induced increases during the construction and operation phases of the pipeline. Inventories would show small decreases in some of the years. Under a fixed exchange rate system, the housing investment would also show some decreases. However, the decrease in housing investment is never more than 0.8 per cent in any one year.

Pipeline investment does not overly stress the other sectors of the economy because of the availability of unemployed resources. Building a pipeline would not come at the expense of some other investment, but would absorb these unemployed resources.

(c) The Board believes that the value of gas production, which is assumed either to be delivered to market to displace imported energy or to allow hypothetical increases in exports of gas,[6] was understated in the CAGPL simulations. For example, CAGPL estimated the average value of gas production for the period 1984-85 to be $1,105 million, representing an implicit price of gas of some $1.97 per Mcf in current dollars in the Toronto market.[7] Based on commodity equivalence with oil the Board views such a price as too low, and the Board believes a price in the range of $3.25 per Mcf in current dollars for this period wuld be a more realistic estimate.[8]

CAGPL has not provided estimates of the impact of building a pipeline at a disaggregated industrial level. The Board's work using CANDIDE provides such estimates at a 75-industry level. In general, the Board has found that industry outputs at a disaggregated level show induced increases (in line with induced increases in GNP).

Balance of Payments and the Exchange Rate

It is the Board's view that CAGPL's estimate of the effect of the operation phase of the pipeline on the balance of payments surplus may be low. Under a flexible exchange rate, CAGPL's underestimation of the surplus would lead to an underestimation of the exchange rate appreciation. This underestimation appears to have been caused principally by the error made by CAGPL in underpricing Delta gas production, as briefly discussed above.[9] For example, the underestimation of the balance of payments surplus would be about $800 million on average for the years 1984 and 1985. Under cross-examination, Dr. Carr, on behalf of CAGPL, agreed that its TRACE study may have underestimated the likely effect on the exchange rate.

The Board's view is that the effect on the exchange rate is, however, only a symptom of the underlying economic factors. CAGPL, by using a lower valuation of the Delta gas, underestimated the negative induced effect of a pipeline on the current account balance. Such an induced deficit may be of the order of $2 billion a year, as shown in Table 4-6. A more extensive discussion of the effect on the exchange rate and balance of payments appears in a subsequent section.

Wages, Prices and Interest Rates

The Board accepts CAGPL's view that the probable effect of a pipeline on all the above variables will be minimal. In the Board's view the direction of the effects on these variables would, however, be different depending upon the exchange rate assumption. Under a fixed exchange rate, the effect of the pipeline would be to increase the values of all these variables. The reverse would be true under a flexible exchange rate case.

Unemployment Rate

The Board accepts CAGPL's view that the effect of the pipeline on the unemployment rate would not be large. However, in the Board's view CAGPL has underestimated the probable beneficial effect a pipeline would have in reducing the unemployment rate. CAGPL estimated that during the operation phase the unemployment rate may increase. The Board's estimate is that positive induced effects on GNP during the operation phase of the pipeline would lead to increases in employment and decreases in the unemployment rate during that period.

CAGPL No Expansion Case

It is obvious that impacts of the CAGPL No Expansion Case on the Canadian economy would be smaller than those arising from the Base Case, particularly the impact on the balance of payments and the exchange rate. It is the Board's view that the appreciation of the exchange rate in the No Expansion Case would be only about half of that in the Base Case (see Table 4-6 below) during the operation phase of the pipeline and certainly not more than three per cent over the whole period to 1985.

Table 4-5

Macroeconomic Effects of CAGPL Base Case Proposal: NEB Estimates

(percent change[1] in constant dollar figures, unless otherwise specified)

	Fixed Exchange Rate								Flexible Exchange Rate							
	1978	1979	1980	1981	1982	1983	1984	1985	1978	1979	1980	1981	1982	1983	1984	1985
Real Consumer Expenditure (Induced)	.44	.43	.74	.75	.76	.82	.79	.74	.36	.63	.91	1.05	1.10	1.13	1.29	1.38
Real Business Capital Investment (Total)	4.74	5.71	5.18	4.24	2.43	1.75	1.59	1.53	4.74	5.74	5.16	4.35	2.68	2.05	1.85	1.79
Direct: Pipeline Construction[2]	2.50	3.43	3.40	2.79	1.06	.64	.57	.40	2.50	3.43	3.40	2.79	1.06	.64	.57	.40
Direct: Gas Field Development	.71	.65	.45	.49	.60	.41	.32	.36	.71	.65	.45	.49	.60	.41	.32	.36
Induced Effects	1.53	1.63	1.32	.96	.77	.70	.70	.76	1.53	1.66	1.30	1.07	1.02	1.01	.96	1.03
Real Exports of Goods and Services (Total)	-.08	-.10	-.09	.23	.90	1.25	1.30	1.43	-.01	-.23	-0.35	-.10	.56	.91	.83	.78
Direct: Gas and Transmission Services	0	0	0	.29	.93	1.27	1.33	1.46	0	0	0	.29	.93	1.26	1.33	1.45
Induced Effects	-.08	-.10	-.09	-.06	-.03	-.02	-.03	-.03	-.01	-.23	-.35	-.39	-.37	-.36	-.50	-.68
Real Imports of Goods and Services (Total)	1.12	1.42	1.63	1.74	1.55	1.55	1.46	1.63	1.00	1.72	1.99	2.25	2.03	1.97	2.06	2.45
Direct: Import Content of Project[3]	.42	.58	.50	.59	.44	.44	.39	.49	.42	.58	.51	.60	.45	.44	.40	.51
Direct: Displacement of Energy Imports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Induced Effects	.70	.84	1.12	1.15	1.10	1.10	1.07	1.13	.58	1.13	1.48	1.65	1.58	1.51	1.66	1.94
Real GNP (Total)	.71	.89	1.04	.97	.86	.89	.90	.85	.72	.90	.98	.94	.90	.95	.97	.90
Direct Effects	.50	.65	.68	.65	.57	.55	.54	.55	.50	.65	.68	.65	.57	.54	.54	.55
Induced Effects	.21	.24	.36	.32	.29	.35	.36	.30	.22	.26	.30	.29	.33	.41	.43	.35
GNP Price Index	-.22	-.27	-.26	-.06	.09	0	.06	.18	-.09	-.51	-.78	-.87	-.87	-1.08	-1.43	-1.86
Long Term Bond Rate (%)[4]	0	1.32	2.20	3.71	3.60	2.20	3.26	3.84	.34	-.22	-.41	-.30	-.10	-.47	-1.27	-2.34
Unemployment Rate (%)[4]	-3.80	-4.92	-5.58	-4.47	-3.21	-3.68	-4.50	-5.18	-4.01	-4.30	-4.59	-3.82	-3.07	-3.56	-3.24	-3.14
Wage Rate Per Hour	.06	.09	.39	.46	.47	.45	.65	.87	.07	.16	.18	-.04	-.32	-.55	-.62	-1.06

(1) Changes from control solution.
(2) Including operating expenses.
(3) Including interest and dividend payments before taxes.
(4) The figures shown are percentage changes on these variables. For example, a 3.8 per cent decrease in the unemployment rate in 1978 is equivalent to decreasing the unemployment rate from a level of 7.64 per cent to 7.35 per cent. The same interpretation applies to the long term bond rate.

Table 4-6

Macroeconomic Effects of CAGPL Base Case Proposal: NEB Estimates

(impact on balance of payments,[1] millions of current dollars)

	Fixed Exchange Rate								Flexible Exchange Rate							
	1978	1979	1980	1981	1982	1983	1984	1985	1978	1979	1980	1981	1982	1983	1984	1985
Foreign Financing of Pipeline	548	1028	1409	1187	134	-312	-312	-312	550	1024	1399	1173	131	-310	-310	-309
Import Content of Pipeline [2]	-206	-349	-402	-531	-454	-469	-474	-639	-208	-344	-394	-520	-447	-426	-460	-620
Goods and Services	-206	-328	-292	-299	-122	-85	-70	-53	-208	-323	-285	-289	-118	-82	-66	-49
Interest and Dividends	0	-21	-110	-232	-332	-384	-404	-586	0	-21	-109	-231	-329	-380	-394	-571
Foreign Exchange Savings and Earnings of Pipeline	0	0	0	655	1725	2200	2568	3067	0	0	0	638	1690	2259	2486	2932
Delta Gas Production and Transmission	0	0	0	655	1311	1366	1698	2088	0	0	0	638	1280	1333	1625	1963
Transmission of Alaska Gas	0	0	0	0	414	834	870	979	0	0	0	0	410	826	861	969
Induced Change in Current Account	-430	-577	-756	-743	-675	-714	-768	-805	-347	-792	-1121	-1295	-1253	-1268	-1538	-1815
Induced Change in Capital Flows	11	103	83	-61	-209	-193	-245	-301	9	109	116	6	-121	-116	-158	-191
Total Impact on Current Account	-636	-926	-1158	-618	596	1016	1327	1623	-554	-1136	-1515	-1177	-10	429	490	497
Total Impact on Capital Account	560	1130	1492	1126	-74	-505	-557	-613	559	1133	1515	1179	10	-425	-468	-501
Impact on Foreign Exchange Reserves	-76	205	333	509	522	511	770	1010	5	-3	0	2	0	3	21	-3
Impact on Exchange Rate [3] (Cdn$/US$)	-	-	-	-	-	-	-	-	.70	-1.75	-2.35	-2.65	-2.34	-2.40	-4.27	-6.05

(1) Change from control solution; all figures are rounded, so adding components may not exactly produce totals shown due to rounding error.

(2) Net of Canadian duties and taxes.

(3) Negative sign indicates an appreciation of the value of the Canadian dollar in per cent form.

Foothills

Tables 4-7 and 4-8 show the principal results of the Board's macroeconomic impact analysis of the Foothills Group proposal. The effects on the major sectors of the economy are discussed below, and are compared with Foothills' estimates discussed above.

Real GNP and its Components

It is the Board's view that the implementation of the Foothills Group proposal would probably increase real GNP in each of the years of construction and operation of the pipeline to 1985. These probable beneficial increases in real GNP are estimated by the Board to be higher than in the Foothills submission because the value of gas production, which displaces imported energy, was underestimated in the Foothills simulations. For example, from Foothills' submission, this value in 1987 would be $2.07 per Mcf[10] in current dollars in the Toronto market.[11] The Board views a price in the range of $3.90 per Mcf for 1987 to be a more realistic estimate.

Foothills has not provided estimates of the impact of building a pipeline at a disaggregated industrial level. In general the Board estimated that industry outputs at the disaggregated level show induced increases except for a few cases. In these cases the industry outputs are either not affected, such as the fishing industry, or show small decreases of the order of about one per cent or less, such as in agriculture.

Balance of Payments and the Exchange Rate

It is the Board's view that given Foothills' assumption of a peak 2.4 Bcf/d throughput, its estimates of the balance of payments surplus may be low. Equivalently, under a flexible exchange rate, the Foothills estimate of the exchange rate appreciation is probably low.

In the Board's view, this underestimation of the possible appreciation of the exchange rate appears to have been caused principally by two factors.[12]

(a) Foothills' price assumption, as discussed above, led to an underestimation of the balance of payments surplus. In 1985, for example, the underestimation was approximately $700 million.

(b) Induced capital outflows in the Foothills study, which tended to clear the surpluses in the balance of payments, were very large, and are in the Board's view unlikely to happen. For example, Foothills estimated such flows to be approximately $1 billion in 1985 whereas the Board's estimate is only $11 million (See Table 4-8).

In the Board's view Foothills may have underestimated the induced deficit in the current account because of these same factors. Such an induced deficit may be of the order of $2 billion a year, as shown in Table 4-8.

The impact on the balance of payments and the exchange rate of the pipeline project is very sensitive to the assumed throughput of Delta gas. The Board views that a throughput of 2.4

Bcf/d assumed in both the Foothills' own macroeconomic impact study and the Board's study of Foothills is not likely given the established reserves of 5.1 Tcf in the Delta. Thus the likely impact on the exchange rate would be much smaller than that reported above, and in the Board's view never more than three per cent over the whole period to 1985.

Wages, Prices and Interest Rates

In the Board's view the probable effect of the Foothills Group proposal on all these variables will be minimal, as was shown in Foothills' estimates. However, the Board thinks that the direction of the effects estimated by Foothills is unlikely. The Board estimates that the hourly wage rate and the long-term bond yield would show increases throughout the period to 1985, under either a fixed or flexible exchange rate system.[13] In Foothills' simulation, these variables declined during the operation phase of the pipeline.

In the Board's view the GNP price index would continuously increase under a fixed exchange rate system. Under a flexible exchange rate system the GNP price index would still show increases unless there is a significant appreciation of the Canadian dollar. Such an appreciation could occur in 1985, and would decrease the GNP price index.

Unemployment Rate

The Board accepts Foothills view that the effect of its proposal on the unemployment rate would be small.

Table 4-7

Macroeconomic Effects of Foothills' Proposal: NEB Estimates

(percent change (1) in constant dollar figures, unless otherwise specified)*

	Fixed Exchange Rate								Flexible Exchange Rate							
	1978	1979	1980	1981	1982	1983	1984	1985	1978	1979	1980	1981	1982	1983	1984	1985
Real Consumer Expenditure (Induced)	.15	.25	.43	.57	.65	.66	.62	.79	.03	.14	.27	.45	.69	.72	1.65	1.41
Real Business Capital Investment (Total)	1.57	3.15	3.93	4.26	3.99	2.93	2.10	2.46	1.57	3.13	3.84	4.01	3.85	2.89	2.28	2.79
Direct: Pipeline Construction (2)	.16	.57	1.55	1.94	1.60	1.29	.45	.69	.16	.57	1.55	1.94	1.60	1.29	1.45	.69
Direct: Gas Field Development	.55	.99	.82	.80	.95	.79	.85	.80	.55	.99	.82	.80	.95	.79	.85	.80
Induced Effects	.86	1.59	1.57	1.52	1.45	.85	.81	.96	.86	1.58	1.48	1.36	1.31	.81	.99	1.29
Real Exports of Goods and Services (Total)	-.03	-.05	-.06	-.07	0	.35	.53	.75	.08	.12	.14	.10	.03	.32	.27	.27
Direct: Gas	0	0	0	0	.06	.39	.55	.78	0	0	0	0	.06	.39	.55	.78
Induced Effects	-.03	-.05	-.06	-.07	-.06	-.04	-.02	-.03	.08	.12	.14	.10	-.03	-.07	-.28	-.52
Real Imports of Goods and Services (Total)	.26	.51	.79	.95	1.03	1.09	.86	1.05	.07	.28	.52	.77	1.12	1.26	1.51	1.98
Direct: Import Content of Project (3)	.003	.023	.083	.113	.138	.223	.131	.135	.00	.02	.08	.11	.14	.22	.13	.14
Direct Displacement of Energy Imports	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Induced Effects	.26	.48	.71	.84	.89	.87	.73	.91	.07	.26	.44	.66	.98	1.04	1.37	1.84
Real GNP (Total)	.21	.44	.70	.84	.83	.75	.66	.85	.22	.47	.71	.82	.80	.71	.69	.89
Direct Effects	.14	.30	.46	.54	.52	.50	.42	.52	.14	.30	.46	.54	.52	.50	.42	.52
Induced Effect	.07	.13	.23	.30	.31	.25	.25	.33	.08	.17	.25	.28	.28	.21	.28	.37
GNP Price Index	0	-.02	-.08	-.08	.03	.26	.41	.54	.20	.36	.45	.46	.34	.43	.04	-.46
Long Term Bond Yield (%) (4)	.15	.43	.70	1.14	1.70	2.41	2.75	3.23	.68	1.42	2.08	2.42	2.33	2.68	1.65	.62
Unemployment Rate (%) (4)	-1.39	-2.71	-3.87	-4.81	-5.14	-4.14	-3.56	-5.05	-1.81	-3.17	-4.21	-4.75	-4.61	-3.94	-2.88	-4.13
Wage Rate per Hour	.02	.05	.22	.35	.48	.68	.77	1.16	.04	.24	.56	.84	.98	1.00	.89	.62

* For Footnotes, see Table 4-5.

Table 4-8

Macroeconomic Effects of Foothills' Proposal: NEB Estimates

(impact on balance of payments[1], millions of current dollars)*

	Fixed Exchange Rate								Flexible Exchange Rate							
	1978	1979	1980	1981	1982	1983	1984	1985	1978	1979	1980	1981	1982	1983	1984	1985
Foreign Financing of Pipeline	0	58	168	354	534	50	0	0	0	59	169	357	537	50	0	0
Import Content of Pipeline[2]	-2	-14	-59	-91	-131	-257	-254	-185	-2	-14	-61	-92	-132	-257	-254	-181
Goods and Services	-2	-14	-53	-67	-74	-146	-35	-75	-2	-14	-55	-68	-74	-145	-34	-71
Interest and Dividends	0	0	-6	-24	-57	-111	-119	-110	0	0	-6	-24	-58	-112	-120	-110
Foreign Exchange Savings and Earnings of Pipeline	0	0	0	0	145	997	1522	2301	0	0	0	0	144	991	1475	2187
Delta Gas Production and Transmission	0	0	0	0	145	997	1522	2301	0	0	0	0	144	991	1475	2187
Transmission of Alaska Gas	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Induced Change in Current Account	-158	-337	-541	-687	-757	-732	-659	-932	-25	-126	-242	-447	-790	-888	-1339	-1992
Induced Change in Capital Flows	45	99	162	219	228	76	-89	-180	41	83	131	186	229	109	15	-11
Total Impact on Current Account	-159	-351	-601	-779	-744	8	709	1185	-27	-140	-303	-540	-778	-154	-18	13
Total Impact on Capital Account	45	158	330	573	761	126	-89	-180	41	141	300	543	766	158	15	-11
Impact on Foreign Exchange Reserves	-115	-193	-270	-205	17	134	620	1005	14	1	-3	3	-12	-4	-3	2
Impact on Exchange Rate[3] (Cdn$/US$)	---	---	---	---	---	---	---	---	.98	1.34	1.47	.90	-.47	-.59	-3.14	-5.0

* For Footnotes see Table 4-6.

Foothills (Yukon)

Introduction

The Board accepts the view that there would be no major differences in the estimates of the macroeconomic impact between the Foothills (Yukon) Group 42-inch diameter pipeline and its 48-inch diameter pipeline. The Board did not conduct its own macroeconomic simulation studies for the Foothills (Yukon) Group project as it did for the other Applicants since the estimates of the macroeconomic impact of the other pipeline proposals indicated that the building of a pipeline would not create any substantial problems for any sectors of the economy. Moreover, the capital cost estimates of the Foothills (Yukon) Group are lower than those of either CAGPL or the Foothills Group and there is no Canadian gas involved in the Foothills (Yukon) case. The Board's view on the macroeconomic impact of the Foothills (Yukon) Group project based upon an analysis of the submitted evidence and having regard to the simulations performed on the other proposals, is that the impacts of the Foothills (Yukon) Group proposal on the economy would not be very large.

Although the Board thus agrees with the Applicant's overall conclusion that the estimated impact of its proposal would not be too large, the Board's view is that the magnitude of the estimated impact by Foothills (Yukon) is not likely correct in the areas discussed below.

Induced Effect on Investment

Foothills (Yukon) estimated that the induced effect on investment would be negative during the operation phase. This was due to its estimated appreciation of the Canadian dollar during this period (mostly less than one cent) which induced substantial imports which, in turn, displaced domestic investment.

The Board's view is that positive induced effects are possible, as discussed above, tending to increase the beneficial effects of the project on the economy.

Exchange Rate

The Board's view is that Foothills (Yukon) underestimated the impact of the project on the exchange rate due to the factors already discussed.

Prices and Interest Rates

The Board's view is that a combination of a modest appreciation of the Canadian dollar and a reduction of prices and interest rates, as shown by Foothills (Yukon), is not likely.[14] Either the appreciation of the exchange rate would not be as modest as claimed, or prices and interest rates would not fall.

Foothills (Yukon) Plus the Dempster Alternative

The Board has not prepared any simulations of the macroeconomic impact of the Foothills (Yukon) Group project combined with the Dempster alternative for reasons similar to those discussed above. The Board's view is that this combined project is not larger than the CAGPL Base Case project, both from the point of view of the construction costs and the flow of gas from the Mackenzie Delta. Therefore, the Board concludes that the macroeconomic impacts of the Foothills (Yukon) proposal plus a Dempster link would certainly not be larger than those estimated for CAGPL.

Summary and Conclusions

In the Board's view the CAGPL project would likely have larger overall effects on the Canadian economy than either the Foothills Group project or the Foothills (Yukon) Group project taken alone or the Foothills (Yukon) Group project combined with the Dempster alternative.[15] However, the Board accepts the view that the likely macroeconomic impacts stemming from any of the three proposals could be absorbed by the Canadian economy, given responsive policies on the part of Governments, without undue problems. The Board concludes that the effect of building any of the proposed pipelines will have a minimal effect at the national level on real GNP and its components, wage rates, prices, interest rates and the unemployment rate. The effect on the balance of payments and the exchange rate will be tolerable. Therefore, macroeconomic impact evidence should not be the basis of a decision between either building or not building a pipeline or choosing between the projects.

Balance of Payments and Exchange Rate

It is the Board's view that the effects of constructing and operating a frontier gas pipeline on the exchange rate would not be unduly large, and would be of the order of two percentage points. The Board's estimates of the exchange rate appreciation presented above are estimates of the possible maximum impacts[16] and not of those which are likely to actually occur. The actual impacts would be smaller for a number of reasons. First, the macroeconomic impact studies discussed above are based on the assumptions of throughputs of Delta gas of 2.25 Bcf/d for CAGPL and 2.4 Bcf/d for Foothills. The Board views these magnitudes to be unlikely and considers an estimate of 0.7 Bcf/d throughput to be more realistic, given the established reserves of 5.1 Tcf in the Delta. Secondly, the price of Delta gas may turn out to be lower than that assumed in the Board's simulations. Thirdly, it has been assumed in the Board's simulations that Delta gas would be displacing imported oil. It may instead to some extent displace other cheaper imported energy, such as coal. Fourthly, these estimates assume that Mackenzie Delta gas would not displace production of other domestic energy resources. In reality, some such displacement is likely to occur, perhaps via delay in construction of, say, nuclear plants.[17]

Canada faced a current account deficit of the order of $4 billion in 1975 and $5 billion in 1976 and this deficit could grow to about $9 billion by the year 1985. Such large deficits on a continuing basis can be supported only by either large foreign borrowings or a depreciation of the value of the Canadian dollar. It is the Board's view that the availability of Delta gas, which in its simulations is shown to appreciate the value of the Canadian dollar over some control solution values, should be viewed as either forestalling a future depreciation of the Canadian dollar, or reducing the need for heavy foreign borrowings in the future.

Prices, Wages and Interest Rates

The Board accepts the Applicants' view that the likely effects of building a pipeline on the general level of prices, interest rates, and wage rates, would be minimal.

Other Effects

The Board accepts the Applicants' views that the effects on real gross national product and on employment would be relatively small. Neither effect would be a reason not to support the construction of a pipeline, as both are in a positive direction.

Footnotes

[1] No application was before the Board in this hearing for a licence to export Mackenzie Delta gas. The hypothetical assumption of exporting Delta gas is used only for the purpose of measuring the impact of the pipeline upon the Canadian economy.

[2] The details of this control solution are provided in the Appendix.

[3] Further discussion of the CANDIDE 1.2M model can be found in the Appendix and in publications of the Economic Council of Canada.

[4] This control solution was also the base of the Board's energy demand forecasting.

[5] The reason why the effect on real GNP is greater under a flexible exchange rate compared to a fixed exchange rate system in some years is that the appreciation of the exchange rate generates forces which have opposing influences. Appreciation discourages exports and encourages imports, tending to depress income. It also decreases the rate of inflation and the interest rates and thus encourages investment and the consumption of durable goods. This tends to increase income. In some years this latter effect overtakes the former.

[6] In this particular CAGPL simulation, displacement of other domestic energy production was not assumed. See also footnote 1.

[7] Assuming gas displaces oil imports in the Toronto market, the value of this displacement calculated by CAGPL implicitly yields a gas price in the Toronto market. This price is obtained by dividing the total value of gas displacing energy imports by the throughput, which is 562 Bcf per year on average during this period.

[8] An oil price of $12 per barrel in 1976 dollars is assumed in the Board's analysis.

[9] The difference in price and income elasticities for exports and imports and different treatment of capital flows in the TRACE and CANDIDE models may also have contributed to these different results.

[10] This price is obtained by dividing the total value of gas displacing energy imports, $1,815 million in 1987, by the throughput, which would be 876 Bcf in the year. If Foothills indeed assumed that frontier gas would displace other domestic energy resources, as Foothills claimed, it would not be correct to simply divide the value of gas displacing energy imports by the throughput to get gas prices as discussed above. However, the assumption of domestic energy resources being displaced is not compatible with the analysis presented by Foothills, since the effect of changes in other domestic energy outputs and investment was then completely ignored in Foothills' analysis, with the result that its study would not correctly demonstrate the impact.

[11] See footnote 7 for details.

[12] Very high income and price elasticities may have also contributed to this result. See also footnote 9.

[13] Even the estimated three per cent appreciation of the Canadian dollar in 1984 did not reverse these expected trends.

[14] The same argument as was made concerning Foothills would apply here.

