A Comparison of Natural Gas Pipeline Options for the North

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Highlights

This study analyzes the costs and benefits of the choices available to transport natural gas from Canada's north to southern markets. High natural gas prices in the North American market, and a more positive investment climate, have renewed interest in development of reserves in the Mackenzie Delta region of the Northwest Territories and Prudhoe Bay in Alaska. The development of the natural gas reserves will require the construction of pipeline infrastructure to get the gas to market. There are several pipeline route options available: 1. Mackenzie Valley Stand Alone, 2. a combination onshore Alaska North Slope with Mackenzie Valley, 3. a combination offshore Alaska North Slope with Mackenzie Valley, 4. the Alaska Natural Gas Transmission System (ANGTS), and 5. a combination ANGTS and Dempster Lateral.

This report describes the results of analysis for these five pipeline options for developing Mackenzie Delta and Prudhoe Bay natural gas. Table 1 below summarizes these results. The table excludes the results from one pipeline option. The Mackenzie Valley with Prudhoe Bay Onshore pipeline route is omitted because it has benefits and costs very similar to the Mackenzie Valley plus Prudhoe Bay Offshore route which is included in the table. The Prudhoe Bay onshore and offshore pipeline routes would connect Alaska gas with gas from the Mackenzie Delta and ship both down the Mackenzie Valley.

Table 1

Economic Impact of Pipeline Projects
($000,000)

	Stand-Alone Mackenzie Valley, 30 in.	Mackenzie 48 in, Plus Prudhoe Offshore	ANGTS Plus Dempster Lateral	Mackenzie Field Development	ANGTS Stand-Alone
Capital cost of Project	2,280	5,570	8,100	1,480	6,000
NWT-Employment[1]-construction	6,640	11,110	2,540	7,370	0
NWT – GDP - construction	707	1,203	255	784	0
Total NWT Fiscal Benefits [2]	365	512	177	8	0
Canada-Employment[1]-construction	31,190	60,020	71,970	20,980	43,360
Canada – GDP - construction	2,132	4,159	5,117	1,434	3,131
Total Canada Fiscal Benefits [2]	6,240	9,007	5,966	157	1,717
Pipeline Tolls[3] ($/gj)	0.88	0.53	1.26	na	na
Producer Revenue[4]	15,849	18,292	13,265	na	0

1. Person years, direct plus indirect
2. Fiscal impacts include the impact on government revenue of construction of the pipeline, field development, ongoing pipeline operation, and gas production. Natural gas production revenues are discounted at 5.5 percent. Canada Fiscal impacts refer to all prov/terr/federal governments. Discounting recognizes the time value of money. As revenues are earned further and further in future, the less the value of those revenues in today's dollars.
3. Tolls are quoted for gas shipped from the Mackenzie Delta to the NWT/Alberta border for the Mackenzie Valley routes, and from the Mackenzie Delta to Boundary Lake Alberta for the ANGTS Plus Dempster Lateral.
4. Discounted at 5.5 percent.

The results indicate that Canada benefits the most from a Mackenzie Valley and Offshore Prudhoe Bay pipeline that ships Prudhoe Bay and Mackenzie Delta gas for the following reasons: 1. construction costs, 2. economic impacts relative to cost, 3. employment relative to cost, 4. fiscal impacts, and 5. lower tolls. NWT benefits from this pipeline route include over 11,000 person years of employment, $512 million of net revenues for the territorial government, and over a billion dollars of economic activity.

1) Construction costs for the Mackenzie/Prudhoe route are more than $2.5 billion less than the ANGTS/Dempster alternative. This option also allows both Mackenzie Delta and Prudhoe Bay gas to be shipped for a lower capital cost than shipping Alaska gas only via the ANGTS route.

2) The GDP cost ratio is also better for the Mackenzie/Prudhoe pipeline compared to the ANGTS/Dempster option. The ratios are 0.75 vs. 0.63 (the ratio = the amount of Canadian GDP generated for every dollar of capital cost incurred). This indicates that a greater proportion of the construction expenses on the Mackenzie/Prudhoe pipeline will be spent on Canadian goods and services.

3) The Mackenzie Valley and Offshore Prudhoe Bay pipeline is also more effective at generating employment, per dollar spent, than the ANGTS/Dempster route. Employment/capital cost ratios are 10.9 vs. 8.9 (the ratio indicates the number of person years of work generated for every million dollars of capital cost).

4) For Canadian governments, taxes and royalties can be maximized with the construction of the Mackenzie Valley plus Prudhoe Bay Offshore option. This option yields revenues with a present value of approximately $9 billion, $3 billion more than the estimated revenues from the ANGTS plus Dempster lateral route.

5) The Mackenzie/Prudhoe Offshore pipeline route provides the lowest tolls among the options available. Thanks to economies of scale when both Mackenzie Delta and Prudhoe Bay gas is shipped down the Mackenzie Valley, tolls, for Mackenzie Delta gas, on the Mackenzie/Prudhoe Offshore route are 53 cents per GJ.[1] On the other hand, ANGTS/Dempster tolls are $1.26 per GJ over the same points. The Mackenzie Valley Stand Alone pipeline tolls would be approximately 88 cents per GJ from the Mackenzie Delta to the NWT/Alberta border. These lower tolls result in higher revenues to producers.

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1 Economies of scale simply refers to the fact that the average cost to provide a good or service, like transportation of natural gas through a pipeline, will decline as the quantity of the good or service produced increases. Therefore, the more gas shipped over a particular route, the lower the average cost per GJ.

Although the ANGTS/Dempster lateral route generates more person years of employment than the Mackenzie/Prudhoe Offshore option, it also provides lower fiscal benefits to the federal and NWT governments, and lower netbacks to natural gas producers.

The ANGTS plus Dempster lateral option provides fewer economic benefits for the NWT than a Stand Alone Mackenzie Valley pipeline that ships only Mackenzie Delta gas. The Mackenzie Valley pipeline would provide about $190 million more worth of government revenues to the Government of the NWT, and it would yield 4,100 more person years of work in the NWT. The ANGTS plus Dempster lateral choice provides few economic benefits for the NWT. The ANGTS stand-alone route provides no fiscal or economic benefits to the NWT and does not ship Mackenzie Valley gas.

Regardless of the pipeline route chosen, the development of the Mackenzie Delta natural gas field can be expected to provide substantial employment advantages for both the NWT and the country. As many as 7,370 person years of work are expected for the NWT and approximately 20,980 person years for the country as a whole on field development. These benefits would not be realized under the ANGTS Stand Alone route, where no Mackenzie Valley gas is shipped.

This report concludes that Canada would best be served with a pipeline down the Mackenzie Valley. Producers generate larger revenues, costs are minimized, and the government generates greater taxes. Looking at the impacts per dollar spent, the Mackenzie Valley route shows clear advantages over the Alaska highway routes in GDP, employment and income.

Fiscal and Producer Benefits

As per Table 1 above, Mackenzie Delta Producers would be better off with the “Mackenzie 48 in, plus Prudhoe Offshore” route as it results in an additional $5 billion in producer revenues compared to the “ANGTS plus Dempster lateral”, and an extra $2.4 billion in revenues compared to the “Stand Alone Mackenzie Valley" pipeline. These large differences in revenue arise only because of the different pipeline alternatives, the same quantity of gas is assumed to be produced from the Mackenzie Delta in each case. Note that the “Stand Alone ANGTS” route yields no revenues for Mackenzie Delta producers.

Note that the “ANGTS Plus Dempster Lateral”, at $1.26 per GJ, has the most expensive pipeline tolls between the Mackenzie Delta and Alberta. “Stand Alone Mackenzie Valley” tolls are cheaper at $0.88 per GJ, and “Mackenzie 48 in, Plus Prudhoe Offshore” and onshore, are cheapest at $0.53 per GJ. These differences in tolls are reflected in the producer revenues that can be earned under each pipeline scenario.

The table above also shows the fiscal benefits available to Canadian governments. The revenues earned by territorial/provincial/federal governments would be over $9 billion under the “Mackenzie 48 in, plus Prudhoe Offshore” alternative, $3 billion more than the “ANGTS plus Dempster lateral” and about $2.75 billion more than the “Stand Alone Mackenzie Valley" route. The lower government revenues are caused by Mackenzie Delta gas that has to pay higher pipeline costs.

Market Need

Natural gas market conditions in North America have undergone a fundamental change in the past two years, resulting in a renewed interest in major pipeline proposals to deliver Mackenzie Delta and Alaska North Slope natural gas to southern markets. A key element in the success of any project to bring northern gas to market will be the ability of the market to absorb the incremental supply. Forecasters are calling for aggressive growth in gas demand over the next fifteen to twenty five years. In Canada, this growth is based primarily on industrial demand, with increasing importance of gas used for electrical generation. In the United States, the majority of growth is fueled by gas-fired electrical generation needs.

In order to fulfill this demand growth, exports from Canada to the U.S. are expected to see robust growth over the next two decades. Table 2 gives the time path of exports from Canada assumed by the EIA and the GRI. The projections call for exports from Canada to the U.S. to be roughly 1 tcf/year higher by 2010, and by 2015 they could be nearly 1.5 tcf higher.

Table 2

Annual Exports from Canada
(tcf)

	1999	2000	2005	2007	2010	2012	2015	2020
EIA	3.34	3.55	4.19	4.29	4.50	4.68	4.99	5.38
GRI	3.20	3.20	4.00	4.20	4.40		4.40	
Actual	3.30							

There are four projected sources for incremental Canadian natural gas production: Eastern Canadian offshore projects, conventional WCSB gas production, coalbed methane, and Northern Canada. There is considerable doubt as to whether conventional production from the WCSB can meet all of the incremental requirements; expectations for growth in Eastern Canada are modest relative to the overall market requirement, and coalbed methane is an undeveloped resource. This gives gas from the Mackenzie Delta/Beaufort Sea a promising outlook.

The outlook for gas from Alaska's North Slope is not as clear. The additional 2.5 bcf/d or more that might become available from Prudhoe Bay in Alaska presents a somewhat more difficult challenge. Some ramp-up of deliveries may be required to handle more than 1.5 to 2 bcf/d of gas from the North. A combined Mackenzie Delta/Prudhoe Bay project would need to be carefully timed, and would best proceed in the context of continued modest supply growth throughout North America.

The natural gas potential of the NWT is concentrated in two regions, the Southern NWT including the Liard area, and the Beaufort Basin. The Liard area represents part of an extension of the prolific WCSB into the NWT. Natural gas resources in this area are estimated at 5 tcf, of which just over 1 tcf have been discovered to date. The Beaufort Basin, which has the largest natural gas potential including both onshore and offshore, includes undiscovered natural gas resources totaling approximately 42 tcf. Discoveries to date are expected to contain 13.5 tcf of natural gas reserves. By comparison, the Sable Offshore Energy Project which has opened the offshore natural gas industry for Nova Scotia has proved reserves estimated at 3.5 tcf, and a total resource potential believed to be 18 tcf. The Mackenzie/Beaufort region currently represents a much larger resource potential, albeit more remote from existing infrastructure and markets.

Pipeline Options

Five pipeline options to bring Northern gas to Alberta were examined in this report: a Mackenzie Valley Stand-Alone, a combination onshore Alaska North Slope with Mackenzie Valley, a combination offshore Alaska North Slope with Mackenzie Valley, the Alaska Natural Gas Transmission System (ANGTS), and a combination ANGTS and Dempster Lateral. Tables 3 and 4 present a summary of the capital cost estimates for the different options. None of the options examined has current cost estimates or facilities applications. As a result, CERI has developed a simple rules-of-thumb methodology for estimating costs. See Chapter 3 for the details.

The first option represents a stand-alone pipeline from the Mackenzie Delta to the NWT/Alberta border, that covers approximately 850 miles following the Mackenzie River valley with a capacity of 1.6 bcf/d.

The second option is for an onshore pipeline from the Alaska North Slope. This option includes an approximately 600-mile link from the Alaska North Slope to the Mackenzie Valley, south of the Alaska National Wildlife Refuge. The route then follows the first route to the Alberta border for a total distance of about 1450 miles. The capacity for the second option is approximately 4 bcf/d combined North Slope and Delta gas.

Option three links the Alaska North Slope to the Mackenzie Delta with an approximately 370 mile offshore line constructed in shallow water. This option then follows the Mackenzie River valley to the NWT/Alberta border. The route travels a total distance of roughly 1220 miles. This option expects 4 bcf/d from the North Slope and Delta as well.

The fourth option is the ANGTS with an assumed capacity of 2.5 bcf/d. This route travels approximately 1700 miles along the Alaska Highway from the North Slope to Boundary Lake in Alberta.

The fifth option involves adding a 750-mile, 1.6 bcf/d lateral following the Dempster highway to the fourth option. This route joins up the ANGTS at Whitehorse and then goes to Boundary Lake. The approximate distances for this route are 1700 miles for gas from the North Slope, and 1470 miles for gas from the Delta.

Table 3

Projected Capital Costs of Mackenzie Valley Options
($000,000)

	Mackenzie Valley Stand Alone	Mackenzie Valley with Alaska North Slope					
		Mackenzie Valley Options		Onshore North Slope Options		Offshore North Slope Options	
Distance (miles)	850	850	850	600	600	368	368
Pipe diameter (inches)	30	48	2-30" lines	42	36	48	42
Capacity (MMcf)	1600	4000	4000	2500	2500	2500	2500
Total Pipe	$1,058	$1,693	$2,117	$1,046	$896	$1,590	$1,430
Total O & M	$30	$30	$59	$21	$21	$13	$26
Total Compressor	$415	$738	$923	$323	$415	$92	$138
Total Metering	$10	$10	$21	$10	$10	$2	$2
Total Other	$767	$969	$1,416	$788	$667	$565	$548
Total for Section	$2,280	$3,440	$4,540	$2,190	$2,010	$2,260	$2,130
Total for Project	$2,280			$5,630	$5,450	$5,700	$5,570

Table 4

Projected Capital Costs
($000,000)

	ANGTS (Alaska Highway)			
	Mackenzie Delta to Whitehorse	Prudhoe to Whitehorse	Whitehorse to Boundary Lake Options	
	Dempster Lateral	ANGTS	ANGTS	ANGTS
Distance (miles)	750	978	722	722
Pipe diameter (inches)	30	36	48	2-30" lines
Capacity (MMcf)	1600	2500	4000	4000
Total Pipe	$934	$1,461	$1,438	$1,798
Total O & M	$26	$34	$25	$50
Total Compressor	$369	$600	$554	$831
Total Metering	$10	$10	$6	$12
Total Other	$761	$1,067	$804	$1,213
Total for Section	$2,100	$3,170	$2,830	$3,910
Total for Project			$8,100	$9,180

Based on these capital cost estimates, the prospects of sending Northern gas to the North American marketplace are promising. The producer economics look favourable in regards to potential netbacks from developing the North. Based on a price of $3.50/GJ at AECO-C, netbacks are in the range of $2/GJ for Mackenzie Delta gas which should make a pipeline project for this gas feasible from a producer standpoint.

As per Table 5, the best netback for Mackenzie Delta and Prudhoe Bay gas comes from a 48" Mackenzie Valley pipeline that ships both. Mackenzie Delta gas receives a netback of $2.62/gj under this configuration. If Alaska gas was shipped via the same route, with a Prudhoe Bay Offshore pipeline, it would yield its highest potential netback of $2.10/gj.

Table 5

Summary of Projected Mackenzie Delta and Prudhoe Bay Netbacks

Pipeline Route	NWT Border Price ($/gj)	Transport cost ($/gj)	Projected Price at Pipeline Inlet ($/gj)
Mackenzie Delta Gas			
Mackenzie Valley Stand Alone, 30"	3.15	0.88	2.27
Mackenzie Valley 48" with Prudhoe Bay	3.15	0.53	2.62
Dempster Lateral, 30" and south ANGTS, 48"	3.15	0.80+0.46	1.89
Prudhoe Bay Gas			
ANGTS, 2.5 bcf/d to Whitehorse and 4 bcf/d Whitehorse to BL, AB	3.15	0.82+0.46	1.87
Prudhoe Offshore Link, 42" + Mackenzie Valley, 48" to Boundary Lake	3.15	0.52+0.53	2.10
Prudhoe Onshore Link, 36" + Mackenzie Valley, 48" to Boundary Lake	3.15	0.54+0.53	2.08

Environmental Impacts

Previous environmental analysis shows that pipeline construction should leave negligible to moderate impacts on the environment of the North. No extreme impacts are foreseen. It is not expected that any of the projected routes would have the impact of destroying whole populations or species of wildlife or plants. Ongoing improvements in mitigation procedures, such as horizontal drilling to bury pipe under stream crossings without affecting the stream, will likely minimize the environmental impacts. No route shows a clear environmental advantage over the others.

Economic Impacts

Quantification of the economic impact of each of the pipeline routes has been undertaken using a combination of Statistics Canada's Interprovincial Input-Output (IO) model and the NWT Bureau of Statistics' Input-Output model. GDP impacts for the five options modeled are reported in Table 6. Employment impacts are shown in Table 7. The expenditures and impacts shown are for the construction phase of the pipeline project and the initial field development only. Although pipeline costs have a positive impact on GDP and employment during the construction phase, they mean smaller wellhead revenues for producers. Smaller revenues may make the difference between a feasible and infeasible project. Although the ANGTS/Dempster lateral route has the greatest impact on GDP, it is also the highest cost alternative of getting Alaska/Mackenzie gas to market. Ongoing impacts from the operations phase are not measured. Additional capital investment beyond that required for normal operating and maintenance activities has not been included.

On the basis of strict resource efficiency, one might argue that the pipeline project that delivers a given volume of natural gas to market at the lowest overall capital cost is to be preferred. Based on that criterion, the combined offshore link from Prudhoe Bay to the Mackenzie Delta, then on through the Mackenzie Valley to market provides the shortest path and lowest capital cost. Careful co-ordination of the two projects would be required to achieve the best economies of scale.

