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Scale-up problems might generate cost overruns during construction of the El Paso natural gas liquefaction plant. The proposed LNG plant would require a significant scale-up from existing plants and involves lower fuel usage than has heretofore been achieved in practice. In addition, the techniques proposed to protect the proposed plant and storage tanks from earthquake damage would also require a size scale-up. Consequently, the LNG plant and terminal appear to have a potential for significant cost overruns.

3. Labor and equipment capacity. The Alyeska project is a classic example of a construction project that exceeded its predetermined labor and equipment capacity. Alyeska was forced to use inexperienced labor and contractors, and thereby incurred significant increases in the size of management and engineering staffs. This resulted in low productivity, management inefficiency, and created the project's own internal demand-pull inflation for some critical items.

Construction of a gas pipeline in Alaska should present fewer problems. Less labor is required for a continuous buried mode of construction and the Alyeska experience expanded the pool of skilled workers and contractors available for arctic construction.

The Alcan project may encounter skilled-labor shortages in Canada. Anticipated shortages in skilled labor and experienced subcontractors could reduce productivity and raise costs. However, training programs and proper project planning would mitigate this problem.

Alcan has been criticized because it will not have an overall project manager. The Canadian companies, however, can control construction in their respective segments of the system without the large increases in management or engineering required for a single project. In addition, the companies will be using control and accounting procedures with which they are familiar. It is reasonable to expect that Alcan will not suffer from the management and control inefficiencies that plagued Alyeska.

4. Incentives to minimize construction costs. The El Paso and Alcan projects would have stronger incentives to control costs than are normally present in a public-utility type project. The variable rate of return will link the earnings of equity investors directly to the cost control performance of management. In Canada, the costs to Canadian consumers for Canadian gas will be materially dependent upon the level of cost overruns in the main Alcan line, providing Canadian regulatory agencies with an incentive to control costs.

One of the terms and conditions contained in the decision will limit the use of cost-plus contracts unless approved by the Federal Inspector. Contractors will thus have incentives to hold down costs. The magnitude of the project investment and the generally limited availability of capital at present will also create financial constraints that should act to minimize costs. Furthermore, the managements of the various gas companies also have a substantial incentive to show that a major arctic project can be constructed with relatively minor cost overruns.

5. The time factor. With a simpler construction mode, fewer environmental problems, a more experienced labor force available, and more favorable terrain in most of Canada, construction of the Alcan system should pose fewer problems, and have a longer lead time to deal with them. While Alyeska had a long delay from 1969 to late 1973, there is little evidence that intensive planning occurred during that period. After Congressional approval came in late 1973, Alyeska carried out its final planning and construction in three and one-half years. The final planning and execution period for either gas project is at least five years and the overrun analyses herein have allowed for six to six and one-half years.

6. Delays. The Alyeska project suffered excessive delays because of strict new environmental laws enacted after it had initially ordered the pipe and some construction equipment. Government agencies required considerable time to write regulations and to staff operations. In addition, after construction started, numerous government inspectors monitored contractors and subcontractors, occasionally shutting down construction.

Conditions should be considerably better during construction of the gas pipeline. First, the government itself is now more knowledgeable about the inspection process and can be expected to make fewer errors. The Office of Federal Inspector is designed to achieve greater coordination of the government monitoring and enforcement process. The occasionally conflicting orders given by different departments or agencies during construction of the Alyeska project will be avoided. Second, contractors have learned to some extent to adapt to the government inspection process. Third, the gas line will raise fewer environmental problems. Overall, delays resulting from environmental regulations and government oversight and inspection should be much less during construction of a gas pipeline.

The projects will also be much less constrained by institutional delays of the type that confronted Alyeska from 1969 until enactment of the TAPS Act in 1973. Similar to the TAPS Act, Section 11 of ANGTA contains tight restrictions on judicial review of the authorization and certification process. While private litigants can still challenge Government actions, such claims must be brought within 60 days of such action, and filed only in the U.S. Court of Appeals for the District of Columbia. This Court will act as a Special Court with exclusive jurisdiction over such matters. There are no specific limitations on judicial review of Federal enforcement actions, but it is not foreseen that such litigation will result in injunctions or restraining orders that increase the potential for delays and cost overruns.