[15] Methodologically, the estimates of CAGPL, Foothills and Foothills (Yukon) are not strictly comparable because some of the input data common to all these studies may be estimated differently by them. For example, the CAGPL study was based on the assumption that the gas exploration and development expenditures would total about $3.8 billion for the period 1978-87, in current dollars. Foothills used a figure of $7 billion for the same variable. Since the Board estimates also used the data provided by the Applicants, these estimates also are subject to this difficulty. The reason why the Applicants' estimates were used in the Board study was to enable the Board to directly compare its own estimates with those of the Applicants. However, in this particular case the Board's conclusions were not affected by this problem.

[16] Estimates of the Board's model show an appreciation on the order of two to four percentage points larger than those shown by the Applicants. In the Board's estimates there is generally a one cent appreciation for approximately every $200 million balance of payments surplus. This is the same as in RDX2.

[17] A comparison of the structures of the CANDIDE model, underlying the Board's simulations, and the TRACE model, underlying the Applicants' analyses, suggests that CANDIDE produces estimates of changes in the exchange rate larger than those in TRACE for any given shocks. Even though it is not possible to unequivocally state which model produces estimates closer to reality, it is the Board's view that the underlying structures of the two models suggest that TRACE underestimates and CANDIDE overestimates the exchange rate impact.

4.4.3 CANADIAN CONTENT AND INDUSTRIAL IMPACT

4.4.3.1 Introduction

Section 44 of the NEB Act states, inter alia, that in considering an application for a certificate, the Board may have regard to the extent to which Canadians will have an opportunity of participating in the financing, engineering, and construction of the line. The Board accepted filings and heard testimony from the Applicants on the extent of estimated Canadian involvement in the projects, and has evaluated the benefits which might accrue to Canada from such participation.

The extent of Canadian participation in the financing of the proposed pipelines is dealt with in the section of the report dealing with financial matters. Canadian participation in the engineering and construction and the associated manufacturing and other segments of Canadian industry is dealt with in this section.

4.4.3.2 CAGPL

CAGPL stated that approximately 78 per cent of the capital invested in its pipeline would remain in Canada, i.e., the money would remain in the hands of Canadian citizens, either corporate or individual. Additionally, CAGPL stated that this percentage would likely remain the same once the frost heave redesign costs were included. Under cross-examination, CAGPL said there was a greater chance of exceeding this percentage than being below it.

CAGPL stated that one of its prime goals was to maximize Canadian content provided its criteria were met with respect to pricing, quality, availability of materials and the financial integrity of the suppliers. CAGPL indicated that it had encouraged some suppliers to do all that they could within their own business capabilities to maximize the Canadian content in their products. Also, CAGPL maintained that in the ultimate selection of suppliers, Canadian content would be a major factor.

CAGPL testified that it had estimated Canadian content by taking a rather broad base average available from various suppliers, making no special effort to reflect the fact that, all other things being equal, it would tend to lean toward the supplier with the highest Canadian content.

CAGPL did not ask Northern Engineering Services, its engineering consultant in these matters, to study the maximum achievable Canadian content but asked it only to estimate what the average might be. Supplier quotes from which CAGPL derived its average Canadian content in some cases omitted potential Canadian suppliers. In one particular instance, the average was based on quotes from four foreign but only one Canadian supplier although several other potential Canadian sources existed. CAGPL also indicated that its management committee had not specifically discussed or given direction to CAGPL executives with respect to policy on Canadian content.

In the following areas, identified by the Board as having the greatest potential to produce growth in Canadian industrial capability, CAGPL's position was:

1) Project and Construction Management: Although CAGPL had not finalized its project management arrangements, it indicated it might utilize a large international project management and construction contractor; however, it anticipated significant involvement of Canadians. CAGPL indicated that one of the major benefits from the pipeline project would be the development of Canadians experienced in managing, engineering, and constructing large projects. However, CAGPL indicated it would be surprised if as a result of this project there would be a single Canadian company with the overall management experience to build projects such as this on a worldwide basis.

CAGPL listed a number of companies which might be involved with it on the project management and engineering aspects; these included Acres, Canadian Bechtel, Fluor Canada, Lavelin, Mannix, Montreal Engineering, Resource Sciences, and SNC. It maintained that Resource Sciences was the only one listed that was non-Canadian.

2) Engineering: Because CAGPL had not yet decided on a project management method, it was unsure how the final engineering would be completed. However, it stated that NES was expected to have a major role, at least in overseeing CAGPL's overall interests. The principal benefit to

Canada, in CAGPL's view, was likely to stem from the experience gained by Canadian individuals as opposed to the establishment or growth of engineering companies in Canada. Engineering services might be provided to CAGPL by one of the project management companies listed above.

3) Compression Equipment: CAGPL identified eight potential suppliers, all foreign-owned, but stated that a final selection had not yet been made. Two were totally foreign with negligible Canadian content and the remainder had varying degrees of Canadian content. CAGPL pointed out that development of a Canadian capability to supply compression equipment for large diameter gas pipelines would likely prove to be of significant advantage in competing in both the Russian and Arab markets.

CAGPL also pointed out that it was carefully assessing Westinghouse Canada Ltd's new gas turbine unit, the CW352, and was encouraging the company to develop and prove it out at the fastest possible rate. CAGPL indicated that it had suggested certain improvements to Westinghouse and if development of the new turbine were to continue as expected, CAGPL would initiate contract negotiations with Westinghouse by June 1977.

4) Valves and Fittings: CAGPL indicated with respect to valves that it had based its calculation of expected Canadian content of 43.6 per cent on an average of one Canadian and four foreign suppliers. CAGPL stated that, if

world demand were sufficient and a Canadian manufacturer could be competitive, the development of Canadian capability to produce large valves would provide industrial benefits to Canada.

CAGPL stated that initial discussions with potential Canadian valve manufacturers were encouraging with respect to their interest in improving their capability and facilities in time to participate in the proposed project. CAGPL indicated that the current inability of Canadian industry to supply certain types of large valves was deemed to be a problem of equipment and facilities, not one of insufficient technology.

Although little specific information was supplied with respect to fittings, a similar situation to that described above for valves appeared to exist, particularly for large diameter fittings.

5) Construction Equipment: According to CAGPL, the Canadian manufacturing content of construction equipment was 13 per cent, compared to 38 per cent Canadian content, after allowance had been made for taxes, duties, and agents' profits.

CAGPL expressed the belief that only limited opportunities were available to enhance industrial development in Canada through the purchase of construction equipment. Nevertheless, CAGPL thought that specific equipment items such as the Rhymes Engineering Arctic ditcher and the Foremost Equipment line of off-road track-vehicles represented new products being developed in Canada that might have application in many other parts of the world.

CAGPL took the position that its management was interested in achieving a high Canadian content, and because this was in the self-interest of the Company, it would be unnecessary to include a Canadian content condition in any certificate which the Board might issue. However, CAGPL said that following the granting of a pipeline certificate, it would be willing to accept a condition guaranteeing a realistic level of Canadian content, once the bidding for material and service contracts was complete.

CAGPL agreed in principle that it would have no problem accepting a condition similar to that proposed by Foothills, provided that in demonstrating compliance to the Board, it would not have to supply too much detail; in other words, such a condition would have to be handled in a practical manner so that it would not delay the implementation of the project.

4.4.3.3 ANG

Alberta Natural Gas indicated that the 95 per cent Canadian content shown in its application was representative of what was likely to be achieved, based on ANG's experience and on estimates made by its suppliers. ANG stated it would give Canadian companies the opportunity of bidding on both services and materials for this project.

ANG stated that engineering and design would be done by its staff and it would control all procurement policy. The construction would be carried out by a Canadian pipeline contractor.

ANG believed it would be realistic to commit itself to the achievement of a Canadian content of at least 93 per cent for its project.

ANG's proposed facilities were estimated to cost $51 million (unescalated) and, other than special pipe ($1.1 million), meter runs ($0.2 million), and compressor wheels ($0.6 million), contained very little foreign content. The compressor wheels were replacements to be used in existing equipment, so those had to be foreign even though some manufacturers made wheels in Canada.

Although ANG indicated 40 per cent foreign content in the valves, it was expected there would be an excellent chance of reducing this when the actual buying occurred.

4.4.3.4 Foothills

Foothills stated that, as long as economic conditions did not change significantly, it would probably achieve a Canadian content of 89.5 per cent.

Foothills adopted the policies and position of Foothills (Yukon), described in a following part of this section, as joint testimony made on behalf of both companies.

4.4.3.5 Westcoast

Westcoast testified that there would be at least 92 per cent Canadian content in the facilities it proposed to have constructed as part of the Foothills project.

Westcoast stated that its policy, although somewhat different in specific areas, was basically similar to that of Foothills. With respect to the purchase of material and equipment, and the hiring of personnel, its policy was to achieve, wherever possible, maximum Canadian content, having regard to quality, price, service, and delivery criteria.

Westcoast's calculation of the Canadian content in materials, equipment, and labour was based on information it had received from its suppliers and on an assessment of the expected availability of Canadian construction equipment and labour during the proposed time-frame of its project. Westcoast stated its Canadian content estimate was based on existing and possible future Canadian manufacturing capabilities.

In the following areas identified by the Board as having the greatest potential to produce growth in Canadian industrial capability, Westcoast's position was:

1) Project Management and Construction Supervision: Westcoast asserted that it would employ its own Canadian personnel for project management, and construction supervision. Westcoast believed it has the key people already on its staff to do the project management work. It would have to hire some management people but they would be Canadian citizens; it was not Westcoast's intention to employ a project management firm to do this work.

2) Engineering: Westcoast stated it had the principal engineering people necessary for it to carry out the engineering of its project with its own staff. It would hire some engineers and draftsmen but they would be Canadians.

3) Compression Equipment: Westcoast, although it has not made its final selection yet, indicated four potential suppliers of compression equipment, all foreign-owned and manufacturing in Canada. Westcoast indicated a preference for aero-derived gas turbines; this preference effectively eliminated industrial-type units from participation in its project (i.e., Westinghouse and General Electric stationary units). Additionally, Westcoast declared that its horsepower requirements were such that Pratt & Whitney's units were much higher-powered than required. The remaining

potential suppliers to Westcoast for this type of equipment were, therefore, Rolls Royce (Spey and RB211) and General Electric (LM2500), both with very low Canadian content.

4) Valves and Fittings: Westcoast indicated that 80 per cent of the value of valves and fittings in the Westcoast portion of the Foothills project would be foreign content based on its assessment of present Canadian manufacturing capabilities. Westcoast indicated it did not believe that Canron, a Canadian manufacturer, was currently capable of producing large-diameter valves. Westcoast would purchase valves manufactured in Canada with a high Canadian content if they were available and competitive in price and quality. Westcoast stated there was only one potential Canadian supplier of large-diameter ball valves and Westcoast felt it should have an alternate source. This fact caused the low Canadian content estimate.

5) Construction Equipment: Westcoast claimed 100 per cent Canadian content for construction equipment. This claim was based on the assumption that the dollars paid probably went to Canadians in the form of a rental fee paid to a Canadian contractor, disregarding the fact that most of the equipment involved would likely have been manufactured outside Canada. Westcoast said that it made this assumption since it had no way of knowing when the contractor had purchased the equipment from a Canadian agent, or when the agent had previously imported it. Westcoast agreed that

most of this equipment was of a high percentage foreign content and that an amortization of the foreign value could have been used to determine actual Canadian content; however, it had not done this.

With regard to a conditioning of the certificate, Westcoast endorsed both the position taken, and the proposed condition, submitted by Foothills.

4.4.3.6 Trunk Line and Trunk Line (Canada)

The Trunk Line portion of the Foothills project was estimated to contain 90.4 per cent Canadian content and the Trunk Line (Canada) portion 92.3 per cent. Both firms indicated that the probability of achieving these levels of Canadian content was very high.

Both Trunk Line and Trunk Line (Canada) adopted the policies and position of Foothills (Yukon), described in a following section, as joint testimony made on behalf of all three companies.

4.4.3.7 Foothills (Yukon)

Testimony on Canadian content was given by a policy witness on behalf of Foothills, Foothills (Yukon), Trunk Line (Canada), and Trunk Line for both the Foothills and Foothills (Yukon) projects.

A Canadian content percentage in excess of 85 per cent was expected for the proposed Foothills (Yukon) facilities. Foothills (Yukon) testified that this estimate was based on the maximum obtainable Canadian content of the dollar flow to Canada and allowed for good commercial practice of meeting cost schedules, quality standards and being cost-competitive.

Foothills (Yukon) and Trunk Line (Canada) stated that their corporate purchasing policy of "Canadian goods and services first" could be summarized as follows: if a sufficient number of qualified Canadian manufacturers were available to provide competitive quotes, Foothills (Yukon) would limit its bid list to Canadian suppliers; if it were necessary to solicit bids from non-Canadian sources, Foothills (Yukon) would purchase Canadian goods whenever terms and conditions were reasonably competitive.

Although Trunk Line's policy was to purchase goods and services from sellers who provided the best combination of price, delivery, service and quality, prior experience in the market-place had shown that suppliers with high Canadian content were generally competitive. Consequently, it was expected that such suppliers would ultimately be selected on the basis of normal business considerations alone.

One aspect of Foothills (Yukon)'s Canadian content policy was to utilize the opportunity offered by this project to encourage new Canadian manufacturing efforts in selected products if it were thought that such manufacturing activity could be maintained on an internationally competitive basis over the long run. A study carried out by Donner and Lazar Associates Ltd., on behalf of Foothills and Foothills (Yukon) expressed the opinion that the proposed project could support production runs of sufficient length to provide substantial incentive towards the establishment of selected Canadian manufacturing facilities.

Foothills (Yukon) further stated that it was its corporate policy to actively encourage the establishment of Canadian-based manufacturing facilities for certain industrial products currently being imported, as advantages would be available to it through the development of mature supplier relationships. Foothills (Yukon) indicated that the attainment of closer supplier support was equally as important from a corporate viewpoint, as maximizing Canadian content; it was actively encouraging the establishment of new facilities in Canada by a pipe-fitting manufacturer and a turbine manufacturer.

In the following areas identified by the Board as having the greatest potential to produce growth in Canadian industrial capability, Foothills (Yukon)'s position was:

1) Project and Construction Management: Foothills (Yukon) and Trunk Line (Canada) would supply the overall project management team insofar as possible with their own staff. They might use some Canadian consultants but they already had in operation and available what might be the largest

engineering project staff (approximately 500 persons) in the pipeline business in Canada. This staff would likely double upon approval of either the Foothills or the Foothills (Yukon) project. The management expertise developed would be owned in Canada and would be available for export. Trunk Line asserted it had previously been involved in several potential projects to export its expertise and were it not for a recent heavy work load, it would have accepted several other such opportunities.

2) Engineering: Foothills (Yukon) would undertake to do its own engineering and design work with the possible use of some Canadian consultants. Foothills (Yukon) stated that the chances were very good that this aspect could be completed 100 per cent in Canada. Foothills (Yukon) said that its pipeline technology had been proven in the international market-place, including Russia, and that new technology developed for this project would be Canadian-owned and Canadian-based, and available for export around the world.

3) Compression Equipment: Foothills (Yukon), although it had not made the final selection, identified a number of potential suppliers of main gas compressor sets, all foreign-owned. Rolls Royce of Canada Ltd., Pratt & Whitney Aircraft of Canada Ltd., Westinghouse Canada Limited, and Canadian General Electric were the only companies listed

that make the gas generator portion of the compression equipment.

Rolls Royce of Canada Ltd. (RRC Ltd.), offered several aero-derived type gas turbines but had only a small part of its gas turbine technology based in Canada (i.e. fuel and lube system development for industrial applications). The Canadian content of the pipeline units was indicated as 20 per cent in the RB 211 and 33 1/3 per cent for the Spey. RRC Ltd. is totally owned by the Rolls Royce world organization.

Pratt & Whitney Aircraft of Canada Ltd. (PWC Ltd.), suppliers of the largest gas turbine available, the CFT4E, an aero-derived type, had the basic technology for this unit developed by its parent company. PWC Ltd. stated it had a substantial engineering group associated with a smaller size gas turbine unit which was totally developed in Canada. Over 70 per cent of its business went to export markets with an average Canadian content of 80 per cent. The Canadian content of the CFT4E gas turbine was reported as 33 1/3 per cent (but by accounting for those components made in Canada for use in foreign-manufactured units, this would rise to about 80 per cent). Although composing only a small part of its parent organization, PWC Ltd. said that it had considerable freedom in making corporate planning decisions.

Westinghouse Canada Ltd. (WC Ltd.) offered a newly developed industrial type gas turbine (CW352) for which the total technology resided in Canada. It had rationalized its gas turbine business with its parent and had complete technical, world marketing and service responsibility for this size range, as well as smaller, two-shaft gas turbines. WC Ltd. exported 80 per cent of its gas turbine business, which had an 85 per cent Canadian content. The CW352 gas turbine had approximately 84 per cent Canadian content but in some cases the need for a foreign regenerator would reduce this slightly. WC Ltd. said that it had considerable corporate independence from its parent corporation which was only slightly larger than Canadian Westinghouse in terms of sales volume of gas turbine units.

Canadian General Electric Company Ltd. (CGE) had indicated to Foothills (Yukon) that it could not respond to the detailed enquiry on Canadian content, marketing practices, ownership, etc. because the matter was under corporate review at the time of the request for information. However, it did indicate that the CGE LM1500 unit would have about 13 per cent Canadian content.

Foothills (Yukon) stated that while Trunk Line (Canada) had used, for purposes of its application, Westinghouse compressor sets which tended to be more fuel-efficient, Foothills (Yukon) had not proposed to use these due to the remoteness of station location. However, since studies and testing of the units with respect to efficiency and durability were still in progress, it might ultimately decide to use the Westinghouse units.

The remaining potential suppliers were primarily gas compressor manufacturers; Cooper-Bessemer, Canadian Ingersol Rand, DeLaval, and Dresser Clark. Each of the four were totally foreign-owned and carried out little or no technological development in Canada. Each had significant exports with relatively high Canadian content (80 - 90 per cent). Each firm, being a branch plant manufacturing operation with relative marketing freedom, exercised some form of product rationalization with its parent.

4) Valves and Fittings: Foothills (Yukon) indicated the Canadian content of large valves was expected to be 90.9 per cent. In response to a Board request, ten potential valve suppliers and eight potential fitting suppliers were identified. The listed suppliers varied from 0 to 100 per cent Canadian in ownership, product content, control of technology and freedom to export from Canada.

Foothills (Yukon) attested to cases in which particular firms were considering the establishment of new or expanded facilities in Canada but maintained that it was important that such enterprises be well founded over the long run with both a domestic base and a potential for export.

Specifically, Foothills (Yukon) noted that this project could easily justify the establishment of a manufacturing facility for large-diameter ball valves in Canada which would be able to compete effectively in an export market that was estimated to have a potential value of about $10 million per year in sales to the USSR alone.

Trunk Line indicated that its wholly owned subsidiary, Grove Valve of California, would most likely build a Canadian facility if Foothills or Foothills (Yukon) were certified. In any event, Foothills (Yukon) thought that there was a high probability that one or more facilities could be equipped to produce large-diameter ball valves in Canada and that, with reasonable encouragement, these sources could be Canadian-owned and dependent upon Canadian technology.

5) Construction Equipment: Foothills (Yukon) estimated the Canadian content of construction equipment for its proposed facilities as 68.2 per cent. Although the volumes of construction equipment required would not be large enough to justify the establishment of a new line of Canadian-manufactured equipment, significant Canadian value could be added to imported equipment to adapt it for Arctic use.

Foothills (Yukon) stated that, if, based upon this project, a significant contribution could not be made to the long-term industrial base in Canada in a specific area such as the manufacture of construction equipment, Foothills (Yukon) did not intend to strive to attain it.

Foothills (Yukon) testified that it would be pleased to have the Board condition a certificate in respect of the amount of Canadian content in the project. Difficulties could perhaps arise in meeting such a condition but in that instance it would be incumbent upon the Applicant to inform the Board of any such problem.

Foothills (Yukon) said that any condition should be very broad in nature, so that the Board could satisfy itself that the Applicant was making the best possible effort to maximize industrial benefit for Canada.

Foothills (Yukon) contended that the onus of responsibility should be on the Applicant to satisfy the Board through a proviso that its procurement plans would have to be submitted within a particular period of time.

Foothills (Yukon) subsequently submitted a proposed wording for a condition, to which both Westcoast and Truck Line (Canada) indicated their concurrence.

4.4.3.8 Westcoast

Approximately 87 per cent Canadian content was estimated for the Westcoast portion of the Foothills (Yukon) project in its submission. Westcoast's testimony has been outlined in the section on the Foothills project and identical testimony was made in respect of Westcoast's portion of the Foothills (Yukon) project.

4.4.3.9 Trunk Line (Canada)

The Canadian content percentage applicable to the Trunk Line (Canada) portion of the Foothills (Yukon) project was estimated at 92 per cent in the application. It was testified that the probability of achieving this level of Canadian content was very high.

Trunk Line (Canada) (Yukon) adopted the policies and position of Foothills (Yukon), described in a previous section, as joint testimony made on behalf of both companies.

4.4.3.10 Views of the Board

Canadian Content and Industrial Benefit

The overall levels of Canadian content indicated by each of the Applicants fall into a relatively high range of 80 to 90 per cent. The methods of estimation used among the Applicants were not identical; with this cautionary note, the Board observes that the Applicants involved in the Foothills and Foothills (Yukon) projects indicated an overall Canadian content somewhat higher than that indicated by CAGPL. Each of the Applicants indicated a high probability that these estimated levels of Canadian content would be either achieved or exceeded.

The Board is of the opinion that an interpretation of benefit attributable to Canadian content should not be limited to primary or secondary stages of expenditures but should be viewed within the context of potential contribution to growth of the Canadian industrial base over the long-term. A policy of maximizing Canadian content, providing it does not result in a short-term dislocation of resources, would stimulate employment and domestic economic activity.

Each of the Applicants indicated that it was prepared to maximize Canadian content within certain limits. Foothills, Foothills (Yukon), Trunk Line (Canada), and Trunk Line were more positive than CAGPL in indicating a strong policy commitment aimed at encouraging supplier firms to establish or expand facilities in Canada when business circumstances favoured this and when it appeared that they could be competitive in the long run.

In the view of the Board, significant opportunities for Canadian industry would be created through the approval of any of the projects. However, the extent to which Canadian industry will be able to take advantage of these opportunities will be largely influenced by the corporate policy of the successful Applicant. Canadian firms selected to participate in the project could benefit, in certain cases, by enhancement of their capabilities to effectively compete in the international market place. Technological leads, special skills, and innovative equipment could be developed and proven through the project; this would result in important subsidiary benefits from associated service and equipment contracts also being available to Canada.

In the opinion of the Board, six or seven product and service supply areas offer the greatest potential for achieving long-term Canadian industrial and technological benefit. These areas are: project and construction management, engineering, construction, compression equipment, valves and fittings, steel pipe, and possibly construction equipment.

The magnitude of the projects, combined with the anticipated difficulties of construction, presents a large and complex management and construction challenge. The experience, knowledge and technological expertise acquired on this project could represent a substantial competitive advantage in bidding for other large international projects of this nature. The evidence put before the Board would seem to indicate that greater potential benefit would be available to Canada through the adoption of the project and construction management approach presented by Foothills and Foothills (Yukon) than through that presented by CAGPL.

With respect to the engineering aspects of the projects, the Board considers the situation to be parallel to that for project and construction managment.

The construction of whichever pipeline project might be certificated is expected to involve only construction contractors resident in Canada. These contractors would utilize large-diameter, pipe-laying spreads based in Canada. (A spread is all the equipment, personnel, etc., to carry out the construction of a section of the pipeline.)

Each of the projects was indicated to have a Canadian labour content of close to, or exceeding, 90 per cent, and would require the importation of only a limited number of specialized skills during peak construction periods due to the restricted availability of these skills in Canada. The peak project manpower requirement was estimated by the Applicants to be approximately 7,800, but this level would only be maintained for a short period of time. It might be necessary, during the peak construction period, to utilize some foreign manpower depending upon how the actual construction activity proceeds.

It is the view of the Board that significant benefit would result for the Canadian pipeline construction industry and its related labour market from whichever project might be built. The magnitude of the benefit to Canada would vary with the particular pipeline construction contractors chosen.

Compression equipment represents one of the highest technological inputs and one of the largest dollar purchases in these projects. Accordingly, it could represent one of the greatest opportunities to obtain significant long-term benefit for Canada. There is a limited number of firms in the world today which have the technology necessary to supply gas turbines and/or gas compressors, especially in the large sizes required for these projects. In Canada there are four gas compressor suppliers and four gas turbine suppliers all of which are foreign owned. There are, however, substantial differences among them in terms of the probable benefit to Canada that would result from the placement of a signficant order for one of these projects.

In evaluating the potential industrial benefit which might result from purchases from particular gas turbine and compressor suppliers, it would be necessary to examine the degree of Canadian ownership and control of the company involved, the Canadian content of the product, and the extent to which the firm's products are internationally competitive and actively exported.

None of the Applicants has made a final selection for its compression equipment because this could only be based upon finalized firm bids which would not be available until after a conditional certificate had been granted.