Table 6

GDP Impacts
($000,000)

	Stand-Alone Mackenzie Valley	Mackenzie Plus Prudhoe Onshore	Mackenzie Plus Prudhoe Offshore	Stand-Alone ANGTS	ANGTS Plus Dempster Lateral	Field Development
Capital Cost of Project	2,280	5,450	5,570	6,000	8,100	1,480
Total Impacts on Canada	2,132	4,078	4,159	3,131	5,117	1,434
NWT & Nunavut	607	1,077	1,064	2	218	673
Yukon	4	167	230	408	1,020	4
Rest of Canada	1,523	2,834	2,865	2,721	3,880	756

Table 7

Employment Impacts of Pipeline Routes
(person-years)

	Stand-Alone Mackenzie Valley	Mackenzie Plus Prudhoe Onshore	Mackenzie Plus Prudhoe Offshore	Stand-Alone ANGTS	ANGTS Plus Dempster Lateral	Field Development
Capital Cost of Project ($000,000 Cdn)	2,280	5,450	5,570	6,000	8,100	1,480
Total Impacts on Canada	31,190	59,430	60,020	43,360	71,970	20,980
NWT & Nunavut	6,290	11,080	10,820	20	2,400	7,150
Yukon	70	1,800	2,270	4,270	10,720	90
Rest of Canada	24,840	46,550	46,930	39,080	58,850	13,730

Fiscal Impacts

The fiscal impacts of the five pipeline and the Mackenzie Delta field development options have been calculated based on the input-output model results from the Bureau of Statistics and Statistics Canada, and based on the NWT Government's tax models. Tax revenues are therefore associated with pipeline construction and the spin-off economic effects only. Ongoing revenues during the operations phase of each project such as Corporate Income Taxes (CIT) and Property Taxes are not included. The fiscal impacts shown in Table 8, for pipeline construction and field development activity, relate to the construction period only. These impacts are likely small relative to the taxes associated with operations for both the pipeline and field production, as well as second round exploration and development expenditures.

Table 8

Fiscal Impacts of Pipeline Construction Options
($000,000s Cdn)

	Stand-Alone Mackenzie Valley	Mackenzie Plus Prudhoe Onshore	Mackenzie Plus Prudhoe Offshore	Stand-Alone ANGTS	ANGTS Plus Dempster Lateral	Field Development
Capital Cost of Project ($000,000)	2,280	5,450	5,570	6,000	8,100	1,480
NWT						
Tax Revenues	23	39	38	0	8	32
Grant Reduction	-17	-28	-27	0	-6	-24
Net Revenues	6	11	11	0	2	8
Yukon						
Tax Revenues	0	5	8	13	34	0
Grant Reduction	-0	-5	-7	-12	-31	0
Net Revenues	0	0	1	1	3	0
Fed. Government						
Tax Revenues	187	357	358	283	438	125
Savings on NWT Grant	17	28	27	0	6	24
Savings on Yukon Grant	0	5	7	12	31	0
Net Revenues	204	390	392	295	475	149

As is shown in table 8, the revenues associated with all of the options will accrue primarily to the federal government. For example, federal tax revenues associated with the construction of a Mackenzie Valley pipeline with a connection to Prudhoe Bay would exceed $350 million, while GNWT tax revenues would be about $40 million. The $40 million in NWT tax revenues would lower the GNWT's Formula Financing Grant by $27-$28 million, leaving the GNWT with net revenues of $11 million. It is important to note that there will also be large gains for the provinces of Alberta, British Columbia and Ontario because a large share of the labour income effects from any of the projects will accrue to these provinces.

Notice that there is a strong correlation between the capital cost of the project and the net revenues for each of the governments. For instance, the Stand Alone Mackenzie Valley route has both the lowest capital cost and the lowest total net revenues. Conversely, the ANGTS plus Dempster Lateral has both the largest capital cost, and the greatest total net revenues. During the gas production phase, greater capital costs relate to higher pipeline tolls, lower producer revenues, lower resource royalties, and lower tax revenue from producers. For these reasons, greater capital costs mean lower net revenues for government in the long run.

Table 9 shows the economic impacts on Canada from each of the pipeline projects. Looking at the table, the Stand-Alone Mackenzie Valley option shows the best results per dollar spent, having the largest value in all three ratios. The project with the largest overall impact is the ANGTS project with the Dempster Lateral, however this is also the project with the highest cost. In terms of fiscal impacts, the Mackenzie Valley routes with gas from Prudhoe Bay show the greatest benefits. While being almost four times as expensive, the ANGTS with the Dempster Lateral shows less than a ten percent increase in fiscal benefits over the Stand-Alone Mackenzie Valley route. From a producer stand point, the Mackenzie Valley routes are preferable, with a margin of greater than $2.5 billion, to the ANGTS plus Dempster Lateral route.

Table 9
Economic Impact of Pipeline Projects

($000,000)

	Stand-Alone Mackenzie Valley	Mackenzie Plus Prudhoe Onshore	Mackenzie Plus Prudhoe Offshore	Stand-Alone ANGTS	ANGTS Plus Dempster Lateral	Field Development
Capital Cost of Project	2,280	5,450	5,570	6,000	8,100	1,480
Canada						
-GDP	2,132	4,078	4,159	3,131	5,117	1,434
-Employment	31,190	59,430	60,020	43,360	71,970	20,980
-Income	1,377	2,628	2,678	1,956	3,216	914
Ratio						
-GDP/cost	0.94	0.75	0.75	0.52	0.63	0.97
-Employment/cost	13.68	10.90	10.78	7.23	8.89	14.18
-Income/cost	0.60	0.48	0.48	0.33	0.40	0.62
Fiscal						
-Construction	210	401	404	296	480	157
-Ongoing from Producers	5,363	7,127	7,127	0	3,560	n/a
-Ongoing from Pipeline	667	1,373	1,476	1,421	1,926	n/a
Total Fiscal Impacts	6,240	8,901	9,007	1,717	5,966	157
Ongoing Producer Revenues	15,849	18,292	18,292	0	13,265	n/a

Based on the analysis in this report, Canada would best be served with a pipeline down the Mackenzie Valley. Producers generate larger revenues, costs are minimized, and the government generates greater taxes with this route. Looking at the impacts per dollar spent, the Mackenzie Valley route show clear advantages over the Alaska highway routes in GDP, employment and income.

Chapter 1

THE MARKET OPPORTUNITY

1.1 Introduction

The market opportunity for Northern gas supplies is substantial. Over the next two to two and a half decades, North American demand for natural gas is forecast to grow to over 30 tcf (trillion cubic feet) on an annual basis, with some estimates showing growth to more than 33 tcf/year by 2020. Of this demand, production from Western and Northern Canada, as well as Alaska is projected to meet 9 tcf or more. Currently the Western Canada Sedimentary Basin (WCSB) meets roughly 6 tcf of North American demand. Therefore, growth in the WCSB, coalbed methane, and Northern gas supplies might potentially be required to supply 3 tcf over the next two decades. Recent growth in WCSB production has been much slower than would be required to meet this supply target by itself. Coalbed methane has not as yet been developed in Canada. For these reasons, Northern gas looks particularly attractive at this moment.

1.2 Forecasts of Market Growth

A key element of the success of any project to bring northern gas to market will be the ability of the market to absorb the incremental supply. This chapter reviews several recent projections of the North American supply/demand balance in order to identify the magnitude and timing of the opportunity for development of Mackenzie Delta and Prudhoe Bay natural gas resources. The focus is entirely on pipeline supplies to North American market. Consideration of options such as LNG and GTL is beyond the scope of this study.

Forecasters are expecting aggressive growth in gas demand over the next fifteen to twenty five years. In Canada, this growth is based primarily on industrial demand, as well as increasing volumes of gas use for electrical generation. In the United States, the majority of growth is fueled by gas-fired electrical generation needs. These sources of demand growth are very robust to changes in prices of both oil and gas, so long as the two commodities continue to move in similar directions. Several reports were used as a background to arrive at a projection for demand growth. For Canada, both the 1998 CERI projection,[1] and the 1999 NEB projection,[2] were used. For the United

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[1]Rob Mahan, North American Natural Gas Long-Term Outlook: Market and Transportation Opportunities, Canadian Energy Research Institute, Study No. 84 (Calgary, Alberta: Canadian Energy Research Institute, May 1998).

[2]National Energy Board, Canadian Energy Supply and Demand to 2025, (Calgary, Alberta: National Energy Board, 1999).

States, the above mentioned CERI study, the 2000 forecast from the Gas Research Institute (GRI) (Baseline Projection of U.S. Energy Supply and Demand-2000 Edition),[3] the 2000 forecast from the U.S. Department of Energy, Energy Information Administration (EIA) Annual Energy Outlook,[4] and the 1999 forecast by the National Petroleum Council (NPC),[5] were used.

The forecasts were reasonably consistent for demand growth in Canada, however, they differed for the U.S. Table 1.1 provides a comparison of the projected growth rates broken down by sector. In Canada, the CERI projection anticipates an average of 2.2 percent per annum growth, whereas the NEB forecasts 2.1 percent growth per year. For the U.S., CERI projects average per annum growth of 1.8 percent, GRI forecasts 1.4 percent growth, the EIA expects 1.95 percent growth, and the NPC forecasts 2.33 percent growth.

Table 1.1

Comparison of Projected Annual Growth Rates by Sector
(percent)

	Canada		U.S.			
Sector	NEB	CERI	CERI	EIA	GRI	NPC
Residential/Commercial/NGV	1.15	1.10	1.10	1.25	1.30	1.82
Industrial (Including Petrochemicals)	2.28	2.40	1.50	1.30	1.60	1.35
Electric Power Generation	6.40	5.30	3.50	4.30	5.64	5.19
Total	2.10	2.20	1.80	1.95	1.40	2.33
End Year of Forecast	2025	2015	2015	2020	2015	2015

For the Canadian projection, the primary differences lay in the industrial and electric power sectors, and the length of the study. CERI expects greater gas demand growth in the industrial sector at 2.4 percent per year compared to 2.28 percent for the NEB. The NEB forecasts that energy intensive industries (e.g., pulp and paper, iron and steel, smelting and refining, cement, and chemicals) will grow at slower pace than less energy intensive industries (Other Manufacturing, Mining, Forestry, and Construction). Both studies expect much of this growth in the industrial sector to come from Alberta, with new bitumen extraction facilities, steam assisted gravity drainage projects, and continued growth in the petrochemical industry.

[3] http://www.gri.org/pub/content/jan/20000119/121410/pressbook-toc.html.
[4] http://www.eia.doe.gov/oiaf/aeo/results.html.
[5] National Petroleum Council, Meeting the Challenges of the Nation's Growing Natural Gas Demand: Summary Report, (Washington, D.C. National Petroleum Council, December, 1999).

With regard to electric power, the NEB expects higher growth in gas demand by about one percent, which is consistent with the industrial sector growth being lower. When the two sectors are combined, the demand difference in 2015 between the two studies (based on the average annual growth rate) is 17 bcf (Billion cubic feet), or less than 0.5 percent of total demand in that year.

For the U.S., the differences are more pronounced. Unlike Canada, the difference is not just composed of industrial sector and electric power generation demands, instead, the projections differ in all sectors. CERI expects industrial gas demand to grow by 1.5 percent per year, GRI expects 1.6 percent growth per year, the EIA anticipates 1.3 percent, and the NPC expects 1.35 percent growth in this sector. Over the last decade, the industrial sector has had a growth rate of about 3 percent, and is anticipated to continue to experience strong growth into the future. Efficiency gains are not likely to offset all of the energy demand growth in this sector. With the emphasis on cleaner fuels, with such agreements as the Kyoto Protocol, it is further likely that less fuel switching capabilities will be employed in the future making natural gas the fuel of choice where possible.

The projections differ on annual gas demand growth for electric power generation as well, from a low of 3.5 percent (CERI) to highs of 5.19 percent (NPC) and 5.64 percent (GRI), with the EIA in the middle with 4.3 percent. As in the above discussion for Canada, the treatment of industrial cogeneration explains much of the difference in growth. CERI includes the new cogeneration facilities as part of industrial demand, whereas NPC, GRI, and EIA include future cogeneration as electric power generation demand.

In 1990, 2,800 terawatt hours of electric power were generated in the United States. By 1999, this number had risen to nearly 3,200 terawatt hours. This growth, combined with anticipated nuclear power plant retirements and emission restrictions on other power plants, underpins a very strong outlook for gas generation facilities. All of the forecasts indicate that gas is the fuel of choice for new power generation. For example, the NPC states that of the 250 proposed new generation facilities examined in connection with their study, 98 percent are gas-fired. The NPC further expects that 110 gigawatts of new gas-fired generation will be built by 2015, and the EIA expects approximately 270 gigawatts of gas-fired or dual fuel (gas/oil) by 2020. There are several reasons for this. Gas is considered a “clean” fuel in regards to its lower levels of emissions. Gas-fired generation facilities are less costly to build, can be built in a shorter time frame, and are very efficient. When all of these factors are combined, the outlook for electricity generation demand for gas is very strong.

Most of the studies agree that in both Canada and the U.S., core demand (residential and commercial) will see slower growth than the industrial and electric power generation sectors. Technical efficiency is behind this result. Although there will likely be an increase in the prevalence of appliances that require natural gas and in the square footage of space being heated, efficiency gains erode some of this growth.

Table 1.2 provides a comparison of the annual demand by end use sector. Notice that GRI projects substantially greater consumption in 2015 than the other three (roughly 10 percent higher).

Table 1.2

Comparison of Projected Annual Consumption by Sector
(quadrillion Btus)

	Canada		U.S.				
Sector	NEB (2025)	CERI (2015)	CERI (2015)	EIA (2015)	GRI (2015)	NPC (2015)	EIA (2020)
Residential/Commercial/NGV	1.46	1.23	9.76	9.51	10.11	10.2	9.90
Industrial (Including Petrochemicals)	1.93	1.76	11.23	10.36	12.64	10.8	10.98
Electric Power Generation	0.89	0.49	6.66	8.93	8.65	7.8	9.15
Pipeline Fuel		0.36	1.15	0.96	1.07		0.99
Total	4.28	3.83	28.80	29.81	32.46	28.7	31.02

The assumptions underlying the forecasts make up an important factor in determining demand. Table 1.3 provides a summary of the different assumptions underlying the forecasts. Notice the price projection for gas. GRI is projecting a gas price in 1998 dollars that is roughly $0.80 lower than any of the other projections. This is a key determinant in the size of end use demand, and helps explain why GRI's demand projection is greater than the others.

Table 1.3

Assumptions Underlying the Forecasts

	GDP Growth Canada (%)	GDP Growth U.S. (%)	Oil Price ($U.S./bbl WTI)[1]	Wellhead Gas Price ($U.S./MMcf Gulf Coast)[1]
CERI[2]			$18.14 ($1995)	$2.24 ($1995)
NEB	2.3		$18.00 ($1998)	$2.75 ($1998)
EIA		2.2	$22.04 ($1998)	$2.81 ($1998)
GRI		2.2	$19.59 ($1998)	$1.93 ($1998)
NPC	2.2	2.5	$18.50 ($1999)	$2.74 ($1998)

[1]Prices for both oil and natural gas are given for the last year of the respective forecast.

[2]The CERI projection is based on other projections, and therefore does not assume a GDP growth rate.

1.2.1 Canadian Regional Demand

The relative regional demand within Canada is experiencing a shift. Prior to 2000, the Atlantic provinces did not have access to natural gas. With the start of production from Sable Island this has changed. The projected growth of industrial demand within Alberta, driven by bitumen extraction, the petrochemical industry, and petroleum recovery techniques, is another reason for this shift. With the national projected growth in gas demand at around 2 percent in Canada and the U.S., what does this mean for the different regions? Since the purpose of this study is to determine the feasibility of gas from the Mackenzie Delta and the North Slope of Alaska, this is an important question. Where, if at all, would this gas flow, and can it be absorbed? To answer these questions, a more detailed breakdown of the regional demand will be required.

British Columbia will see its annual demand for natural gas rise by about 110 bcf between 1998 and 2015. This growth will be spread fairly evenly between core and industrial sectors.

Alberta will see growth in annual demand of 360 bcf over this period. More than half of this growth will be because of bitumen extraction facilities and other such investments in the oil and gas industry that require natural gas. Electrical generation makes up the majority of the rest of the growth with approximately 4 gigawatts of new capacity being built.

Saskatchewan will see an increase in its annual gas demand by 40 bcf which is driven by increases in the industrial sector. Manitoba will see an additional 20 bcf a year in annual consumption by 2015, with this growth coming from the industrial sector.

Ontario will see 410 bcf in additional annual gas demand by 2015. This growth will be spread across sectors. Electrical generation growth is expected to be substantial in Ontario with a total of 13 gigawatts of additional gas fired generation to be built in this province, more than half the expected total for Canada.

Quebec and Atlantic Canada are expected to see the greatest rate of increase in natural gas demand because of the recent introduction of gas to the Atlantic provinces from the Scotian Shelf. Quebec will see an additional 130 bcf of demand by 2015, and Atlantic Canada is expected to see demand grow from zero up to 140 bcf in this time frame.

Incremental demand for Atlantic Canada will most likely be filled with production from the Scotian Shelf. Currently this region has the capability to produce close to 200 bcf a year, with expectations of significant future potential.

Table 1.4 gives a summary of the regional demand growth to 2020 for Canada.

Table 1.4

Regional Gas Demand in Canada
(tcf)

	1998	2000	2005	2010	2015	2020
British Columbia	0.27	0.30	0.34	0.36	0.38	0.40
Alberta	0.72	0.78	1.01	1.04	1.08	1.11
Saskatchewan	0.17	0.18	0.2	0.2	0.21	0.22
Manitoba	0.07	0.07	0.08	0.09	0.09	0.10
Ontario	0.83	0.87	1.07	1.15	1.24	1.32
Quebec	0.21	0.23	0.28	0.3	0.34	0.37
Atlantic Region	0.00	0.10	0.13	0.14	0.14	0.15
Total Canada	2.26	2.43	3.09	3.27	3.47	3.66

SOURCE: Canadian Energy Research Institute, 1998, 2000.

1.2.2 Lower 48 Regional Demand

In the U.S., the relative percentages of regional consumption are not changing much. The South Central region gives up a small portion of its market share to the Pacific and Northeast regions. This is largely due to increases in gas demand for electrical generation. There is some dispute about the increase in gas-fired electricity generation in the Midwest. This region uses coal for the bulk of its electrical generation, and nuclear generation is the second most predominant fuel. With the need for cleaner burning fuels and expiring licenses of nuclear plants, this region should see robust growth in gas demand. Currently more than 10 gigawatts of nuclear capacity is subject to licenses that expire prior to 2020. Combined with annual growth in electrical demand of 1.4 percent, this leaves lots of room for increased gas-fired generation.

The Western region consisting of California, Oregon, and Washington, is expected to see demand grow by nearly 1.6 tcf (Trillion cubic feet) by 2020 primarily consisting of growth in gas-fired electric generation.

The Mountain region consisting of Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming, is expected to have annual demand for gas grow by 0.5 tcf. The growth in demand is balanced between core users and industrial demand.

The Midwest region including Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin, is projected to see annual gas demand increase by about 2.5 tcf by 2020. Core markets and industrial users account for about 40 percent of this increase, with the electrical generation sector accounting for the largest share of the growth.

The Northeast region which is made of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont, is expected to have demand grow by 1.74 tcf by 2020. This is dominated by electrical generation demand growth (1.3 tcf).

The South Central region which includes Alabama, Arkansas, Kentucky, Louisiana, Mississippi, Oklahoma, Tennessee, and Texas, is projected to see demand grow by 2.9 tcf over this period. This growth is fairly evenly split between the industrial and electric power sectors. The strength of industrial growth in this sector is dominated by gas used in the oil and gas industry for such items as enhanced oil recovery.