El Paso and Alcan each face institutional barriers other than potential judicial delays. For El Paso, the problem of siting an LNG facility in California has high potential for delay. The Western LNG Terminal Company has been investigating proposed locations for approximately two years, and no final decision has yet been reached. Recently, an offshore LNG facility has been receiving consideration, but gas companies and State officials estimate that 8 to 10 years of design development and construction work would be required before it could be operational.

For Alcan, the problem of resolving native claims in the Yukon Territory in Canada had once threatened to delay construction. However, the Government of Canada has recently assured the U.S. that resolution of these claims will not delay construction and will not result in any monetary cost or claim against the Pipeline. Under the Agreement, it is expected that construction in the Yukon will commence by January 1, 1981.

In general, the magnitude of these projects virtually ensures some delay in the start of full operations -- either because of material supply, logistics, reduced labor productivity or other problems. Therefore, this Report estimates that commencement of full operations for Alcan could be delayed to January 1, 1984, and for El Paso to July 1, 1984. By comparison, the Task Force Report on Cost Overrun and Construction Delay estimated a starting date of July 1984 for Alcan and February 1985 for El Paso.

7. Remote and inhospitable location. Both projects would experience many of the same problems associated with remote locations as did Alyeska. The benefit of the Alyeska experience, however, should assist in coping more

successfully with these problems. The most tangible benefit of the Alyeska experience is the existence of the infrastructure -- e.g., roads, camps, communications -- created by Alyeska. In Canada, the southern portions of the Alca' system would be in less remote locations and present fewer problems.

8. Geotechnical considerations. Alyeska encountered many unexpected geotechnical conditions, but had done relatively little advance coring and soil testing which could have reduced the unexpected problems that arose later and allowed for improved engineering design and scheduling of work requirements.

Either of the gas pipeline projects will be able to reduce its number of site-required design changes by using the construction data generated by Alyeska and by carrying out a more extensive coring and soil testing program prior to construction. In addition, the site-specific design changes that were required will probably be less expensive.

Unexpected geological conditions could significantly increase the cost of constructing an El Paso LNG plant and shipping terminal. Similarly, Alyeska experienced significant cost overruns in constructing the Valdez terminal.

El Paso probably would escape such problems if, as expected, it finds shallow bedrock at the Gravina Point terminal site. If not, El Paso could duplicate or exceed the Valdez terminal cost overrun.

Cost Overrun Estimates Under Expected Conditions

Comparison of the El Paso and Alcan projects under expected conditions with Alyeska indicates that both projects would be able to avoid or minimize many problems that led to high cost overruns for Alyeska. Cost estimates of both projects appear to be based on much more reliable data and experience. There are also fewer uncertainties than were associated with Alyeska's early estimates, or even its estimates made as late as 1974 or early 1975. In addition, several problems that significantly contributed to cost overruns on the Alyeska project will not be as serious for these projects. While overruns can be expected, they will be of relatively lower magnitude than Alyeska's.

Obviously, any prediction of future cost overruns is highly judgmental. Specifically, it depends on judgments about future productivity, future supply-demand relationships, and geological and technical problems. But despite these uncertainties, for the purpose of this analysis some judgments must be made.

Overall, it has been estimated that cost overruns of 30 percent or more should be expected in Alaska and Canada for construction of a gas transportation system. But in many areas, the managers of a gas transportation project should benefit from the Alyeska experience and hold down overruns. This conclusion is based on careful comparison with the Alyeska experience and proceeds from the findings of the July Task Force Report on Cost Overruns and Construction Delays.