The placement of orders for valves and fittings that would result from a project approval would present an opportunity for Canadian industry to expand the range of both its technological capability and its manufacturing capacity. It is the view of the Board that the approach as proposed in the Foothills and the Foothills (Yukon) projects has potential for benefiting Canada through strengthening the technology base and manufacturing capability in large-diameter ball valves and large fittings, thus improving the potential for competing in the export market.

The quantities of mainline steel pipe required for the proposed projects in Canada would range from about 1.2 to almost 2 million tons, depending on which project proceeded. Under the Foothills purchasing program 1.2 million tons of pipe would be obtained in Canada; none would come from foreign sources. Under the Foothills (Yukon) purchasing program, the total requirement of approximately 1.33 million tons would be obtained in Canada. Under the CAGPL program, 1.34 million tons of pipe would be obtained from Canadian sources and 0.61 million tons from foreign sources. CAGPL's need to purchase some of its pipe from foreign sources arises largely from the high pressure design of the CAGPL line and the anticipated limited capacity for manufacturing thick-wall, large-diameter pipe in Canadian mills during the construction period. Taking into account the evidence put before it, regarding the nature of the pipe and its potential sources, the view of the Board is that, of the several proposals, the Foothills (Yukon) program for purchasing pipe would probably, in the long run, result in the greatest benefits for the steel and pipe industries of Canada.

With respect to the potential purchasing of construction equipment, the Board sees little difference in the benefit that is likely to result from among the Applicants' programs. However, due to the high percentage of foreign content and the large expenditures involved, the Board believes it is important that all practical opportunities for Canadian involvement be seriously explored.

With respect to the general assessment of Canadian content matters, the Board judges that the Canadian content programs as presented by Foothills and Foothills (Yukon) would offer higher probabilities of greater benefit than the program presented by CAGPL.

In the opinion of the Board, the potential industrial benefits available to Canada are signficant, but for this potential to be realized, the successful Applicant must adopt and follow certain policies and practices. Accordingly, any certificate which the Board might issue would be conditioned in respect of Canadian content.

Industrial Impact

The previous section discussed the extent to which investment in a pipeline project could be of benefit to specific segments of Canadian industry. However, in addition to these impacts of a specific nature, there would be induced effects on all industries. The effects would not be distributed symmetrically on the industrial sector but would be more concentrated in the steel, metal fabricating, and air and water transport industries.

To obtain information on the nature of the overall industrial effects of a representative pipeline project in terms of value added to specific industries, a simulation using the CANDIDE model was prepared by the Board.(1)

The simulation results reported in Table 4-9 are based on the CAGPL Base Case project, and on its maximum impact, as discussed in the section on macroeconomic impact and in an Appendix to that section. The industrial effects of the other pipeline projects would be comparable.

In the Board's view, the expected industrial impacts are all of a magnitude which could be absorbed by the affected industries without serious production bottlenecks arising.

(1) The Applicants did not present any overall view of the industrial impact on the economy.

TABLE 4-9

Industrial Impacts of a Representative Pipeline Project: NEB Estimates

(Per cent change over control solution in constant dollar figures)

Industry	1978	1979	1980	1981	1982	1983	1984	1985
Construction	1.4	2.6	3.9	3.3	2.6	2.0	2.2	2.3
Transportation, Communication and Storage	2.7	3.1	3.0	2.4	2.2	3.2	3.1	3.1
Utilities	.2	.2	.3	2.4	4.3	4.2	4.8	5.5
Manufacturing	.5	.6	.5	.4	.3	.3	.1	0
Mining	.8	.6	.4	.3	.4	.3	.2	.1
Trade	.5	.6	.7	.8	.8	.8	.9	.9
Finance	.3	.3	.4	.6	.7	.8	.8	.8
Services	.4	.5	.7	.7	.7	.6	.6	.5
Administration	0	.1	.2	.2	.3	.3	.3	.4
Housing	0	.1	.4	.8	1.1	1.3	1.4	1.6
Total Economy(1)	.7	.8	.9	.9	.9	1.0	1.0	1.0

(1) The industrial impact data at the level of aggregation provided here exists in CANDIDE at a 13-industry level. The data for three industries, agriculture, fishing and forestry, do not appear in the table because of the insignificant magnitudes of the impacts on these industries.

The construction, transportation and utilities industries would be affected to the largest extent relative to the impact on the total economy, as expected, because of their direct relationship with any of the pipeline projects. Manufacturing and mining are two other industries which would also be significantly affected. The impacts on trade, finance, services, administration and housing industries would be mostly secondary effects due mainly to higher incomes generated by the pipeline. Each of these impacts raises possibilities of industrial benefits to Canada.

By far the greatest increase in output would be in the iron and steel industry. However, the metal fabricating, the mining-related, the cement and concrete, and the air and water transport industries would also have substantially increased output requirements. In a relatively slack economy these impacts would not only help large firms but would also provide orders for small firms such as those in wholesale and retail trade.

Over the five year construction period, 1978 to 1982, induced employment totalling some 222,000 man-years has been estimated for all industries.

4.4.4 COST-BENEFIT ANALYSIS

4.4.4.1 Introduction

The size of the Mackenzie Valley and Yukon pipeline projects and their possible consequences for Canada were such that the Board considered it advisable to examine their impact in the framework of a social cost-benefit analysis.

Cost-benefit analyses were submitted by Foothills, by Foothills (Yukon) (for a 42-inch diameter pipeline), and by CAGPL for both its Base Case and its No Expansion Case. Trunk Line, Trunk Line (Canada) and Westcoast adopted the studies submitted by Foothills and Foothills (Yukon). Among the intervenors, only John F. Helliwell, a professor of economics at the University of British Columbia, submitted evidence in this regard.

At the Board's request, the Applicants' initial submissions were subsequently updated to reflect changes in cost estimates to a 1976 base.

Purpose of Cost-Benefit Analysis

Social cost-benefit analysis aims to estimate the quantifiable primary net economic benefits to Canadian society resulting from a major project. Secondary or induced benefit streams are excluded from this analysis, although they should be considered in an overall assessment of a project. In the case of the pipeline proposals, the scope of a cost-benefit analysis includes the production, transmission and sale of gas.

Social cost-benefit analysis considers a project from the viewpoint of society and costs are included only if they truly represent the use of capital, labour, or other real resources by the project. Payments incurred by the project for expenses such as taxes are considered as transfers within the economy, and therefore they are not considered as costs to society. Also, the cost of government infrastructure is not included in these cost-benefit assessments.

While theoretically cost-benefit analysis should include costs of effects on the environment and other difficult-to-quantify costs, such as from the impact on cultures, the Board has viewed cost-benefit analysis as attempting to measure only the direct economic benefits from the proposed pipelines, albeit from the perspective of society as a whole. Accordingly the Board refers to the net benefits, estimated for various proposals, as net economic benefits.

In the view of the Board the sine qua non for economic justification of a pipeline proposal is that the expected direct (social) net economic benefit to Canada should be positive. If a proposed project is expected to yield positive social net economic benefits, then the question of its commercial profitability must also be addressed.

Private cost-benefit analysis refers to the commercial profitability of a project. All costs including taxes and royalties internal to the firm or firms involved are considered.

A project may indicate social net economic benefit but it may lack commercial viability. In such a case, government may wish to implement a project and to consider policy action to increase commercial profitability.

Major Assumptions

At the outset, it is important to note some basic assumptions employed in the cost-benefit analysis of the proposed pipelines.

For a project, the net economic benefits are defined as the present value of estimated future benefits less the present value of estimated future costs. Present values are calculated at a social discount rate (interest rate) appropriate for the projects being analysed.

A social discount rate (opportunity cost of capital) differs from the internal rate of return used by a firm in making a profitability decision regarding a project. This is because the social discount rate is unaffected by tax considerations, among other things. A real discount rate of between five and ten per cent per year is considered to be reasonable by the Board, with a rate near ten per cent probably appropriate in the circumstances of the proposed projects.

The net economic benefits as estimated are for Canada, whether accruing to individuals, corporations, or governments.

The Applicants' analyses of the projects proposing to deliver Delta gas to Canadian markets assumed that the gas would be needed and sold as delivered in those markets at a competitive price.

To estimate net economic benefits, it was necessary to forecast costs and benefits for a future period of some 20 to 30 years. This, in conjunction with the requirement to forecast future gas discoveries over the entire period, implies that the estimates are clouded by great uncertainty.

In an attempt to reduce uncertainty, the Board's analysis, based upon the evidence, includes consideration of cost-benefit results with only the established reserves as available from the Delta. Further, by considering possible cost overruns, the Board has tried to account for uncertainty in the Applicants' cost estimates. Even so, although the results of all the analyses are based upon the evidence they must be viewed as being no more than best estimates contingent upon uncertain future events.

The net economic benefits to Canada from the transmission of Alaska gas to United States markets stem from corporation and other taxes included in the cost of service. In addition, the divergence of the actual rate of return earned by a pipeline from the social discount rate can affect net economic benefits.

Dr. Helliwell's evidence is considered in a subsequent section.

4.4.4.2 CAGPL Analysis

CAGPL submitted two cost-benefit analyses; one for its Base Case (which assumed gas flows of 2.25 Bcf/d from Alaska and 2.25 Bcf/d from the Mackenzie Delta) and one for its No Expansion Case (which assumed 2.0 Bcf/d from Alaska and 1.25 Bcf/d from the Delta).

Benefits

Benefits were derived from three sources. The value of gas deliveries was the primary benefit. Total delivered volumes of Delta gas were valued as though all throughputs were delivered to Empress. The price at Empress was taken to be the Toronto city gate price less a transmission and distribution charge. The price of gas at Toronto was assumed to be at parity with oil on a Btu basis at the burner tip. Three scenarios were considered with crude oil being priced at $8, $11, and $15 per barrel at Toronto in 1976 constant dollars. The value of gas at Empress was determined by subtracting the gas distribution margin and a pipeline tariff of 46 cents per MMBtu from the Toronto price. The implied equivalent gas prices at Empress were $1.05, $1.58, and $2.28 respectively. To derive the primary benefit, these prices were then multiplied by delivered volumes.

The revenues earned by CAGPL from tariffs on Alaska gas transmission constituted the second major benefit of the project. For the Base Case this benefit was 56 per cent of total operating revenue on the basis of an Mcf/mile allocation of the total cost of service.

The third benefit stream was stated to be from capital inflows resulting from foreign investment in the pipeline facility. The capital outflow associated with debt retirement and interest and dividend payments was treated as a cost. CAGPL calculated the net present value of this stream of capital inflows and outflows to be negative.

Under cross-examination, CAGPL claimed that an apparent overstatement in revenues from transmitting Alaska gas was offset by the fact that the net foreign investment flows were estimated to be negative due to the same "error". The error involved the use of nominal interest rates in constant dollar calculations.

The total benefits and net economic benefits, as estimated by CAGPL, at various prices and discount rates, are shown in Tables 4-10 and 4-11.

Costs

CAGPL considered four distinct cost streams:

construction of the pipeline facility;

operation and maintenance of the pipeline and associated facilities;

exploration and development of gas fields and investment in gas plant (including connecting facilities);

and operation and maintenance of the gas production facilities.

The construction cost data were updated to include redesigned frost-heave mitigative measures and to reflect a delay of first Delta flow until 1982. Costs used were net of interest during construction. All costs incurred prior to 1977 were considered sunk and were excluded. Sales taxes and import duties included in materials costs were also removed, on the basis of data submitted in CAGPL's Canadian content study. All data were stated in 1976 dollars.

CAGPL's No Expansion Case construction costs were estimated in an identical fashion.

Pipeline operation and maintenance costs were based on cost of service data. However, these costs did not include depreciation, amortization, and municipal and income taxes. This was because only cash investments were included and income and municipal taxes were considered to be transfer payments.

Gas production costs were included as part of the cost-benefit evidence. Estimates for the costs of exploration, field development, and construction of gas processing plants including connecting facilities of Westcoast and TCPL, were stated to be derived from evidence submitted for the Supply/Demand Balance Phase of the hearing.

Also included in gas costs was the stream of expenditures associated with operation and maintenance of the gas production plant and equipment.

The present value of total costs, as estimated by CAGPL, at various discount rates is shown in Tables 4-10 and 4-11.

Difficult-to-Quantify Features

CAGPL made reference to several elements which, while not quantified or non-quantifiable, were felt to be important in an overall assessment of a project of this nature.

CAGPL felt that delay of the project would entail significant costs for Canada in the form of larger than necessary energy imports.

CAGPL also suggested that "consumer surplus" or savings to consumers from using gas in the place of higher-priced alternatives, could be a benefit.

"Security of supply" or the value of increased energy independence was alluded to during the hearing. CAGPL suggested that this could be an important feature but stated that any particular value an Applicant attached to security of energy supply would likely be challenged by others.

The avoidance of possible environmental pollution through the burning of gas rather than other hydrocarbons was also mentioned as a possible benefit.

CAGPL suggested that the net effect of all non-quantifiable elements could be significant in evaluating a marginal project. However, it claimed that the large predicted direct net economic benefits of its project precluded such elements from affecting decisions as to its economic desirability.

Results: CAGPL

The present values of total costs and benefits were estimated under the three price scenarios previously outlined. CAGPL then subjected these results to sensitivity analysis with respect to discount rates varying from five to 15 per cent.

Table 4-10, below, summarizes the CAGPL Base Case results. It is noteworthy that the estimates of net economic benefits changed markedly as the assumed price of oil (and gas) changed. Considering the estimates at a ten per cent discount rate it can be seen that a 36 per cent increase in the oil (and gas) price from $11/bbl. to $15/bbl. more than doubled the estimated net economic benefits. CAGPL's view was that the world oil price would probably remain constant in real terms into the mid 1980's but would increase slightly thereafter. The present price of a barrel of imported oil at Toronto is approximately $13.50 (1976 dollars).

CAGPL also stated that it believed that a ten per cent discount rate was reasonable for its project.

The main result of CAGPL's analysis was that $3 to 4 billion (1976 dollars) could be considered to be the probable net economic benefit to Canada from its Base Case.

The CAGPL Base Case assumed that some 25 Tcf of Delta gas reserves would be connected over the 27-year period of analysis, and accordingly gas finding and development costs for some 20 Tcf beyond present discoveries were included. The No Expansion Case assumed the finding and development of only approximately ten Tcf

Table 4-10

Selected Results of CAGPL Base Case Cost-Benefit Analysis, Using Various Discount Factors and Various Canadian Gas Prices

(Assumes approximately 25 Tcf of Delta gas reserves connected for Canadian markets and approximately 24 Tcf of Prudhoe Bay reserves connected for United States markets)

	Total Benefits: Canadian Gas Price at Commodity Value with Oil Prices in Toronto of:				Net Economic Benefits: Canadian Gas Price at Commodity Value with Oil Prices in Toronto of:		
Discount Rate	$8/ bbl.	$11/ bbl.	$15/ bbl.	Total Costs	$8/ bbl.	$11/ bbl.	$15/ bbl.
%	(Present Value, Billions of 1976 Dollars)						
5	14.0	18.4	24.3	11.5	2.5	6.9	12.8
10	9.0	11.5	14.9	9.5	-0.5	2.0	5.4
15	6.4	8.0	10.1	8.2	-1.8	-0.2	1.9

Note: Figures are rounded from CAGPL Exhibit No. N-AG-3-152-2.

Table 4-11

Selected Results of CAGPL No Expansion Case Cost-Benefit Analysis, Using Various Discount Factors and Various Canadian Gas Prices

(Assumes approximately 16 Tcf of Delta gas reserves connected for Canadian markets and approximately 24 Tcf of Prudhoe Bay reserves connected for United States markets)

	Total Benefits: Canadian Gas Price at Commodity Value with Oil Prices in Toronto of:				Net Economic Benefits: Canadian Gas Price at Commodity Value with Oil Prices in Toronto of:		
Discount Rate	$8/ bbl.	$11/ bbl.	$15/ bbl.	Total Costs	$8/ bbl.	$11/ bbl.	$15/ bbl.
%	(Present Value, Billions of 1976 Dollars)						
5	11.4	14.3	18.0	7.9	3.6	6.4	10.1
10	7.6	9.3	11.5	6.7	0.9	2.6	4.9
15	5.6	6.7	8.2	5.9	-0.3	0.8	2.3

Note: Figures are rounded from CAGPL Exhibit No. N-AG-3-152-2.

of reserves beyond what has been established to date. As may be seen by comparing Tables 4-10 and 4-11, the present values of total benefits and total costs for the No Expansion Case are lower than those for the Base Case.

The net economic benefits, however, were not substantially different between the two cases. The No Expansion Case appeared somewhat better than the Base Case at lower prices or at higher discount rates. This result stemmed principally from the fact that sunk costs for the discovery of some 6 Tcf of Delta reserves are excluded from each analysis, and finding and development costs for future discoveries are estimated to be substantial.

Overall, the CAGPL No Expansion Case results showed more robustness than those of the Base Case. As Table 4-11 shows, even at a ten per cent discount rate with the low price assumption, the No Expansion Case gave an estimated positive net economic benefit of close to $1 billion. In contrast, under the same condition, the Base Case showed negative net economic benefit.

Considering the array of results at the ten per cent discount rate (comparing Tables 4-10 and 4-11) it is evident that CAGPL estimated future discovery and development of Delta reserves to be economically marginal at gas prices based on a Toronto oil price lower than $14 - $15/bbl. in 1976 dollars. The evidence of Imperial, Shell and Gulf corroborated this.

4.4.4.3 Foothills Analysis

In addition to estimating the direct net economic benefits flowing from the production and transmission of Delta gas to market, Foothills explicitly considered the net economic benefits which would be lost by potential producers of alternative fuels should a pipeline be built. To be consistent, it also considered the "consumer surplus" which would be gained through consumers using natural gas rather than switching to more expensive alternative fuels.

This approach assumed that there would be an excess demand over supply for gas in the absence of a Delta pipeline and that not having frontier gas would create a gas "deficit" which would be filled by substitute fuels.

While the scope of Foothills' analysis was extended as mentioned above, it was limited in other respects. For the purposes of cost-benefit analysis it assumed that the proposed pipeline, as a regulated enterprise, would yield neither net benefits nor net costs.

Benefits

Benefits were assumed by Foothills to be derived from two sources. The first source of benefits was the value of Delta gas at the Delta plant gate. This was evaluated by subtracting the transmission costs of the TCPL system and the proposed Foothills Group pipeline from the Toronto city gate value of gas.

The price of gas at Toronto was estimated under two assumptions; one, that gas would be priced at commodity value with oil at the burner tip and, two, that gas would be priced on a crude oil parity basis at the Toronto city gate (using the assumption of 5.49 MMBtu/bbl.).

In both calculations the crude oil price in Toronto was predicted to be around $14/bbl. (1976 dollars) from 1982 to 1995, and to increase slightly thereafter, as a result of a tightening in world oil supplies. By 2012 the Toronto oil price was assumed to be about $16/bbl. (1976 dollars).

The second source of benefit was the gain in consumer surplus from using gas instead of being obliged to switch to higher cost alternative fuels such as electricity in the absence of frontier gas.

Foothills predicted the future prices of all energy forms and estimated the amount by which annual consumer spending on energy in the absence of the pipeline would exceed those expenditures if natural gas were available from the Delta. This additional consumer expenditure was said to be a loss in "consumer surplus". Consequently, having a pipeline would forestall such a loss of consumer surplus.

Costs

Foothills considered three cost streams:

- exploration and development of gas fields and investment in gas plant;
- operation and maintenance of the gas production facilities; and

the net benefits which alternative Canadian energy producers would have earned if frontier gas were not available to the Canadian market.

Like CAGPL, Foothills considered all costs which were incurred prior to 1977 as sunk and therefore they were excluded from the cost-benefit analysis. The analysis covered a period of 36 years during which time it was assumed that some 32 Tcf of Delta gas reserves would be connected for Canadian markets.

Foothills used a complicated approach for discounting, which resulted in an effective discount rate of about ten per cent per year.

Difficult-to-Quantify Features

Foothills predicted, but did not quantify, an increase in polluting emissions resulting from the production and use of less clean fuels in the place of gas. The avoidance of such pollution through the use of frontier gas was stated to be one of the non-quantified benefits of the proposal.

It was acknowledged that social and regional impacts could be important factors, but they were considered beyond the scope of cost-benefit analysis. Similarly, employment effects were stated to be primarily local with little long-run impact on the overall Canadian economy. Foothills also stated that the probable effect of the project on income distribution would be negligible.

Results: Foothills

Table 4-12, below, summarizes the Foothills results.

With gas priced according to commodity value at the burner tip, Foothills estimated the net economic benefit of the project to be $3.8 billion (in 1976 dollars). This consisted of $3.2 billion in net economic benefits associated with the production of Delta gas and $1.2 billion in savings to consumers, less $0.6 billion which would have accrued to producers of alternative fuels in the absence of the proposed Foothills pipeline.

Under crude oil Btu-parity pricing, the net economic benefit of the project was estimated to be some $5 billion (in 1976 dollars).

The consumer surplus, stated to be a "major" benefit of the project, was estimated mainly to result from consumers switching to electricity and No. 2 light fuel oil. Most of this benefit (about $900 million) was estimated to occur in Ontario markets.

4.4.4.4 Foothills (Yukon) Analysis

Foothills (Yukon)'s cost-benefit study dealt with its proposed 42-inch diameter line which involved extensive looping of the Westcoast and Trunk Line systems. The Foothills (Yukon) Group withdrew this application for the 42-inch diameter line, in favour of its proposed "express line", a 48-inch diameter line. Additional prepared evidence was then submitted which included a

Table 4-12

Results of Foothills Cost-Benefit Analysis

(Assumes approximately 32 Tcf of Delta gas reserves connected for Canadian markets)

	Net Economic Benefits		
	Canadian gas price at commodity value with oil price in Toronto of about \$14-16/bbl.		Canadian gas price at Btu equivalence with oil price in Toronto of about \$14-16/bbl.
Recipient	(Present Value, Billions of 1976 Dollars, at about 10% discount rate)		
Gas Producers	1.9		
Governments	1.2		
Consumers	1.2	4.3	
less			
Potential Producers of Alternative Fuels		-0.6	
Net Economic Benefit		3.8	5.0(1)

(1) Foothills assumed 5.49 MMBtu/bbl. for this case. No division of net benefits among recipients was provided.

Note: Figures are rounded from Foothills Exhibit Nos. N-FH-5-107 and N-FH-5-5-1, and do not add exactly due to rounding.

statement that "the cost-benefits for the 48-inch alternative could be slightly more attractive to Canada than the original proposal", but that the difference would not likely be significant. As a result, no cost-benefit analysis of the 48-inch diameter proposal was submitted.

Benefits

The benefits were defined to include:

- the revenue from tariffs for transmission of Alaska gas; and
- net foreign capital inflows (valued at a foreign exchange shadow-price in the social analysis).

Costs

The costs were estimated as:

- the value of wages and salaries (adjusted in the social analysis for the use of some previously unemployed labour); and
- the cost of materials used during pipeline construction and operation (adjusted in the social analysis for certain taxes considered to be resource costs).

Private Cost-Benefit Analysis

Foothills (Yukon) began the examination of its 42-inch diameter proposal with a private cost-benefit analysis in which the profitability of the pipeline system was measured by costs and revenues internal to the participating companies.

Since costs and revenues internal to the companies were not considered as equivalent to costs and benefits to society, certain adjustments were made in order to appraise the project from a social perspective.

Adjustments for Social Costs and Benefits

Foothills (Yukon) adjusted foreign exchange cost and benefit flows upward by 13 per cent by shadow-pricing to account for supposed distortions, caused by tariffs and taxes, between the market exchange rate and the "socially correct" exchange rate.

Foothills (Yukon) also made certain assumptions about the opportunity cost of labour which would have been previously unemployed. Using an assumption of partial unemployment in the local economies from which labour would be drawn, only part (88 per cent) of the wage bill was considered as a cost to society.

The social cost of imported materials was computed net of sales taxes and tariffs because the demand for these imports was assumed to be incremental.

One-half the municipal taxes and the materials portion of indirect taxes were treated as payments for the use of real resources by the project. The other half was considered as transfer payment.

Difficult-to-Quantify Features

Foothills (Yukon) made reference to the possibility of benefits, in the regional economies close to the pipeline, stemming from induced income streams. However, such effects were not estimated on the grounds that local effects were likely to be offset by corresponding changes elsewhere.

No specific adjustments were made for any income distributional effects caused by the Foothills (Yukon) Group project, although the Applicant acknowledged these to be a legitimate concern.

Results: Foothills (Yukon)

Table 4-13, shown below, summarizes the Foothills (Yukon) results. The net economic benefit was estimated to be some $800 million (1976 dollars).

Table 4-13

Results of Foothills (Yukon) Cost-Benefit Analysis

(Assumes approximately 24 Tcf of Prudhoe Bay reserves connected for United States markets)

(Present Value, Billions of 1976 Dollars, at a 10% discount rate)

Total Benefits	2.6
LESS	
Labour Costs	-0.4
Materials Costs	-1.3
Taxes (considered as Costs)	-0.1
Net Economic Benefit	0.8

Note: Figures are rounded from Foothills (Yukon) Exhibit No. FH(Y)-114-31. The reported results were estimated for the original 42-inch diameter proposal which provided cost of service savings to Westcoast and Trunk Line. It is unlikely that the 48-inch diameter proposal would affect the cost of service of the existing systems.