The South Atlantic Region which is made up of Delaware, the District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia, is expected to see annual gas demand grow by 0.85 tcf. This is primarily electric power generation demand growth.

Table 1.5 summarizes the regional demand growth in the U.S.

Table 1.5

Regional Gas Demand in the Lower 48 United States
(tcf)

	1998	2000	2005	2010	2015	2020
Western	2.69	3.10	3.32	3.77	4.11	4.27
Mountain	1.10	1.33	1.36	1.43	1.53	1.60
Midwest	5.23	5.63	5.83	6.47	7.14	7.72
Northeast	3.03	3.01	3.33	3.98	4.57	4.77
South Central	7.85	7.64	8.36	9.38	10.29	10.75
South Atlantic	2.25	1.98	2.17	2.44	2.88	3.10
Total Lower 48	21.79	22.79	24.24	27.05	30.50	32.21

SOURCES: (1) EIA Annual Energy Outlook 2000; and (2) Canadian Energy Research Institute, 2000.

1.3 Supply Constraints and Pricing Implications

Given the tremendous growth in demand for gas that is forecast for Canada and the U.S., do the gas resources from the Mackenzie Delta have room to move into the market? Two items were considered to answer this. The first is the supply in the U.S., and the second is supply in Canada. Gas demand in the U.S. is greater than supply causing the U.S. to be an importer of gas. The studies examined agree that imports from Canada will continue to grow over time. Moreover, there is agreement that although there are significant resources remaining in the Lower 48 U.S. states, access restrictions prevent these resources from being exploited.

The NPC expects imports from Canada to increase by 1 tcf, from 3 tcf/year to 4 tcf/year, by 2010. GRI expects imports from Canada to increase by 1.2 tcf/year and reach 4.4 tcf annually by 2010. These estimates ignore the potential of Mackenzie Delta gas. The biggest area of increase in production is the Gulf of Mexico region which is also expected to be the largest contributor to supply in the U.S. This region is projected to increase its production by more than 3 tcf/year over this period. This may be optimistic. Recently the offshore Gulf region has been subject to high, and increasing, decline rates. GRI believes that a focus on deeper water will improve this and allow for production increases. However, it is worth noting that the gas/oil ratio in deeper water favours oil rather than gas, GRI assumes a 60/40 oil to gas split (previously the reverse was assumed 40/60 oil to gas).

The EIA has a different view of the future. The EIA expects U.S. production to reach 25 tcf per year by 2015. Most of this production is assumed to continue to be from onshore resources, with the share of offshore production in total production declining by two percent. Conventional onshore production makes up 46 percent of this

25 tcf, and a further 26 percent is made up of non-conventional onshore resources. Imports from Canada are expected to grow from 3.34 tcf in 1999 to 5.38 tcf by 2020. Table 1.6 gives the time path of imports from Canada assumed by the EIA and GRI. Table 1.7 provides a regional breakdown using the CERI study. From the table it is clear that the projections call for exports from Canada to the U.S. to be roughly 1 tcf/year higher by 2010, and by 2015 they could be nearly 1.5 tcf higher than current levels.

Table 1.6

Annual Imports from Canada
(tcf)

	1999	2000	2005	2007	2010	2012	2015	2020
EIA	3.34	3.55	4.19	4.29	4.50	4.68	4.99	5.38
GRI	3.20	3.20	4.00	4.20	4.40		4.40	
Actual	3.30							

Table 1.7

Daily Exports to the U.S.
(bcf)

Destination	Source	1995	2000	2005	2010	2015
Western	B.C.	0.88	0.89	0.93	1.08	1.12
	Alberta	2.23	2.29	2.33	2.34	2.18
	Total	3.11	3.16	3.18	3.42	3.32
Midwest	WCSB	2.74	3.56	4.14	5.04	5.42
Northeast	WCSB	1.77	1.97	2.18	2.44	2.57
	East Coast	0	0.27	0.40	0.50	0.59
	Total	1.77	2.24	2.58	2.94	3.15
Total		7.61	8.97	9.99	11.4	11.87

SOURCE: Canadian Energy Research Institute, 1998.

In addition to these export volumes, Canadian demand is projected to grow by 1.2 tcf by 2015, bringing the total requirement for incremental Canadian gas supply to 2.5 tcf. Estimates of East Coast production increases are between 0.15 tcf and 0.42 tcf/year by 2015, leaving almost all of the incremental volumes of over 2 tcf to come from the WCSB and the northern frontier. CERI expects production from the WCSB to increase from 6.1 tcf to 7.6 tcf over this period. The NEB forecasts that the WCSB will produce up to 7.9 tcf/year by 2015, and then have its production decline from there. This does not leave much room for gas supplies from the Mackenzie Delta. However, these supply numbers are based on fairly aggressive assumptions. Table 1.8 provides a summary of the production estimates by region for Canada.

Table 1.8

Annual Canadian Production
(tcf)

		2000	2005	2010	2015
CERI	Total	6.29	7.01	7.65	7.95
	WCSB	6.09	6.74	7.33	7.60
	East Coast	0.20	0.27	0.32	0.35
	Non conventional WCSB	0	0	0	0
	Mackenzie Delta	0	0	0	0
NEB Case 1	Total	6.41	7.41	8.14	8.99
	WCSB	6.26	7.20	7.74	7.89
	East Coast	0.14	0.21	0.39	0.56
	Non conventional WCSB	0	0	0	0.54
	Mackenzie Delta	0	0	0	0
NEB Case 2	Total	6.25	6.95	7.45	8.08
	WCSB	6.05	6.71	6.81	5.95
	East Coast	0.18	0.24	0.40	0.49
	Non conventional WCSB	0	0	0.24	1.64
	Mackenzie Delta	0	0	0	0

Production from the WCSB in 1999 was 5.7 tcf. This is only a 0.3 tcf increase from 1996. This translates to a 1.9 percent growth rate per year. If production continues to grow at this rate then in 2010 production will be 7 tcf, and in 2015 it will be 7.7 tcf, which corresponds to the estimates. However, in 1999 the growth rate was only 1.5 percent which corresponds to supply of 6.7 tcf in 2010 and 7.2 tcf in 2015. Under this scenario production will fall short of demand by 0.67 to 1.26 tcf in 2015.

The NEB projects gas production to be 6.26 tcf in 2000 with 5.16 tcf or 82 percent of this production coming from Alberta. Assuming a 1.86 percent growth rate, which is the average over the last three years, production from the WCSB would be only 5.81 tcf, which is 0.45 tcf lower than the NEB projection. If instead we assume the 1.5 percent growth rate that occurred in 1999 to continue then production in 2000 will be 5.78 tcf or 0.48 tcf lower than forecast by the NEB.

Examining the NEB's alternative case, which assumes a less prolific growth in resources, the prospects are better. In this case production from WCSB in 2000 is expected to be 6.05 tcf. Assuming a lower 2000 projection of 5.81 tcf and the growth rate of 11 percent to 2010 and a decline of 14 percent between 2010 and 2015 that the NEB assumes for the alternate case, production is only 6.72 tcf in 2010, and 5.76 tcf in 2015. This would suggest that all of the incremental demand would have to be served by gas from the Mackenzie Delta/Alaska or unconventional sources by 2015. Table 1.9 shows production estimates for the WCSB that would result from the different growth rates.

Table 1.9

Extrapolated Conventional WCSB Production

Growth Rate	1999	2000	2005	2007	2010	2015
NEB Case 1	5.72	6.25	7.19	7.39	7.70	7.71
NEB Case 2	5.72	6.05	6.70	6.71	6.72	5.76
CERI		6.09	6.74	6.97	7.33	7.36
3 Year Average Growth 1997-1999 1.86%	5.72	5.83	6.27	6.51	6.87	7.54
1999 Growth 1.5%	5.72	5.80	6.16	6.35	6.64	7.15

Growth by 2005 may only be in the order of 0.4 tcf to 0.9 tcf. During this time exports are forecast to increase by roughly 0.7 tcf, and domestic demand by 0.6 tcf. This leaves a potential shortfall of 0.4 to 0.9 tcf by 2005. This disparity could continue to rise by 2010 if production grows at only 1.5 to 1.8 percent. Demand growth being 2 tcf, 1.2 tcf for export and 0.8 tcf for domestic uses, and supply growth of only 0.8 to 1.0 tcf, a disparity of 1 to 1.2 tcf in 2010.

In case 1, the NEB assumes that between 2010 and 2015 coal bed methane production will reach 0.54 tcf. This translates to roughly 1.5 bcf/day by 2015. Mackenzie Delta gas could potentially displace this. With the assumptions of their case 2, the NEB projects that coal bed methane will supply 0.24 tcf by 2010, and 1.64 tcf by 2015. Given the relatively small amount of work that has been done on coal bed methane to date, this gives Mackenzie Delta gas room to move into the market.

Table 1.10 provides a summary of the price projections for gas in North America.

Table 1.10

Assumptions Underlying the Forecasts

	Wellhead Gas Price in 2005 ($U.S./Mcf Gulf Coast)	Wellhead Gas Price in 2010 ($U.S./Mcf Gulf Coast)	Wellhead Gas Price in 2015 ($U.S./Mcf Gulf Coast)	Nominal Price in 2010 @ 2% Inflation ($U.S./Mcf)
CERI	$1.93 ($1995)	$2.10 ($1995)	$2.24 ($1995)	$2.83
CERI[1]	$1.66 ($1995)	$1.82 ($1995)	$1.99 ($1995)	$2.45
NEB		$1.89 ($1998)	$2.75 ($1998)	$2.40
NEB[1]		$1.89 ($1998)	$2.61 ($1998)	$2.40
EIA	$2.34 ($1998)	$2.60 ($1998)	$2.71 ($1998)	$3.30
GRI	$2.05 ($1998)	$2.02 ($1998)	$1.93 ($1998)	$2.56
NPC			$2.74 ($1998)	

[1]Canadian average plant gate price.

1.4 The Window of Opportunity

As shown in Table 1.8, Canadian natural gas production is expected to rise from 6.25-6.41 tcf/year in 2000 to 7.45-8.14 tcf/year in 2010. The range of estimates for incremental production in 2010 is therefore 1.2 - 1.73 tcf/year, or 3.3 - 4.7 bcf/d. This incremental requirement is based on assessments of Canadian and U.S. Lower 48 natural gas demand growth, Lower 48 natural gas production growth, and the requirement for incremental exports.

Incremental Canadian natural gas production is expected to come from four sources: Eastern Canadian offshore projects, conventional WCSB gas production, coalbed methane, and Northern Canada. Should a pipeline from the Mackenzie Delta with a capacity of 1.6 bcf/d become a reality, frontier gas would account for between 25 and 50 percent of the incremental requirement for Canadian gas supply in 2010. This target appears to be well within the realm of possibility, given that coalbed methane is not yet a developed resource, expectations for growth in eastern Canadian production are modest, and conventional WCSB supply is currently growing at only 1 percent/year (which would account for 1.8 bcf/d of incremental production by 2010).

Factoring in the additional 2.5 bcf/d or more that might become available from Prudhoe Bay in Alaska presents a somewhat different outlook. A combined total of 4 bcf/d incremental supply from the north within the next ten years would best be absorbed in a case where conventional natural gas production throughout North America underperforms relative to the projections shown above. Another issue that arises is the ability of the market to absorb an incremental 4 bcf/d over a short period of time. Some ramp-up of deliveries may be required.

The market opportunity for Northern gas supplies has clearly been identified and is substantial. Because of the long lead time involved and the dynamic nature of the market, the window of opportunity will likely change size and shape more than once as the projects develop.

Chapter 2

BACKGROUND

2.1 History of Exploration and Development in the North

Natural gas market conditions in North America have undergone a fundamental change in the past two years, resulting in a renewed interest in major pipeline proposals to deliver Mackenzie Delta and Alaska North Slope natural gas to southern markets. Although potential projects are still at the very initial stages of planning, a sense of urgency is developing. This chapter provides a brief history of oil and gas exploration in Northern Canada and Alaska, as well as an introduction to the transportation options examined in subsequent chapters. A review of the regional resource base and exploration activity to date is provided to assist in comparing the potential economic impacts of the pipeline routes examined.

The Canadian north stands as one of the few remaining frontiers for hydrocarbons exploration in North America. Significant discovered natural gas resources exist in the Mackenzie Delta, although only very limited development of those resources has occurred to date. In the last decade, very little exploratory activity has taken place in the Mackenzie Valley and Delta with recent activity focused primarily in the Ft. Liard area, and in onshore areas of the upper Mackenzie Valley for which exploration licenses have been granted.

The history and concentration of seismic lines shot in the north provides an indication of the areas that have been of interest to oil and gas explorationists. Lines shot between 1955 and 1980, cover a broad area from the Cameron Hills in the south proceeding north to the Beaufort Sea, reflecting an initial assessment phase. Activity between 1980 and 1985 seems to be more concentrated in specific areas such as the Tuk Peninsula, specific areas in the Cameron Hills, and Ft. Liard. Activity between 1985 and 1990 shows concentrated efforts in Cameron Hills, the Ft. Liard area and the central Norman Wells area. Activity after 1992 is on the Tuk Peninsula north of Inuvik. The confidential, yet most recent, activity seems to be concentrated in the southern regions with the exception of lines associated with the Inuvik gas project and recent exploration licenses.

Exploration drilling activity in the north has occurred in cycles created by economic and political factors. The first major cycle occurred in the 1940s during the Second World War and shortly afterwards. This period included the further development of the Norman Wells oil property. The second cycle occurred in the 1960s as the federal government opened the Arctic and Beaufort for exploration. The third cycle occurred beginning in the early 1970s as the price of oil increased. The fourth cycle occurred in the late 1980s and culminated in the export application for natural gas from the Mackenzie Delta/Beaufort Sea. A current cycle is being initiated in response to favorable market conditions, recent licensing opportunities, significant settled land claims, and an attractive fiscal regime.

Ft. Liard Region

The Western Canada Sedimentary Basin (WCSB) extends into the southern NWT and Yukon between 60°and 62° north latitude. This region has seen approximately 400 wells drilled, of which 23 have been designated as Significant Discoveries. Drilling activity peaked in the late 1960s and early 1970s with up to 40 wells being drilled per year. The largest discovery in the area, the Pointed Mountain field, was discovered in 1966, the Kotaneelee field was discovered in 1976 and the Liard field was discovered in 1986. This area is a natural gas area.

The first well drilled in this general area (Northern B.C.) was spudded in 1957 and completed as a gas well (Beaver River B-63-K) in 1959 by AMOCO. In 1962 a follow up well, Kotaneelee YT P-50 tested gas and confirmed the extension of this resource into the territories. In the Territories there was further exploration effort during the 1960s by several other companies including 150 km of seismic and several additional wells. Celebeta H-78 was discovered in 1960 and Netla in 1961. The largest discovery in the area, the Pointed Mountain pool, was discovered in 1966. Bovie Lake was also discovered in 1966. Several development wells were drilled on the Beaver River and Pointed Mountain fields.

During the early 1970s LaBiche K-08 and Tattoo a-78L were gas discoveries. Most of the drilling in this area occurred during the 1960s and early 1970s. During the 1980s the exploration activity was relatively low with only a few wells drilled per year.

Recently, interest has returned to this region. Current development in the Ft. Liard region includes six wells. Four wells, Paramount F-36, Paramount B-21-K, Ranger P66a, and Chevron K-29, are currently on stream. The fifth well, Chevron M-25, is expected to be connected by the end of this year, and the sixth, Forrest Oil's I-46 should be tied in during the fourth quarter of 2000.

Cameron Hills and Interior Plains

The first wells drilled on the interior plains of the southern Northwest Territories were drilled on oil seeps near Great Slave Lake in the 1920s. The first gas discovery was made at Rabbit Lake in 1955. Cameron Hills F-51 was discovered in 1968. South Island River was discovered in 1964, Trainor Lake in 1965 and Tathlina in 1973. The most significant level of drilling and exploration in this area occurred in the 1960s and early 1970s. Since then there has been low but consistent activity in the Cameron Hills area only where Paramount has taken a significant interest. The region is natural gas prone with several gas discoveries in the Cameron Hills area which is close to the Alberta / NWT border. Other gas discoveries have been made further north and west of Cameron Hills. Since 1990 Paramount has spudded 10 wells in the Cameron Hills region, the results of which are confidential. All of the licenses in the Cameron Hills region are Significant Discovery Licenses or Production Licenses. The recent wells have been drilled upon existing Significant Discovery Licenses or Production Licenses. There are no current exploration licenses in the region. Paramount Resources plans an oil and gas development to be operational by April of 2001. It consists of 7 gas wells and 12 oil wells.

Central NWT and Yukon

This area includes the Norman Wells region, the sedimentary basins immediately around the Norman Wells discovery and the basins to the north and northwest containing significant gas discoveries. This area can be divided into three sub-areas: the Eagle Plain in the Yukon, the Colville Hills 200 miles north of Norman Wells and the Mackenzie Valley area including Norman Wells.

Early exploration in the Eagle Plain intermountain basin occurred in the late 1950s with the discovery of the Chance oil and gas well in 1959. During the 1960s, 1970s and 1980s some 30 wells in total were drilled in this basin resulting in two additional discoveries at Birch (1965) and Blackie (1964). There are currently no exploration licenses in this area.

Exploration in the Colville Hills began in the 1970s and the first discovery was at Tedji Lake in 1974. Exploration picked up again in the 1980s with the issuance of exploration licenses. The two further gas discoveries were made in 1985 (Tweed Lake) and 1986 (Bele).

Norman Wells Region

In 1920 the Norman Wells oil discovery was made (Northwest Discovery No.1). The development of this oil field occurred during the Second World War and afterwards. More recent development occurred after the construction of the Norman Wells Pipeline in the 1980s. Other exploration activity increased in the 1960s and 1970s with 76 exploratory wells being drilled and a significant amount of seismic lines being shot. Exploratory effort disappeared during the late 1970s and early 1980s. There are currently 10 Exploration Licenses issued in the area around Norman Wells and an additional 4 licenses issued 100 miles to the north of Norman Wells along the Mackenzie Valley. Companies in the area are looking for oil primarily, although there is a chance for significant gas discoveries in the deeper locations.

Beaufort Sea and Mackenzie Delta

Exploration in this area began in the late 1960s with the first discovery on shore at Atkinson on the Tuk peninsula. Considerable seismic had been run prior to 1980 indicating the bulk of exploration was accomplished during this period. The history of the wells shows a concentration of onshore wells from 1968 to 1976. In the early 1970s offshore drilling began and accelerated during the late 1970s and mid 1980s. Onshore wells picked up again during the later 1980s. Since 1990 there have been 5 wells drilled in this area. In 1992 Shell drilled two wells at Unipkat. Both were dry and abandoned. Japex drilled a Well at Mallik in 1998. The Inuvialuit Petroleum Corp drilled two wells at Ikhil in 1998. A pipeline from the Ikhil gas discovery to the Town of Inuvik (approximately 30 miles) was constructed by Enbridge, the Inuvialuit Petroleum Corporation (IPC), and Altagas Services. In addition, two recent rounds of exploration licenses have generated significant spending commitments for this area.