Certain distinctions, however, should be drawn between Alcan and El Paso with regard to cost overruns. For Alcan, the cost estimates in Canada are substantially lower than the cost estimates for equivalent work done in Alaska. These estimates are highly uncertain. Alcan offers several explanations for the significant differential between costs to do the same job in Alaska and Canada. It contends that wage rates in Canada are about one-half the level in Alaska and that the productivity of labor in Canada has historically been higher. Furthermore, with the exception of the Yukon section, the Canadian terrain is typically much better. Below the 60th parallel, the requirement for gravel work pads is minimal. As the line moves into British Columbia and Alberta, the Alcan construction conditions will not vary materially from those encountered in the Northern United States, and lower construction costs can be expected.

On the other hand, the NEB closely examined Alcan's costs in Canada and concluded that cost overruns in the range of 20 to 30 percent were "not unlikely". Furthermore, it is significant that the Alcan productivity estimates for Alberta are substantially higher than the estimates of Arctic Gas for comparable terrain. The Alcan cost estimates must be substantially adjusted to enable a realistic comparison between Alcan and El Paso. Therefore, the cost estimates used herein provide for a 40 percent increase in the filed costs of Alcan for Canada.

The cost estimates of El Paso are in turn, subject to two major uncertainties. The first is El Paso's cost estimates for pipeline construction in Alaska. El Paso estimated these costs, including interest during construction, at $2.204 billion ($1975) -- $242 million less than Alcan's Alaska estimates of $2.446 billion. The relation between the El Paso cost estimates and the Alcan cost estimates is simply not consistent, however, with the physical plant requirements, but may be partially explained by the fact that the El Paso estimates were made several months earlier.

The higher Alcan estimates represent 731 miles of pipeline in Alaska, 9.6 percent less mileage than El Paso's 809 miles.10/ While Alcan would use a larger diameter pipe (48-inch for Alcan, 42-inch for El Paso), it would also have a thinner wall (0.60 inch for Alcan, 0.752 inch for El Paso). Consequently, Alcan would require about 17 percent less pipe steel in Alaska than El Paso. This differential is reflected in the respective cost estimates of the parties. The El Paso estimated materials cost for pipe was $805 million. Alcan estimated $659 million, or some 18 percent less. Finally, El Paso could have 10 compressor station sites in Alaska; Alcan would have only 8 sites. El Paso would have 234,000 installed compressor horsepower; Alcan would have 212,000 horsepower.

On the other hand, Alcan would have more installed refrigeration horsepower than El Paso, and installation costs for 48-inch pipe would be slightly higher than those for 42-inch pipe. The following Exhibit summarizes the comparisons.

10/ There would be 831 miles for the realignment which El Paso now proposes to build. The comparisons here consider only the base cases of El Paso and Alcan. El Paso estimated the realignment to have a net cost of about $70 million additional.

EXHIBIT 3

Comparison of El Paso & Alcan Pipeline
Facilities in Alaska

	El Paso (2.4 Bcfd)	Alcan (2.4 Bcfd)	%
Miles (L)	809	731	-9.6%
Pipe	42" (D) x .75 (T)	48" (D) x .60 (T)	
Relative Steel Factor (π DTL)	8.006	6.614	-17.4%
Pipe Material Est.	$805,171,000	$659,239,000	-18.1%
Compressor Stations	10	8	-20.0%
Compressor HP Installed	234,000	212,000	-9.4%
Refrigeration Comp. Installed	53,690	84,470	+57.0%

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By way of further comparison, Alcan and El Paso propose virtually identical alignments for the first 539 miles in Alaska. The overall costs of the two systems should be comparable to that point. At Delta Junction, the Alcan line departs from the Alyeska corridor and proceeds southeast along the Alcan Highway. The El Paso line continues along the Alyeska corridor to a point about 40 miles from Gravina Point, from which it creates a new right-of-way through the mountainous Chugach National Forest. From the common point of Delta Junction southward, Alcan would traverse 192 more miles in Alaska, while El Paso would traverse about 265 miles and some significantly more difficult terrain.[11/] There is no readily apparent reason that the 192 miles of Alcan pipeline should cost significantly more than the 265 miles of El Paso pipeline.