4.4.4.5 Views of the Board

Summary of Applicants' Results

It is the view of the Board that great care is required in attempting to evaluate the various proposals through comparison of the cost-benefit results. Each submission contains numerous assumptions and the methodologies, while generally similar, vary enough to make unqualified comparisons of dubious value.

However, it may be useful to summarize the estimates of net economic benefit submitted by the Applicants for their base cases. For comparability between CAGPL and Foothills the estimates of consumer surplus and net benefits accruing to producers of alternative fuels included in Foothills' analysis are omitted.

Table 4-14 indicates that, according to the submitted material, the CAGPL project ranks first, the Foothills second and Foothills (Yukon) third in terms of estimated net economic benefit to Canada. However, this ranking assumes that 25-32 Tcf of Delta gas reserves would be connected in the case of either the CAGPL or the Foothills projects. To date, established reserves in the Delta amount to only 5.1 Tcf. No Canadian gas reserves are involved in the evaluation of Foothills (Yukon) as submitted.

Approach of the Board

To achieve comparability of analysis for the various proposals and to provide useful interpretation of the results,

Table 4-14

Summary Comparison of Net Economic Benefit Results of Base Cases Submitted by CAGPL, Foothills, and Foothills (Yukon)

CAGPL	Foothills	Foothills (Yukon)
Canadian gas price at commodity value with oil price in Toronto @		No Canadian Gas Connected
$15/bbl.	$14-16/bbl.	
(Present Value, Billions of 1976 Dollars at 10% discount rate)		
5.4	3.2(1)	0.8

(1) This is not directly comparable with the figure reported in Table 4-12. This figure excludes the amount of consumer surplus and the associated net benefit accruing to producers of alternative fuels.

Note: Foothills' analysis used an effective discount rate of about ten per cent. It should be noted that a $1.00 increase in the assumed oil price provides an increase of some $800 million in net economic benefit. Oil prices are in 1976 dollars. The CAGPL and Foothills analyses assume some 25-32 Tcf of Delta gas reserves are connected for Canadian markets.

the Board has undertaken cost-benefit analyses including the following considerations:

Delta Gas Reserves - In addition to using the Applicants' proposed throughputs the Board used throughputs based on its own estimate of established reserves in the Delta.

Delta Gas Production Costs - The Board considered costs which reflected the evidence filed by the producers. Also, each proposal was evaluated under a range of assumed gas production cost overruns, although not reported herein.

Natural Gas Market Pricing - Each proposal was evaluated under a range of assumed prices in Toronto. Reported herein are results with gas priced at $2.30/MMBtu at the Toronto city gate, approximately 100 per cent Btu-parity with crude oil.

Pipeline Project Life - CAGPL assumed a 27-year project. Foothills assumed a 36-year project. The Board assumed an intermediate project life of 29 years (1977-2005), as did Foothills (Yukon).

Social Discount Rate - The Board considered a rate between five and ten per cent to be a reasonable value.

Consumer Surplus - Foothills argued that the higher cost of No. 2 light fuel oil and electricity would amount to a loss in consumer surplus. Since it is possible that a switch to electricity when oil is available could be a matter of preference, it is the Board's view that the inclusion of consumer surplus was not strongly suggested by the evidence. Hence, the Board's analysis did not include consumer surplus as an additional benefit.

CAGPL Revenue from Transmission of Alaska Gas - CAGPL made an error in converting tariff revenues into constant dollars in its cost-benefit analysis, which resulted in an overstatement of the benefit. The Board's analysis corrected this.

Savings on Cost of Service - The Foothills (Yukon) claim of a cost reduction from utilization of existing capacity in the Westcoast and Trunk Line systems was considered unlikely to be valid for the 48-inch diameter express line.

Shadow-Pricing - Foothills (Yukon) argued that the social value of any foreign exchange earned by Canada was higher than the value determined by the market. The Board did not think that such a refinement would alter the ranking of the various projects and therefore excluded this consideration from its analysis.

The Board also rejected arguments for shadow-pricing of labour.

The Board's Analysis of Basic Proposals

Prior to considering any sensitivity analysis, the Board's view of the Applicants' cases is presented below in Table 4-15. A possible Dempster link to Foothills (Yukon) is considered in subsequent sections.

While some significant adjustments were made by the Board to the Applicants' calculations, the basic ordering of the projects, in terms of net economic benefit, remains unchanged - CAGPL first, Foothills second and Foothills (Yukon) third.

Table 4-15

Summary Comparison of Net Economic Benefit Results of Base Cases as Estimated by the Board for CAGPL, Foothills and Foothills (Yukon)

Discount Rate	CAGPL	Foothills	Foothills (Yukon)
%	(Present Value, Billions of 1976 Dollars)		
5	8.3	6.0	1.7
10	1.9	1.1	0.5
Assumes approximate connected reserves: Tcf from			
Delta	28	30	0
Alaska	24(1)	0	24

(1) The cost of producing Alaska gas does not enter the Board's model. Therefore, it was not necessary to change the size of Prudhoe Bay reserves in line with the assumed project life.

Note: The Board used a constant gas price of $2.30/MMBtu at the Toronto city gate. This price is approximately 100 per cent Btu-parity with crude oil and about the same as the commodity value of gas with competing oil products.

The Foothills (Yukon) project (considered above without the prospect of a Dempster pipeline link from the Delta) emerges as the project with low risk, but with low expected net economic benefit.

It must be stressed that the results shown (for CAGPL and Foothills) in Table 4-15, like those of Table 4-14, presume the discovery and connection of some 20 Tcf of as-yet-undiscovered marketable Delta reserves over the life of the pipeline projects. Although the geology of the region appears favourable, discoveries to date have been disappointing. Consequently the estimated net economic benefits must be viewed with great caution.

While the possibility of future discoveries must be kept in mind, the critical net economic benefit test for these projects is that which considers only existing reserves as being available for pipeline throughputs. The Board has examined the projects on this basis, and the results are shown in Table 4-16.

With presently established reserves the Foothills project would not yield a net economic benefit at a ten per cent discount rate but would show positive benefit at the low discount rate of five per cent. Delta gas production for transmission by Foothills would not likely be commercially viable.

Table 4-16

Summary Comparison of Net Economic Benefit Results, as Estimated by the Board, for CAGPL, Foothills and Foothills (Yukon), Assuming 5.1 Tcf of Delta Reserves

Discount Rate	CAGPL No Expansion	Foothills	Foothills (Yukon)
%	(Present Value, Billions of 1976 Dollars)		
5	4.72	0.80	1.68
10	1.34	-0.26	0.53
Assumes approximate connected reserves: Tcf from			
Delta	5.1	5.1	0
Alaska	24(1)	0	24

(1) The cost of producing Alaska gas does not enter the Board's model. Therefore, it was not necessary to change the size of Prudhoe Bay reserves in line with the assumed project life.

Note: The Board used a constant gas price of \$2.30/MMBtu at the Toronto city gate. This price is approximately 100 per cent Btu-parity with crude oil and about the same as the commodity value of gas with competing oil products. No pipeline link from the Delta to Foothills (Yukon) is considered in the above.

Thus, from the perspective of estimated net economic benefit, the two feasible alternatives are CAGPL (5.1 Tcf Case) and Foothills (Yukon). As Table 4-16 shows, the CAGPL project is estimated to provide larger net economic benefit to Canada than would Foothills (Yukon), at the relevant range of social discount rate of between five and ten per cent. The estimated net economic benefit of some $4.7 billion for CAGPL (5.1 Tcf Case) at the five per cent discount rate would represent a significant net economic gain to the Canadian economy.

It may be argued that the above results for CAGPL and Foothills understate the possible net economic benefits for either project because each project could be modified for the assumed lower throughputs, however ranking would not change.

The Board analysis now focuses on CAGPL and Foothills (Yukon). For purposes of comparison two additional situations beyond those of Tables 4-15 and 4-16 are considered. The four comparisons are summarized in Table 4-17. The Foothills (Yukon) pipeline is assumed to be rerouted in the Yukon to meet a Dempster Highway pipeline from the Delta at Dawson. This project was outlined by Foothills (Yukon) in its Studies Related to Alternate Methods of Connecting Mackenzie Delta Gas, Study No. 3, filed with the Board.

Table 4-17

Four Comparisons of Net Economic Benefit as Estimated by the Board for CAGPL and Foothills (Yukon)[1]

CAGPL						Foothills (Yukon)					
Assumed Connected Reserves		Flat Life Throughput		Net Economic Benefit (Present Value, Billions of 1976 $)		Assumed Connected Reserves		Flat Life Throughput		Net Economic Benefit (Present Value, Billions of 1976 $)	
U.S.[2]	Delta	U.S.	Delta			U.S.	Delta[3]	U.S.	Delta		
(approximate Tcf)		Bcf/d		@ 10%	@ 5%	(approximate Tcf)		Bcf/d		@ 10%	@ 5%
24	28	2.25	2.25	1.91	8.31	24	0	2.4	0	0.53	1.68
24	5.1	2.0	0.7	1.34	4.72	24	0	2.4	0	0.53	1.68
24	5.1	2.0	0.7	1.34	4.72	24	5.1	2.4	0.7	1.04	3.54
24	16.0	2.0	1.25	1.32	5.84	24	16.0	2.0	1.25	0.91	4.49

(1) The Board used a constant gas price of $2.30/MMBtu at the Toronto city gate. This price is approximately 100 per cent Btu-parity with crude oil and about the same as the commodity value of gas with competing oil products.

(2) The cost of producing Alaska gas does not enter the Board's model. Therefore, it was not necessary to change the size of Prudhoe Bay reserves in line with the assumed project life.

(3) Assumes Delta gas flow through a Dempster link in 1983 whereas Delta gas flows in 1982 in CAGPL's case. A second difference in timing is that of Prudhoe Bay flows, assumed to start in 1981 by Foothills (Yukon) and in 1983 by CAGPL.

The first two comparisons which do not consider the possible Dempster link from the Delta to Foothills (Yukon) have been discussed briefly and summarized in Tables 4-15 and 4-16.

The third situation compares CAGPL with Foothills (Yukon) plus a Dempster link, although reserves are not increased over those now established.

The fourth situation assumes that Delta reserves of some 16 Tcf will become available over the life of the pipelines because that level of reserves will yield deliverability of 1.25 Bcf/d. While the discovery and development of the additional ten Tcf (approximately) must be viewed as uncertain, exploration expectations, as given in evidence by the producers, indicate this is probable.

The cost of service on the Dempster pipeline from the Delta to Dawson is assumed to be borne entirely by Canadians following the procedure in Alternate Study No. 3 filed by Foothills (Yukon). In contrast, the CAGPL cost of service is assumed to be allocated system-wide as proposed by CAGPL.

If the Dempster tariff were rolled in with the Foothills (Yukon) mainline, the estimated net economic benefit of the Foothills (Yukon) plus a Dempster link would increase slightly. However, this would not eliminate the difference in the net economic benefit between that system and the CAGPL project.

If CAGPL's cost of service were to be segmented, this would further increase CAGPL's advantage over Foothills (Yukon) plus a Dempster link.

From the comparative results, shown in Table 4-17, it can be seen that CAGPL ranks ahead of Foothills (Yukon) in each of the situations.

If increased throughputs were available from Alaska (to offset the low Delta production), the net economic benefits of both CAGPL and Foothills (Yukon) would be improved, with the relative improvement for CAGPL being somewhat larger.

In the fourth comparison, it is assumed that some 16 Tcf of Delta reserves would be connected to a pipeline which in turn assumes that new reserves are discovered in the near future.

In the third and fourth comparisons, the CAGPL project shows higher estimated net economic benefit than Foothills (Yukon) with a Dempster link although both systems are assumed to have much the same volumes from Alaska and identical volumes from the Delta. Two forces contribute to these results.

First, although the submitted per unit tariff for Foothills (Yukon) with the Dempster link is somewhat lower than the CAGPL No Expansion tariff, the CAGPL system traverses more Canadian territory. CAGPL's pipeline enters Canada in the far North and crosses the Delta to Tununuk Junction. The result is that a greater proportion of the cost of service for Alaska gas is paid in Canada under the CAGPL proposal, and correspondingly higher revenues from transmission of that gas are paid to CAGPL.

The second major difference between CAGPL and Foothills (Yukon) with a Dempster link lies in the timing of proposed gas deliveries. Canadian gas is assumed to flow in 1982 by CAGPL and in 1983 by Foothills (Yukon). This increases the net economic benefit for CAGPL from Delta gas. Prudhoe Bay gas, which flows in 1981 through Foothills (Yukon) does not begin until 1983 in the CAGPL cases. This increases the net economic benefit to Foothills (Yukon) from the transmission of Alaska gas. The net effect of these differences in timing provides an advantage to CAGPL.

Pipeline Cost Overrun

The Board's cost-benefit analysis for CAGPL and Foothills (Yukon) includes as benefits the taxes (paid by United States shippers of Alaska gas to Canadian governments) included in the cost of service on transmission of Alaska gas. Consequently, the estimated economic benefit to Canada from this source tends to increase with pipeline construction cost overrun. However, cost overruns reduce the net economic benefit associated with the production of Delta gas. On balance, the net economic benefit to Canada tends to be insensitive to cost overrun with CAGPL or Foothills (Yukon) plus a Dempster link.

Cost-Benefit Conclusions

The first conclusion which can be stated is that the Foothills project, with existing reserves in the Delta (5.1 Tcf), would not provide sufficient net economic benefit to Canada.

The Foothills (Yukon) project without a link to the Delta may be viewed as a project with limited potential for Canadian economic gain but also one with limited risks.

In view of the above conclusions, the attention of the foregoing cost-benefit analysis has been directed towards an assessment of the basic economics of the CAGPL project and Foothills (Yukon) project plus Dempster link. These alternatives have been considered under various conditions of reserves but in particular with the existing established reserves of 5.1 Tcf in the Delta and some 24 Tcf of Alaska reserves. In terms of estimated net economic benefit, the CAGPL project ranks ahead of Foothills (Yukon) plus Dempster under all of the conditions tested. Generally speaking, the net economic benefit from CAGPL is estimated to be about a third higher than that for Foothills (Yukon). These advantages could be greater under circumstances of substantially larger Delta reserves because of the relatively low cost expansibility of the CAGPL system in the range of throughput between the CAGPL No Expansion Case levels and its Base Case.

4.4.4.6 John F. Helliwell Analysis

Professor Helliwell also provided evidence of the estimated net economic benefits of a Mackenzie Valley pipeline, assuming various start-up times for the project. Although Professor Helliwell discussed both the CAGPL and the Foothills projects in his evidence, he presented an empirical analysis of only the CAGPL Base Case proposal. The essence of Dr. Helliwell's submission was his contention that, if no new gas export licences were to be issued, the estimated net economic benefits to Canada would be maximized if Delta gas were to be brought on stream in the early 1990's. Any earlier date for bringing on frontier gas was estimated to reduce net benefits. Underlying this contention were two related arguments:

(i) frontier gas would not be required to meet the sum of Canadian domestic demand plus existing export licences until the 1990's and export licences would not be changed; and

(ii) Delta gas would be more expensive to produce and transport to a common point, say Toronto, than gas from conventional, non-frontier areas, until virtually all existing and expected non-frontier gas was connected and producing.

In his direct evidence Professor Helliwell argued that it would be possible to meet total demand for Canadian natural gas (the sum of domestic demand plus existing export licences) from conventional, non-frontier sources until between 1989 and 1994, depending upon various assumptions.

Detailed discussions of Professor Helliwell's gas deliverability assumptions and his energy demand estimates are contained in Chapter 2 of this report.

The estimation of the relative costs of frontier and non-frontier gas constituted a key element of Professor Helliwell's deferral argument. He admitted that his estimates of the exploration and development costs of non-frontier gas might have been somewhat low. His estimates were made with a straight line projection of recent cost increases. However, he argued that non-frontier gas costs would continue to be much lower than those for Delta gas so that even doubling his estimated costs would leave non-frontier gas cheaper to produce and deliver than Delta gas. Professor Helliwell's estimates of Delta gas costs were obtained from the applications filed by Foothills and CAGPL.

Professor Helliwell argued that, even if there were Canadian oil deficits through the 1980's, it was unlikely that Delta gas could displace much of the oil imports. The assumption that oil and gas would be priced at Btu parity in Toronto in 1981 would mean that there would be no economic incentive for consumers to shift energy sources. He discussed estimates which had been made with his model in which gas was priced at 85 per cent Btu parity with oil, in order to determine how much oil might be displaced by gas. With his model's energy demand equations, the results were that only a small net displacement of oil could be expected.

Thus he contended that even a 15 per cent reduction in the city gate price of gas would not be sufficient to create a market for all of the Delta gas production. Any further price reduction would be impossible in his view because then Delta gas would certainly be uneconomic to produce.

Thus, if Delta gas were to come on stream prior to the 1990's, Professor Helliwell claimed it would be marketable in Canada only by shutting in gas production from the non-frontier producers.

Professor Helliwell quantified his argument for deferral by pointing out that bringing the pipeline (CAGPL with Base Case volumes) on stream in 1982 would produce total rents to frontier producers and the Federal government of about $1.6 billion (1976 dollars) but the loss to non-frontier producers and governments would have a present value of $5.5 billion (1976 dollars).

Professor Helliwell contended that the real costs of pipeline construction were not likely to rise with deferral and that there might even be technical progress in Arctic pipeline construction that would drive down the real costs. However, his estimates included the assumption that real pipeline costs would rise with deferral.

He also contended that deferral need not mean the loss of the opportunity to share pipeline costs between Delta gas and gas from another source, as there were several possibilities for future shared transmission. These included transmission of Delta gas with possible gas from the Point Barrow Naval Reserve, transmission via a connection to the Foothills (Yukon) pipeline if it were built, and possible transmission with Arctic Island gas. In addition there would remain the possibility that future discoveries of Mackenzie Delta/Beaufort gas would support an independent pipeline.

Concerning possible cost overruns, he calculated that the net economic benefits from the production and delivery of Delta gas would be reduced to zero by a pipeline construction cost increase of 58 per cent, or by a cost overrun on gas development and processing costs of about 20 per cent, or by a combination of a pipeline construction cost increase of about 25 per cent and a gas development and processing cost overrun of 10 per cent, or by an overrun of 15 per cent in all costs.

Professor Helliwell also claimed that the use by CAGPL of an Mcf/mile tariff raised the tariff to Delta producers over what it would have been under a cost-of-construction-per-segment tariff-setting arrangement.

Turning to the question of security of supply, Professor Helliwell argued that a Mackenzie pipeline was poor insurance against shortfalls because it required a high load factor in order to be economical. It was his opinion that security of supply could be achieved more economically by eliminating any bottlenecks in non-frontier gas deliverability to allow for expansion if needed to meet unexpected shortfalls. This, he argued, would increase the net economic benefits to Canada accruing from natural gas production and distribution.

Professor Helliwell admitted that there could be definite advantages for Canada in diversifying sources of supply, if the least cost alternatives were pooled. Thus one would not rely entirely on the single least-cost source if it had some risks attached to it. However, he advised against connecting any additional source simply because it offered different risks from the sources used at the moment. In his view, if the Delta gas costs were high relative to costs for non-frontier gas, Delta gas would be an unacceptably costly addition to Canadian deliverability potential.

He concluded that the Delta, as a risk-of-shortage-reducing source of gas was as effective in its present state as an unconnected reserve as it would be as a producing reserve.

In relation to balance of payments, Professor Helliwell stated that Delta gas should not be brought on stream for export. He argued that Canada should concentrate on exporting those goods in which it had some advantage relative to the world. He contended that the Delta gas was only marginally profitable at current world oil prices, so that if there were social costs that would not be borne by the participants which might tip the scales against the projects being socially profitable, then the balance of payments argument would lose any weight it might otherwise have had.

Furthermore, even if there were benefits to exporting Delta gas now, there were also costs in terms of the loss of the gas as back-stopping for subsequent use when it might at some time become the next cheapest Canadian source of natural gas.

Professor Helliwell admitted that the loss of rent to non-frontier producers which he had estimated from early Delta gas production would be reduced or eliminated if gas swaps such as exporting Alberta or Delta gas early with the right to replace it later with Alaska gas could be arranged.

4.4.4.7 Views of the Board

Professor Helliwell's conclusion that a Mackenzie Valley pipeline would not be needed for the delivery of Canadian gas to Canadian markets stems primarily from the estimated time at which a Canadian deficit of natural gas could occur, in his model. In Chapter 2, the Board has examined Professor Helliwell's contention that the gas deficit will occur in the early 1990's. In the view of the Board a deficit of gas supply will probably occur between 1982 and 1985.

While Professor Helliwell's recommendations were drawn principally from the results of his cost-benefit model, the various subsidiary arguments reviewed in the foregoing section, related to a recommendation for delaying a Delta pipeline, are discussed below.

Professor Helliwell's approach assumed that non-frontier gas including trend gas would be available up to the expected level of ultimate marketable reserves at a full cycle cost of production lower than that of Delta gas. To estimate exploration and development costs in the non-frontier he relied on straight line projections of recent average costs in Alberta. In the view of the Board this approach to expected costs for trend gas lacks credibility. Whether gas discoveries will be made according to the estimated trend is uncertain, particularly when as yet undefined gas plays are assumed to occur. Even more uncertain are the costs which might be associated with future discoveries; notably, those costs could rise much faster than indicated by a straight line projection of cost during the exploitation of each play. Subsequent plays are always uncertain and in the view of the Board it is inappropriate to compare expected average long run costs for possible non-frontier gas reserves with essentially known costs for the development and production of established reserves such as those in the Delta.

Following the above line of argument, it is the view of the Board that the appropriate cost comparison should be between costs for producing and delivering known reserves and the market prices which would be available for those reserves.

Generally the Board is in agreement with Professor Helliwell that consumers are not likely to shift from natural gas to the use of fuel oils in very large amounts under conditions where gas is priced at 85 per cent Btu parity with oil. The Board also agrees that pricing gas at 85 per cent parity with oil could render Delta gas production economically marginal, at least for the less profitable gas pools. However, the Board does not believe that non-frontier producers are likely to suffer economic losses if Canada were lucky enough to have gas supply available in excess of Canadian market demand. As Professor Helliwell agreed, gas swaps of various kinds could be arranged, could benefit Canada, and could reduce or eliminate any question of shutting in excess gas deliverability.

Professor Helliwell's contention that deferral of a Delta pipeine need not mean the loss of the opportunity to share pipeline costs between Delta gas and Alaska gas is possibly reasonable but it is no more than an expression of hope that future circumstances may provide conditions at some unknown future time which could make such a sharing of cost possible. Such an expression of hope is interesting but it does not provide adequate reasons for Board decision making concerning the applications in this hearing.

Concerning possible cost overruns the Board notes that in estimating net economic benefits of a frontier pipeline Professor Helliwell included taxes and duties as costs and he excluded taxes associated with the transmission revenues of Alaska gas which would be paid by United States gas customers. In the view of the Board both of these factors combine to lead Professor Helliwell to estimate a low value for net economic benefits. Also, they lead to analytical results which indicate a high degree of sensitivity to cost overruns. His analysis in this regard, however, accords approximately with the Board's assessment of the commercial viability of Delta gas production.

In the view of the Board Professor Helliwell's argument that the development of Delta reserves would not provide an appropriate measure of security of supply is based upon unreasonable optimism concerning costs of non-frontier gas supply and his pessimism concerning the profitability of Delta gas production. In the view of the Board the attachment of Delta reserves can add significantly to Canada's security of energy supply. This follows from the Board's view that Delta reserves will be profitable to develop and that unconnected reserves (particularly when thousands of miles from markets) cannot be viewed as providing security of supply against any of the kinds of supply risks with which Canada may be faced.

Again Professor Helliwell's argument concerning balance of payments hinges around his contention that Delta gas is likely to be unprofitable to develop and produce from the standpoint of society. This is not the view of the Board.

4.4.5 Economic Viability of Mackenzie Delta Gas Production

4.4.5.1 Introduction

The major reserves of natural gas discovered to date in the Mackenzie Delta are located at Parsons Lake, Taglu and Niglintgak. These reserves are controlled by Gulf, Imperial and Shell respectively. Other smaller accumulations of gas are known to exist but their development depends on the larger reserves being connected to market by a pipeline.

To assist the Board in its assessment of the economic viability of Mackenzie Delta reserves, Gulf, Imperial and Shell submitted analyses of the economics of producing the above-mentioned reserves. Their submissions arrived at a judgment of economic viability by comparing the expected plant gate price, based on assumed market prices of natural gas, with the required plant gate price necessary to earn an adequate rate of return.

The approach taken to derive the expected plant gate price and to derive a required plant gate price was the same in general principle for all three Producers, although assumption details varied.

All three Producers used a discounted cash flow (DCF) analysis to calculate required plant gate prices necessary to earn a reasonable rate of return. Differences in the analyses stemmed from varied capital cost estimates, (due in part to variances in gas plant capacities and in the expected rate of capital cost escalations), differences in field sizes, and variations in the rates of return used.

One other difference was that Gulf did its analysis beginning from the commencement of exploration investment in the Delta, thus considering the full life-cycle of costs and revenues associated with producing gas from Parsons Lake. Imperial and Shell, on the other hand, considered exploration investments as sunk costs and therefore analysed only the costs and revenues associated with the future development and production, or half cycle, of their respective gas fields.