Of the supply regions examined in this report, the Mackenzie Delta/ Beaufort region presents by far the strongest picture for both proved reserves and undiscovered potential. Proved reserves of 13.5 tcf are sufficient to support a large diameter pipeline project, subject to appropriate transportation economics.

2.2 Hydrocarbon Resource Potential

2.2.1 The Sedimentary Basins of the NWT and Yukon

Generally, the sedimentary basins in the NWT and Yukon area are bounded by the Cordillera (Mountain Ranges) of the west and the Precambrian Shield to the east. The southern region, from 60^{o} N latitude to 61^{o} N latitude, is an extension of the WCSB. The other northern sedimentary basins extend northwards expanding to the west as the mountains swing to the west at about 65^{o} latitude and expanding to the east through the Arctic Ocean up into the Arctic Islands. Each basin has different physical characteristics which determine the likelihood of the basin containing hydrocarbons. The depth of sediment, age and maturity of sediment, the trapping mechanisms present and the nature of the potential reservoir rock are all important in determining economic deposits of hydrocarbons. Some basins such as the Beaufort Basin are deep and contain appropriate age and trapping mechanisms where others like the Great Bear Basin are shallow and not very prospective for finding hydrocarbons.

The NWT contains the following basins:

- the extension of the WCSB into the NWT,
- the Mackenzie Plain (containing the Norman Wells oil discovery),
- the Great Bear Basin immediately north of the WCSB,
- the Peel Plain,
- the Colville Hills,
- the Anderson / Horton Plains, and
- the Mackenzie Delta /Beaufort Sea.

Three basins in the Yukon have been included:

- the WCSB extension into the southeast corner of the Yukon,
- the Eagle Plain Basin, just to the west of the Mackenzie Mountains, and
- the Peel Plain, west of the Mackenzie River.

2.2.2 Potential Hydrocarbon Resources of the Major Basins

Hydrocarbon resources in the NWT are unevenly distributed between seven key sedimentary basins. Of these seven basins, five have significant oil and gas potential. The Norman Wells region contains the only producing oil deposits in the NWT with an initial volume in place of 37.5 million cubic meters (m^3), of which less than 10 percent remains to be produced. The Beaufort region contains an additional 339 million m^3 of discovered oil which is currently beyond economic reach and without delivery infrastructure. Total oil potential for the NWT, including discovered and undiscovered resources has been estimated at 913 million m^3 (see Table 2.1).

Table 2.1

Summary of Oil Potential

Play	Estimated Undiscovered Potential (Million M^3)
Beaufort Basin & Mackenzie Valley	856
Other Mainland Territories	57

SOURCE: *Petroleum Exploration in Northern Canada*, Northern Oil and Gas Directorate, 1995.

The natural gas potential of the NWT is concentrated on two regions. The Southern NWT, particularly the Liard region, contains significant natural gas discoveries, as well as potential for further activity. The Liard area represents part of an extension of the prolific WCSB into the NWT. Natural gas resources in this area are estimated at 5 tcf, of which just over 1 tcf have been discovered to date. The largest natural gas potential is in the Beaufort Basin, including both onshore and offshore natural gas resources totaling approximately of 56 tcf. Discoveries to date are expected to contain 13.5 tcf of natural gas reserves. By comparison, the Sable Offshore Energy Project which has opened the offshore natural gas industry for Nova Scotia has proved reserves estimated at 3.5 tcf, and a total resource potential believed to be 18 tcf. The Mackenzie/Beaufort region represents a much larger resource base, albeit much more remote from existing infrastructure and markets.

The Geological Survey of Canada (GSC), the National Energy Board and the Canadian Gas Potential Committee (CGPC) have provided estimates and information with respect to natural gas potential by sedimentary basin. Overall estimates of natural gas potential for the basins reviewed are shown in Table 2.2.

Table 2.2

Summary of Natural Gas Potential in Established Basins

Basin	Estimated Undiscovered Marketable Potential (bcf)	Estimated Number of Fields
Beaufort Basin	42,397[a]	1,250[a]
Mackenzie Valley	2,500[a]	n/a
Eagle Plain	1,005[b]	n/a
WCSB Extension	5,000[c]	n/a
Yukon (Liard Plateau)	1,000[c]	n/a
NWT	4,000[c]	n/a
Total	50,902	

[a]CGPC Estimate.
[b]Petroleum Resource Assessment of the Eagle Plain Basin, Yukon Territory, NEB, November 1994.
[c]A Natural Gas Resource Assessment of the Southeast Yukon and Northwest Territories, Canada, NEB, June 1996 .
[d]Petroleum Resource Assessment of the Liard Plateau, NEB, November 1994.

SOURCES: (1) NEB; (2) GSC; and (3) Gas Potential Committee. The Yukon study done by the NEB estimates that there is 1.99[d] tcf of potential in the Yukon Liard Basin alone. A similar study has not been done for NWT.

Extension of the WCSB into the Southern Northwest Territories and Yukon

The WCSB extends north from Alberta and B.C. into the Northwest Territories and Yukon. This part of the basin is approximately 180,000 square kilometers in size and extends from the Cordillera (mountain ranges) in the west to the Canadian Shield in the east, and between 60^o and 62^o latitude north. The Geological Survey describes this area as a northern extension of the prolific WCSB which shares several exploration plays with northern Alberta and B.C. Within this extension of the WCSB, the region from 60° to 61°N is the more prospective area for hydrocarbons.

The Geological Survey of Canada, the National Energy Board, the Yukon Territories, and the Canadian Gas Potential Committee have each published estimates of the likely volume of remaining undiscovered resources in this part of the WCSB. Clearly, the level of these estimates suggests the undiscovered natural gas resource of this area is approximately 5 tcf.

Mackenzie Plain

The Mackenzie Plain lies between the eastern slopes of the Mackenzie Mountains and the Mackenzie River extending northward from approximately 62^o N latitude to above Norman Wells at 65^o N latitude. The GSC has suggested there is a considerable amount of potential for hydrocarbons in this basin. There have been gas shows and associated gas production at Norman Wells but the best possibility for significant gas reserves remains in the deeper parts of the basin. No estimate of potential reserves has been given by the NEB, GSC or CGPC. The main exploration initiative in this area is a search for additional oil fields in light of the Norman Wells discovery and the available oil pipeline serving the region.

Great Bear Plain

This shallow basin extends from the Franklin Mountains to the Precambrian Shield below and above the Great Bear Lake. There has been a limited amount of exploration in this basin and no discoveries have been made. The basin has been assessed by the GSC to have low to moderate potential for oil and gas pools. Large pools are very unlikely.

Peel Plain and Plateau

This area is a relatively undisturbed sedimentary basin north of the Cordillera (Mountain ranges) which swings to the west above 65^{o} latitude, and west of the Mackenzie River. Fifty-two wells have been drilled in this basin with some significant gas shows. Drilling has been concentrated closer to the Mackenzie River, and the central area of the Peel Plain is only sparsely explored. Although this basin may have good gas potential, the lack of significant discoveries to date makes estimation difficult.

Colville Hills

The Colville Hills is a relatively sparsely explored area of approximately 20,000 sq. km lying north of Norman Wells, east of the Peel Plain and west of the northern portion of the Great Bear Plain. Although the three existing discoveries are spread over a large area and are not adequately delineated, this area has high potential for additional reserves of natural gas. In the Cambrian gas play in the Mackenzie Valley the CGPC has estimated an additional 2.5 tcf of undiscovered potential exists in this area. This is currently the largest gas potential of any of the plays in the Mackenzie Valley.

Anderson and Horton Plains

This basin lies north of the Peel Plain and Colville Hills and extends north-eastward to the Amundsen Gulf of the Arctic Ocean. There have been no discoveries and only one gas show in this area, with twenty-one wells drilled. The seismic coverage has large gaps. The GSC has no current estimate of potential in this area.

The Southern Mackenzie Delta and Tuktoyaktuk Peninsula

Drilling began in this area in 1969 as the entire far north was opened up to petroleum exploration. The first oil discovery was, Atkinson H-25. It was followed in 1972 by the Parsons Lake gas discovery, estimated to contain 1.4 tcf of reserves. There were a significant number of wells drilled in this region resulting in 8 significant discoveries. They included several oil discoveries and a gas/condensate discovery at Tuk. The CGPC estimates that this portion of the basin contains 4.96 tcf of undiscovered potential of marketable natural gas and 2.3 tcf of recoverable gas equivalent in oil.

The Beaufort Mackenzie Basin

The Beaufort Mackenzie Basin is classified as a prolific deltaic basin similar to other deltaic basins around the world. This type of basin is expected to have giant pools but not super giants. So far there have been 53 discoveries including the onshore discovery, Taglu, by Imperial Oil in 1969. There was offshore success at Kopanoar in 1976. One hundred and eighty three exploratory wells have been drilled. In the 1980s exploration moved offshore and Amauligak was discovered in 1983. The CGPC has estimated that this basin contains 13.5 tcf of discovered recoverable natural gas and 42.4 tcf undiscovered recoverable natural gas.

Northern Yukon

The Eagle Plain Basin is located between mountain ranges across the Mackenzie Mountains from the Peel Plain. Both oil and gas have been discovered in this basin. The estimated discoveries total 1.86 million cubic meters of oil and 2524 million cubic meters of natural gas (89 bcf). The GSC states that the likelihood of further discoveries of gas in the basin is high and estimates that a total undiscovered resource of 1,005 bcf of gas is likely.

Prudhoe Bay

Prudhoe Bay was discovered in 1968 as an oil field. It is the largest oil field in North America with more than 13 billion barrels of oil, and approximately 30 tcf of proved gas reserves. Currently, more than 3 tcf of gas is being produced annually with 92% of it reinjected to enhance oil production. Oil is shipped by pipeline to Valdez where it is shipped by tanker. Oil production at Prudhoe Bay peaked from 1979 to 1989 at 1.5 million barrels per day and has declined since. In 1979 production was around 750,000 barrels per day. With the decline of oil production, the potential to market the natural gas resources has become more attractive since they are becoming less valuable to enhance oil recovery. The recoverable natural gas resource in the North Slope area is estimated to be 38 tcf, and the resource base around 64 tcf.

2.3 Discovered Resources

Estimates of the total marketable natural gas discovered in the northern basins of Canada not including the northern portions of the WCSB, are in the 30.4 tcf range. The Arctic Islands make up 16.4 tcf of this total leaving 14 tcf in the Mackenzie Delta/ Beaufort Sea, Colville Hills and Eagle Plain Basins. However, the bulk of the discovered resources of both oil and gas are in the Beaufort Sea and Mackenzie Delta. A summary of these northern reserves is presented below in Table 2.3. The basins not mentioned have no discoveries. It should be clear from the table that the primary focus of any development will be the Beaufort/Mackenzie Basin.

Table 2.3

Estimates of Discovered Gas Reserves by Area

Play	Number of Fields	Initial Reserves (bcf)	Remaining Reserves (bcf)
Beaufort/Mackenzie Basin	50	13,534	13,534
Mackenzie Valley	3	421	421
Eagle Plain Basin	4	89	89
WCSB Extension	17	1064	474
Total	74	15,108	14,518

SOURCE: Canadian Gas Potential Committee, 1997.

The magnitude of the reserves already discovered in the Beaufort Sea/Mackenzie Delta is approximately 10 times the volume of the discovered reserves of basins further south in the Territories. The estimate of natural gas potential for the Beaufort / Mackenzie Delta region is over 40 tcf while the estimate for all other basins combined is approximately 8 tcf. Significant discoveries to date in the Beaufort/ Mackenzie Delta are shown in Table 2.4. As a result of the last two land sales in this area, firms bid over 72.5 million dollars in work commitments for four parcels in the Mackenzie delta region. This is a significant amount of work commitment and represents renewed interest in the area.

Table 2.4

Reserves Estimates for Beaufort / Mackenzie Delta Gas

Significant Discovery	1976 Hearings Company Estimate (bcf)	NEB/GSC Gas Reserves (bcf)	NEB/GSC Oil Reserves (MMbbls)	Potential Gas Committee (bcf gas equiv.)
1. Atkinson H25				192
2. Taglu G33	3030>	2000		3380
3. Mayogiak j17			>10	50
4. Parsons F09	1827	1000 – 2000		1400
5. Ivik J26			100-25	150
6. Mallik A06	100	10-100		50
7. Titalik K36	85	10-100		50
8. Niglitgak H30	708	500-1000	25-10	1000
9. Yaya S P53	119	100-500		100
10. Reindeer F36	11	10-100		50
11. Kugpic O13			25-10	100
12. Ivic K54			25-10	105
13. Kumak J08			100-25	150
14. Adgo F28	185	100-500	100-25	675
15. Yaya N A28	68	10-100		50
16. Pelly B35		10-100		50
17. Imnak J29			25-10	100
18. Garry S P04	305	100-500	25-10	400
19. Netserk F40	115	100-500		300
20. Kamik D48	17.9		<10	30
21. Nektoralik K59		10-100		150
22. Kopanoar M13			500-100	1800
23. Ukalerk C50		100-500		100
24. Nerlerk M98		<10	<10	10
25. Isserk E27		10-100		50
26. Garry N G07		100-500		300
27. Tarsuit A 25			100-25	600
28. Kenalooak J94		500-1000		750
29. Kookoak 022			100-25	600
30. Issungnak O61		1000-2000	100-25	1500
31. W. Atkinson L17			25-10	100
32. Kiggavik A43		10-100		50
33. Itiyok 27		10-100	<10	50
34. Havik B 41			100-25	240
35. Pitsiulik A 05			100-25	300
36. Kadluk O 07		10-100		50
37. Amauligak J44		1000-2000	500-100	4100
38. Tuk Cret M09		100-500		300
39. Amerk O 09		10-100		50
40. Nipturk L19				180
41. Tuk Turk J29			25-10	100
42. Adlartok P 09			500-100	600

(Continued on Next Page)

Table 2.4 (continued)

Significant Discovery	1976 Hearings Company Estimate (bcf)	NEB/GSC Gas Reserves (bcf)	NEB/GSC Oil Reserves (MMbbls)	Potential Gas Committee (bcf gas equiv.)
43. Minuk I 53		10-100		50
44. W. Amauligak I 65A		??		50
45. Hansen G07		100-500		300
46. Ikhil K35		10-100		50
47. Arnak K06			<10	50
48. Unak L 28		? gas		50
49. Nipterk P32			25-10	?
50. S. Isserk I15		10-100		?
51. Kingark J54		100-500		675
52. Unipkat N12			100-25	375

2.4 Mackenzie Delta Pipeline Development Options

In August of 1989, the National Energy Board issued licenses to Esso Resources Canada Limited, Shell Canada Limited, and Gulf Canada Resources Limited for the export of 144 billion cubic meters (Bcm), 25 Bcm, and 91 Bcm of natural gas respectively. The natural gas was to be produced from reserves in the Mackenzie Delta/Beaufort Sea region of Northern Canada. Exports were to commence sometime between October 31, 1996 and October 31, 2000, and continue for a term of twenty years. Maximum annual volumes licensed were 445 bcf (1.2 bcf/d). When the licenses were granted, the NEB reviewed evidence of a notional pipeline system to carry the gas to Caroline, Alberta and then south to the U.S. border.

Since the export licenses were granted, there has been no progress toward construction of a pipeline until very recently. Subsequent chapters of this report will examine the potential economic and employment benefits that might attach to each of five potential pipeline options.

Only one of the options, the Alaska Natural Gas Transportation System (ANGTS) has completed a significant regulatory review (more than 20 years ago). Because of this, the detailed routing, cost, and other information is generally not available. High level planning estimates have been used where necessary. Details of assumptions and methodology are in Chapter 3.

The five pipeline routes examined in this report are:

- a stand-alone Mackenzie Valley route from the Delta to the NWT/Alberta border,

- a Mackenzie Valley route with an onshore link to Prudhoe Bay (south of ANWR),
- a Mackenzie Valley route with an offshore link to Prudhoe Bay,
- the original ANGTS project on a stand-alone basis, and
- the ANGTS project with a Dempster Highway lateral to the Mackenzie Delta and Beaufort Sea.

Chapter 3

PIPELINE OPTIONS

3.1 Overview

The existing pipeline infrastructure in the Northwest Territories and Yukon is limited to one crude oil pipeline and three natural gas lines. Enbridge Pipelines (NW) Inc. operates a 13 inch crude oil pipeline that reaches 538 miles from Norman Wells in the NWT to Zama Lake in Alberta where it interconnects with the facilities of Rainbow Pipe Line Company Ltd. The pipeline follows the Mackenzie River valley from Norman Wells to Fort Simpson, then continues south to Zama. The initial design included three pumping stations with a throughput capability of approximately 31,500 barrels per day, with expansion capability to 45,000 barrels per day fully powered. The line was constructed in the early 1980s.

The largest and longest serving natural gas pipeline infrastructure currently in service in Northern Canada is an extension of a 20 inch Westcoast raw gas transmission line from Northeast British Columbia through the southeast Yukon and into the Pointed Mountain gas processing plant in the Ft. Liard region of the Northwest Territories. Chevron is currently delineating a small, short extension of the line to gather gas from their properties just north of the Pointed Mountain plant. Paramount Resources also built the Shiha pipeline for its F-36 and B-21-K wells. This line connects to the Westcoast pipeline. An additional natural gas pipeline project has recently been completed by Enbridge, AltaGas, and the Inuvialuit Petroleum Corporation. This project includes two gas wells at the IPC Ikhil field, a 50 km transmission line, a gas distribution system in Inuvik, and potential service to Northwest Territories Power Corporation to supply gas for power generation.

No other pipeline projects are at or near the construction stage. As natural gas supply capability continues to build in the Cameron Hills area, long-standing plans to connect into the NOVA system will advance toward reality. Also, as exploration in the Norman Wells, Colville Hills, and Peel Plain areas continues, there may be additional requirements for trucking or crude oil gathering pipeline infrastructure.

The objective of this report is to provide a comparison of economic benefits related to a representative range of possible pipeline projects from the north. Because the current proposals are largely at a very preliminary stage of planning, CERI has made comparisons on the basis of very preliminary routing and costing assumptions. Five possibilities were examined.