The proper relationship between El Paso and Alcan is reflected in the recently released Aerospace, Inc., study of June 1977 that was prepared for the Department of the Interior. The direct cost estimates therein for the El Paso pipeline in Alaska are $1.963 billion. The cost estimate for a

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11/ The El Paso realignment case has about 285 miles beyond Delta Junction.

48-inch, 1680 psig[12/] pipeline along the Alcan base route in Alaska is $1.812 billion.

To allow for cost overruns the El Paso estimates were escalated by the same amount used by the Cost Overrun Task Force to arrive at $2.5 billion in direct costs (1975 dollars) or $2.85 billion (1975 dollars) including interest during contruction (IDC). The overrun case for Alcan used here is $2.38 billion in direct costs, $2.67 billion including IDC. These figures provide a better comparison between Alcan and El Paso in Alaska.

The second major uncertainty for El Paso is the cost of the LNG liquefaction plant and marine terminal on Prince William Sound, Alaska. The scale up factor and the geotechnical uncertainties create a high risk of substantial cost overruns. The Cost Overrun Task Force estimated the cost of these facilities to be $2.0 billion. The Aerospace, Inc., study estimated $1.59 billion. The estimates here used allow for $1.8 billion, plus $75 million to cover cooling towers that would likely be required to minimize the thermal pollution of Prince William Sound.

12/ This would be more expensive than Alcan's 48-inch, 1260 psi system because of more pipe steel.

El Paso would also construct eight LNG tankers of 165,000 to 175,000 cubic meter capacity (m^3) with roughly 125,000 tons displacement.13/ El Paso estimates the LNG tanker cost at $1.365 billion. The Cost Overrun task force estimated $1.65 billion; Aerospace, Inc. uses $1.234 billion. The evidence submitted by Arctic Gas in the FPC proceeding shows an 8.8 percent overrun or $1.485 billion, and in fact, the most probable estimate is $1.45 billion.

In the lower 48 States, the facilities for El Paso and Alcan present no unique construction problems. Therefore, the cost overrun case used herein assumes only a few percent overrun for these facilities.

The following table sets forth the estimated capital costs for the base and overrun cases. The capital cost or the gross plant in service is a dominant element in the cost of service and net national economic benefit calculations.14/

13/ The ultimate size of the El Paso ships would be determined by the siting of the regasification facility in California. For example, if Point Conception was the site, 165,000 m^3 would be adequate. If Oxnard was the site, 175,000 m^3 would be required. See FPC, Recommendation to the President, pp. VIII - 26-28.

14/ NNEB calculations, however, use only the direct capital costs, without interest during construction.

Capital Costs
(Billions of Dollars)

	Base Case[2/] (Current $)	Overrun Case (Current $)	Overrun Case (1975 $)
ALCAN[1/]			
Alaska	3.335	4.147[3/]	2.673
Canada	4.365	6.501	4.191
Northern Border	1.427	1.573	1.014
PGT, PG&E	.914	.983	.634
Subtotal	10.041	13.204	8.511
U.S. Share of Dempster Line	.431	.653	.382
Subtotal	10.472	13.857	8.893
Less Canadian "Share"	(1.000)	(1.489)	(.960)
U.S. "Share" of Capital Cost	9.472	12.368	7.933
EL PASO			
Alaska Pipeline	3.050	4.419	2.849
Alaska LNG	2.385	3.289	2.120
Ships	2.027	2.285	1.473
Regas Plant	.542	.674	.434
Lower-48	.991	1.032	.665
Total	8.995	11.699	7.541

1/ Based on a 48 inch 1680 psi system between Whitehorse and James River capable of transporting 3.6 bcfd. If a 54 inch 1120 psi system was constructed, the capital costs could be slightly less.

2/ Derived from the 1975 Direct Capital Costs submitted by the applicant.

3/ The Base cases assume completion one year earlier than the overrun cases which accounts for a portion of the difference.