As well as evidence with respect to known reserves the Producers provided evidence with regard to possible profitability of prospective reserves of gas that might be discovered in the Mackenzie Delta region, both on and offshore. This portion of the Producers' submissions is reported in a later section of this chapter.

Although a direct comparison of the Gulf, Imperial and Shell submissions was difficult due to the different assumptions each had made, the evidence submitted did provide the basis for a reasonable assessment of the prospects of the Parsons Lake, Taglu and Niglintgak reserves being economically profitable. To provide greater comparability the Board re-worked the submitted data using a common set of assumptions. The results of this analysis are presented in the section on Views of the Board.

The Board also examined the economic viability of the known reserves assuming only 5.1 Tcf of reserves were available for development and (i) the CAGPL No Expansion system was built, (ii) the Foothills pipeline system was constructed, or (iii) that the Foothills (Yukon) proposal was constructed with a connection from the Delta to the Foothills (Yukon) line following the Dempster Highway to Dawson.

4.4.5.2 Producer Evidence on the Economics of Known Mackenzie Delta Reserves

Gulf Canada Limited

Gulf calculated the expected plant gate price for production from its Parsons Lake reserves by estimating the market price of natural gas in Toronto and then subtracting the estimated transportation charges to deliver the gas from the Mackenzie Delta to Toronto.

Gulf assumed that natural gas at the Toronto city gate would be priced at the Btu equivalent of crude oil priced at the refinery gate.

Regarding crude oil prices, Gulf projected Canadian oil prices to be equivalent to international oil prices.

International oil prices were forecast to rise at five per cent a year from 1976 to 1985 and at seven per cent annually from 1985 to 1990.

Transportation charges were calculated on the basis of estimates of tariffs for the TCPL system and for the No Expansion version of the CAGPL system. The tariff on CAGPL's No Expansion system, however, did not reflect higher capital costs attributable to the frost-heave mitigative measures and the 1982 first flow date CAGPL had proposed nor did this tariff include shrinkage. However, a reduction in the expected plant gate price was made to allow for pipeline shrinkage.

Using this methodology Gulf estimated that its expected plant gate price would average $2.55 per MMbtu, in current dollars, over the ten-year period 1982-1991.

Gulf estimated the required plant gate price to earn a 16 per cent full cycle (including exploration costs) after tax, current dollar, discounted cash flow rate of return.

Gulf, in its initial submission, had used an analysis based on a return on average capital employed. However, under cross-examination Gulf admitted that a more meaningful economic assessment would result from a discounted cash flow approach and subsequently submitted its DCF analysis.

Based on its data and assumptions, Gulf calculated that the required plant gate price to earn a 16 per cent after tax, full cycle, DCF rate of return was $1.30 per MMbtu in 1982, rising to

$2.10 per MMbtu in 1988 and remaining constant at that level, in current dollar terms, from then on.

Gulf stated that it had historically earned an 11 to 12 per cent rate of return on its exploration and development investments in conventional areas of Canada. However, Gulf stated that it would expect a full cycle DCF rate of return of between 11 and 25 per cent on investments in frontier areas in order to cover the higher risks associated with investment in these regions.

Gulf testified that the reserves at Parsons Lake would be economic to develop. Gulf substantiated that assessment in its evidence by showing that for the 1982 to 1991 period the average expected plant gate price of $2.55 per MMbtu exceeded the average required plant gate price of $1.80 per MMbtu indicating that at least a 16 per cent full cycle DCF rate of return could be earned.

Shell Canada Limited

Shell calculated the expected plant gate price that it would receive for production from its Niglintgak reserves by estimating the market price of natural gas in Toronto and then subtracting the estimated transportation charges to deliver the gas from the Mackenzie Delta to Toronto.

It was assumed that natural gas at the Toronto city gate would be priced at the Btu equivalent of crude oil priced at the refinery gate. Oil prices were based on a 1980 world crude oil price of $15/bbl., f o b Middle East, escalating at seven per cent a year thereafter.

Shell estimated the cost of transporting natural gas from the Mackenzie Delta to Toronto by estimating the transportation charges on TCPL's system and on CAGPL under its No Expansion case. The CAGPL No Expansion system tariff used, however, did not reflect the higher capital costs attributable to CAGPL's proposed frost-heave mitigative measures and an assumed date of 1982 for first flow, nor did it include pipeline fuel usage. Shell did, however, reduce its expected Delta plant gate price by 3.1 per cent to allow for fuel use.

Details of Shell's expected plant gate price are given in Table 4-18 which was taken from evidence submitted by Shell.

The table shows that Shell's expected Delta plant gate price (column 10), in current dollars, would rise from $0.91 per MMbtu in 1981 to $8.02 per MMbtu in 2000. Shell estimated that, in 1976 constant dollars, this would be equivalent to a price of $0.66 per MMbtu in 1981, rising to $2.31 per MMbtu in 2000. The average 1976 constant dollar price over the 1981-2000 period was $1.59 per MMbtu (See column 11 of Table 4-18).

Shell then estimated the Mackenzie Delta plant gate price required to earn a current, half cycle (excluding exploration costs) DCF rate of return of 18 per cent. Shell testified that an after tax 18 per cent rate of return on investment in Niglintgak would be barely adequate.

Shell estimated required plant gate prices, which would yield an 18 per cent rate of return, for two cases to reflect the uncertainties involved in capital cost and reserve estimations. Basic differences in the cases were:

(i) the low cost case assumed 1 Tcf of reserves compared with 0.8 Tcf for the high cost case; and

(ii) capital costs were $30 million higher in the high cost case, analogous to a contingency allowance of 18 per cent.

On the basis of Shell's analysis, the average required plant gate price (in 1976 constant dollars) over the 1981-2000 period to yield an 18 per cent half cycle DCF rate of return was estimated to be $1.14 per MMbtu in the low cost case and $1.68 per MMbtu in the high cost case.

Shell testified that based on its analysis the development of Niglintgak reserves would yield a marginal return. Shell substantiated this in its evidence where it showed that the expected plant gate price of $1.59/MMbtu (in 1976 constant dollars) was less than the required $1.68/MMbtu plant gate price in the high cost case while it exceeded the $1.14/MMbtu required plant price in Shell's low cost case.

TABLE 4-18

SHELL CANADA'S FORECAST OF NATURAL GAS PRICES NETTED BACK TO THE MACKENZIE DELTA

(assuming CAGPL's pipeline tariffs as filed for 3.25 Bcf/d system prior to revisions to reflect frost heave mitigative measures)

(1981 - 2000)

YEAR	$/BBL - CURR. $ CANADIAN CRUDE @ TORONTO AVG.YR. (1)	YR.END (2)	¢/MMBTU = ¢/MCF - CURR. $ NATURAL GAS @ TORONTO BASED ON BTU EQUIV. WITH CRUDE @ CITY GATE AVG.YR. (3)	YR.END (4)	TRANSCANADA TARIFF TORONTO TO EMPRESS INCL. FUEL (5)	NATURAL GAS @ EMPRESS AVG.YR. (6)	YR.END (7)	ARCTIC GAS FILED TARIFF- 3.25 BCFPD DELTA/EMPRESS W/O FUEL (8)	DELTA PRICE BEFORE ARCTIC GAS FUEL AVG.YR. (9)	DELTA NAT. GAS AFTER ARCTIC GAS FUEL @ 3.1% AVG.YR. (10)	¢/MCF CONST. 76$ DELTA NATURAL GAS PRICES IN 1976 CONST. $ USING GNE DEFL. AVG.YR. (11)
1980		17.25		297	57		240				
1981	17.93	18.40	300	317	59	241	258	147	94	91	66
1982	19.14	19.63	320	338	61	259	277	139	120	116	80
1983	20.37	20.93	342	360	64	278	296	132	146	142	94
1984	21.75	22.36	364	384	66	298	318	124	174	169	106
1985	23.16	23.85	388	411	69	319	342	116	203	197	118
1986	24.73	25.44	416	439	71	345	368	114	231	224	128
1987	26.32	27.17	444	467	74	370	393	112	258	250	136
1988	28.15	29.04	472	500	77	395	423	110	285	270	143
1989	30.02	30.93	505	532	80	425	452	108	317	307	151
1990	32.02	33.01	538	569	83	455	486	106	349	338	158
1991	34.16	35.25	575	608	87	488	521	104	384	372	166
1992	36.44	37.62	615	649	90	525	559	102	423	410	174
1993	38.92	40.17	656	693	94	562	599	99	463	449	182
1994	41.53	42.89	701	739	98	603	641	97	506	490	189
1995	44.34	45.80	747	790	103	644	687	95	549	532	195
1996	47.34	48.91	799	843	107	692	736	92	600	581	203
1997	50.54	52.22	852	900	111	741	789	90	651	631	210
1998	53.96	55.76	910	961	116	794	845	88	706	684	217
1999	57.61	59.56	972	1027	121	851	906	86	765	741	224
2000	61.55	63.60	1039	1097	127	912	970	84	828	802	231
											Avg. = 159

NOTES:

COLUMN 1 Based on a world crude price forecast of $15/BBL FOB Middle East in 1980 and escalating at approximately 7% AAI thereafter. Toronto price is derived by adding to the resulting forecast, a forecast of ocean tanker rates, and of Portland/Montreal PL Tariffs and by subtracting a forecast of IPPL Toronto/Montreal pipeline differentials (calculated prior to NEB decision re add-on tariff).

2 Based on equivalence with international crude @ Montreal being achieved by 1980. Year end prices at Toronto are first estimated for the end of each decade by applying to a year end 1979 Toronto price ($16.29/BBL) the growth rate implicit in column 1. Intermediate year end prices are then determined by interpolation.

3 Equals Column 4 (Year N - 1) X 10/12 + Column 4 (Year N) X 2/12 implying a November 1 price change date each year.

4 Column 2 divided by 5.8.

5 Based on TCPL's rate application in the last half of 1976 with the non-fuel transportation cost component inflating at 3%/year to 1980 and 2.1%/year thereafter.

6 Column 3 less Column 5.

7 Column 4 less Column 5.

8 Derived from a plot of as filed Arctic Gas tariffs in ¢/MMBTU for a 3.25 BCFPD system.

9 Column 6 less Column 8.

10 Column 9 multiplied by 0.969

11 Column 10 deflated to 1976 constant dollars by use of GNE implicit price deflator forecast at 7% AAI through 1980 and 5% AAI thereafter. Column total of 3171¢ divided by 20 years yields a mathematical average constant dollar Delta net back of 159¢/MCF for the period.

Revised Feb. 9, 1977

Source: Exhibit No. N-30-6-1, Schedule I.

Imperial Oil Limited

Imperial calculated a range of expected plant gate prices for its production from Taglu reserves based on various estimates of the natural gas market price in Toronto minus the estimated costs of transporting gas from the Mackenzie Delta to Toronto.

Three different pricing relationships were assumed to exist between natural gas and crude oil. These were:

(i) natural gas at the Toronto city gate was priced at the Btu equivalent of the crude oil price at the refinery gate plus 25 cents per MMbtu;

(ii) natural gas at the Toronto city gate was priced at the Btu equivalent of the crude oil price at the refinery gate; and

(iii) natural gas at the Toronto city gate was priced at 85 per cent of the Btu equivalent of the crude oil price at the refinery gate.

Imperial made two different assumptions about future crude oil prices. In one case it assumed crude oil prices would escalate, in current dollars, by five per cent per year. In the second case it assumed crude oil prices would escalate, in current terms, at five per cent per year until 1982 and then would escalate, in current terms, by seven per cent per year.

To arrive at an expected plant gate price in the Delta, Imperial subtracted from its estimated Toronto natural gas prices the estimated transportation charges on the TCPL system and on

CAGPL's No Expansion version of its proposed pipeline. The estimated tariff included fuel usage but did not reflect the higher capital costs CAGPL had submitted to cover frost-heave mitigative measures or 1982 first flow.

Based on the assumption that crude oil prices would escalate at five per cent a year, Imperial estimated the expected plant gate prices as shown below:

Pricing Assumption	1982	1990
Btu parity + 25¢/MMbtu	$1.29	$2.72
Btu parity	$1.00	$2.24
85 per cent of Btu parity	$0.59	$1.70

Imperial then estimated the economic viability of Taglu production using a half cycle discounted cash flow analysis.

Imperial, however, unlike Gulf and Shell, did not estimate a required plant gate price necessary to earn a certain DCF rate of return. Instead, Imperial estimated the rate of return that it would earn assuming plant gate prices equalled the expected plant gate prices calculated according to its various pricing scenarios.

A summary of the results of this analysis is shown in Table 4-19.

Imperial's analysis, based on the half cycle DCF rate of return, showed it would earn from 12.3 per cent to 23.0 per cent on an investment in Taglu depending on which natural gas pricing scenario was used.

Using the price scenario where natural gas was priced at Btu parity with crude oil plus 25¢/MMbtu and oil prices were assumed, in current dollar terms, to escalate at five per cent per year, Imperial also estimated the rate of return they would receive if there was a 25 per cent increase in (a) gas plant investment, (b) total investment in Taglu development, (c) operating costs, and (d) CAGPL investment.

These studies indicated DCF rates of return varying from 17.2 per cent in the case where total Taglu costs increased 25 per cent, to 19.1 per cent when only operating costs increased. These results compared to a 19.9 per cent DCF rate of return that was obtained when Imperial's original estimated costs were used. Results of this analysis are also shown in Table 4-19.

Imperial testified that a current after tax half cycle DCF rate of return of 15 per cent represented the cost of capital in an inflationary environment for low risk investment. Because of the risk associated with Taglu development Imperial felt an acceptable rate of return from investment in Taglu would be between 15 per cent and 25 per cent dependent in part on exploration cost recovery. In its view this allowed for both risk and an annual inflation rate of six per cent.

Based on its analysis, Imperial testified that Taglu was economic to develop. This was supported by Imperial's findings that, in five of its six price scenarios, the estimated DCF rate of return exceeded 16 per cent and only in the case where natural gas was priced at 85 per cent of crude oil prices, on a Btu basis, and world oil prices escalated at five per cent per year, did the rate of return drop below 15 per cent.

TABLE 4-19

IMPERIAL OIL LIMITED's ANALYSIS OF THE ECONOMICS OF TAGLU DEVELOPMENT

NATURAL GAS PRICING ASSUMPTION CASE	DCF (HALF CYCLE)(1) RATE OF RETURN %
1. Btu Parity + 25¢/MMbtu - 1982	
a) 5% Price Escalation	19.9
b) 7% Price Escalation	23.0
2. Btu Parity - 1982	
a) 5% Price Escalation	17.0
b) 7% Price Escalation	20.3
3. 85% Btu Parity - 1982	
a) 5% Price Escalation	12.3
b) 7% Price Escalation	16.3
4. Btu Parity + 25¢/MMbtu - 1982	
5% Price Escalation	
25% Increase in:	
a) Gas Plant Investment	17.5
b) Total project Investment	17.2
c) Operating Costs	19.1
d) CAGPL Investment	17.6

(1) excludes investment in exploration

4.4.5.3 Comparison of the Submitted Evidence on Known Fields

The major differences between the expected plant gate prices in the Mackenzie Delta as estimated by the three Producers resulted from variances in the estimated Toronto city gate prices of natural gas, from which the plant gate prices were derived.

The following table shows the range of estimated natural gas prices at the Toronto city gate as calculated on the basis of the Producers' evidence. As the table illustrates, Imperial had six different city gate price estimates because it considered two crude oil pricing scenarios, and for each oil pricing scenario calculated three possible price relationships between oil and natural gas.

Estimated Toronto City Gate Prices of Natural Gas

(Current Dollars per MMbtu)

	GULF	SHELL	IMPERIAL					
			85 per cent parity		100 per cent parity		100 per cent parity + 25¢/ MMbtu	
			A(1)	B(2)	A(1)	B(2)	A(1)	B(2)
1982	$3.26	3.20	2.66	2.66	3.12	3.12	3.46	3.46
1985	3.77	3.88	3.08	3.26	3.61	3.82	4.00	4.24
1990	5.29	5.38	3.93	4.57	4.61	5.36	5.11	5.95
2000	(3)	10.39	6.40	8.99	7.51	10.55	8.32	11.69

(1) Case A assumed world oil prices escalated at five per cent a year.

(2) Case B assumed world oil prices escalated at seven per cent a year after 1982.

(3) Gulf in its evidence only estimated expected prices up to 1990.

As all the Producers based their expected Toronto city gate gas prices on a presumed relationship with crude oil prices, (or relationships in Imperial's case) and assumed that Canadian crude oil prices would equal world oil prices (adjusted for transportation costs), a major premise in their analyses was their expectations as to future world oil prices. The various assumptions made, in current terms were:

Expected Percentage Rate of Increase in

Current World Oil Prices

Company		**Time Period**	**Annual Percentage Increase**
Gulf		1976 to 1985	5
		1985 to 1990	7
Shell		1976 on	7
Imperial	A)	1976 on	5
	B)	1976 to 1982	5
		1982 on	7

The Applicants used similar assumptions regarding the pricing relationship between crude oil and natural gas and the future world price of crude oil. CAGPL provided explicit assumptions regarding the future price of world crude oil while Foothills provided only the forecasted prices, which implicitly assumed various escalation rates in the price of world crude oil.

CAGPL forecast gas to be priced at the Btu equivalent of world crude oil by 1982. World crude oil was forecast to escalate at five per cent per year to 1982, and at seven per cent per year after 1982. This higher rate of price increase after 1982 reflected their view of a tightening in the world crude oil market.

Foothills also forecast natural gas to be priced at the Btu equivalent of crude oil by 1982. Their price forecast of world crude oil reflected increasing prices in real terms to the early 1980's, decreasing in real terms in the mid 1980's, and a return to increasing real prices after 1990.

The following table lists the natural gas prices estimated by both Applicants for selected years.

Toronto City Gate Prices of Natural Gas Estimated by CAGPL and Foothills (Current Dollars per MMbtu)

	CAGPL	Foothills
1982	3.06	3.54
1985	3.67	3.99
1990	5.00	4.70
2000	9.50	7.44

A meaningful comparison between the required plant gate prices, as estimated and submitted by the Producers, was not possible due to the variations in approach taken, including the use of different DCF rates of return.

In comparing the DCF rates of return that the Producers felt would be acceptable on investment in the Mackenzie Delta fields the evidence indicated as follows:

Acceptable Current After Tax

DCF Rate of Return

Company	Low risk investment (Minimum Return)	High risk investment (Expected Maximum Return)
Gulf	11% (full cycle)	up to 25% (full cycle)
Shell	not given	18% minimum (half cycle) (no maximum given)
Imperial	15% on half cycle investment but with no allowances for recovery of exploration costs	up to 25% on half cycle investment (this would be adequate to recover sunk exploration costs)

The conclusions, as presented in the evidence, were that Gulf and Imperial considered the development of the Parsons Lake and Taglu fields to be economically viable propositions while Shell considered the development of its Niglintgak reserves to be only a marginal investment opportunity.

4.4.5.4 Economic Viability of Natural Gas Production from Prospective Fields in the Mackenzie Delta

It was not possible, given the stage of development of the Mackenzie Delta region, to estimate with any reasonable degree of certainty the economic viability of Mackenzie Delta natural gas fields, either onshore or offshore, that might be discovered in the future.

Gulf, Imperial and Shell stressed in their evidence that many factors affect the cost of reservoir development. These include the field's physical location, depth, structure, size, productivity, gas/oil ratio, and proximity to other fields and to the delivery system.

As all these factors and other information pertinent to the estimation of production costs were unknown for prospective fields, neither Gulf nor Shell filed detailed evidence with respect to prospective natural gas pools in the Delta. Imperial did file evidence on the economics of hypothetical new gas pools onshore and offshore in fifty feet of water. However it was stressed that this analysis was illustrative only.

The major point illustrated in Imperial's analysis was that a pool located offshore in fifty feet of water would have to be about six times as large as an onshore pool (assuming all other factors were the same for both) to earn the same rate of return on the investment necessary for its development.

4.4.5.5 Views of the Board

Economic Viability of Known Fields

The Board has reviewed the evidence presented by the Producers concerning the economic viability of the three major known fields in the Mackenzie Delta: Parsons Lake, Taglu and Niglintgak, and has made its own assessment of the potential profitability of these fields.

There are two elements in the Board's analysis that varied from the evidence filed by the Producers. First, the Board used in its analysis various tariff structures placed in evidence. As one case, the Board used the tariff for the CAGPL No Expansion system that reflected the higher capital costs due to the proposed frost heave mitigative measures and the later first flow date of 1982. The Producers had used the original estimated tariffs for the CAGPL No Expansion case. In addition, the Board repeated the analysis using tariff structures based on Foothills and CAGPL's No Expansion case assuming established reserves of only 5.1 Tcf. The Board also examined a case in which reserves in the Mackenzie Delta were linked to the Foothills (Yukon) pipeline project by a pipeline following the Dempster highway to Dawson, again assuming established reserves of only 5.1 Tcf in the Mackenzie Delta.

For each of the cases, the Board, realizing the uncertainty that must be attached to estimates of future oil and natural gas prices, chose to examine the economic attractiveness of the fields under both a high and a low natural gas price scenario. These were:

(a) **High price scenario**

This scenario assumed natural gas at the Toronto city gate was priced equal to the value of international crude, at the Toronto refinery gate, on a Btu basis. International oil prices were assumed to escalate, in current terms, at five per cent per year from 1976 to 1985 and at seven per cent per year after 1985; and

(b) **Low price scenario**

This scenario assumed natural gas at the Toronto city gate was priced equal to 85 per cent of the value of international crude oil at the Toronto refinery gate, on a Btu basis. International oil prices were assumed to escalate from 1976 on at five per cent per year (equivalent to constant oil prices in real terms).

Using filed data, with the changes outlined above, the Board then calculated the current, after tax, half cycle DCF rate of return that would be earned on each of the three fields. To further test the economic soundness of investment in the fields, the Board also performed a sensitivity analysis of the DCF rates of return to tariff increases on the various systems considered. Such tariff increases would occur should there be cost overruns in construction of the various systems.

The results of the Board's analysis, based on the CAGPL No Expansion case, can be summarized as follows:

CASE 1

Current After Tax Half Cycle DCF Rates of Return Estimated to be Attainable from Known Delta Reserves Assuming Tariffs Based on the CAGPL No Expansion Case As Revised

	High Price Scenario			**Low Price Scenario**		
	Tariff Overrun			**Tariff Overrun**		
	0%	**25%**	**50%**	**0%**	**25%**	**50%**
	(Per Cent)			(Per Cent)		
Gulf (Parsons Lake)	27	25	22	20	17	15
Imperial (Taglu)	23	20	18	16	14	12
Shell (Niglintgak)	19	16	15	11	9	7

As the table above illustrates, under the high price scenario, investment in all three fields would earn a current, after tax, half cycle DCF rate of return in excess of 14 per cent.

However, under the low price scenario, investments in the Parsons Lake and Taglu fields are projected to earn a DCF rate of return of about 14 per cent or higher except in the event of a 50 per cent tariff overrun in which case investment in Taglu could earn just under 12 per cent. However, investment in the Niglintgak field is estimated to earn a current, after tax, half cycle DCF rate of return of only about 11 per cent or less.

The Board also analysed three cases, assuming that only 5.1 Tcf of marketable reserves were available. For the case where the Foothills project was projected to transport the natural gas from the Delta to Southern Canada, the results of the analysis were that the expected plant gate price became negative even assuming no tariff overrun, resulting in a negative rate of return. The results for the case of the CAGPL No expansion system with only 5.1 Tcf of reserves connected are outlined below.

CASE 2

Current After Tax Half Cycle DCF Rates of Return Estimated to be Attainable from Known Delta Reserves Assuming the CAGPL No Expansion System is Used and Only 5.1 Tcf of Reserves are Available

	High Price Scenario			Low Price Scenario		
	Tariff Overrun			Tariff Overrun		
	0%	25%	50%	0%	25%	50%
	(Per Cent)			(Per Cent)		
Gulf (Parsons Lake)	23	20	17	18	14	12
Imperial (Taglu)	19	16	14	14	11	9
Shell (Niglintgak)	14	12	9	8	6	3

Case 2, where the CAGPL No Expansion system is the northern transportation line and only 5.1 Tcf of reserves are available to be connected, shows that under the high price scenario investment in Parsons Lake would earn at least 17 per cent (even with a 50 per cent tariff overrun) while investment in Taglu would earn about 14 per cent or higher. The rate of return from investment in Niglintgak, however, could drop to nine per cent.

Under the low price scenario only investment in Parsons Lake would yield a rate of return in excess of 14 per cent, and if a 50 per cent tariff overrun should occur the highest rate of return on investment in any of the fields would be 12 per cent, with investment in Niglintgak yielding only three per cent.

The Foothills (Yukon) system with a Dempster connection was put forward in the hearing only as a "study" and detailed examination and testing of this proposal was not carried out.

It is the Board's opinion that, assuming only 5.1 Tcf of Delta reserves are connected, the Foothills (Yukon) system with a Dempster connection would result in the Producers earning a rate of return up to two percentage points lower than for CAGPL transporting the same volumes. At a throughput of 1.2 Bcf/d the returns would likely be about the same.