Route 1: Mackenzie Valley Stand Alone

The first option represents a stand-alone pipeline from the Mackenzie Delta to the NWT/Alberta border, roughly following the Mackenzie River valley. This route would cover approximately 850 miles. CERI has assumed a 30 inch high pressure design could be utilized with a capability of 1.6 bcf/d throughput. The smaller pipe diameter is expected to decrease the total weight of the pipe to be transported, thereby reducing construction costs. Compressor stations are assumed at approximately 100 mile spacings for this and all routes. CERI has not undertaken any studies to optimize designs, but has used very high level assumptions. Larger diameter pipe would have the advantage of potentially larger throughput capability, but would require significantly larger investment. The working assumption is that 1.6 bcf/d will be sufficient capacity to serve the Delta for at least the first ten years of the outlook period.

Route 2: Mackenzie Valley with Alaska North Slope-Onshore

In this option Alaska North Slope gas is piped overland to the Mackenzie Delta, following a route of approximately 600 miles that passes south of the Alaska National Wildlife Refuge, then follows route 1 to the Alberta boundary. Both 42 inch and 36 inch options were considered for the interconnect, either option with a throughput capability of 2.5 bcf/d. The more economical of the two options is the 36-inch pipe overland to the Mackenzie Delta. Two options have been examined to carry a total of 4.0 bcf/d combined North Slope and Mackenzie Delta gas to southern markets. The most economical option would be a 36 inch line from Alaska to the Mackenzie Valley, then a 48 inch line down the valley. This option would require coordination of the two lines with regard to routing and timing. Should either project proceed ahead of the other without this coordination, the possibility arises of parallel lines down the Mackenzie Valley (probably sharing a right of way). An option of two 30 inch high pressure lines for the Valley segment has been included to allow for this possibility.

Route 3: Mackenzie Valley with Alaska North Slope-Offshore

A second option to link the Alaska North Slope to the Mackenzie Delta would see an offshore line constructed in shallow water. The distance involved is approximately 370 miles. Two cases are considered for pipe size to carry 2.5 bcf/d capacity. The two cases are a single 48 inch line, and a single 42 inch line. Larger pipe is considered for the offshore route under the assumption that compression would only be available on land at the inlet and outlet of the pipe. The choice between 48 inch and 42 inch pipe might well hinge on expectations regarding the ultimate flow capability required and the length of time required to achieve maximum flow.

Route 4: Alaska Natural Gas Transmission System

CERI has taken the original Alaska Natural Gas Transmission System (ANGTS) route and updated costs based on the methodology described below. With an assumed capacity of 2.5 bcf/d, a single 36 inch line would be adequate. Larger pipe might be required for increased capacity. This particular route does not include a Dempster highway lateral.

Route 5: ANGTS with Dempster Lateral

The final route considered would combine the ANGTS system with a lateral carrying Mackenzie Delta gas to an interconnect near Whitehorse. The lateral would follow the Dempster Highway. This 750 mile lateral is assumed to be 30 inch high pressure line with 1.6 bcf/d throughput capacity. From Whitehorse to Boundary Lake a single 48 inch line would be installed to carry the combined 4.0 bcf/d of North Slope and Delta gas. A second case was examined with twin 30 inch lines from Whitehorse to Boundary Lake in the event that the timing of the two lines differs.

3.2 Cost Methodology

The routes described in the previous section are largely hypothetical in nature, or have not published current capital cost estimates. CERI has developed a methodology to estimate capital costs for the various routes on the basis of recent projects elsewhere in North America. These costs have then been adjusted as necessary to represent the increased costs related to transportation and the northern construction and operating environment. The resulting numbers have been discussed with industry representatives to gather feedback on costing issues. It is important to note that the purpose of these estimates is to provide inputs for the input-output modeling, and to compare the potential economic impacts of the various routes.

The projected capital costs for the Northern routes have been developed from rules of thumb based on three pipeline projects: the Alliance Pipeline Project (Alliance), the Maritimes and Northeast Pipeline Project (MNPP) (with supplementary information from the Sable Offshore Energy Project (SOEP)), and the TransCanada Pipelines 1998 Facilities Application (TCPL). The costs from these three projects were grossed up to 1999 Canadian dollars using a discount rate of 2 percent for 1998 and 1.5 percent for 1997 and 1996. (This gross up was arrived at by averaging the price indexes for pipe and other manufacturing components.) These three projects were chosen due to the fact that they were all recent (undertaken within the last three years), and they provide a good spectrum of the different projects. For instance, both Alliance and MNPP are ‘greenfield’ projects, which refers to the fact they were new pipelines rather than expansions of an existing project. TCPL, although an expansion, is the most recent of the three projects, and offered a more detailed breakdown of some of its costs. Moreover, the diameter and thickness of the pipe, the distance, and the operating pressure all varied between the three.

Having identified these sources of information, the next step was to put this information into a useable form. The capital costs for these projects were used to calculate rules of thumb for cost per mile and cost per unit calculations. Subject to these sources, the capital costs were broken down into several categories to calculate the projected capital costs for the project. Once this was done, a more detailed breakdown of the costs could be achieved by using a weighting scheme developed from those pipelines which gave a more detailed breakdown of the particular item.

Pipe materials were assumed to be influenced by both diameter and distance. To arrive at a reasonable cost per inch mile, the costs for each of the three projects were calculated and then a weighted average of distance and diameter was taken. This was thought to be reasonable given the fact that the distance and diameter of the three pipelines varied (Alliance involved a 972 mile 36 inch pipeline, MNPP involved a 347 mile 30 inch pipeline, and TCPL had a 117 mile 48 inch line). Moreover, the thickness and design pressures also varied both among projects and within projects (e.g., Alliance involved pipe of grade 483 that varied in thickness from 14.23 mm to 22.74 mm, while TCPL involved grades 483 and 550 with a thickness of 11.7 mm and 15.3 mm respectively.) By taking a weighted average, it is assumed that the costs associated with the requirements for different pipe specifications (i.e., stream and road crossings, above ground sections) within a project will be captured.

Installation of the pipe materials was assumed to be related to both distance and diameter as well. The costs of the Alliance pipeline were grossed up by a factor of 1.5 to achieve this rule of thumb. This was done to allow for additional costs associated with northern construction. It is assumed that the Alliance project gave the most reasonable approximation given the distance and potential flows. A diameter factor was included here to capture any additional costs that may be associated with larger pipe (e.g., additional equipment to handle heavier pipe, longer time involved to weld).

Operation and maintenance facilities were assumed to be distance based, and were calculated based on the Alliance project, with a similar gross up of 1.5 times for the installation portion. Material costs were not expected to be influenced much from being in a frontier area.

Land costs were assumed to be double that of the Alliance project to allow for some additional costs that may be accrued because of the frontier. These costs were distance based as well.

Engineering costs were assumed to be twice the costs of the TCPL facilities, and also based on distance. It is believed that TransCanada would be the most likely company to be involved with the construction and operation of a pipeline through the

Mackenzie Valley, and therefore their engineering costs were used. Doubling the costs made allowances for additional difficulties that might arise in the north.

Logistics and material transportation costs were assumed to be distance based. These were calculated based on the MNPP because of the fact that it was built in an area with little pipeline development, just as any pipeline out of the north will be. The costs were then grossed up by 50 percent to allow for additional costs that arise because of lack of infrastructure (i.e., roads) and the use of seasonal transportation. A further adjustment of +30 percent was made to those routes which were primarily in the mountains.

Management was calculated based on a distance-based calculation. These costs included corporate management, administration and legal costs for head office functions, business development, and regulatory requirements. The Alliance costs were doubled for this to achieve a reasonable estimate for additional costs of the north. The calculation of a distance-based fee gave similar answers for both the Alliance and TCPL projects and was therefore believed to be reasonable. The Alliance number was thought to be more reasonable than the TCPL number because it was based on a new project rather than an existing pipeline expansion.

Compressor stations were assumed to be spaced using the Alliance project as a template, and it was assumed that the compressor station costs were based on a per station basis. However, it was assumed that instead of having stations with multiple units, the units would be spread out over the length of the pipeline. This gave a spacing of about one station every 100 miles. With the use of 48 inch pipe, it was assumed that, in order to run at the pressure required to transport the volumes, additional compression would be needed. To accommodate this, the ratio of pipe size was used to gross up the compression. The materials cost for the Alliance project were then grossed up by a factor of 1.3 to allow for any additional requirements for being up north (e.g., additional insulation to avoid damaging the permafrost). The installation costs were based on double the Alliance costs to further allow for additional costs in the north.

Metering stations were assumed to be the costs of the MNPP as that was the only one of the three projects that included metering. (Alliance had metering for the laterals, however, the size and design of the laterals did not always match with the mainline, and the cost per station varies quite greatly from about $307,000 to $1.1 million. This made it difficult to infer an appropriate per station cost.) It is assumed that metering would be put on at receipt and delivery points, as well as at some of the towns/communities along the routes.

A contingency was allowed to cover any additional costs that were neglected, as well as to allow for a range of costs greater than what was estimated. It is believed that a 10 percent contingency on materials and 25 percent for the rest is sufficient to allow for these. The result is a contingency of 14-18 percent of the total project costs.

For the offshore route, an additional premium was allowed for certain items. The pipe materials and installation were adjusted based on the SOEP, where the actual cost per inch mile was used from the SOEP. Engineering, Logistics and Material Transportation, and Contingency were all adjusted by an additional 15 percent to reflect possible additional costs of offshore work.

Table 3.1 provides a summary of the rules of thumb used to calculate the capital costs.

Table 3.1

Derivation of Pipeline Capital Cost Rules of Thumb

Item	Units	Alliance	TCPL	M&NPP	Rules of Thumb
Distance	miles	972	117	347	850
Pipe diameter	inches	36	48	30	30
	units	Cost/unit	cost/unit	cost/unit	Cost/unit
Pipe		($000)	($000)	($000)	($000)
Materials	inch mile	$20.27	$19.50	$16.93	$19.50
Installation	inch mile	$14.36	$13.88	$23.99	$22.00
O & M					
Materials	miles	$16.39			$16.40
Installation	miles	$12.29			$18.44
Land	miles	$2.36	$38.18	$42.92	$4.72
Engineering	mile	$33.18	$20.55	$33.60	$41.10
Logistics and Materials Transportation	mile			$196.35	$294.53
Contingency	mile	$108.58		$146.67	$350.73
Management	mile	$44.03	$50.11		$88.06
Compressor	# of Compressors	1/97 mile			1/97 miles
Materials	station	$23,014	$25,014		$29,919
Installation	station	$8,113	$14,240		$16,226
Metering	station			$1,039	$1,039

3.3 Cost Assumptions

A detailed comparison of the five routes outlined above was undertaken. Table 3.2 provides a summary of the routes and capital costs for the Mackenzie Valley options, with Table 3.3 summarizing the ANGTS alternatives. All costs are project capital costs and exclude any allowance for items such as interest during construction. These items are added in below in determining tolls.

The Mackenzie valley only route is assumed to involve an 850 mile (1,369 km), 30 inch pipeline that extends from Mackenzie Delta to the NWT/Alberta border. Nine compressor stations have been assumed (1 for every 97 miles or 155 km). Ten metering stations have been assumed, 4 for receipt points, 1 for a delivery point, and 5 for communities that will likely wish to tap the pipeline for gas supplies. This route has an expected capital cost of about $2.3 billion Canadian.

Prior to examining the results of our research for accessing gas from Alaska, it is useful to state that Foothills Pipe Lines LTD. has estimated the costs of building this route at about $8.8 billion Canadian ($6 billion U.S.). This is about 20 percent above our calculations for a single line case and in line with our dual line case, as will be discussed below.

The Alaska Highway (ANGTS) route extends from Prudhoe Bay, Alaska to Boundary Lake, Alberta, approximately 1,700 miles (2,737 km). Two cases were examined, one with a single 48 inch line, and one with dual 30 inch lines. The single 48 inch line has a projected capital cost of about $6 billion Canadian, and the dual 30 inch lines are expected to have a cost of about $7.1 billion Canadian.

The Dempster Lateral route extends from the Mackenzie Delta to Whitehorse, following the Dempster Highway, where it joins up with the ANGTS. The route involves a 750 mile (1,210 km), 30 inch line. The costs for the Dempster Lateral are about $2.1 billion Canadian, and would be subject to the ANGTS system being built. The total for the ANGTS system with the Dempster lateral is about $8.1 billion Canadian with a single line, or $9.18 billion for the dual lines.

The Onshore North Slope Mackenzie Valley route extends south from Prudhoe Bay, Alaska, around the Wildlife Preserve, then east to meet up with the Mackenzie Valley line that originates in the Delta and terminates at the NWT/Alberta border. This route has a distance of 600 miles (970 km) from Prudhoe Bay to the Mackenzie Valley, and 850 miles for the Mackenzie Valley portion as mentioned above. Again there are many choices of pipe size and configuration for this route, two of which were examined, a single 42 inch line from Prudhoe Bay to Mackenzie Valley with a single 48 inch line in the Mackenzie Valley, and a single 36 inch line from Prudhoe with dual thirty inch lines for the Mackenzie Valley portion. The cost for the 42 inch line is about $2.2 billion Canadian, and the 36 inch line from Prudhoe Bay is expected to cost about $2 billion. The Mackenzie Valley portion with a 48 inch pipe will likely cost $3.4 billion, and dual 30 inch lines is expected to be about $4.5 billion Canadian. The total for the project is projected to be between about $5.4 billion and $6.7 billion Canadian depending on choice of pipeline diameter.

The Offshore North Slope Mackenzie Valley route extends 368 miles underwater from Prudhoe Bay to the Mackenzie Delta by way of the Beaufort Sea. The Mackenzie Valley portion then extends, as above, 850 miles to the NWT/Alberta border.

Two configurations were explored here. The first is a 48 inch pipe from Prudhoe Bay to the Delta, and then a 48 inch line through the Mackenzie Valley. The second is a 42 inch offshore line, then dual 30 inch lines through the Valley. The Offshore portion is expected to cost \$2.1 to \$2.3 billion depending on whether the 42 inch or the 48 inch lines are used, the larger line being the more costly. The Mackenzie Valley portion has the same expected costs as in the Onshore case, being \$3.4 to \$4.5 billion Canadian depending on the pipe size chosen. This would give the total project a capital cost of \$5.5 to \$6.8 billion Canadian depending on the choice of pipe.

3.4 Tolling Methodology

Estimates of transportation costs for each of the above routes have been prepared, based on a standard cost-of-service tolling approach. Based on input assumptions for each of the items identified below, the model generates an annual revenue requirement and calculates the unit charge required. No effort has been made to levelize or optimize the tolls in any way. Project capital has been assumed at the levels in Tables 3.2 and 3.3, and does not include any future capital investment beyond operations and maintenance. It is also assumed that net earnings are distributed to owners as dividends, fully returning invested capital by the end of the project. Project debt is amortized over the useful life of the project. Although the actual project debt is more likely to be amortized over ten years, financings are often done with structures that have the impact of spreading the amortization over the life of the project.

Input variables include:

- capital cost of the pipeline (as shown in Tables 3.2 and 3.3)
- construction start date, and number of construction years (3)
- distribution of construction costs by year, according to overall share of construction (Year 1: 30 percent; Year 2: 30 percent; Year 3: 40 percent)
- capital structure (70 percent debt, 30 percent equity)
- interest rate on long-term debt (9 percent)
- a target equity return (12 percent)
- interest during construction calculated based on mid-year capital invested
- annual operating cost (set as a percentage of capital cost) (1.5 percent)
- inflation rate (2 percent)
- income tax rate (combined federal and provincial) (36 percent)
- non-income taxes (set at 1.5 percent of capital costs on an annual basis)
- Project life (30 years)
- Straight line depreciation over the project life
- Debt amortized over the life of the project
- Pipeline capacity (as shown in Tables 2 and 3)
- Load factor (45 percent in year 1, 65 percent in year 2, 85 percent in all subsequent years)

Table 3.2

Projected Capital Costs of Mackenzie Valley Options
($000,000s)

	Mackenzie Valley Stand Alone	Mackenzie Valley with Alaska North Slope					
		Mackenzie Valley Options		Onshore North Slope Options		Offshore North Slope Options	
Distance (miles)	850	850	850	600	600	368	368
Pipe grade	550	550	550	550	550	550	550
Pipe diameter (inches)	30	48	30	42	36	48	42
			Note 2-30" lines				
Capacity (MMcf/d)	1600	4000	4000	2500	2500	2500	2500
Pipe							
Materials	$497	$795	$995	$492	$421	$737	$645
Installation	$561	$898	$1,122	$554	$475	$853	$785
	$1,058	$1,693	$2,117	$1,046	$896	$1,590	$1,430
O & M							
Materials	$14	$14	$28	$10	$10	$6	$12
Installation	$16	$16	$31	$11	$11	$7	$14
Total O & M	$30	$30	$59	$21	$21	$13	$26
Land	$4	$4	$4	$3	$3	$2	$2
Engineering	$35	$35	$35	$25	$25	$29	$29
Logistics & Materials Transportation	$250	$250	$501	$322	$230	$125	$125
Contingency	$403	$605	$801	$386	$357	$377	$360
Management	$75	$75	$75	$53	$53	$32	$32
Total Other	$767	$969	$1,416	$788	$667	$565	$548
Compressor	9	16	20	7	9	2	3
Materials	$269	$479	$598	$209	$269	$60	$90
Installation	$146	$260	$325	$114	$146	$32	$49
Total Compressor	$415	$738	$923	$323	$415	$92	$138
Metering	10	10	20	10	10	2	2
Total Metering	$10	$10	$21	$10	$10	$2	$2
Total for Section	$2,280	$3,440	$4,540	$2,190	$2,010	$2,260	$2,130
Total for Project	$2,280			$5,630	$5,450	$5,700	$5,570

Table 3.3

Projected Capital Costs
($000,000s)

	ANGTS (Alaska Highway)			
	Mackenzie Delta to Whitehorse	Prudhoe to Whitehorse	Whitehorse to Boundary Lake Options	
	Dempster Lateral	ANGTS	ANGTS	ANGTS
Distance (miles)	750	978	722	722
Pipe grade	550	550	550	550
Pipe diameter (inches)	30	36	48	30
				note 2-30" lines
Capacity (MMcf/d)	1600	2500	4000	4000
Pipe				
Materials	$439	$686	$676	$845
Installation	$495	$775	$762	$953
	$934	$1,461	$1,438	$1,798
O & M				
Materials	$12	$16	$112	$23
Installation	$14	$18	$13	$27
Total O & M	$26	$34	$25	$50
Land	$4	$5	$3	$3
Engineering	$31	$40	$30	$30
Logistics & Materials Transportation	$287	$374	$213	$425
Contingency	$373	$562	$495	$691
Management	$66	$86	$64	$64
Total Other	$761	$1,067	$804	$1,213
Compressor	8	13	12	18
Materials	$239	$389	$359	$539
Installation	$130	$211	$195	$292
Total Compressor	$369	$600	$554	$831
Metering	10	10	6	12
Total Metering	$10	$10	$6	$12
Total for Section	$2,100	$3,170	$2,830	$3,910
Total for Project			$8,100	$9,180

3.5 Assessment of Tolls and Netback Revenues

Based on the capital costs and tolling methodologies described above, CERI has developed the annual tolls shown in Table 3.4 for each of the routes examined. In all cases the tolls are for transport only and exclude the cost of fuel. The tolls presented are for the specific segment identified as the route, and are average projected transport costs over the first ten years of operation. Some segments may need to be added together to arrive at the total cost between points. For instance the 48 inch Prudhoe Bay Offshore link and the Mackenzie Valley 48 inch link need to be added to achieve the toll that a shipper would face for sending gas from Prudhoe Bay to Alberta via that route. A shipper from the Mackenzie Delta would only need to look at the Mackenzie Valley toll. Similarly, for the ANGTS route, a shipper from the Mackenzie Delta needs to add the ANGTS Dempster Lateral toll with the ANGTS Whitehorse to Boundary Lake toll, and a shipper from Prudhoe Bay needs to add the ANGTS Prudhoe to Whitehorse toll to the ANGTS Whitehorse to Boundary Lake toll, to calculate the cost of shipping to Alberta. In order to calculate the cost of shipping a given volume of gas from the Mackenzie Delta to the NWT/Alberta border, a shipper would need to multiply the volume in GJ's times the toll per GJ. For example, if a shipper were shipping 1000 GJ per day from the Delta, they would face a daily cost of $880 dollars when using the Mackenzie Valley Stand Alone Pipeline.