The foregoing table includes all capital costs in Canada in which the U.S. shares. If the Dempster Line is never constructed, the capital cost on the main line in the overrun case would be $6.111 billion (1984 dollars) because of the reduced compression horsepower requirements. Total U.S. share of capital cost would be $12.767 billion.

Cost of Service

The cost of service advantage of the Alcan overland pipeline system is substantial and constitutes a crucial element of this decision. Cost of service is perhaps the principal factor in determining the value of the project to individual consumers. If the cost of service is not sufficiently low enough to ensure that the delivered cost of the gas will be below the cost of alternative fuels, the value of the project is greatly reduced.

A cost of service calculation generally includes all transporation charges other than fuel expense. The major categories of expense include the return on invested capital (interest and dividends), return of invested capital (through annual depreciation charges), Federal and State income taxes, other taxes, and operating and maintenance expenses (O&M). While annual depreciation charges are constant throughout the depreciable life of the project and O&M expenses tend to increase with the rate of inflation, the other items decline over time as the amount of net invested capital (gross plant less accumulated depreciation) falls.

These declining items usually result in a project cost of service that decreases steadily over time, with the extent of the decrease dependent upon the rate of inflation. Although this decreasing cost of service is customary, a downward-sloping service charge to the consumer over the life of the project is not essential. Payments from consumers can be adjusted to a more constant or stable level over the accounting life of the project.

However, to compensate investors for deferral of their return in the early years of the project, and to cover the resultant increase in the total interest burden, the average delivered cost of the gas to consumers must be increased substantially; a complete leveling would increase the average cost about 20 percent over the life of the project. The decision whether to "level out" the tariff must be made by the FPC in the context of the actual financing and tariff proposals made by the applicants prior to final certification.

Alcan and El Paso: Cost of Service Comparison

The fundamental difference between El Paso and Alcan is that an overland pipeline system is inherently more efficient than an LNG transportation system. The liquefaction process involves significant energy losses that have a multiplying adverse effect upon cost of service. First, the direct cost[15/] for the natural gas consumed by El Paso is 34 percent higher than Alcan or equivalent to 3 cents per mmbtu (1975 dollars). Second, the volumes of gas delivered are reduced thus leaving a 3.4 percent smaller base over which to spread the capital costs. The increase in cost of service for this volume differential is about 4 cents per mmbtu. The El Paso system also has 100 percent higher operating costs, or the equivalent of another 9.5 cents per mmbtu increase in the cost of service. This operating cost differential is attributable to the added labor required to operate the Alaska LNG plant and the LNG tankers. In sum, the Alcan pipeline system has a 16.5 cent direct advantage apart from capital cost of financing consideration.

15/ Consistent with practice throughout the Report the fuel cost is assumed to be $1.00 per mmbtu (1975 dollars). This unquestionably is lower than actual cost will be. A higher fuel cost would increase El Paso's cost of service to a relatively higher degree than Alcan's.

The El Paso cost of service would approach the Alcan cost of service only if the more technologically complex El Paso system could be constructed for about 25 percent less than the portion of the Alcan system attributable to the U.S. There is no basis for such a conclusion. No reasonably plausible independent assessment of capital costs, suggests that to be a possibility16/. On the basis of filed costs, the El Paso 20-year average cost of service is $1.09 per mmbtu; Alcan's is $.81 per mmbtu17/, or $.28 less. The Cost Overrun task force "expected case" cost of service was $1.26 for the El Paso system and $1.09 for the Alcan system, or $.17 less.

As indicated in the following Table, the overrun cases used in the Decision and Report place the cost of service at $1.21 for El Paso18/ and $1.04 for Alcan.19/ This is a $.17 difference. Over the first 20 years alone, the overland pipeline system will save consumers conservatively about

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16/ The overrun case used herein places El Paso 5 percent lower; the July 1 task force "expected case" placed El Paso 4.2 percent lower, of course, not including the adjustments resulting from the Agreement on Principles with Canada.

17/ Not including a U.S. share of the Dawson Spur which on filed costs would be $.0479.