To determine the adequacy of these estimated rates of return, the Board weighed the submitted evidence and came to the conclusion that, for known Delta fields, something close to a nine per cent real after tax DCF rate of return on half cycle investment would be adequate to compensate the Producer for the use of his capital, including compensation for risk. Assuming an annual rate of inflation of five per cent per year, the corresponding current, after tax, DCF rate of return on half cycle investment would be 14 per cent.

Based on the 5.1 Tcf of reserves considered to be available in the Delta, the Foothills project proposal would not be economically viable in that it would not yield a positive rate of return.

Considering the CAGPL No Expansion case, with only 5.1 Tcf of reserves available, if future natural gas prices should be approximately as outlined in the low price scenario, then the Board believes development of the Niglintgak field would not be economically attractive, the Taglu field would be a marginal investment opportunity at best, while the Parsons Lake field could be a viable investment opportunity provided actual tariffs in the CAGPL system do not exceed the filed tariff structure by more than 25 per cent. Under the high price scenario, investment in all three fields appears economically viable provided no tariff overruns occur. With a 25 per cent tariff overrun, investment in Niglintgak is no longer attractive, and with a 50 per cent tariff overrun, only investment in Parsons Lake would earn a current after tax DCF rate of return in excess of 14 per cent.

If the CAGPL No Expansion case, with no reserves availability constraint is considered, then the Board concludes that, provided the tariff charged on the CAGPL No Expansion system does not exceed by over 25 per cent the estimated tariff as filed, Gulf's Parsons Lake field and Imperial's Taglu field would be economic to develop. However, Shell's Niglintgak field is a marginal investment.

Economic Viability of Prospective Fields

The Board believes that a quantitative estimate of the economic costs of producing natural gas from fields in the Mackenzie Delta that might be discovered in the future can only be speculative, since these costs depend on a number of factors which are unknown at this time.

However, it can reasonably be assumed that the most promising structures in the onshore Delta region have been drilled and that consequently the unit costs of production of future discoveries onshore will most likely be higher than that of known reserves.

With regard to future offshore discoveries there is insufficient information to assess their production costs at this time.

4-1. Comparative Costs of Transportation

Unit transportation costs to Empress, Alberta and the 49th parallel as shown in Table 4-1 of Section 4.3.5 were based on material filed by each Applicant.

The following summary table and exhibit reference tables identify the exhibit or transcript source of those unit costs set forth in Table 4-1.

Figures have been underlined on the tables to draw attention to the relevant numbers. In addition, explanatory footnotes have been added by the Board to the tables as filed by the Applicants.

SUMMARY

UNIT TRANSPORTATION COSTS

EXHIBIT REFERENCE TABLES

LINE NUMBER[1]	ITEM	EXHIBIT REFERENCE TABLES Number	Line
	Delta to Empress		
	Based on Reserves Discovered		
1	Foothills 42"	Transcript Ref. 36,276	
2	CAGPL (Alaskan 2.0 Bcfd)	1	7
	No Expansion Cases		
3	Foothills 42"	2	6
4	Foothills 30"	3	5
5	Foothills (Yukon) Dempster-Whitehorse	3	7
6	Foothills (Yukon) Dempster-Dawson	3	18
7	CAGPL	4, 5	8, -
	Base Cases		
8	Foothills 42"	3	1
9	CAGPL	6, 7	8, -
	Prudhoe Bay to 49th Parallel		
10	Foothills (Yukon) Only	3	4
11	Foothills (Yukon) Dempster-Whitehorse	3	10
12	Foothills (Yukon) Dempster-Dawson	3	21
13	CAGPL No Expansion Case	8, 9	-
14	CAGPL Base Case	10, 11	-

(1) Same line numbers as shown on Table 4-1 of Section 4.3.5.

EXHIBIT REFERENCE

TABLE 1

CANADIAN ARCTIC GAS PIPELINE LIMITED

Pro Forma Cost of Service
For each of the years 1982 to 1989
(Amounts in millions of dollars)

Section II
Schedule 4
Case 3
Escalated

Line No.	Particulars (a)	Schedule No. (b)	1982 (c)	1983 (d)	1984 (e)	1985 (f)	1986 (g)	1987 (h)	1988 (i)	1989 (j)
	Cost of service:									
1	Operating expenses	2	$ 30.6	$ 69.7	$ 91.2	$ 93.6	$ 96.4	$ 99.7	$ 103.5	$ 107.9
2	Depreciation and amortization	5	41.6	186.9	291.7	296.0	300.1	351.4	349.0	349.0
3	Municipal and other taxes	2		6.5	13.0	13.8	14.2	14.7	15.2	16.0
4	Provision for income taxes	6	43.7	204.4	337.6	336.7	330.2	393.7	409.1	431.6
5	Return on rate base	7	116.1	525.8	794.7	746.1	697.8	774.7	747.0	724.6
6	Total cost of service		$ 232.0	$ 993.3	$1,528.2	$1,486.2	$1,438.7	$1,634.2	$1,623.8	$1,629.1

Tariffs under MCF-Mile Cost Allocation Modified for Equalization of Southern Mileages in Alberta - ¢/MMBtu

Line No.	Particulars		1982	1983	1984	1985	1986	1987	1988	1989
7	Mackenzie Delta to Empress		178.8	161.0	135.9	132.1	127.9	145.3	144.4	144.8
8	Alaska-Yukon border to Monchy			146.0	149.2	145.1	140.4	159.5	158.5	159.0
9	Alaska-Yukon border to Alberta-B.C. border			133.7	136.6	132.8	128.6	146.1	145.2	145.6

Note:

Per MMBtu cost of service amounts shown on lines 7 to 9 illustrate the general range of transportation costs which may reasonably be anticipated for transmission from the two major points of supply to the system to the major points of delivery by the system to Shippers. The amounts have been calculated by applying the "MCF-Mile" method of cost allocation (with the mileages in the Province of Alberta, south of the Caroline Junction, equalized for these purposes). The amounts are expressed in terms of gross heating value content since each Shipper will take delivery of MCF quantities of commingled gas having an aggregate gross heating value equal to the gross heating value of gas volumes delivered to the system by such Shipper less the Shipper's allocable gross heating value of company use gas.

NEB NOTE: Unit costs as shown are based on a supply volume of 0.7 Bcf/day from the Mackenzie Delta commencing on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay commencing on July 1, 1983. The two volumes are held constant thereafter.

Source: Exhibit Number N-AG-3-234

TABLE 2

UNIT COST OF SERVICE COMPARISONS - ESCALATED
\$/MMBTU (1)

LINE	ITEM	1982	1983	1984	1985	1986	198
A.	PRUDHOE BAY GAS DELIVERED TO THE 49th PARALLEL (2)						
1.	Alaska Highway 48" Project	2.43	1.63	1.58	1.53	1.47	1.42
2.	Alaska Hwy. 48" + 30" Dempster/Whitehorse	2.46	1.65	1.58	1.52	1.46	1.41
3.	Alaska Hw. 48" + 30" Dempster/Dawson	2.63	1.75	1.68	1.62	1.56	1.50
4.	Arctic Gas No-Expansion (as filed) (3)	-	-	1.78	1.65	1.58	1.55
5.	Arctic Gas No-Expansion (as adjusted)	-	-	2.27	2.11	2.02	1.99
B.	MACKENZIE DELTA GAS DELIVERED TO EMPRESS (2)						
6.	Maple Leaf 42" - No Expansion	-	2.11	1.66	1.53	1.47	1.42
7.	Alaska Hwy 48" + 30" Dempster/Whitehorse	-	1.52	1.37	1.33	1.28	1.23
8.	Alaska Hwy 48" + 30" Dempster/Dawson	-	1.38	1.25	1.21	1.17	1.13
9.	Arctic Gas No-Expansion (as filed) (3)	-	1.52	1.38	1.29	1.24	1.22
10.	Arctic Gas No-Expansion (as adjusted)	-	1.88	1.71	1.60	1.54	1.51

Notes: (1) excludes field cost of fuel gas

(2) figures are excluded where gas deliveries are for a partial year only.

(3) Arctic Gas No-Expansion case is based on 2000 MMCFD from Prudhoe and 1250 from the Delta for a total supply of 3250 MMCFD. The Alaska Hwy 48" plus Dempster or Maple Leaf cases are based on 2400 MMCFD from Prudhoe and 1200 from the Delta for a total supply of 3600 MMCFD. If Arctic Gas incremented the Prudhoe supply to 2400 MMCFD their unit costs at the 49th parallel would be somewhat closer to those of the Alaska Hwy. Project.

Source: Exhibit Number N-FH-5-96-3

EXHIBIT REFERENCE

TABLE 3

COST OF SERVICE SUMMARY

($/MMBtu)

LINE	ITEM	1981	1982	1983	1984	1985	1986	1987
A.	MAPLE LEAF PROJECT (42" AS FILED):							
1.	Mackenzie Delta to Empress (TCPL)	-	1.65	2.06	1.55	1.29	1.17	1.02
B.	ALASKA HWY PROJECT (48" AS FILED):							
2.	Prudhoe to Kingsgate (b)	2.36	2.52	1.69	1.64	1.59	1.53	1.48
3.	Prudhoe to Monchy (b)	2.26	2.44	1.65	1.59	1.54	1.48	1.43
4.	Prudhoe to 49th Parallel (b)	2.29	2.46	1.66	1.61	1.56	1.50	1.45
C.	STUDY #1 (30" MACKENZIE VALLEY CONNECTION):							
	(C-1) WITH SERVICE COMMENCING 1 JAN 83 (a)							
5.	Mackenzie Delta to Empress (TCPL)	-	-	1.75	1.54	1.49	1.44	1.39
	(C-2) WITH SERVICE COMMENCING 1 NOV 84							
6.	Mackenzie Delta to Empress (TCPL)	-	-	-	1.38	1.91	1.68	1.63
D.	STUDY #2 (30" DEMPSTER CONNECTION TO WHITEHORSE):							
	(D-1) WITH SERVICE COMMENCING 1 JAN 83:							
7.	Mackenzie Delta to Empress (TCPL)	-	-	1.52	1.37	1.33	1.28	1.23
8.	Prudhoe to Kingsgate	2.33	2.46	1.67	1.59	1.54	1.48	1.42
9.	Prudhoe to Monchy	2.26	2.45	1.64	1.57	1.51	1.45	1.40
10.	Prudhoe to 49th Parallel	2.28	2.46	1.65	1.58	1.52	1.46	1.41
	(D-2) WITH SERVICE COMMENCING 1 NOV 84:							
11.	Mackenzie Delta to Empress (TCPL)	-	-	-	1.41	1.67	1.50	1.45
12.	Prudhoe to Kingsgate	2.34	2.50	1.68	1.64	1.59	1.51	1.46
13.	Prudhoe to Monchy	2.26	2.45	1.65	1.60	1.56	1.49	1.44
14.	Prudhoe to 49th Parallel	2.29	2.46	1.66	1.61	1.57	1.50	1.44

NOTES:

(a) The unit costs of transportation are estimated only at this time.

(b) For purposes of this study the base 48" system capital costs, and resulting transportation costs, have been modified slightly from those filed by the addition of $51.8 million to account for a slight change in the route in the Foothills Yukon section, by a modification of the compressor build-up schedule in the northern Westcoast section, and by modified pipe delivery and pre-permit costs in the AGT(Canada) section.

Source: Exhibit Number FH(Y)-114-48-2, Page (viii)

EXHIBIT REFERENCE

TABLE 3 (Continued)

COST OF SERVICE SUMMARY (cont'd)
($/MMBTU)

LINE	ITEM	1981	1982	1983	1984	1985	1986	1987
E.	STUDY #3 (30" Dempster Connection to Dawson with re-routed 48" Express line):							
	(E-1) With No Dempster Connection:							
15.	Prudhoe to Kingsgate	2.50	2.65	1.77	1.72	1.67	1.61	1.55
16.	Prudhoe to Monchy	2.42	2.59	1.74	1.69	1.64	1.58	1.52
17.	Prudhoe to 49th par.	2.45	2.60	1.75	1.70	1.65	1.59	1.53
	(E-2) With Dempster service commencing 1 Jan 83:							
18.	Mackenzie Delta to Empress (TCPL)	-	-	1.38	1.25	1.21	1.17	1.13
19.	Prudhoe to Kingsgate	2.50	2.67	1.74	1.66	1.60	1.54	1.48
20.	Prudhoe to Monchy	2.42	2.61	1.75	1.69	1.63	1.56	1.50
21.	Prudhoe to 49th par.	2.44	2.63	1.75	1.68	1.62	1.56	1.50

Source: Exhibit Number FH(Y)-114-48, page (ix)

EXHIBIT REFERENCE

TABLE 4

CANADIAN ARCTIC GAS PIPELINE LIMITED

Pro Forma Cost of Service
For each of the years 1982 to 1989
(Amounts in millions of dollars)

Section II
Schedule 4
No Expansion Case
Escalated

Line No.	Particulars (a)	Schedule No. (b)	1982 (c)	1983 (d)	1984 (e)	1985 (f)	1986 (g)	1987 (h)	1988 (i)	1989 (j)
	Cost of service:									
1	Operating expenses	2	$ 30.6	$ 69.7	$ 91.2	$ 93.6	$ 96.4	$ 99.7	$ 103.5	$ 107.9
2	Depreciation and amortization	5	61.5	233.6	341.4	341.4	341.4	340.8	338.3	338.3
3	Municipal and other taxes	2		7.0	14.6	15.5	15.9	16.4	16.9	17.6
4	Provision for income taxes	6	67.8	265.9	402.7	369.3	356.7	369.6	384.4	403.2
5	Return on rate base	7	175.8	658.9	914.5	825.7	767.2	737.3	711.5	684.3
6	Total cost of service		$ 335.7	$1,235.1	$1,764.4	$1,645.5	$1,577.6	$1,563.8	$1,554.6	$1,551.3
	Tariffs under MCF-Mile Cost Allocation Modified for Equalization of Southern Mileages in Alberta - ¢/MMBtu									
7	Mackenzie Delta to 60th Parallel		77.2	73.3	66.6	62.1	59.6	59.0	58.7	58.6
8	Mackenzie Delta to Empress		158.8	152.2	138.1	128.8	123.5	122.4	121.7	121.4
9	Alaska-Yukon border to Monchy			152.3	151.6	141.4	135.6	134.4	133.6	133.3
10	Alaska-Yukon border to Alberta/B.C. border			139.5	138.9	129.5	124.2	123.1	122.4	122.1

Note:

Per MMBtu cost of service amounts shown on lines 7 to 10 illustrate the general range of transportation costs which may reasonably be anticipated for transmission from the two major points of supply to the system to the major points of delivery by the system to Shippers. The amounts have been calculated by applying the "MCF-Mile" method of cost allocation (with the mileages in the Province of Alberta, south of the Caroline Junction, equalized for these purposes). The amounts are expressed in terms of gross heating value content since each Shipper will take delivery of MCF quantities of commingled gas having an aggregate gross heating value equal to the gross heating value of gas volumes delivered to the system by such Shipper less the Shipper's allocable gross heating value of company use gas.

Gas volume delivery assumptions utilized in computing the tariffs above are in accordance with the Summary of Projected Gas Volumes by year in Section 8.b.1.1 and as illustrated in tables 1 and 2 of that section.

NEB NOTE: Unit costs as shown are based on supply volumes of 1.25 Bcf/day from the Delta commencing on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay commencing on July 1, 1983. The two volumes are held constant thereafter.

Source: Exhibit Number N-AG-3-181, page 17

EXHIBIT REFERENCE

TABLE 5
ARCTIC GAS PROJECT

DELIVERIES TO EMPRESS
No Expansion Case

Year	CAGPL Delta to Empress ($ Millions)	Delivered Volumes (TBtu/Yr.)	Unit Trans-portation Cost (¢/MMBtu)	Cost of Fuel @ $1/MMBtu (¢/MMBtu)	Total Unit Cost to Empress (¢/MMBtu)
1982	300.5	189.2	158.8	1.7	160.5
1983	564.2	370.7	152.2	2.5	154.7
1984	501.3	362.9	138.1	3.3	141.4
1985	467.5	362.9	128.8	3.3	132.1
1986	448.2	362.9	123.5	3.3	126.8

NEB
NOTE: Unit costs as shown are based on supply volumes of 1.25 Bcf/day from the Delta commencing on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay commencing on July 1, 1983. The two volumes are held constant thereafter.

Source: Exhibit Number N-AG-3-198, figure 3.A.2

EXHIBIT REFERENCE

TABLE 6

Section II
Schedule 4
Base Case
Escalated

CANADIAN ARCTIC GAS PIPELINE LIMITED

Pro Forma Cost of Service
For each of the years 1982 to 1989
(Amounts in millions of dollars)

Line No.	Particulars (a)	Schedule No. (b)	1982 (c)	1983 (d)	1984 (e)	1985 (f)	1986 (g)	1987 (h)	1988 (i)	1989 (j)
	Cost of service:									
1	Operating expenses	2	$ 30.6	$ 69.7	$ 90.0	$ 99.6	$ 105.0	$ 110.0	$ 114.3	$ 119.1
2	Depreciation and amortization	5	50.9	186.4	279.2	323.7	379.3	408.0	405.5	405.5
3	Municipal and other taxes	2		7.0	14.6	15.5	18.2	21.8	22.3	23.2
4	Provision for income taxes	6	55.1	196.7	312.0	388.7	466.1	482.8	490.3	509.3
5	Return on rate base	7	144.3	523.8	758.9	837.6	921.4	912.1	870.5	837.7
6	Total cost of service		$ 280.9	$ 983.6	$1,454.7	$1,665.1	$1,890.0	$1,934.7	$1,902.9	$1,894.8
	Tariffs under MCF-Mile Cost Allocation Modified for Equalization of Southern Mileages in Alberta - ¢/MMBtu									
7	Mackenzie Delta to 60th Parallel		64.6	59.5	54.5	57.9	58.1	54.5	53.6	53.4
8	Mackenzie Delta to Empress		133.0	124.2	113.3	120.6	121.6	114.6	112.7	112.3
9	Alaska-Yukon border to Monchy			119.2	124.3	132.5	134.2	126.2	124.1	123.6
10	Alaska-Yukon border to Alberta-B.C. border			109.1	113.8	121.3	122.6	115.3	113.4	112.9

Note:

Per MMBtu cost of service amounts shown on lines 7 to 10 illustrate the general range of transportation costs which may reasonably be anticipated for transmission from the two major points of supply to the system to the major points of delivery by the system to Shippers. The amounts have been calculated by applying the "MCF-Mile" method of cost allocation (with the mileages in the Province of Alberta, south of the Caroline Junction, equalized for these purposes). The amounts are expressed in terms of gross heating value content since each Shipper will take delivery of MCF quantities of commingled gas having an aggregate gross heating value equal to the gross heating value of gas volumes delivered to the system by such Shipper less the Shipper's allocable gross heating value of company use gas.

Gas volume delivery assumptions utilized in computing the tariffs above are in accordance with the Summary of Projected Gas Volumes by year in Section 8.b.1.1 and as illustrated in tables 1 and 2 of that section.

NEB NOTE: Unit costs as shown are based upon a system constructed so that by the fifth operating year the system could transport approximately 4.5 Bcf/day, 2.25 Bcf/day from both the Delta and Prudhoe Bay. Supply volumes commence at 1.25 Bcf/day from the Delta beginning on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay on July 1, 1983.

Source: Exhibit Number N-AG-3-181, page 7

EXHIBIT REFERENCE

TABLE 7

ARCTIC GAS PROJECT

DELIVERIES TO EMPRESS - BASE CASE

Year	CAGPL Delta to Empress ($ Millions)	Delivered Volumes (TBtu/Yr.)	Unit Trans-portation Cost (¢/MMBtu)	Cost of Fuel @ $1/MMBtu (¢/MMBtu)	Total Unit Cost to Empress (¢/MMBtu)
1982	251.4	189.1	133.0	1.8	134.8
1983	459.0	369.6	124.2	2.7	126.9
1984	423.6	373.8	113.3	3.8	117.1
1985	541.3	448.8	120.6	4.3	124.9
1986	651.9	535.9	121.7	5.6	127.3
1987	770.1	671.8	114.6	6.1	120.7
1988	757.4	671.8	112.7	6.1	118.8
1989	754.2	671.8	112.3	6.1	118.4
1990	746.8	671.8	111.2	6.1	117.3
1991	728.1	671.8	108.4	6.1	114.5
1992	709.0	671.8	105.5	6.1	111.6
1993	688.7	671.8	102.5	6.1	108.6
1994	671.5	671.8	100.0	6.1	106.1
1995	653.7	671.8	97.3	6.1	103.4
1996	637.0	671.8	94.8	6.1	100.9
1997	621.2	671.8	92.5	6.1	98.6
1998	606.3	671.8	90.3	6.1	96.4
1999	592.3	671.8	88.2	6.1	94.3
2000	579.1	671.8	86.2	6.1	92.3
2001	561.0	671.8	83.5	6.1	89.6
2002	538.9	671.8	80.2	6.1	86.3

NEB
NOTE: Unit costs as shown are based upon a system constructed so that by the fifth operating year the system could transport approximately 4.5 Bcf/day, 2.25 Bcf/day from both the Delta and Prudhoe Bay. Supply volumes commence at 1.25 Bcf/day from the Delta beginning on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay on July 1, 1983.

Source: Exhibit Number N-AG-3-198, figure 3.A.1

EXHIBIT REFERENCE

TABLE 8

ARCTIC GAS - NO EXPANSION CASE
Versus
ALASKA HIGHWAY/DEMPSTER HIGHWAY 30" PROJECT

Per Unit Cost Comparison
Deliveries -[1] Prudhoe Bay to Kingsgate

Year	Via Arctic Gas (¢/MMBtu)	Via Alaska Highway Project (¢/MMBtu)	Difference (¢/MMBtu)	Increase %
1983	182.2	214.6	32.4	17.8
1984	178.5	214.5	36.0	20.2
1985	166.6	203.7	37.1	22.3
1986	159.3	196.0	36.7	23.0
1987	157.0	189.0	32.0	20.4
1988	155.1	183.0	27.9	18.0
1989	153.9	178.9	25.0	16.2
1990	151.0	173.9	22.9	15.2
1991	147.1	169.5	22.4	15.2
1992	143.4	165.1	21.7	15.1
1993	139.8	160.3	20.5	14.7
1994	136.7	156.3	19.6	14.3
1995	133.6	153.0	19.4	14.5
1996	130.6	150.1	19.5	14.9
1997	128.1	148.0	19.9	15.5
1998	126.0	146.2	20.2	16.0
1999	122.7	145.1	22.4	18.3
2000	119.2	144.5	25.3	21.2
2001	116.1	144.4	28.3	24.4
2002	112.4	144.2	31.8	28.3
5 year average	167.2	202.9	35.7	21.4
10 year average	158.2	188.1	29.9	18.9
20 year average	142.0	168.4	26.4	18.6

NEB NOTES: Unit costs as shown include the field cost of fuel gas.

Unit costs as shown are based on supply volumes of 1.25 Bcf/day from the Delta commencing on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay commencing on July 1, 1983. The two volumes are held constant thereafter.

Source: Exhibit Number N-AG-3-214, figure F.3

EXHIBIT REFERENCE

TABLE 9

ARCTIC GAS - NO EXPANSION CASE
Versus
ALASKA HIGHWAY/DEMPSTER HIGHWAY 30" PROJECT

Per Unit Cost Comparison
Deliveries - Prudhoe Bay to Monchy

Year	Via Arctic Gas (¢/MMBtu)	Via Alaska Highway Project (¢3MMBtu)	Difference (¢/MMBtu)	Increase %
1983	186.3	214.1	27.8	14.9
1984	183.2	216.7	33.5	18.3
1985	170.6	207.6	37.0	21.7
1986	163.4	199.5	36.1	22.1
1987	161.1	191.6	30.5	18.9
1988	159.3	185.8	26.5	16.6
1989	158.1	181.8	23.7	15.0
1990	155.2	176.8	21.6	13.9
1991	151.1	172.4	21.3	14.0
1992	147.3	167.9	20.6	14.0
1993	143.7	163.0	19.3	13.4
1994	140.4	158.9	18.5	13.2
1995	137.2	155.5	18.3	13.3
1996	134.3	152.7	18.4	13.7
1997	131.7	150.4	18.7	14.2
1998	129.5	148.7	19.2	14.8
1999	126.1	147.6	21.5	17.0
2000	122.5	147.0	24.5	20.0
2001	119.2	146.8	27.6	23.2
2002	115.4	146.4	30.0	25.8
5 year average	171.4	205.4	34.0	19.8
10 year average	162.4	190.8	28.4	17.5
20 year average	145.8	171.0	25.2	17.3

NEB NOTES: Unit costs as shown include the field cost of fuel gas.

Unit costs as shown are based on supply volumes of 1.25 Bcf/day from the Delta commencing on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay commencing on July 1, 1983. The two volumes are held constant thereafter.