Table 3.4

Summary of Projected Pipeline Tolls

Pipeline Route	Capacity (MMcf/d)	Throughput @ 85% load factor (MMcf/d)	Toll ($/Mcf)	Toll ($/gj)
Mackenzie Valley 30"	1,600	1,360	0.93	0.88
Mackenzie Valley dual 30"	4,000	3,400	0.74	0.70
Mackenzie Valley 48"	4,000	3,400	0.56	0.53
Prudhoe Offshore Link 48"	2,500+	2,125	0.59	0.56
Prudhoe Offshore Link 42"	2,500	2,125	0.55	0.52
Prudhoe Onshore Link 42"	2,500	2,125	0.61	0.58
Prudhoe Onshore Link 36"	2,500	2,125	0.57	0.54
ANGTS (Prudhoe to Whitehorse)	2,500	2,125	0.86	0.82
ANGTS (Whitehorse to BL) 48"	4,000	3,400	0.48	0.46
ANGTS Dempster Lateral 30"	1,600	1,360	0.84	0.80

Using the above transport costs, projected intra-Alberta transport costs of $0.35/gj, and an assumed AECO-C price of $3.50/gj, one can generate netback prices for the Mackenzie Delta based on each of the relevant transport routes. The assumed $3.50

price is below current Alberta natural gas pricing, but is consistent with the long term market outlooks presented in Chapter 1 of this study. Table 1.10 presented forecasts for natural gas prices. The prices given were in U.S. dollars per Mcf. Applying the current exchange rate of about 1.48 and converting to GJ yields a price that is consistent with $3.50/GJ at AECO-C. Netback prices are shown in Table 3.5.

Table 3.5

Summary of Projected Mackenzie Delta Netbacks

Pipeline Route	NWT Border Price ($/gj)	Transport Cost ($/gj)	Projected Price at Pipeline Inlet ($/gj)
Mackenzie Valley 30"	3.15	0.88	2.27
Mackenzie Valley dual 30"	3.15	0.70	2.45
Mackenzie Valley 48"	3.15	0.53	2.62
ANGTS (Whitehorse to BL) 48"	3.15	0.46	
ANGTS Dempster Lateral (Mackenzie Delta to Whitehorse) 30"		0.80	1.89

The netback gives the price that a producer would receive for gas after it has left the field processing facility. Therefore the price that a producer receives for the gas is the netback less processing cost and gathering system costs. This leaves a reasonably attractive price for a producer. The netbacks shown in table 3.5 are directly related to the pipeline toll. The pipeline toll as seen from table 3.4 is influenced by the capital cost of the pipeline and the volume that is shipped. For instance, the three Mackenzie Valley routes all travel the same distance but differ in the cost of the projects from roughly $2.3 billion to $4.5 billion depending on the size of the pipe. Similarly the volumes associated with the larger pipeline (either the dual 30 inch or the single 48 inch line) give rise to economies of scale, making each unit of gas less expensive to ship.

A netback of around $2.00/GJ should make the development of NWT gas resources feasible. Continuing with the example above, shipping 1,000 GJ a day would result in a shipping charge of $880 per day and sell for $3,150 per day, leaving the producer with $2,270 per day to cover processing and gathering costs as well as to provide a return on the investment for drilling and completing the well.

With regard to ongoing operations, a pipeline has the potential to create large revenues to the provincial/territorial governments as well as the Federal Government of Canada. Table 3.6 outlines the income tax revenues from ongoing pipeline operations over a thirty year period. Tax revenues have been discounted at a rate of 5.5 percent. The tax revenues generated are proportional to the capital costs of the pipelines, as well as to the portion of the route that is within Canada. The Mackenzie Valley Stand-Alone shows the smallest total income tax benefits to all of Canada, from pipeline operations, as should be expected because it has the smallest total capital cost. Likewise, the ANGTS plus Dempster Lateral shows the greatest income tax benefits from pipeline operations as it has the greatest capital costs. However, pipeline operations represent only a small part of the total fiscal impacts. Fiscal impacts from natural gas production are more substantial, and are discussed in Chapter 6.

Table 3.6

Potential Income Tax Revenues from Pipeline Operations

($000,000)

Route		NWT	Yukon	B.C.	Canada	Total
Mackenzie Valley Stand Alone		150	0	0	517	667
Mackenzie Valley 48"	Offshore 48"	235	151	0	1,091	1,476
	Onshore 36"	251	89	0	1,032	1,373
Mackenzie Valley dual 30"	Offshore 48"	306	151	0	1,339	1,796
	Onshore 36"	323	89	0	1,281	1,693
ANGTS Stand Alone		0	174	342	905	1,421
ANGTS + Dempster Lateral		26	323	342	1,235	1,926

3.6 Downstream Issues

The above discussion of capital costs, tolls, and netbacks are based on an assumption that the full incremental volumes can be absorbed by the market without significant increases in downstream transport costs, and without pushing the AECO-C price below $3.50/GJ. This report does not include any assessment of the investments that might be required to transport volumes that might be incremental to existing downstream pipeline capacity.

Chapter 4

ENVIRONMENTAL ISSUES

4.1 Summary

The following report is a summary of environmental implications for proposed pipelines in the Northwest Territories. This report summarizes existing studies on the environmental impacts of alternative pipeline routes for gas transportation from the North: the Alaska Natural Gas Transport System (ANGTS), Dempster Lateral, Mackenzie Valley and The Offshore Beaufort Sea route. It addresses the potential environmental impacts of the proposed natural gas routes separately and does not attempt to delineate cumulative effects with co-existing activities or generate a comprehensive environmental impact assessment of each alternative. The information reviewed is summarized in tabular format for ease of presentation and comparison. As is typical for the environmental sensitivities related to any pipeline route, CERI organized the material for each pipeline into the following categories:

Additional sensitive issues will include:

- Background
- Geology
- Hydrology
- Climate
- Biological
- Unique and Sensitive Areas
- Cultural

The methodology for completing the "Natural Gas Transportation Options: Environmental Implications" report included review of relevant available literature, searching information available on the Internet, as well as discussions with key informants.

The potential impacts were ranked based on definitions provided by the Canadian Environmental Assessment Agency, Cumulative Effects Assessment Practitioners Guide.

It is important to note that the scope of this report covers only the potential impacts of the four proposed natural gas pipeline routes based on available literature and it does not address mitigation of these impacts, although some alternative suggestions are made. Mitigation of many of the potential impacts identified in this report has been addressed by additional studies for existing pipelines and projects in the Northwest Territories and the Yukon.

4.2 Key Findings

4.2.1 Alaska Natural Gas Transportation System

The Alaska Natural Gas Transportation System (ANGTS) is a pipeline project intended to transport Alaskan and Northern Canadian natural gas to southern markets in Canada and the United States. One of the most significant issues was the potential environmental effect associated with a buried gas pipeline passing through areas containing permafrost. The entire route proposed for the Yukon lies in the zone of discontinuous permafrost. The potential effects of the proposed pipeline project on slope instability and erosion will depend if the slope is in areas of unfrozen ground or in areas of permafrost. Construction of the pipeline will involve considerable disturbance to vegetation and surface soil along the proposed right-of-way as well as on the access roads and at, or near, associated facilities. Concern has been expressed with regards to the proposed pipeline route passing through known earthquake-prone areas.

In addition, the proposed route in the Yukon involves a variety of water crossings. Environmental concerns associated with river crossings were identified for both construction and operation phases of the project. The potential impacts include direct interference with fish spawning, migration and overwintering, and possible deleterious effects of siltation on fish and fish habitat. The construction and operation of the proposed pipeline may contribute to some air quality degradation, though not on a regional scale. Environmental impact on air quality may include fugitive dust, emissions from equipment during the construction phase and the formation of ice fog during operations.

A potential significant impact could be indirect habitat loss through the displacement of wildlife during the construction phase of the pipeline project. Certain wildlife species such as Dall's Sheep, grizzly bears, and woodland caribou are particularly sensitive to human related disturbance. Critical winter range for Dall sheep is in close proximity of the proposed pipeline right-of-way.

Some important species of birds that might be impacted include Peregrine Falcon, Osprey, Gyrfalcon, Golden Eagle, Trumpeter and Whistling Swans, Bald Eagle, Sandhill Crane, and Canada Goose. Project activities that could affect bird populations are human presence, operation of construction equipment, aircraft overflights and noise from compressor stations. Possible impacts include direct mortality, displacement, disruption of migration-movement, destruction of habitat, degradation of habitat, disruption of feeding-resting activity and disruption of reproductive activity.

Construction of the proposed pipeline will mostly affect vegetation along the right-of-way. Project facilities such as compressor stations, stockpile sites and camps will occupy a relatively small area but could have a significant impact on vegetation depending on site location.

The pipeline right-of-way traverses the northern boundary of Kluane National Park and in close proximity to some International Biological Program (IBP) Sites. Unique or sensitive areas include: Sheep Mountain, Ibex Pass, Mt. Michie-Squanga Lake area and Pickhandle Lake.

It is unlikely that there will be significant conflict between pipeline construction activities and archaeological sites. The proposed route in most cases lies close to and parallels the Alaska Highway, and some of the archaeological sites likely to have been impacted during the construction phase are known and either already salvaged, protected or impacted by previous construction activities. However, there is a potential concern at three major areas (i.e., along Kluane Lake, Dezadeash-Aishihik River confluence, and in the vicinity of Champagne).

4.2.2 Dempster Lateral

The Dempster Lateral is a pipeline proposal that approximately follows the Dempster Highway joining an existing mainline north of Whitehorse. The Dempster Route crosses three broad physiographic regions: the Arctic Coastal Plain, the Interior Plains, and the Cordillera.

A buried pipeline along the proposed Dempster Lateral route could encounter a wide variety of geotechnical problems. These problems relate to slope stability, river crossings, frost heave, thaw settlement and drainage and erosion control. Possible challenges with a buried pipeline along the proposed Dempster Route include mountainous terrain, intermontane valleys, other bedrock, and frost-susceptible soils. An alternative approach would be an above ground warm pipeline.

Continuous permafrost is present along the pipeline from Richards Island to the southern portion of the Ogilvie Mountains. From the Ogilvie Mountains to Whitehorse, the pipeline is located in the discontinuous permafrost zone. Possible impacts with a pipeline in areas of permafrost are frost heave and thaw settlement.

There are six to nine water crossings that may cause significant design and construction challenges due to the potential for frost heave. Other potential problems include ice scour, bed scour, and bank stability.

Construction machinery and routine road traffic would generate small amount of gaseous emissions to the atmosphere, but are not expected to have a significant impact on regional air quality.

One of the more significant biological concerns along the highway and proposed lateral pipeline is the potential implications on the Porcupine caribou herd. The proposed Dempster lateral traverses winter range and spring and fall migration routes of the Porcupine caribou herd. Any pipeline along the Dempster Highway has the potential of dissecting the Porcupine caribou's winter range. Additional wildlife related concerns are related to critical sheep habitat near Rock River in the Ogilvie Mountains and furbearer habitat along most of the proposed route. Construction activities may disrupt life cycle activities of sensitive bird species.

There is a potential for increased siltation of fish spawning and nursery areas during pipeline construction and operation. Increased siltation would be caused by construction of access roads, and grading and ditching of the right-of-way. Construction of water crossings could physically interrupt spawning and migration, destroy eggs present in the stream beds, and alter existing spawning grounds and other fish habitat.

Vegetative zones along the route include tundra, grasslands, wetlands, riparian, and spruce and mixed wood forest. Construction of the proposed pipeline will mostly affect vegetation along the right-of-way.

Although most archaeological sites should have been identified with the construction of the Dempster Highway, any existing sites could be impacted by the proposed pipeline construction.

4.2.3 Mackenzie Valley

The Mackenzie Valley has seen increasing interest from oil industry since the moratorium was lifted in 1994. Recently, several factors combined to dramatically increase the interest expressed by producers and transporters in Mackenzie Valley. These include: concerns over future conventional natural gas supplies, recent gas price strength, and the potentially large future incremental gas demand due to environmental considerations and electricity restructuring.

Many parts of the Mackenzie Valley terrain are sensitive to disturbance. Potential impacts are primarily associated with the construction stage of the pipeline project.

The northern part of the proposed route lies within the zone of continuous permafrost. Pipeline construction and operation in these conditions could influence permafrost integrity and stability, which may increase erosion potential.

Pipeline construction activities can potentially impact hydrological features by disrupting natural drainage profiles, modifying and disturbing channel bank and bed habitats, promoting increased sediment loading and altering water quality. The potential effects on creeks that flow into Fisherman Lake is an area of concern.

Construction machinery and routine road traffic would generate small amounts of gaseous emissions to the atmosphere. There are no refineries or processing plants proposed over the length of the pipeline therefore operational gases would be from compressor stations.

The proposed pipeline route provides year-round habitat for numerous wildlife species and seasonal habitat for many other species during the summer months. Wildlife in the area can potentially be impacted directly by the project through habitat loss or modification, sensory disturbance from construction vehicles and equipment during sensitive overwintering periods, and increased access to the area for hunters. Moose wintering habitat has been noted near Fisherman Creek. A number of salt licks occur within the project area. During pipeline operations, regeneration of vegetation on the pipeline right of way may increase the presence of ungulates, and in particular, bison. Clearing operations on the right-of-way will alter some preferred habitat for these species, while creating new habitat for other species. Increased access could be an issue until vegetation regenerates on the pipeline right-of-way. Important areas for birds include staging and nesting sites for waterfowl in the valley habitats. Large numbers of ducks and Canada geese, loons and shorebirds nest in the Mackenzie Valley. The most important nesting, molting and staging areas for waterfowl are Ramparts River, Camkay Creek, Brackett Lake, Mills Lake and Beaver Lake. The birds are susceptible to disturbance during these stages.

Most fish in the Mackenzie Valley have specific migration routes and limited spawning, overwintering, nursery and feeding areas. The proposed pipeline involves the crossing of several watercourses that are varied in size. There is the potential for short-term impacts on fish habitat at the crossing sites and in the immediate downstream areas that will result from construction activities. The potential impacts related to fish and fish habitat include increased sediment loading in streams, loss or alteration of habitat, and effects from blasting.

The proposed route has been designed to avoid sensitive vegetation communities such as wetlands, major drainages, and steep topography. Pipeline construction activities will remove and alter vegetation along the right-of-way that may result in local destabilization of terrain and modification to natural habitats.

A number of archaeological and historical traditional use sites have been recorded along the shores and relic beaches of Fisherman Lake and at several sites on the northern fringes of the lake. In addition, archaeological sites are known to occur on Richards Island, at the mouth of Thunder River, Loon River, Fort Good Hope, Chick Lake, Nota Creek, Bear Rock, Bear Rock lakes, Great Bear River, Big Smith Creek, Little Canyon Creek, Saline River, Willowlake River, Cardinal Lake, and Peace River. The physical impacts of the pipeline are predicted to have negligible effect on the archaeological record of the region.

4.2.4 Beaufort Sea-Mackenzie Delta Offshore Route

The primary environmental constraint affecting offshore petroleum operations is sea ice. Floating ice in the Beaufort Sea scours the sea floor. The ice action potentially poses a threat for seabed installations such as pipelines or flow lines. There is permafrost in the ground below the Beaufort Sea. There is also the potential for buried pipelines to melt the permafrost and create frost heave.

The Delta is dominated by approximately 25,000 lakes and perched basins. These water bodies play a significant role in the ecology of the Delta. They affect the distribution of permafrost, support populations of fish, waterfowl and mammals, and provide storage for water, sediment and pollutants. Potential impacts to the Beaufort Sea-Mackenzie Delta during pipeline construction and operation could include discharges of sewage, heated cooling water, drilling muds, blowout preventer fluid, and produced water.

Dredging activities may have short-term affects on water quality and may alter the Beaufort Sea Continental shelf.

Gaseous and particulate emissions from marine vessels, and equipment during construction and operation could impact air quality in the Beaufort Sea region. There is a possibility of ice fog formation around emissions sources, however, the wind conditions over the Beaufort should disperse emissions and ice fog if it occurs.

Within the Beaufort Sea region, the principal area of biological concern is the shear zone and the open leads at the edge of the land-fast ice. This area provides critical habitat for migrating birds, polar bears, arctic fox, beluga whales, bowhead whales, and several different species of seals.

The Delta, the coast of the Delta region, the coastal waters and the offshore leads of the Beaufort Sea are of great importance for migratory birds. Two million migrating seabirds and waterfowl representing about 100 species frequent the Beaufort Sea and its coastal margins. The variety of habitat in the Delta-Beaufort supports critical life stage areas for several wildlife species. The nesting, staging and molting areas of the outer Delta are important to various bird species. The offshore leads are critical for birds, seals and polar bears. The calving grounds in the shallow waters of the Delta are critical for the beluga whales. Impacts on birds will depend on facility location and timing of construction activities.

Fish are abundant in the Mackenzie Delta. Some populations of fish pass through the Delta on their way to the Beaufort Sea. The fish are at greatest risk from pipeline construction and operation during spawning, overwintering and migration. Potential impacts on fish could result from changes in the smaller food organisms and exclusion from important habitats. Offshore development in the Beaufort is expected to have minor impacts on fish. Closer to shore, the potential for impacts from pipeline construction and operation is greater, particularly during the summer months.

Two different habitat types are dominant in the vegetation communities of the Delta, tundra along the Beaufort Sea and taiga further inland. Successional changes in some plant communities are maintained by seasonal flooding and by fire. Potential impact of pipeline construction and operation on vegetation in the Delta will be negligible.