[Footnotes continued]

COMPARATIVE SYSTEM COST ECONOMICS
COST OVERRUN CASE

	El Paso	Alcan a/	Alcan b/
Direct Cost ($1975)	$6.800 billion	$7.166 billion	$8.011 billion
Interest During Construction	0.740	0.767	0.882
Total Capital Cost ($1975) c/	$7.540 billion	$7.933 billion	$8.893 billion
Annual O&M Costs ($1975)	$ 168 million	$ 84 million d/	
Annual Fuel Cost @ $1/mmbtu	106 million	79 million	
Annual U.S. Delivered Volumes e/	888 Tbtu	918 Tbtu	
Fuel Efficiency	89.1% f/	92.1%	
Average U.S. Cost of Service ($1975)			
First 5 years	$ 1.84	$ 1.71	
Second 5 years	1.28	1.13	
Third 5 years	.95	.77	
Fourth 5 years	.77	.57	
Twenty year average	1.21	1.04	
Net National Economic Benefit	$ 4.63 billion	$ 5.77 billion	

a/ Direct and total capital costs are complete Alaska and lower-48 costs plus the U.S. share of these costs for the section of the system in Canada plus 83.3% of the Dawson-to-Whitehorse section of the Dempster line.

b/ The direct and total capital costs are the complete cost of the entire system, including the Canadian section of the main line in its entirety, plus 83.3% of the Dawson-to-Whitehorse section of the Dempster line.

c/ In current dollars, at an assumed inflation rate of 5%, the total capital costs are $11.7 billion for El Paso and $12.4 and $13.9 billion for the U.S. allocated and total Alcan system, respectively. See p. 157.

d/ Based on U.S. share of costs in the sections of the system carrying both U.S. and Canadian volumes, plus 83.3% of O&M costs on the Dawson-Whitehorse section of the Dempster line.

e/ Based upon 2.4 bcfd at 1138 Btu/cf input at Prudhoe Bay and each system's fuel efficiency. The El Paso system as filed is designed to transport and liquify slightly lower volumes (2.3614 bcfd) at slightly lower Btu content (1130).

f/ Excludes bunker oil consumption by El Paso tanker fleet which would further reduce overall system energy efficiency to 87.5%.

$6 billion (nominal), an average of $300 million per year. Further, savings will continue long into the future. The Prudhoe Bay field is expected to produce gas in significant volumes for more than 25 years. The pipeline facilities will have a useful life in excess of 40 years.

Alcan Cost of Service Pursuant to the Agreement on Principles

The Alcan cost of service must be analyzed from the perspective of both the Canadian National Energy Board (NEB) Decision and the Agreement on Principles between the United States and Canada.

(continued from page 160)

18/ Apart from cost overruns, the principal variable in the El Paso cost of service is financing costs. The $1.21 per mmbtu cost of service is based upon 8.5 percent cost of debt for the LNG tankers on the assumption that the MARAD guaranteed loans be available. The return on equity for the ships is 17 percent calculated on a discounted cash flow basis, as filed by El Paso. The overall cost of the remainder of the capital is dependent upon the debt-equity ratio assumed and whether and how much preferred stock could be used. These matters have been the subject of considerable debate thrugh the proceeding. The capital structure used here is the same as that assumed for Alcan, 75-25 debt-equity ratio, 15 percent return on equity, 10 percent cost of debt. Under various other assumptions,the cost of service could be between $1.19 and $1.21.

19/ Including the cost of the U.S. share of the cost of the Dawson Spur.

The NEB decision provided for a rerouting of the Alcan main line through Dawson City, Yukon, to facilitate the transportation of up to 1.2 bcfd of Mackenzie Delta reserves. That rerouting would have compelled the expenditure of $600 million at least two to three years prior to the time it would be needed and would have added further interest costs of $150 to $240 million. If Canada did not construct the Dempster Line, the U.S. consumer would have paid more than $2 billion over the life of the project for no reason.