Source: Exhibit Number N-AG-3-214, figure F.4

EXHIBIT REFERENCE

TABLE 10

PRUDHOE BAY TO KINGSGATE

ARCTIC GAS

DELIVERIES TO ALBERTA-B.C. BORDER AND KINGSGATE

Year	Alaska ($ Millions)	Canada ($ Millions)	Total Trans-portation Cost ($ Millions)	Delivered Volumes (TBtu/yr.)	Unit Trans-portation Cost (¢/MMBtu)	Fuel Cost @ $1/MMBtu (¢/MMBtu)	ANG Unit Cost to Kingsgate (¢/MMBtu)	Total Unit Cost to Kingsgate (¢/MMBtu)
1983	38.1	136.3	174.4	124.9	139.6	3.8	7.6	151.0
1984	69.9	284.2	354.1	249.7	141.8	3.8	6.9	152.5
1985	64.0	307.7	371.7	253.7	146.5	4.3	6.8	157.6
1986	60.6	338.8	399.4	276.2	144.6	5.6	6.3	156.5
1987	57.9	316.9	374.8	274.9	136.3	6.1	6.2	148.6
1988	55.2	311.7	366.9	274.9	133.5	6.1	6.1	145.7
1989	53.1	310.4	363.5	274.9	132.2	6.1	6.0	144.3
1990	50.7	307.3	358.0	274.9	130.2	6.1	5.9	142.2
1991	48.4	299.6	348.0	274.9	126.6	6.1	5.9	138.6
1992	46.4	291.7	338.1	274.9	123.0	6.1	5.8	134.9
1993	44.5	283.4	327.9	274.9	119.3	6.1	5.6	131.0
1994	42.9	276.3	319.2	274.9	116.1	6.1	5.5	127.7
1995	41.7	269.0	310.7	274.9	113.0	6.1	5.4	124.5
1996	40.7	262.1	302.8	274.9	110.1	6.1	5.2	121.4
1997	40.1	255.6	295.7	274.9	107.6	6.1	5.1	118.8
1998	39.6	249.5	289.1	274.9	105.2	6.1	5.0	116.3
1999	39.5	243.7	283.2	274.9	103.0	6.1	4.8	113.9
2000	39.6	238.3	277.9	274.9	101.1	6.1	4.7	111.9
2001	39.9	230.6	270.5	274.9	98.4	6.1	4.6	109.1
2002	40.0	221.7	261.7	274.9	95.2	6.1	4.4	105.7

NEB NOTE: Unit costs as shown are based upon a system constructed so that by the fifth operating year the system could transport approximately 4.5 Bcf/day, 2.25 Bcf/day from both the Delta and Prudhoe Bay. Supply volumes commence at 1.25 Bcf/day from the Delta beginning on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay on July 1, 1983.

Source: Exhibit Number N-AG-3-198, Figure 3.A.4

EXHIBIT REFERENCE

TABLE 11

PRUDHOE BAY TO MONCHY

ARCTIC GAS

DELIVERIES TO MONCHY

Year	Alaska ($ Millions)	Canada ($ Millions)	Total Trans-portation Cost ($ Millions)	Delivered Volumes (TBtu/Yr.)	Unit Trans-portation Cost (¢/MMBtu)	Fuel Cost @ $1/MMBtu (¢/MMBtu)	Total Unit Cost to Monchy (¢/MMBtu)
1983	84.9	331.3	416.2	278.0	149.7	4.1	153.8
1984	156.2	690.8	847.0	555.6	152.4	4.2	156.6
1985	143.1	747.9	891.0	564.3	157.9	4.7	162.6
1986	135.3	823.5	958.8	613.7	156.2	6.1	162.3
1987	129.2	770.3	899.5	610.4	147.4	6.7	154.1
1988	123.3	757.6	880.9	610.4	144.3	6.7	151.0
1989	118.5	754.4	872.9	610.4	143.0	6.7	149.7
1990	113.3	747.1	860.4	610.4	141.0	6.7	147.7
1991	108.2	728.3	836.5	610.4	137.0	6.7	143.7
1992	103.6	709.2	812.8	610.4	133.2	6.7	139.9
1993	99.3	688.9	788.2	610.4	129.1	6.7	135.8
1994	95.7	671.7	767.4	610.4	125.7	6.7	132.4
1995	93.0	653.9	746.9	610.4	122.4	6.7	129.1
1996	90.9	637.2	728.1	610.4	119.3	6.7	126.0
1997	89.4	621.4	710.8	610.4	116.4	6.7	123.1
1998	88.5	606.5	695.0	610.4	113.9	6.7	120.6
1999	88.1	592.4	680.5	610.4	111.5	6.7	118.2
2000	88.3	579.2	667.5	610.4	109.4	6.7	116.1
2001	89.2	561.2	650.4	610.4	106.6	6.7	113.3
2002	89.3	539.0	628.3	610.4	102.9	6.7	109.6

NEB NOTE: Unit costs as shown are based upon a system constructed so that by the fifth operating year the system could transport approximately 4.5 Bcf/day, 2.25 Bcf/day from both the Delta and Prudhoe Bay. Supply volumes commence at 1.25 Bcf/day from the Delta beginning on July 1, 1982 and 2.0 Bcf/day from Prudhoe Bay on July 1, 1983.

Source: Exhibit Number N-AG-3-198, Figure 3.A.5

4-2 Appendix to 4.4.2 Macroeconomic Impact

This appendix contains information on various aspects of the Board's macroeconomic impact studies of the Applicants' projects using the CANDIDE 1.2M model. These aspects are:

Control Solution

Specification of a Pipeline Submodel in CANDIDE

Assumptions of the Impact Analysis

Pipeline Data and Sources

References

Control Solution

Table 1 specifies the values of some of the key economic variables from the control solution underlying the Board's macroeconomic impact analysis.

The principal assumptions used in generating this control solution are:

(a) investment and government expenditures were assumed to change little in 1976 and 1977 and to return gradually to the model's estimated growth rates over the period to 1985;

(b) Anti-Inflation Board controls were assumed to be removed in 1978;

(c) a permanent reduction of eight per cent was assumed in federal income tax rates from 1978 on;

(d) the supply of high powered money was assumed to grow at 90 per cent of the rate of growth of nominal GNP; and

(e) the Canadian dollar was assumed to be worth 98 United States cents over the whole period to 1985.

Specification of a Pipeline Submodel in CANDIDE

The method used to shock the model involved treating pipeline investment as a demand category separate from other demand items in the CANDIDE model, not passing information on this new project through the real side input/output converters (except for a few minor adjustments as outlined in the next section), and directly shocking the relevant variables by working outside the existing real side CANDIDE input/output framework. This implicitly meant providing specific information on the input/output relationships of the pipeline project to the appropriate sectors of the model.

The reason for selecting this method instead of directly shocking the existing final demand items in CANDIDE is that the latter is equivalent to assuming that the structure of this new pipeline development could be properly captured by the 1961 based CANDIDE input/output table, modified by the adjustment equations (to capture the historical structure of the economy). Such an assumption was not, on the whole, valid.

TABLE 1

Major Economic Indicators From the Control Solution

(year to year percentage change, in constant dollar figures unless otherwise specified)

	1978	1979	1980	1981	1982	1983	1984	1985
Gross National Product	6.045	5.010	5.284	4.676	4.587	4.058	4.143	4.257
Total Consumption	5.655	3.225	4.004	4.107	4.321	3.994	4.256	4.321
Government Current Expenditures	3.214	5.211	3.936	4.969	4.983	4.747	4.529	4.392
Gross Fixed Capital Formation	11.866	7.128	7.620	5.700	5.551	4.801	4.611	4.706
Exports of Goods & Services	5.531	7.027	8.018	6.318	4.721	4.168	4.459	4.916
Imports of Goods & Services	9.156	4.676	6.287	5.656	4.911	4.717	5.257	5.492
Implicit Price Index GNE	6.029	6.399	6.106	6.533	6.001	6.127	5.944	6.012
Consumer Price Index	6.013	6.015	5.699	5.896	5.397	5.443	5.333	5.473
Unemployment Rate (%) (1)	7.638	7.321	6.807	6.472	5.921	5.444	5.114	4.627
Total Employment (Thousands)	2.633	2.786	2.850	2.667	2.688	2.374	2.350	2.433
90 Day Finance Company Paper Rate (%) (1)	7.122	7.493	7.673	8.209	8.140	8.465	8.722	9.215
Long-term Industrial Bond Rate (%) (1)	9.935	9.831	9.826	9.997	10.080	10.236	10.416	10.686
Wages & Salaries (2) (Millions of Current $)	10.616	11.063	11.724	11.348	11.428	10.915	11.013	11.244

(1) The figure shown is the rate during the year, not a percentage change.
(2) Including supplementary income and military pay and allowance.

The inclusion of a specific pipeline sector requires that industry outputs be shocked directly, in addition to creating a pipeline final demand sector. Those links in the model between industry outputs and industry wages, which are outside the direct influence of the pipeline, are allowed to operate normally. Specific information on pipeline wages and employment is added directly. The CANDIDE wage-price framework remains unchanged. The direct effect of the pipeline on the balance of payments is also added to the model. These changes include the direct effects on foreign borrowing and retirement of debt, interest and dividend payments, imports of goods and services, reductions in oil imports or increases in gas exports during the operation phase, and revenues from transmitting Alaska gas to the United States markets (where applicable). (See Figure 1).

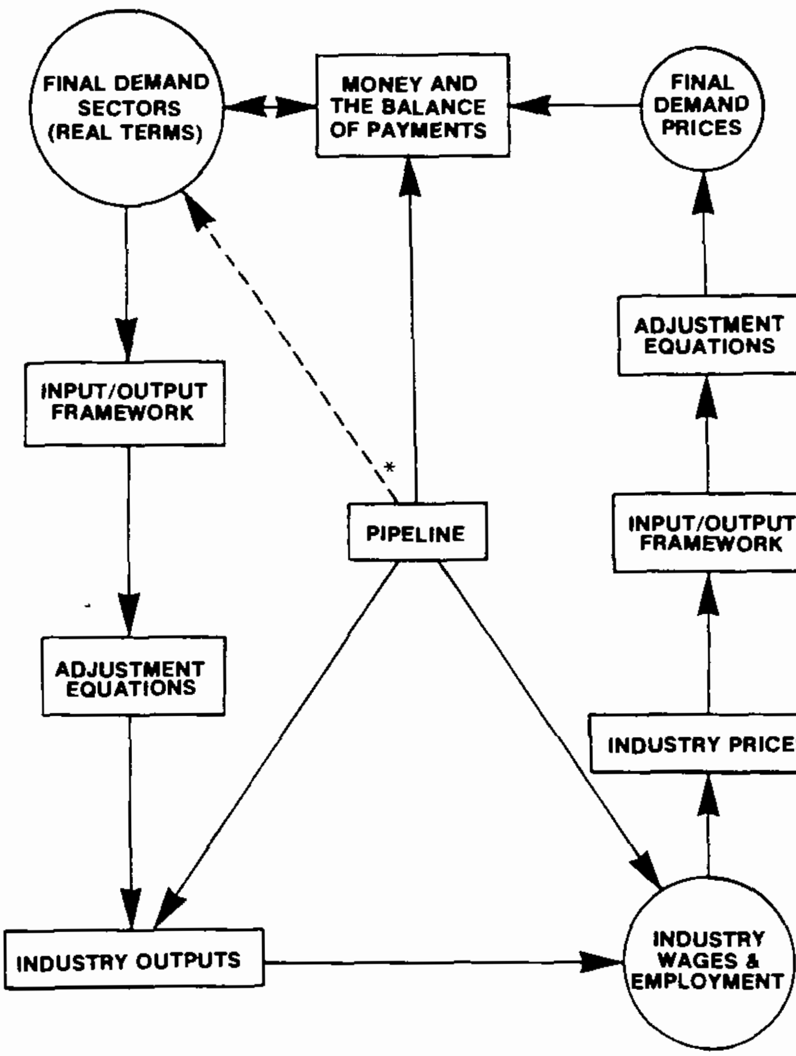
The specification of a pipeline submodel in CANDIDE on the lines suggested above involves adding new equations and changing the existing relevant CANDIDE equations to capture the detailed information on the pipeline project. The equations of this pipeline submodel are recorded in Table 2, followed by a glossary of those symbols which are not self-explanatory in the pipeline submodel. The reader is referred to Economic Council of Canada publications on CANDIDE Model 1.2M, for a definition of all other symbols.[1]

All pipeline variables have been underlined for quick identification. An underlined variable on the left hand side of an equation indicates that a pipeline equation has been **added** to the CANDIDE model. If underlined variables appear only on the right hand side of an equation, this means that that particular CANDIDE equation has only been **modified** to include the direct effect of the pipeline project.

[1] The reader may notice that the definition of certain variables in the pipeline submodel of Table 2 has changed from that used by the Economic Council. The reason for this is that such CANDIDE variables are "free" variables, i.e., they can be redefined and used at the user's discretion without affecting the model solution (except for those variables). These free variables have been used to introduce the pipeline variables into the model in the Board's analysis.

FIGURE 1

METHOD FOR CONDUCTING A PIPELINE MACROECONOMIC IMPACT STUDY USING CANDIDE



*THE PIPELINE VARIABLES ON THE FINAL DEMAND SIDE GENERALLY DO NOT PASS THROUGH THE INPUT/OUTPUT FRAMEWORK AS DISCUSSED IN THE TEXT

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CHAPTER 4 - Continued

ROUTE MAPS

CAGPL Project

Foothills Project

Foothills (Yukon) Project

TABLE 2

THE PIPELINE SUBMODEL IN CANDIDE

```
                                                                        (BLOCK.EQUATION
C       IMPORTS,$1961.,INT.,DIV.,INCOME PAYMENTS TO U.S.
E 44    INCUMK=INCUMK+(STF+BASBAL)/TOSVMP                                      (8.44)

C       COMMODITY REQUIREMENT-CEMENT AND CONCRETE PRODUCTS
E 60    CMNTCR=CMNTCR+IMPX19                                                   (9.60)

C       COMMODITY REQUIREMENT-FUELS,PETROLEUM
E  2    FUELCR=FUELCR+IMPX13                                                  (10.02)

C       COMMODITY REQUIREMENT-ROADS,HIGHWAYS,AIRSTRIPS
E 13    ROADCR=ROADCR+IMPX06                                                  (10.13)

C       TRANSPORTATION          - TOTAL EMPLOYMENT
E 25    TSET=EXP(-.45533*ALOG(TSCK)<-1>+B(1)+B(2)*DPSIXT+B(3)*(TIME           (11.25)
2           *DPSIXT)+B(4)*ALOG(TSY-IMPX01*IMPX08)
3                  +B(5)*ALOG(TSY-IMPX01*IMPX08)<-1>
4                  +B(6)*ALOG(TSY-IMPX01*IMPX08)<-2>
5                  +B(7)*ALOG(TSY-IMPX01*IMPX08)<-3>)+IMPX10

C       CONSTRUCTION            - TOTAL EMPLOYMENT
E 24    COET=COET+IMPX22                                                      (11.24)

C       CONSTRUCTION            - TOTAL MANHOURS
E 36    COETH=COETH+IMPX22*(COETH/COET)<-1>                                   (11.36)

C       TRANSPORTATION          - TOTAL MANHOURS
E 37    TSETH=TSETH+IMPX10*(TSETH/TSET)<-1>                                   (11.37)

C       CURRENT DOLLAR PIPELINE INVESTMENT INCLUDING IMPORTS=AGHPW
E  1    AGHPW=CO4P*IMPX06+TST3P*IMPX07+TSTP*IMPX08+MA20P*IMPX09+MA17P*        (12.01)
2           IMPX19+COULC*IMPX20+MA14P*IMPX12+MA155P*IMPX03+MA18P*IMPX13+
3       COP*IMPX05+CSP*IMPX04+TSCP*IMPX26+UTP*IMPX15+(AGHPW/
4           (RECCA*REXN+FSHPW))*TRHPW+REXN*RECCA*(AGHPW/(RECCA*REXN+
5           FSHPW))

C       CONSTANT DOLLAR PIPELINE INVESTMENT-NET OF IMPORTS=FSHPW
E  3    FSHPW=IMPX06+IMPX08+IMPX09+IMPX19+IMPX20+IMPX12+IMPX03+               (12.03)
2             IMPX13+IMPX05+IMPX04+IMPX26+IMPX15+TRHPW+IMPX07
C       PIPELINE---CONST.DOLLAR INDIRECT TAXES AND DUTIES
E  9    TRHPW=.1288939296*(FSHPW+RECCA)                                       (12.09)

C       PIPELINE CAPITAL STOCK--MANF.
E 5     MAHPW=MAHPW<-1>+IMPX03+IMPX09+IMPX13+IMPX19+IMPX12                    (12.05)

C       PIPELINE CAPITAL STOCK--TRAN.
E 8     TSHPW=TSHPW<-1>+IMPX07+IMPX08+IMPX26                                  (12.08)
```

```
C      PIPELINE CAP.STOCK---SERVICES
E 11   CSHPW=CSHPW<-1>+IMPX04                                          (12.11)

C      PIPELINE CAPITAL STOCK--CONST.
E 6    COHPW=COHPW<-1>+IMPX05+IMPX06+IMPX20                            (12.06)

C      PIPELINE CAPITAL STOCK--UTIL.
E 7    UTHPW=UTHPW<-1>+IMPX15                                          (12.07)

C      PIPELINE CAPITAL STOCK--MISC.
E 4    MIHPW=MIHPW<-1>+RECCA+TRHPW                                     (12.04)

C      PIPELINE CAPITAL STOCK--TOTAL
E 12   TEHPW=MAHPW+TSHPW+CSHPW+UTHPW+MIHPW                             (12.12)

C      CAPITALIZED VALUE OF PIPELINE EXPENDITURES
E  2   FOHPW=FOHPW<-1>+(AGHPW*DT+MINR+BASBAL+DICAN+BALDIA)             (12.02)

C      VALUE OF SERVICES ON GAS TRANSMISSION TO U.S.
E 10   FIHPW=RTRB3M*TMPX23                                             (12.10)

C      WAGES,SAL.&SUPP.INC.&MIL.PAY&ALL.-CONSTRUCTION,MILLION CURR.$
E 6    COWA=COWA<-1>*(1.+Q(COETH))*(1.+Q(CPI<-1>))                     (13.06)
2          *(1.+(B(1)+B(2)*P(COET<-1>)+B(3)*P((COY+IMPX20)/COET)
3          +B(4)*(D56-.5*D57-D58)+B(5)*D(D73)+B(6)*P(CUP<-1>))/100.)

C      WAGES,SAL.&SUPP.INC.&MIL.PAY&ALL.-COMM.BUS.PERS.SERV.,MIL.CUR.$
E 13   TEWA=TEWA+COULC*IMPX20                                          (13.13)

C      UNIT LABOUR COST,CONSTRUCTION
E 27   COULC=1.37955866*COWA/(COY-.37955866*IMPX20)                    (13.27)
C      UNDEPRECIATED BALANCE-TRANSPORTATION,STORAGE AND COMMUNICATION
E 10   TSUB=TSUB+TST3P*IMPX07+TSTP*IMPX08+TSCP*IMPX26                  (19.10)

C      UNDEPRECIATED BALANCE-UTILITIES
E 11   UTUB=UTUB+UTP*IMPX15                                            (19.11)

C      UNDEPRECIATED BALANCE (INCLUDING GOVERNMENT
C              AND RESIDENTIAL CONSTRUCTION)
E 15   UB=UB<-1>+IPG-CCA<-1>+AGHPW                                     (19.15)

C      CAPITAL CONSUMPTION ALLOWANCES - TRANS.STORAGE AND COMM.
E 20   TSCCA=TSCCA+.071183*(TST3P*IMPX07+TSTP*IMPX08+TSCP*IMPX26)      (19.20)

C      CAPITAL CONSUMPTION ALLOWANCES - UTILITIES
E 21   UTCCA=UTCCA+.03296566*(UTP*IMPX15)                              (19.21)
```

```
C       VALUE OF IMPORTS-CONSTANT U.S.DOLLARS
E 24    RECCA=(.8711060704*IMPX11*FSHPW)/(1.+.8711060704*.1288939296*        (19.24)
2        IMPX11*REXN)

C       FEDERAL INDIRECT TAXES
E 30    TIF=TCUS+FSALES+EXCISE+FTOTH                                          (19.30)
2        +(AGHPW/(FSHPW+REXN*RECCA))*TRHPW

C       TARIFF RATE PER BCF/YR THROUGHPUT IN DOLLAR UNITS
E  6    RTRB3M=(MELT+TMPX25)*FOHPW/TMPX21                                     (20.06)

C       TOTAL STOCK OF LONG TERM DEBT
E 1     MCODCH=MCODCB<-1>+TOCBW-DICAN                                         (20.01)

C       TOTAL STOCK OF EQUITY DEBT
E  2    MDR=MDR<-1>+TNDFSB*NNIPMW                                             (20.02)

C       DOMESTIC INTEREST PAYMENTS
E  3    MINR=(RINDB+1.15)*(MCODCH-MSAVR)<-1>/100.                            (20.03)

C       STOCK OF FOREIGN LONG TERM DEBT
E  4    MSAVR=NETLTF+MSAVR<-1>                                                (20.04)

C       TOTAL PIPELINE DEBT RETIREMENT
E 2     DICAN=TMPX27*MCODCB<-1>                                               (21.02)

C       TOTAL PIPELINE DIVIDEND PAYMENTS
E 3     BALDIA=TMPX02*MDR<-1>                                                 (21.03)

C       PIPELINE BORROWINGS-ALL SOURCES
E  4    NNIPMW=TMPX14*(AGHPW*DT+HASBAL+MINR+DICAN+BALDIA)                    (21.04)

C       BOND BORROWINGS-ALL SOURCES
E  6    TOCBW=NNIPMW*(1.-TNOFSB)                                              (21.06)

C       FOREIGN BORROWINGS OF EQUITY
E  7    BALLTP=TMPX17*TNDFSB*NNIPMW                                           (21.07)

C       FOREIGN BOND BORROWINGS NET OF RETIREMENT
E  8    NETLTF=TMPX16*TOCBW-D54*DICAN                                         (21.08)

C       CURRENT ACCOUNT BALANCE ( BOP BASIS )
E 17    CURBAL = XPBPXC - IMBPMC                                              (21.17)
2       +FIHPW-REXN*RECCA*(AGHPW/(FSHPW+RECCA*REXN))
3        +NFDEF*CPGSXP
```

```
C      INTEREST PAYMENTS TO FOREIGNERS-PIPELINE
E 18   BASHAL=(TR*1.15)*MSAVR<-1>/100.                                  (21.18)

C      TOTAL NET CAPITAL FLOW
E 22   NETFLO=NETFLO                                                     (21.22)
2      +BALLTP+NETLTF

C      PIPELINE DIVIDEND PAYMENTS TO FOREIGNERS
E 20   STF=IMPX17+BALDIA                                                 (21.20)

C      MACHINERY -REAL DOMESTIC PROD. $MILL-1961
E 24   MA14Y=MA14Y+IMPX12                                                (23.24)

C      RAILROAD ROLLING STOCK-REAL DOMESTIC PROD. $MILL-1961
E 28   MA155Y=MA155Y+IMPX03                                              (23.28)

C      MISC.MANUFACTURERS-REAL DOMESTIC PROD. $MILL-1961
E 35   MA20Y=MA20Y+IMPX09                                                (23.35)

C      PIPELINES-REAL DOMESTIC PROD. $MILL 1961
E 38   TST3Y=TST3Y+IMPX07                                                (23.38)

C      GAS-REAL DOMESTIC PROD<$MILL-1961
E 47   UT2Y=UT2Y+NFDEF                                                   (23.47)

C      PIPELINE TRAN. DEFLATOR
S      NFSUB=NFSUB<-1>*(RTRB34/RTRB3M<-1>)                               (X280)

C      TRANSPORTATION-REAL DOMESTIC PROD. $MILL-1961
E 63   TSTY=TSTY+IMPX08+(FIHPW/NFSUB)                                    (23.63)

C      COMMUNICATION-REAL DOMESTIC PROD. $MILL-1961
E 64   TSCY=TSCY+IMPX26                                                  (23.64)

C      COY-REAL DOMESTIC PROD. $MILL-1961
E 70   COY=COY+IMPX05                                                    (23.70)

C      UTILITIES-REAL DOMESTIC PROD. $MILL-1961
E 71   UTY=UTY+IMPX15                                                    (23.71)

C      SERVICES-REAL DOMESTIC PROD. $MILL-1961
E 76   CSY=CSY+IMPX04                                                    (23.76)

C      TOTAL ECONOMY-REAL DOMESTIC PROD. $MILL-1961
E 78   TEY=TEY+IMPX20                                                    (23.78)

C      CONSISTENCY MECHANISM
E 80   FDK=FDK+FSHPW-TRHPW+(FIHPW/NFSUB)+NFDEF                           (23.80)
```

```
C       GROSS NATIONAL PRODUCT LESS RESIDUAL ERROR,CURRENT$
E 36    GNPLR=CZ+IPG+TEVPCC+XPTTXC-IMPTMC+GCURRC                    (24.36)
2        +AGHPW-REXN*RECCA*(AGHPW/(FSHPW+REXN*RECCA))+
3       FIHPW+NFDEF*CPGSXP

C       TOTAL ECONOMY GROSS DOMESTIC PRODUCT, CURRENT $
E 37    TEYC=TEYC+.0038561*(AGHPW-REXN*RECCA*(AGHPW/(FSHPW+         (24.37)
2        REXN*RECCA))-TRHPW*(AGHPW/(FSHPW+REXN*RECCA))
3         +(FIHPW/NFSUB)*(NFSUB-TSTP)+NFDEF*(CPGSXP-UT2P)
4       +TMPX20*(COULC-TEP))+TMPX20*(COULC-TEP)
5         +(FIHPW/NFSUB)*(NFSUB-TSTP)+NFDEF*(CPGSXP-UT2P)

C       GROSS NATIONAL PRODUCT LESS RESIDUAL ERROR, CONSTANT $
E 39    GNPKLR=CZK+GCURRK+GFICAK+IME+INRC+IR+RIAD+TIAD+TEVPCK      (24.39)
2               +XPTTXK-IMPTMK+GNPAD
3       +FSHPW+(FIHPW/NFSUB)+NFDEF

C       CONSISTENCY MECHANISM
E 23    CURSUM=CURSUM                                               (35.23)
2       +(AGHPW-REXN*RECCA*(AGHPW/(FSHPW+REXN*RECCA))
3       -TRHPW*(AGHPW/(FSHPW+REXN*RECCA))-TMPX20*(COULC-TEP)
4        +FIHPW*TSTP/NFSUB+NFDEF*UT2P)*.9961439
5       +TRHPW*(AGHPW/(FSHPW+REXN*RECCA))

C       MANUFACTURING          -TOTAL REAL GROSS CAP.STOCK
E 58    MACK=MACCOK+MACMEK                                          (45.58)
2       +MAHPW*(1.+MIHPW/TEHPW)

C       CONSTRUCTION           -TOTAL REAL GROSS CAP.STOCK
E 59    COCK=COCCOK+COCMEK                                          (45.59)
2       +COHPW*(1.+MIHPW/TEHPW)

C       TRANSPORTATION         -TOTAL REAL GROSS CAP.STOCK
E 60    TSCK=TSCCOK+TSCMEK                                          (45.60)
2       +TSHPW*(1.+MIHPW/TEHPW)

C       UTILITIES              -TOTAL REAL GROSS CAP.STOCK
E 61    UTCK=UTCCOK+UTCMEK                                          (45.61)
2       +UTHPW*(1.+MIHPW/TEHPW)

C       SERVICES               -TOTAL REAL GROSS CAP.STOCK
E 64    CSCK=CSCCOK+CSCMEK                                          (45.64)
2       +CSHPW*(1.+MIHPW/TEHPW)

C       VALUE OF ALL CAPITAL  ITEMS
E 68    KBC=KBC+(KBC/KSTOCK)<-1>*TEHPW                              (45.68)
```

Source: CANDIDE 1.2M model code as modified by the Board.