Sensitive habitats for certain fish species have been identified in several water bodies adjacent to the Beaufort Sea. Almost all water bodies within the Beaufort Sea-Mackenzie Delta area contain spawning habitat for anadromous species, such as arctic grayling or longnose sucker. Migratory routes for the Arctic cisco, Least cisco, whitefish species and Arctic char exist in the Mackenzie Delta. Spawning, migratory routes, and overwintering areas could be impacted by reduced stream flows, low water levels, heavy ice scour, contaminants, and reduced dissolved oxygen levels caused by pipeline construction and operation.

Although no documents were located that listed site specific information, it is expected that several historic and archaeological sites could exist in the Beaufort Sea-Mackenzie Delta Area.

4.3 Summary of Potential Impacts

The following two tables summarize the potential impacts. The potential impacts are divided into construction and operational phases of pipeline development.

Table 4.1

Potential Impacts of Proposed Pipelines During Construction Phase

CONSTRUCTION	ANGTS				Dempster Lateral				Mackenzie Valley				Beaufort Sea Mackenzie Delta			
	Negligible	Minor	Moderate	Major	Negligible	Minor	Moderate	Major	Negligible	Minor	Moderate	Major	Negligible	Minor	Moderate	Major
Geology																
Permafrost			yellow				yellow				yellow				yellow	
Erosion			yellow				yellow				yellow				yellow	
Slope Instability			yellow				yellow				yellow				yellow	
Soil		blue				blue				blue				blue		
Seismic			yellow		green				green				green			
Hydrology																
Water Crossing			yellow				yellow				yellow				yellow	
Ground Water		blue				blue									yellow	
Surface Water			yellow				yellow			blue	yellow				yellow	
Ice	green				green				green						yellow	
Climate																
Air Quality		blue				blue				blue				blue		
Biological																
Wildlife			yellow				yellow				yellow				yellow	
Fisheries			yellow				yellow				yellow				yellow	
Vegetation			yellow				yellow				yellow				yellow	
Sensitive Areas																
Species			yellow				yellow				yellow				yellow	
Archeolgical			yellow			blue					yellow				yellow	
Cultural			yellow				yellow				yellow				yellow	

Negligible	green
Minor	blue

Moderate	yellow
Major	red

Table 4.2

Potential Impacts of Proposed Pipelines During Operation

OPERATION	ANGTS				Dempster Lateral				Mackenzie Valley				Beaufort Sea Mackenzie Delta			
	Negligible	**Low**	**Moderate**	**Major**	**Negligible**	**Low**	**Moderate**	**Major**	**Negligible**	**Low**	**Moderate**	**Major**	**Negligible**	**Low**	**Moderate**	**Major**
Geology																
Permafrost			yellow				yellow				yellow				yellow	
Erosion	green				green				green				green			
Slope Instability	green				green				green				green			
Soil	green				green				green				green			
Seismic		blue			green				green				green			
Hydrology																
Water Crossing		blue				blue				blue			blue			
Ground Water		blue				blue				blue			blue			
Surface Water		blue				blue				blue			blue			
Ice	green				green				green						yellow	
Climate																
Air Quality	green				green				green				green			
Biological																
Wildlife		blue				blue				blue				blue		
Fisheries		blue				blue				blue				blue		
Vegetation		blue				blue				blue				blue		
Sensitive Areas																
Species	green					blue			green					blue		
Archeolgical	green				green				green				green			
Cultural	green				green				green				green			

Negligible	green
Minor	blue
Moderate	yellow
Major	red

Chapter 5

ECONOMIC BENEFITS

5.1 Methodology

One of the objectives of this study is to examine the potential economic benefits of each pipeline option. Economic benefits include both direct project expenditures as well as indirect or induced impacts that result from the direct expenditures. These benefits can be measured at the territorial/provincial and federal levels. This chapter reviews the economic impacts. Related fiscal and tax impacts are examined in Chapter 6.

Quantification of the economic impact of each of the pipeline routes has been undertaken using a combination of Statistics Canada's Interprovincial Input-Output (IO) model and the NWT Bureau of Statistics' Input-Output model. This combination of models results in some minor data inconsistencies in that the Statistics Canada model is nation-wide and based on 1990 relationships between industries, whereas the NWT Bureau of Statistics model considers only the NWT and is more recent, based on 1996 input-output data.

The objective of an IO model is to estimate the total economic impact of a project, presenting estimates of direct, indirect and induced impacts associated with the project. Based on the observed inter-connection between industries in the economy, the multiplying of demand is traced through these industrial linkages to yield a set of aggregate impacts.

One of the most common uses of the IO model is to simulate the impact of a demand shock on the economy. By shock, we mean any change or departure from the status quo; in this case the changes in demand for goods and services associated with pipeline development and natural gas field development scenarios. Any increase in consumption of goods and services will generate direct, indirect and induced economic production. Since an IO model is based on a static “snap shot” of an economy, there is the potential for the relationships to change over time. The more time that passes from when the snap shot was taken to the time the model is used the more likely it is that this will create inconsistencies. Moreover, it is possible that a large enough shock may disturb these relationships by itself.

The Statistics Canada IO model is a comprehensive model that is capable of isolating impacts occurring in individual provinces and territories. The IO model simulates the impact of an industry output or final demand shock on the economy, by exploiting the inter-industrial linkages of the input and output tables to track the total production of the goods and services in order to satisfy the output or final demand shock. It indicates which domestic industries were directly responsible for meeting the demand and how much of that demand was siphoned or "leaked" off to foreign imports and other "leakages" such as inventories. This first round impact is referred to as the direct effects. These direct suppliers will in turn purchase goods and services from other industries as inputs. The model repeats this process of purchasing intermediate inputs until the model has identified all the indirect commodities in the full chain of the production process. The accumulation of these rounds of impact is referred to as the indirect effects. The direct and indirect effects combine to form the total open model impacts.

The Bureau of Statistics' Input-Output (IO) model is a structural model of the Northwest Territories (NWT) economy. It is the only model that isolates the NWT from Nunavut. The core of the IO model is a set of three tables (Input, Output and Final Demand) which present the most detailed accounting of the NWT economy available. The tables together detail the supply and disposition of individual commodities and the commodity composition of the output of industries, and the complete costs of production of industries.

The industry and commodity dimensions of the tables are highly disaggregated – 679 commodities and 243 industries – although fewer are represented in the NWT. The tables comprise detailed information obtained from Statistics Canada's surveys of establishments and enterprises.

Direct Impacts are the resources (inclusive of contracted resources) purchased by a proponent to meet its production needs.

Indirect Impacts are ripple effects that occur when the proponent buys inputs from other firms, and those firms expand production to meet demand.

Induced Impacts represent the increased production required to meet increased household demand for commodities that is generated by the increased labour income (net of taxes and savings) associated with the increased production.

Total Open Impacts is the sum of direct and indirect impacts.

Total Closed Impacts is the sum of direct, indirect and induced impacts.

5.2 Comparison of Economic Impacts

Economic impacts were calculated for a subset of the pipeline capital costs summarized in Tables 3.2 and 3.3. The five options considered were:

- A stand-alone Mackenzie Valley pipeline based on a 30 inch line,
- A combined Mackenzie Valley/ Prudhoe Onshore route using 36 inch line between Prudhoe Bay and the Mackenzie Valley, and 48 inch line down the valley,
- A combined Mackenzie Valley/ Prudhoe Offshore route using 42 inch line between Prudhoe Bay and the Mackenzie Delta, and 48 inch line down the valley,
- A stand-alone ANGTS project from Prudhoe Bay to Boundary Lake, and
- A combined ANGTS/Dempster Lateral route with 36 inch pipe from Prudhoe Bay to Whitehorse, 30 inch pipe for the Dempster Lateral, and 48 inch pipe from Whitehorse downstream.

GDP impacts for the five options modeled are reported in Table 5.1. The expenditures and impacts shown are for the construction phase of the pipeline project only. They do not include ongoing operating and maintenance costs once a pipeline is in service. They also exclude the costs of field development activities which are shown separately. The impact of any further oil and gas exploration and development activity that might result from the existence of a pipeline is also excluded from this analysis.

Table 5.1

GDP Impacts of the Construction Phase by Pipeline Route
($000,000s)

	Stand-Alone Mackenzie Valley	Mackenzie Plus Prudhoe Onshore	Mackenzie Plus Prudhoe Offshore	Stand-Alone ANGTS	ANGTS Plus Dempster Lateral
Capital Cost of Project	2,280	5,450	5,570	6,000	8,100
GDP Impacts on the NWT (NWT model)					
Direct Project GDP	338	623	625	-	112
Total Open	603	1,054	1,034	-	215
Total Closed	707	1,229	1,203	-	255
Total Impacts on Canada (Statistics Canada model)	2,132	4,078	4,159	3,131	5,117
NWT & Nunavut	607	1,077	1,064	2	218
Yukon	4	167	230	408	1,020
British Columbia	408	693	709	1,653	1,958
Alberta	254	487	489	343	572
Ontario	561	1,126	1,124	452	865
Quebec	207	345	345	110	210
Rest of Canada	93	183	198	163	275

Finally, it is important to note that northern gas producers will likely be price takers. This means that they will receive wellhead revenues that are based on Alberta border prices net of transportation costs from the field. In a netback world, pipeline costs have a positive impact on GDP and employment during the construction phase, but larger pipeline costs mean smaller wellhead revenues. By increasing GDP by having larger capital costs, the producers are hurt. Increasing capital costs may mean that the project no longer yields a necessary rate of return to make the project worthwhile from the perspective of the producer. This truism is important because the upstream sector of the industry creates significantly more employment per dollar of spending and higher spending multipliers than does the pipeline sector.

From Table 5.1 it is evident that a stand-alone ANGTS project, which would completely by-pass the NWT would have no impact on that territory. The ANGTS option with a Dempster lateral represents the highest total project costs at $8.1 billion and the largest GDP impact on all of Canada at $5.1 billion. However, the ANGTS + Dempster project shows a lower GDP multiplier than other options due to the significant portion of project costs that would be incurred in Alaska. It is possible that the impacts of the ANGTS route are understated, as the potential exists for some of the impacts on Alaska to "spill over" into Canada.

With regard to options that would carry Mackenzie Delta gas, the two options that combine Prudhoe Bay gas with Mackenzie Delta gas in a Mackenzie Valley pipeline route show the largest GDP impacts on the NWT, as well as large GDP impacts on the rest of Canada. These options also provide the lowest transport cost from the Mackenzie Delta to market, leaving the largest wellhead revenue stream for a given gas price in Alberta.

A final observation with regard to expenditure impacts can be made by comparing the provincial impacts across cases. In particular, the options that show significant expenditures in the Yukon also show significant impacts on British Columbia, reflecting the close linkages between the two economies. Similarly, the NWT and Ontario economies appear to be strongly linked in that economic activity in the NWT has large spillovers into Ontario. Given the size of the proposed pipeline projects, these types of input-output model linkages based on fixed coefficients and historical trade patterns may not hold entirely.

In addition to the GDP impacts shown, each of the options that involves development of the Mackenzie Delta natural gas resource will involve investment in field development activities. These economic impacts are shown in Table 5.2. These impacts relate strictly to the initial field development assumed necessary to provide initial supply for the pipeline, and are subject to considerable uncertainty. Also, within the first ten years of operations, additional field expenditures would be required to maintain production. The numbers cited also exclude any exploration expenditures that are currently occurring, or that might occur once the pipeline is in place and available to carry gas to market. Given the geographic distribution of the resource base outlined in Chapter 1, these kinds of spin-off effects will be an important element of the impact of whatever pipeline project is built.

Table 5.2

GDP Impacts of Field Development
($000,000s)

	Field Development
Capital Cost	1,480
GDP Impacts on the NWT (NWT model)	
Direct Project GDP	235
Total Open	639
Total Closed	784
Total Impacts on Canada (Statistics Canada model)	1,434
NWT & Nunavut	673
Yukon	4
British Columbia	86
Alberta	192
Ontario	332
Quebec	109
Rest of Canada	37

The IO modeling framework also allows estimates of the impact of each pipeline project on Labour Income. These impacts for the five options modeled are reported in Table 5.3. Labour income is a necessary element in calculating tax revenues that will result from construction of a pipeline. In calculating these impacts, it is assumed that 20% of direct project employment will accrue to NWT residents.

In addition to the labour income impacts shown for the pipeline projects, each of the options that involves development of the Mackenzie Delta natural gas resource will involve investment in field development activities. The labour income impacts of the initial field development are shown in Table 5.4.

Table 5.3

Labour Income Impacts of Pipeline Routes
($000,000s)

	Stand-Alone Mackenzie Valley	Mackenzie Plus Prudhoe Onshore	Mackenzie Plus Prudhoe Offshore	Stand-Alone ANGTS	ANGTS Plus Dempster Lateral
Capital Cost of Project	2,280	5,450	5,570	6,000	8,100
Labour Income Impacts on the NWT (NWT model)					
Direct Labour Income	274	503	504		90
Total Open	468	821	805		167
Total Closed	535	932	913		192
Total Impacts on Canada (Statistics Canada model)	1,377	2,628	2,678	1,956	3,216
NWT & Nunavut	424	756	748	1	149
Yukon	2	118	163	286	712
British Columbia	269	456	467	1,082	1,278
Alberta	137	258	257	165	279
Ontario	365	732	731	284	547
Quebec	132	217	217	66	128
Rest of Canada	47	90	95	72	123

Table 5.4

Labour Income Impacts of Field Development
($000,000s)

	Field Development
Labour Income Impacts on the NWT (NWT model)	
Direct Project Labour Income	191
Total Open	497
Total Closed	589
Total Impacts on Canada (Statistics Canada model)	914
NWT & Nunavut	438
Yukon	3
British Columbia	59
Alberta	110
Ontario	215
Quebec	69
Rest of Canada	21

5.3 Construction Employment

Employment impacts of the pipeline projects and field development activities are shown in Tables 5.5 and 5.6, respectively. The employment numbers are shown in total person-years of employment. Assuming a three year construction period, one would need to divide the numbers shown by three to estimate the full time employment required over the construction period. It is also important to note that the IO model simply estimates the total labour requirements based on industry structures and technologies in use at the time the model coefficients are determined (1996 for the NWT model and 1990 for the Statistics Canada inter-provincial model). Further, the IO structure makes no judgement as to the scale impacts, both positive or negative, of a given project. The IO model does not examine the issue of capacity utilization in the economy. This means that the employment numbers should not be read as incremental new jobs given that some of the activity will come from utilization of spare capacity within industry.

Table 5.5

Employment Impacts of Pipeline Routes
(person-years)

	Stand-Alone Mackenzie Valley	Mackenzie Plus Prudhoe Onshore	Mackenzie Plus Prudhoe Offshore	Stand-Alone ANGTS	ANGTS Plus Dempster Lateral
Capital Cost of Project ($000,000s)	2,280	5,450	5,570	6,000	8,100
Employment Impacts on the NWT (NWT model)					
Direct Employment	2,490	4,580	4,580	-	830
Total Open	5,300	9,210	8,940	-	2,030
Total Closed	6,640	11,460	11,110	-	2,540
Total Impacts on Canada (Statistics Canada model)	31,190	59,430	60,020	43,360	71,970
NWT & Nunavut	6,290	11,080	10,820	20	2,400
Yukon	70	1,800	2,270	4,270	10,720
British Columbia	5,860	10,330	10,670	22,300	28,070
Alberta	4,150	7,830	7,780	4,840	8,350
Ontario	9,580	19,210	19,150	7,680	14,720
Quebec	3,780	6,340	6,330	1,980	3,810
Rest of Canada	1,470	2,840	3,000	2,280	3,900

Table 5.6

Employment Impacts of Field Development
(person-years)

	Field Development
Employment Impacts on the NWT (NWT model)	
Direct Project Employment	1,740
Total Open	5,520
Total Closed	7,370
Total Impacts on Canada (Statistics Canada model)	20,980
NWT & Nunavut	7,150
Yukon	90
British Columbia	1,720
Alberta	3,370
Ontario	5,850
Quebec	2,090
Rest of Canada	700

As well, the size of these projects relative to the overall northern economy suggests that capacity building may be a key requirement to generate the level of local employment indicated in Tables 5.5 and 5.6. The IO model simply assumes that regional shares of GDP will be maintained, and does not examine the availability of workers with the skills required to complete the project. Construction requirements for each of the projects examined are likely to require resources beyond the current capacity of the NWT economy. A significant number of workers will likely be imported from other regions of Canada during the construction period. It is estimated that approximately 20% of direct employment will accrue to residents of the NWT.

In addition to the impacts shown for the pipeline projects, each of the options that involves development of the Mackenzie Delta natural gas resource will involve investment in field development activities. These employment impacts are shown in Table 5.6.

5.4 The Operations Phase and Second Round Impacts

The above impacts are limited to the construction and field development phase of each potential project. Ongoing impacts from the operations phase are not measured. Additional capital investment beyond that required for normal operating and maintenance activities has not been included. These assumptions provide a conservative picture of the long-term impact of the projects examined.

For example, the stand-alone Mackenzie Valley pipeline, which represents the smallest capital expenditure of any of the options examined, is assumed to generate \$35 - \$40 million per year in O&M expenditures, \$40 - \$50 million per year in income tax, and millions of dollars per year in property and non-income taxes over its operating life. As the capital cost of the pipeline project increases, the revenue to gas producers and tax revenues from these producers decreases. These expenditures and taxes will occur over the operations phase of the project, and have therefore been excluded from the analysis of project construction impacts. A preliminary estimate of income taxes that might be paid by the pipeline companies was presented in Table 3.6.

In a similar vein, second round exploration and development impacts will occur which have not been quantified. These impacts are likely to differ according to the pipeline routing chosen. As indicated in Chapter 1, the natural gas potential of the Eagle Plain in the Yukon is estimated at 1 tcf, with current discoveries of only 89 bcf. The Dempster lateral, if constructed could make future discoveries in this region economic to transport to market. The various basins in the Mackenzie Valley are currently estimated to have 2.5 tcf of natural gas resource potential, with current discoveries of 421 bcf, which may be available should that route be constructed. In each case, the economics of a given discovery will depend on its size, resource quality, and proximity to the transmission line, among other factors.

Chapter 6

FISCAL AND TAX IMPLICATIONS

6.1 Fiscal and Tax Impacts During the Construction Period

The fiscal impacts of the five pipelines and the Mackenzie Delta field development options have been calculated based on the input-output model results from the Bureau of Statistics and Statistics Canada, and based on the NWT Government's tax models. Tax revenues are therefore associated with pipeline construction and the spin-off economic effects only. Ongoing revenues during the operations phase of each project such as Corporate Income Taxes (CIT) and Property Taxes are not included. The fiscal impacts shown in Table 6.1 for pipeline construction and Table 6.2 for field development activity relate to the construction period only and are likely small relative to the taxes associated with operations for both the pipeline and field production, as well as second round exploration and development expenditures. The fiscal impacts shown also exclude any revenues related to current exploration licenses and existing oil and gas production in the NWT.