If the Dempster Line had been constructed, and 1.2 bcfd of Canadian gas flowed, the U.S. cost of service would have increased from $1.07 to $1.12 per mmbtu because of system inefficiencies. The amount of natural gas delivered to the U.S. would have decreased by about 40 Tbtu annually. As a result of these lost volumes and inefficiencies, the cost to American consumers would still have been $2 billion more over the first 20 years than the project which emerged from the Agreement on Principles.

The project authorized in the Agreement on Principles also represents one of those unique, rare negotiating results in which both parties can justifiably claim to have improved their position over the starting point - the original NEB decision. This is apparent from the following comparison.

	Agreement on Principles		NEB Decision	
	U.S.	Canada	U.S.	Canada
Dempster Line Not Constructed				
Cost of Service[a/]	1.00	-	1.07[b/]	-
Fuel Usage	6.1%	-	6.7%	-
Dempster Line Constructed				
Cost of Service	1.04	1.23	1.12	1.43
Fuel Usage	7.7%	7.3%	11.2%	9.7%

a/ U.S. cost of service is the 20-year average in 1975 dollars. Canadian cost of service is for 1985, in nominal dollars.

b/ Including the $200 socioeconomic payment recommended by the NEB.

The Agreement on Principles contemplates that a higher capacity system[20/] will be constructed from Whitehorse to the James River. If Canada does not construct the Dempster Line, the United States would bear the full additional cost of the higher capacity system. The cost of service data contained in this analysis is based upon a 48-inch, 1680 psi system from Whitehorse to James River. The 1680 psi system is slightly more efficient in the 3.6 bcfd range than the 54-inch, 1120 psi system. Thus, if the 54-inch system ultimately is installed, the U.S. cost of service would be higher by about 1 percent in all cases except where Canada does not construct the Dempster Line.[21/]

If a 1680 system is installed and Canada does not build the Dempster Line, the 20-year average U.S cost of service would be about $1.00. The system would have lower fuel and operating expenses than a 1260 system but the savings would not be quite sufficient to offset carrying charges on the increased capital outlays. On the other hand, the system

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20/ Either a 48-inch, 1680 psi or a 54-inch, 1120 psi are the most likely alternatives. The selection will be determined after a joint testing program is completed.

21/ At 2.4 bcfd, the 54-inch, 1120 psi system would be slightly more economically efficient. It has a lower initial capital cost.

does provide a large amount of inexpensive expansibility that would be used in the event significant new finds of natural gas are made in Alaska.

If Canada builds the Dempster Line and deliverability from the Mackenzie Delta is 1.2 bcfd, the cost of service will vary with the level of cost overruns on the mainline system in Canada and on the Dawson Spur. From a 0 to 35 percent cost overrun, the U.S. would pay 100 percent of the Whitehorse to Dawson section. At the expected 40 percent case, the U.S. would pay 83 1/3 percent or the ratio of U.S. to joint volumes at Whitehorse, whichever is higher. At 45 percent and over the U.S. would pay 66 2/3 percent, or the ratio of U.S. to joint volumes at Whitehorse, whichever is higher.

In the cost overrun range of 35 to 45 percent, the U.S. share would vary linearly from 100 percent to 66 2/3 percent, unless the actual volumes of U.S. gas in the line commit the U.S. to provide a greater share.

In the lower cost overrun case of 35 percent or below, under which the U.S. would be required to pay the entire cost of the Dawson spur, the cost of service reduction from such overrun savings on the main line would more than offset any increase in cost of service resulting from increasing to 100 percent the U.S. share of the Dawson to Whitehorse segment. For example, with an overrun of 25 percent in Canada, the U.S. pays 100 percent. In this example, the average U.S. cost of service over a twenty year period would be approximately $1.00 per mcf (1975 dollars), or 4 cents less than the expected overrun case of 40 percent under which the U.S. would pay only 83 1/3 percent of the Dawson spur instead of the 100 percent the U.S. would pay in the 25 percent overrun case.