Glossary of Symbols

TMPX01	Operating expenses as a proportion of TMPX08 (transportation investment, including operating expenses)
TMPX11	Import content (goods and services only) of pipeline
TMPX16	Ratio of foreign to total pipeline bond borrowings
TMPX17	Ratio of foreign to total equity borrowings
TMPX21	Total quantity of gas flows
TMPX25	Rate of return on the capitalized value of total pipeline expenditures
DT	Adjustment factor to balance investment estimates in cost of facilities and financing schedules of submitted evidence (=1 in the Board's simulations)
D54	Ratio of foreign to total long-term debt retirement
MELT	Operating expenses as a ratio of the capitalized value of total pipeline expenditures
TNOFSB	Ratio of equity to total pipeline borrowings

Assumptions of the Analysis

The Board's macroeconomic impact study is based on the following assumptions:

(a) Pipeline investment would not directly reduce any other domestic investments, such as those in energy resource development. Of course, the model is free to determine the induced effects of this project on investment in other sectors of the economy.

(b) The availability of Delta gas may be viewed as displacing imported oil, generating new exports of gas or any combination of the two. The choice of any of these assumptions does not, however, in any way affect the conclusions of the analysis as long as commodity equivalence between oil and gas prices is assumed for the period when Delta gas would be available. This study assumed such equivalence. Also the availability of Delta gas was assumed not to displace the production of other domestic energy resources.

(c) The money supply (as defined in CANDIDE) was assumed not to change in response to any disturbances in the economy. Fiscal policy was unaltered from that implicit in the control solution. Simulations were carried out, both for CAGPL and Foothills, under the alternative assumptions of fixed and flexible exchange rates.

The simulation of the CANDIDE model under a flexible exchange rate system required certain revisions to the model. The mechanism which was introduced in CANDIDE for this purpose is essentially the same as that in TRACE. The model keeps trying a new value for the exchange rate in response to a shock and does not converge as long as the change in foreign exchange reserves is different from a specified value (approximating zero in the case of a completely flexible exchange rate system). The solution of the model with this mechanism automatically provided an estimated value for the exchange rate.

Pipeline Data and Sources

The data with which the pipeline submodel in CANDIDE was shocked were derived from the submissions of the Applicants. Table 3 lists the major input data, with sources, for the Board's analysis of the CAGPL proposal. The current dollar data for the CAGPL study were first converted to 1976 dollars using deflators assumed by CAGPL and filed as evidence. Using deflators from the

CANDIDE model, these 1976 dollar values were converted to 1961 dollars.

Table 4 lists the major input data, with sources, for the Board's analysis of the Foothills proposal. Again current dollar figures were first converted to 1976 dollar figures using deflators assumed by Foothills and filed as evidence. Using deflators from the CANDIDE model, these 1976 dollar values were converted to 1961 dollars.

It should be noted that the current dollar estimates of the direct effects of the pipeline as utilized in the Board's analysis are slightly different from the data submitted by the Applicants because these data are converted, where required by the model, to 1961 dollars using CANDIDE deflators. Current dollar estimates of the pipeline variables in the model are then derived using the CANDIDE deflators in the shocked simulation. Thus, the use of CANDIDE deflators yielded current dollar estimates of pipeline variables slightly different from those submitted by the Applicants. This procedure has two advantages. First, price changes over time in the pipeline project are then consistent with those projected by the model for the rest of the economy. Secondly, the pipeline submodel becomes a simultaneous part of the whole model, so that the pipeline variables are adjusted automatically in current dollars if the project affects the rate of inflation.

TABLE 3

MAJOR INPUT DATA AND SOURCES FOR THE BOARD'S MACROECONOMIC IMPACT STUDY OF CAGPL BASE CASE

(millions of current dollars unless otherwise stated)

Variable	1978	1979	1980	1981	1982	1983	1984	1985
1. Total Pipeline Investment	812	1,357	1,782	1,550	640	299	329	128
2. Import Content	239	374	324	317	114	68	57	29
3. Operating Expenses (Millions of 1976 dollars)	0	0	0	22	48	61	65	64
4. Associated Delta Gas Field Development and Exploration Expenditures (Millions of 1976 dollars)	367	363	274	316	402	290	235	280
5. Employment, Construction Phase (Thousands of Men)	2	3	8	8	3	1	1	1
6. Employment, Operation Phase (Thousands of Men)	0	0	0	0	1	1	1	1
7. Total Borrowings	1,083	1,491	2,043	1,798	745	430	429	162
8. Total Equity Borrowings	750	500	500	0	0	0	0	0
9. Foreign Equity Borrowings	367.5	245.0	245.0	0	0	0	0	0
10. Total Debt Borrowings	333	991	1,543	1,798	745	430	429	162
11. Foreign Debt Borrowings	198	871	1,218	1,248	270	0	0	0
12. Total Debt Retirement	0	0	0	0	161	444	444	444
13. Foreign Debt Retirement	0	0	0	0	118	312	312	312
14. Return on Rate Base	0	0	0	134	490	706	759	854
15. Volume of Production of Delta Gas (BCF/Yr).	0	0	0	226	434	433	515	609
16. Volume of Total Gas Transported (BCF/Yr.)	0	0	0	226	800	1,158	1,248	1,412

Sources:

Item 1-2. Canadian Content Study (1976), Exhibit N-AG-3-126.

3-4. Exhibit N-AG-3-152, Appendix C, page 7.

5-6. Exhibit N-AG-3-64-1, Table 9.

7-13. Exhibit N-AG-3-140, Panel 1, Appendix A, pages2-10.

14. Exhibit N-AG-3-140, Panel 5, Section 11, Schedule 4.

15. Exhibit N-AG-3-152, Appendix C, page 3.

16. Exhibit N-AG-3-15, Part 3B, page 39.

TABLE 4

MAJOR INPUT DATA AND SOURCES FOR THE BOARD'S MACROECONOMIC IMPACT STUDY OF FOOTHILLS

(millions of current dollars unless otherwise stated)

Variable	1978	1979	1980	1981	1982	1983	1984	1985
1. Total Pipeline Investment	58	233	759	1,057	984	973	223	534
2. Import Content	2	15	59	74	76	133	25	61
3. Operating Expenses (Millions of 1976 dollars)	0	0	0	0	31	53	61	68
4. Associated Delta Gas Field Development and Exploration Expenditures (Millions of 1976 dollars)	287.2	454.0	499.6	515.0	637.0	553.2	638.6	619.4
5. Employment, Construction Phase (Thousands of Men)	1	1	2	4	4	2	2	2
6. Employment, Operation Phase (Thousands of Men)	0	0	0	0	0	1	1	1
7. Total Borrowings	85	455	895	1,347	1,278	583	60	60
8. Total Equity Borrowings	85	245	320	25	75	99	0	0
9. Total Debt Borrowings	0	210	575	1,322	1,203	484	60	60
10. Foreign Debt	0	60	175	370	555	50	0	0
11. Volume of Production of Delta Gas (BCF/Yr.)	0	0	0	0	48.5	316.5	462.5	608.5

Sources:

Item 1. Exhibit N-FH-5-5-1, page 5A-3.

2. Exhibit N-FH-5-5-1, page 5A-128.

3. NEB estimates.

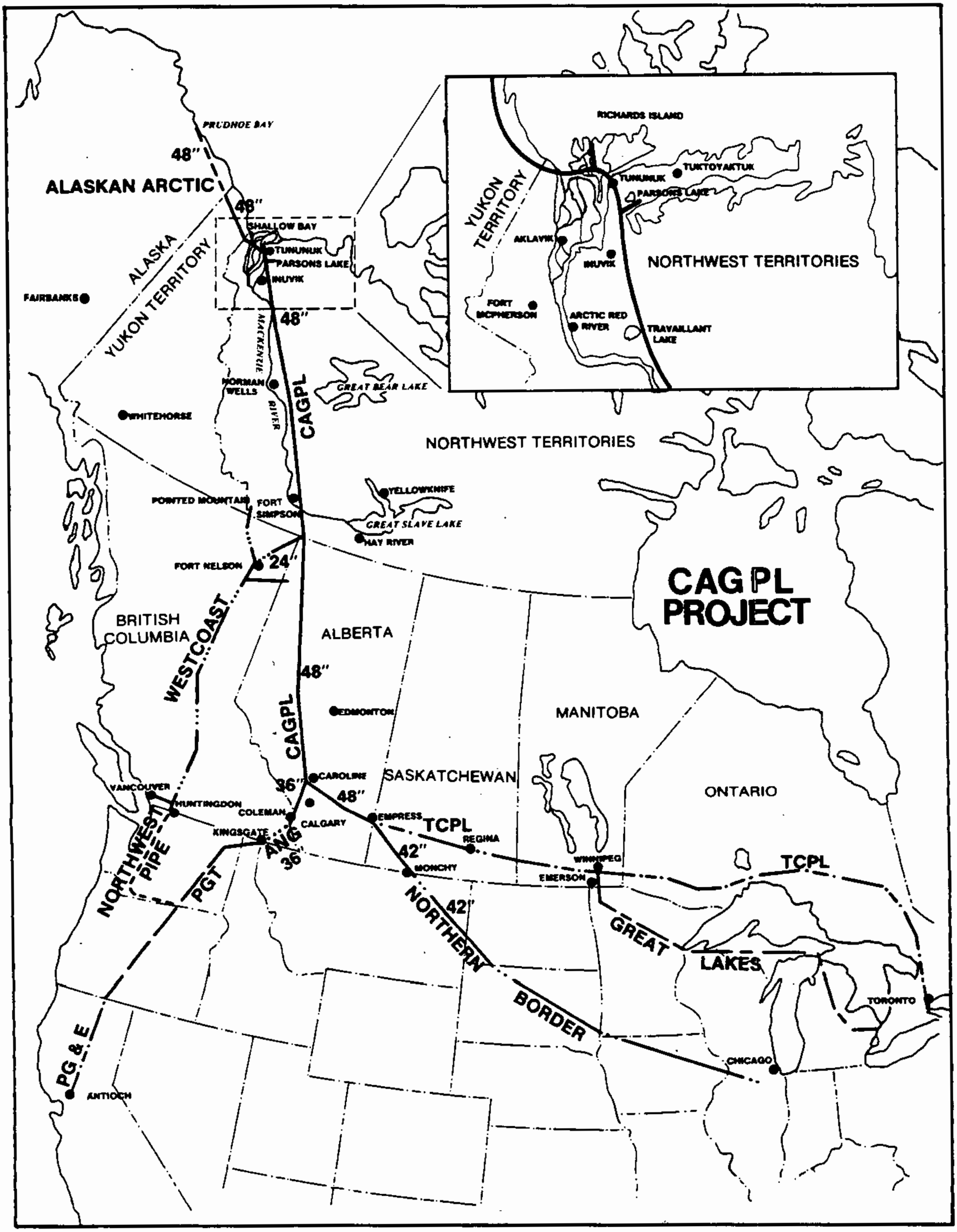
4. Exhibit N-FH-5-5-1, pages 5A-52 and 5A-53, sum of exploration, development, processing plant, and Beaufort Basin operating expenditures.

5-6. Exhibit N-FH-5-5-1, page 5A-128.

7-10. Exhibit FH(Y)-114-20, Schedule B for TCPL Financing and Exhibit N-FH-5-79, page 4 of the "Plan of Financing" for the financing of Foothills, Trunk Line, Trunk Line (Canada), Westcoast.

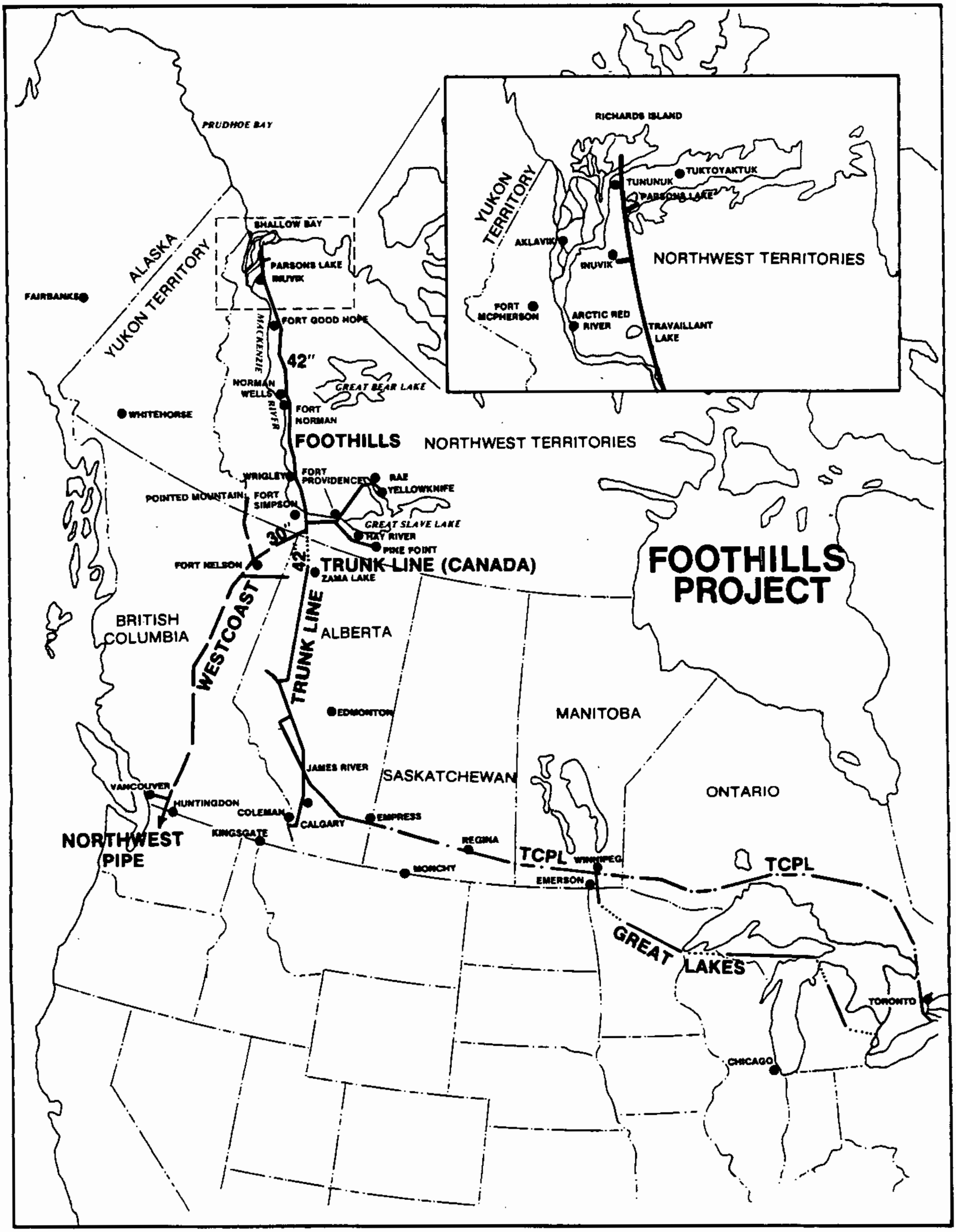
11. Exhibit N-FH-5-5-1, page 5A-46.

MAP 3–1

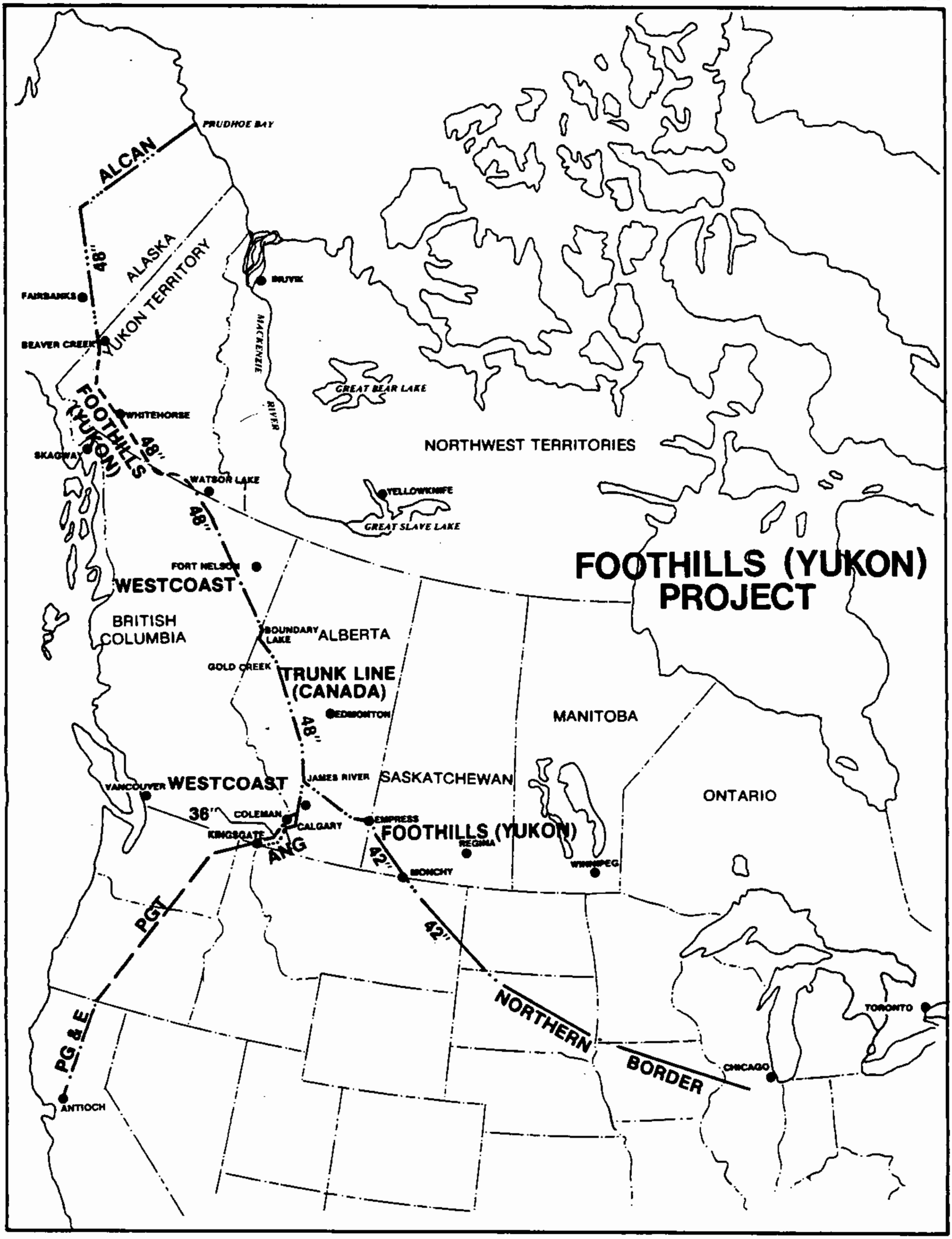


PRUDHOE BAY
48"
ALASKAN ARCTIC
48"
ALASKA
YUKON TERRITORY
FAIRBANKS
SHALLOW BAY
TUNUNUK
PARSONS LAKE
INUVIK
48"
MACKENZIE RIVER
NORMAN WELLS
GREAT BEAR LAKE
WHITEHORSE
CAGPL
NORTHWEST TERRITORIES
POINTED MOUNTAIN
FORT SIMPSON
YELLOWKNIFE
GREAT SLAVE LAKE
HAY RIVER
FORT NELSON
24"
CAGPL PROJECT
BRITISH COLUMBIA
WESTCOAST
ALBERTA
48"
EDMONTON
CAGPL
MANITOBA
CAROLINE
SASKATCHEWAN
ONTARIO
36"
48"
VANCOUVER
HUNTINGDON
COLEMAN
CALGARY
EMPRESS
TCPL
REGINA
KINGSGATE
ANG
36"
42"
MONCHY
WINNIPEG
EMERSON
TCPL
NORTHWEST PIPE
PGT
NORTHERN
42"
GREAT LAKES
BORDER
TORONTO
CHICAGO
PG & E
ANTIOCH
RICHARDS ISLAND
TUKTOYAKTUK
TUNUNUK
PARSONS LAKE
YUKON TERRITORY
AKLAVIK
INUVIK
NORTHWEST TERRITORIES
FORT MCPHERSON
ARCTIC RED RIVER
TRAVAILLANT LAKE

MAP 3-3


FOOTHILLS PROJECT
PRUDHOE BAY
ALASKA
YUKON TERRITORY
FAIRBANKS
SHALLOW BAY
PARSONS LAKE
INUVIK
FORT GOOD HOPE
MACKENZIE RIVER
42"
NORMAN WELLS
GREAT BEAR LAKE
FORT NORMAN
WHITEHORSE
FOOTHILLS
NORTHWEST TERRITORIES
WRIGLEY
FORT PROVIDENCE
RAE
YELLOWKNIFE
POINTED MOUNTAIN
FORT SIMPSON
GREAT SLAVE LAKE
HAY RIVER
PINE POINT
30"
42"
FORT NELSON
TRUNK LINE (CANADA)
ZAMA LAKE
BRITISH COLUMBIA
WESTCOAST
TRUNK LINE
ALBERTA
EDMONTON
MANITOBA
JAMES RIVER
SASKATCHEWAN
ONTARIO
VANCOUVER
HUNTINGDON
COLEMAN
CALGARY
EMPRESS
NORTHWEST PIPE
KINGSGATE
REGINA
TCPL
WINNIPEG
TCPL
MONCHY
EMERSON
GREAT LAKES
TORONTO
CHICAGO
RICHARDS ISLAND
YUKON TERRITORY
TUKTOYAKTUK
TUNUNUK
PARSONS LAKE
AKLAVIK
INUVIK
NORTHWEST TERRITORIES
FORT MCPHERSON
ARCTIC RED RIVER
TRAVAILLANT LAKE

MAP 3-8



FOOTHILLS (YUKON)
PROJECT
PRUDHOE BAY
ALCAN
48"
ALASKA
YUKON TERRITORY
FAIRBANKS
BEAVER CREEK
INUVIK
MACKENZIE RIVER
GREAT BEAR LAKE
WHITEHORSE
SKAGWAY
FOOTHILLS (YUKON)
48"
WATSON LAKE
NORTHWEST TERRITORIES
YELLOWKNIFE
GREAT SLAVE LAKE
48"
FORT NELSON
WESTCOAST
BRITISH COLUMBIA
BOUNDARY LAKE
ALBERTA
GOLD CREEK
TRUNK LINE (CANADA)
EDMONTON
48"
MANITOBA
JAMES RIVER
SASKATCHEWAN
VANCOUVER
WESTCOAST
ONTARIO
36"
COLEMAN
CALGARY
EMPRESS
KINGSGATE
FOOTHILLS (YUKON)
REGINA
ANG
42"
MONCHY
WINNIPEG
PGT
42"
NORTHERN
BORDER
TORONTO
CHICAGO
PG & E
ANTIOCH