Table 6.1

Fiscal Impacts of Pipeline Construction Options
($000,000s Cdn)

	Stand-Alone Mackenzie Valley	Mackenzie Plus Prudhoe Onshore	Mackenzie Plus Prudhoe Offshore	Stand-Alone ANGTS	ANGTS Plus Dempster Lateral
Capital Cost of Project	2,280	5,450	5,570	6,000	8,100
NWT					
Tax Revenues	23	39	38	0	8
Grant Reduction	-17	-28	-27	0	-6
Net Revenues	6	11	11	0	2
Yukon					
Tax Revenues	0	5	8	13	34
Grant Reduction	-0	-5	-7	-12	-31
Net Revenues	0	0	1	1	3
Federal Government					
Tax Revenues	187	357	358	283	438
Savings on NWT Grant	17	28	27	0	6
Savings on Yukon Grant	0	5	7	12	31
Net Revenues	204	390	392	295	475

NOTE: NWT and Yukon Tax Revenues include personal income tax, payroll tax, and fuel taxes. Federal Tax Revenues include personal income tax, EI premiums, and fuel taxes.

In calculating income taxes during the construction period, it is assumed that 20 per cent of direct labour income and 100 per cent of indirect labour income in the NWT is attributable to NWT residents (i.e., those who file tax returns in the NWT). A similar assumption is made for Yukon labour income. 2000 Personal Income Tax (PIT), Payroll Tax, Fuel Tax and Employment Insurance premium rates are used. Formula Financing Grant impacts are estimated based on the 2000-01 Formula Financing Grant and data as at May 2000.

The overall fiscal impacts are proportionate to the GDP and labour income impacts from the input-output model. So, the construction of the ANGTS line with a Dempster lateral, yields, in absolute terms, the largest GDP and labour income impacts and will generate the largest tax revenues for the Governments of Canada, and Yukon. However, the Mackenzie plus Prudhoe Onshore yields the greatest net revenues for the NWT Government. There is a trade off between these initial impacts from the pipeline construction and the ongoing impacts from future development. Although higher capital costs from the pipeline mean greater GDP and labour impacts now, lower development activity (and therefore reduced taxes from gas producers) into the future is also a result.

The revenues associated with all of the options will accrue primarily to the federal government. For example, federal tax revenues associated with the construction of a Mackenzie Valley pipeline with a connection to Prudhoe Bay would exceed $350 million, while GNWT tax revenues would be about $40 million. The $40 million in NWT tax revenues would lower the GNWT's Formula Financing Grant by $27-$28 million, leaving the GNWT with net revenues of $11 million. It is important to note that there will also be large gains for the provinces of Alberta, British Columbia, and Ontario because a large share of the labour income effects from any of the projects will accrue to these provinces.

Table 6.2

Fiscal Impacts of Field Development
($000,000s Cdn)

	Field Development
NWT	
Tax Revenues	32
Grant Reduction	-24
Net Revenues	8
Yukon	
Tax Revenues	0
Grant Reduction	0
Net Revenues	0
Federal Government	
Tax Revenues	125
Savings on NWT Grant	24
Savings on Yukon Grant	0
Net Revenues	149

NOTE: NWT and Yukon Tax Revenues include personal income tax, payroll tax, and fuel taxes. Federal Tax Revenues include personal income tax, EI premiums, and fuel taxes.

6.2 Long Term Fiscal and Tax Impacts – Field Developments

The fiscal impacts of the field developments have been estimated using a discounted cash flow model. This model calculates the project revenues using an inputted market price, cash flow based on the revenues and inputted costs, and then calculates all corporate income taxes and royalties applicable to each project based on current tax and royalty regimes of Canada and the Northwest Territories. Approximately 80 per cent of NWT corporate income taxes from the new field developments would be offset by a reduction in the NWT's Formula Financing Grant. Also, the estimates of Territorial taxes may be overstated given the ability of corporations to shift the tax burden to other provincial jurisdictions.

In this analysis, three existing fields have been modeled for development. These are the Parsons Lake, Taglu, and Niglintgak. It is beyond the scope of this study to look at the economic potential of each of these developments on an individual basis, rather it is the purpose to look at the economic impact of the different pipeline options on the field developments in aggregate. The same price will be used in all scenarios with the resulting netback prices to the fields reflecting only the difference in tolls for each pipeline option. The total throughput of these fields over their production life is 5.759 tcf, while it has been assumed that Mackenzie Delta total throughput is 14.892 tcf over a period of 30 years (representing 1.36 bcf per day). The portion of the throughput (9.133 tcf) from fields not modeled will use the average revenue, cash flow, corporate income taxes and royalties from the modeled fields on a per unit basis in order to extrapolate the values of these outputs for this throughput. It is further assumed that development is isolated to the Beaufort Mackenzie basin, as this basin holds enough potential to supply the required throughput.

Some assumptions that have been made include consideration of the investment royalty credit applicable to past frontier exploration expenditures of companies on frontier lands. These have been estimated at $125 million for the purpose of this analysis. The development costs are grossed up estimates of development costs that were contained in the 1989 Gas Export applications made to the National Energy Board. Although they may be considered “ball park” cost estimates, they will be suitable for the comparison of the impacts of the different pipeline options on the revenues, corporate income taxes and royalties of the field developments. The production estimates are also taken from the 1989 Gas Export applications. The price used for this analysis is the same price for all cases. This price was calculated by netting back the price of gas in the U.S. midwest from a northern Alberta receipt point to Chicago. This produces the NWT/Alberta border price of $3.15 per gj, in Canadian dollars. It is assumed that downstream pipeline transportation is sufficient to handle the throughput under all cases. All values have been discounted at a rate of 5.5 percent.

Case 1: Mackenzie Valley Stand Alone

This case examines the fiscal impacts of the Mackenzie Delta gas developments assuming that Mackenzie Valley stand-alone pipeline option is constructed. As stated in Section 3.5, the netback price for this option is $2.27/gj for Mackenzie Delta production. The estimated throughput of the pipeline is 1.36 bcf per day, held constant over the 30-year period. Table 6.3 contains the aggregate fiscal impacts from this scenario, with all values discounted at a rate of 5.5 percent. For the purposes of this analysis, this will be referred to as the base case for comparison against all the following options.

Table 6.3

Mackenzie Valley Stand-Alone Option
($millions)

	Revenues	After-tax Cash Flow	Federal Corporate Income Tax Plus Grant Offset	NWT Corporate Income Tax Less Grant Offset	Federal Crown Royalties
Modeled Fields	6,129	1,688	1,158	81	835
Modeled Fields Average per Unit Produced (per gj)	1.064	0.293	0.201	0.014	0.145
Extrapolated Values for Un-modeled Field Production	9,720	2,677	1,836	128	1,325
Totals	15,849	4,365	2,994	209	2,160

These results show positive economic development of Mackenzie delta gas resources over the 30-year life of the pipeline. The fiscal benefits accruing to the federal government from development are very strong, with tax (including reduction in GNWT operating grant) and royalties totaling $5.154 billion. The GNWT will receive a net corporate income tax benefit of $209 million for the field developments. For the Delta producers, revenues are $15,849 billion with a positive cash flow of $4,365 billion.

Case 2: Mackenzie Valley Dual 30” Pipeline
with Alaskan Throughput

Under this scenario, two 30” pipelines are constructed down the Mackenzie Valley to carry production from both the Mackenzie Delta region and production from Prudhoe Bay, Alaska. The total throughput is estimated at 3.4 bcf per day, which will produce economies of scale for the pipeline transportation. The netback price is estimated at $2.45 per gj, an improvement of $0.18 per gj that is totally attributable to the lower toll due to the improved pipeline economies of scale. Table 6.4 contains the estimates of the fiscal impacts under this pipeline option.

Table 6.4

Mackenzie Valley Dual 30” Pipeline Option
($millions)

	Revenues	After-tax Cash Flow	Federal Corporate Income Tax Plus Grant Offset	NWT Corporate Income Tax Less Grant Offset	Federal Crown Royalties
Modeled Fields	6,615	1,889	1,320	92	1,002
Modeled Fields Average per Unit Produced (per gj)	1.149	0.328	0.229	0.016	0.174
Extrapolated Values for Un-modeled Field Production	10,491	2,995	2,094	146	1,589
Totals	17,106	4,884	3,414	239	2,590

Under the dual 30” pipeline option and the assumed price, Mackenzie delta gas development is again economic. The fiscal impacts are $6.004 billion for the federal government and $239 million for the Government of the NWT. For the federal take, this has increased by $850 million dollars versus the base case (Mackenzie Valley stand-alone). For the GNWT, its take has increased by $30 million. These increases are due solely to the increased netback prices in the field achieved through higher pipeline economies of scale.

The economics for the producers in the Mackenzie Delta have also improved under this option. The estimated revenues are $17.106 billion, an increase of $1,257 million from the base case. Cash flow has also increased from $4.365 billion to $4.884 billion, an increase of $519 million.

Case 3: Mackenzie Valley 48” Pipeline with Alaskan Throughput

This pipeline option is similar to the previous dual 30” option, except now it is just a single 48” line running down the Mackenzie Valley. The throughput includes Alaskan gas delivered to the pipeline in the delta region, with the combined throughput being 3.4 bcf per day. The calculated netback price of this option is $2.62/gj, which is $0.35/gj higher than the netback price under the base case. This higher netback price is solely due to increased economies of scale of the pipeline development (the single 48” is more efficient than the dual 30” lines, even though the throughput is the same). The fiscal impacts under this pipeline option are presented in Table 6.5.

Table 6.5

Mackenzie Valley 48” Pipeline Option
($millions)

	Revenues	After-tax Cash Flow	Federal Corporate Income Tax Plus Grant Offset	NWT Corporate Income Tax Less Grant Offset	Federal Crown Royalties
Modeled Fields	7,074	2,058	1,474	103	1,180
Modeled Fields Average per Unit Produced (per gj)	1.228	0.357	0.256	0.018	0.205
Extrapolated Values for Un-modeled Field Production	11,218	3,263	2,337	163	1,871
Totals	18,292	5,321	3,811	266	3,050

The results of the modeling show an improvement in all fiscal impacts versus the previous two cases. Federal government taxes and royalties are $6.861 billion, while the GNWT has net tax revenues of $266 million.

The revenues to the delta producers have increased to $18.292 billion, with cash flows also increasing to $5.321 billion. As before, these increases are totally attributable to the increased economies of scale of the larger pipeline combined with the Alaskan throughput.

Case 4: Alaska Natural Gas Transmission System (ANGTS) with Dempster Lateral

Under this case, the Mackenzie delta gas production is shipped on a pipeline constructed along the Dempster highway in the Yukon. This gas will then be combined with Alaskan throughput and shipped down the ANGTS from Whitehorse, Yukon, to British Columbia. The netback price for this option is $1.89/gj, a decrease of $0.38/gj from the base case netback price. This lower netback demonstrates a longer distance for Mackenzie delta gas to travel and the lack of economies of scale on the Dempster lateral portion of the pipeline option. The fiscal impacts of this option are shown in Table 6.6.

Table 6.6

ANGTS and Dempster Lateral Pipeline Option
($millions)

	Revenues	After-tax Cash Flow	Federal Corporate Income Tax Plus Grant Offset	NWT Corporate Income Tax Less Grant Offset	Federal Crown Royalties
Modeled Fields	5,130	1,274	824	58	495
Modeled Fields Average per Unit Produced (per gj)	0.891	0.221	0.143	0.010	0.086
Extrapolated Values for Un-modeled Field Production	8,135	2,020	1,307	91	785
Totals	13,265	3,294	2,131	149	1,280

Under the ANGTS/Dempster option, the federal government revenues are $3.411 billion and the GNWT revenues are $149 million. These values are less than the base case by $1.743 billion and $60 million, respectively. For the delta producers, their revenues are $13.265 billion, a decrease of $2.584 billion. Cash flow has also decreased $1.071 billion from the base case to $3,294 billion. Note that the ANGTS without the Dempster lateral will yield no benefit to the GNWT.

6.3 Conclusions

In examining the different pipeline options for Mackenzie delta gas production, the best option is Case #3, the 48" pipeline down the Mackenzie Valley. This option provides the highest netback price to producers due to the realization of economies of scale in combining Alaskan and Mackenzie delta throughput right at the delta. The

48” pipeline is also more efficient than the dual 30” pipeline option, which is the next best case. Given that the Mackenzie delta stand-alone option provides a higher netback price than the ANGTS/Dempster option is significant. One can conclude that Mackenzie delta production would best be transported on a pipeline down the Mackenzie Valley.

In comparing the best case (48”) versus the worst case (ANGTS/ Dempster), the results are very significant. The difference in federal revenues is $3.450 billion dollars in favour of the 48” pipeline option. The GNWT will realize $117 million more under this option versus the ANGTS/Dempster.

For the producers, the 48” pipeline option results in $5.027 billion in additional revenue and $2.027 billion in additional cash flow in comparison with the ANGTS/Dempster option. This is a very significant amount that the producers would surely not want to forego. What has not been examined in this analysis is the impact of the different options on the economics of the Alaskan gas production. Although it has not been quantified, the offshore option of transporting the Alaskan gas throughput to the Mackenzie delta and down the 48” pipeline option will provide the highest netback price to Alaskan gas producers. Given that this throughput is 2.5 bcf/day and the gas is already being produced and re-injected, the economic and fiscal impact on this Alaskan gas development will be very substantial for a Mackenzie Valley route versus an ANGTS route.

Chapter 7

CONCLUSIONS

Demand for natural gas is expected to grow substantially over the next two decades. In order to meet this demand supply will need to grow as well. In Canada, there are four areas that will need to combine to fill the incremental need of approximately 2.5 tcf. These are conventional WCSB production, coalbed methane, Eastern Canada offshore projects, and Northern gas. Although conventional production from the WCSB has been forecast to be able to meet all of this requirement, this requires its production to rise by about 2 percent a year. Recent production from this maturing basin has only grown by about 1 percent per year. This casts some doubt on the ability of this basin to fulfill its requirements. Coalbed methane is an undeveloped resource. Estimates of the size of this resource range substantially as is to be expected when dealing with a resource that is untested. Expectations for Eastern Canada offshore projects are modest. The Mackenzie Delta holds 13.5 tcf of discovered resources with a total potential of an additional 42 tcf. It is the primary basin of focus for any development that will occur in the NWT. The entire resource base in the North is expected to total greater than 50 tcf. This places Northern gas in a promising position to fill some of the required demand.

The projected capital costs that were discussed in chapter three show that there is the potential for a pipeline to supply Northern gas to Southern markets. Cost estimates for the projects range from about $2.3 billion for the Mackenzie Valley stand alone route to roughly $9 billion for the dual 30 inch ANGTS line with Dempster Lateral. The potential for either Mackenzie Delta stand alone, or a combination of Prudhoe Bay and Mackenzie Delta gas is there. At this moment in time the Mackenzie Valley route looks the most attractive from a volume of gas perspective. A 1.6 bcf/day flow translates into roughly 0.6 tcf/year to be absorbed by a growing market. Four bcf/day (which is an estimate of the Prudhoe Bay and ANGTS routes) translates to about 1.5 tcf/year leaving far less room for WCSB growth and coalbed methane potential. Given the projected capital costs of the projects, and a cost of service toll, the netbacks to producers appear to be at a level that makes developing Northern gas feasible.

A pipeline to deliver Northern gas to the North American market has large potential economic benefits to the residents of the NWT and the Yukon, as well as other residents of Canada. The GDP impacts on the NWT and Nunavut from a pipeline that connects with the Mackenzie Delta (either a Mackenzie Valley route or an ANGTS route with the Dempster Lateral) could potentially range from $218 million to $1.1 billion, with another $784 million for field development. The Yukon could see GDP impacts that range from $4 million to over $1 billion for the pipeline depending on the route. For

Canada as a whole the GDP impact of a pipeline could range from $2.1 billion to $5.1 billion depending on the route and size. The initial impacts of field development that would accompany a pipeline are $1.4 billion for Canada. With a pipeline in place, further exploration and development would mean increased future impacts over and above these initial GDP impacts.

Employment impacts show that the pipeline may create between 31,000 and 72,000 person years of employment for Canada depending on the pipeline route chosen. 11,500 person years of employment could be created for the NWT from the Mackenzie Plus Prudhoe Onshore project and the Yukon could experience as many as 10,700 person years of additional employment from the ANGTS plus Dempster Lateral pipeline.

The project will have substantial tax and fiscal benefits as well that will accrue primarily to the federal government. The impacts on the net revenues of the NWT Government are roughly $6 million for the stand-alone route, and are over $11 million for a combined Prudhoe-Mackenzie Valley route. Field development would add nearly $8 million more. Impacts on the Yukon Government's net revenues range from about $2,000 to $3 million for the pipeline. As for the Federal Government, the net revenues range from $200 million to $475 million for the pipeline and another $149 million for the field development.

Ongoing impacts from field development and operation of the pipeline have the potential to generate large revenues. Income tax revenues from pipeline operations range from approximately $670 million for the Mackenzie Valley Stand-Alone project to over $1.9 billion from the ANGTS with Dempster Lateral. Combined income tax and royalty revenues from producers range from zero in the Stand-Alone ANGTS to $7.1 billion for the 48 inch Mackenzie Delta route with an offshore link from Prudhoe Bay. Combining these revenues, Canada is better off, from a fiscal stand point, with any route down the Mackenzie Valley. The combined fiscal revenues are over $6.2 billion with the Stand-Alone Mackenzie Valley route as compared to $6 billion for the ANGTS with Dempster Lateral. With a link to Prudhoe Bay, the Mackenzie Valley route improves to over $8.8 billion in taxes and royalties. From a producer stand point, revenues from the Mackenzie Valley route over the ANGTS with Dempster Lateral range from nearly $2.6 billion greater for the Stand-Alone Mackenzie Valley route to over $5 billion more for the 48 inch Mackenzie Valley route. Clearly producers are better served by a Mackenzie Valley route as well.

Environmental impacts for all the pipeline routes look to be moderate for the construction phase and low to negligible for the operation. There is little difference between the proposed routes with regard to the magnitude of the environmental impacts. The differences between routes will likely only be with regard to which specific sites are impacted rather than the overall magnitude of impact. All routes have the potential to affect the geology, hydrology, climate, and biological aspects of the areas surrounding them. It is not expected that any of the projected routes would have the impact of destroying whole populations or species of wildlife or plants. It is important to note that there have been substantial improvements in mitigation procedures over the last few years such as horizontal drilling to bury pipe under stream crossings without affecting the stream. It is very likely that the future will bring further improvements to reduce the impacts on the environment of pipeline construction. Differing magnitudes of environmental impacts are relevant only to the extent that mitigation factors may be more applicable to certain routes than others.