The agreement also imposes a ceiling on U.S. liability for the Dawson spur of 35 percent above filed costs. The Canadians, in turn, can credit all the cost overrun savings they achieve on the main line system carrying just Canadian gas, and 2/3's (or relative volumes) of such savings on the shared system, against their cost overruns on the Dawson to Whitehorse section. Finally, the U.S. share of the Dawson spur cost of service can never be less than the U.S. percentage of actual volumes at Whitehorse, multiplied by the actual costs of the Dawson spur, notwithstanding the Dawson spur ceiling and the overrun formula. This last condition is only relevant in the case where substantial overruns in excess of 50 percent are experienced on the entire system.

This agreement creates new incentives - on a portion of the project within Canada's jurisdiction and not otherwise subject to our control - which could significantly lower the cost of service to the U.S. and at the same time enhance the project's financeability.

The application of these principles in varying factual situations is illustrated by the following table.

	Main Line Cost Overrun	Dawson Spur Cost Overrun	U.S. Base COS[a/]	Dawson Spur COS U.S.	Total U.S. COS
1.	25%	25%	.9556	.0567	1.0122
2.	30%	30%	.9679	.0601	1.0280
3.	30%	50%	.9679	.0717	1.0396
4.	30%	100%	.9679	.0692	1.0371
5.	35%	35%	.9822	.0606	1.0478
6.	40%	35%	.9927	.0505	1.0432
7.	40%	40%	.9927	.0505	1.0432
8.	45%	35%	1.0047	.0404	1.0451
9.	45%	45%	1.0047	.0436	1.0483
10.	50%	50%	1.0130	.0480	1.0610
11.	50%	100%	1.0130	.0582	1.0712

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a/ Assumes volumes of 2.4 bcfd from Prudhoe Bay and 1.2 bcfd from the Mackenzie Delta.

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Lines 1 and 2 represent 25 percent and 30 percent cost overrun cases for both the main line and the Dawson Spur. Under the Agreement, the U.S. would pay 100 percent of the Dawson spur cost of service.

Line 3 provides an example of the crediting mechanism between the main line and the Dawson spur. The 30 percent cost overrun would result in a capital savings of about $245 million below the 35 percent cost overrun. Assuming that U.S. and Canadian volumes are 2.4 bcfd and 1.2 bcfd, respectively, and all of the cost reduction is on the main line south of Whitehorse, Canada would have a credit of $163 million to apply to the cost of the Dawson Spur. A 50 percent cost overrun on the Dawson spur would be only $81 million greater than a 35 percent cost overrun. Thus, Canada would have a sufficient credit to hold the U.S. share to 100 percent.

The case in Line 4 assumes a 100 percent cost overrun on the Dawson spur.[22/] The Canadian credit here also would be $163 million. The Dawson Spur (DS) adjustment is determined by the following formula:

22/ This assumes a very unlikely occurrence in light of the cost of the main line.

$$\frac{1.35 \text{ Filed DS Cost (Base)}}{\text{Actual DS Cost minus Credit}}$$

Applied to this case, the formula is:

$$\frac{733}{1084 - 163} = .7959 \times \text{DSCOS}(.0869) = .0692$$

for the Dawson Spur cost of service.

Note that the U.S. contribution to the Dawson Spur is slightly less in this 100 percent Dawson Spur overrun case than in the 50 percent overrun case. Under the agreement, the U.S. share of the Dawson spur cost of service decreases from 100 percent to 66 2/3 percent in this instance depending on the overrun level of the Dawson Spur. This increase in capital costs of the Dawson spur above a 35 percent overrun level has a greater impact under the formula in reducing U.S. cost of service share than it has in increasing the full Dawson Spur cost of service. This is so because full cost of service contains fixed costs that do not vary with capital cost overruns (e.g., operating and maintenance expenses). The greater the percentage of fixed costs, the less cost the overall cost of service will increase because of a given addition to capital costs.

While this precise effect (i.e., reduction in U.S. share where cost overruns are higher) would not obtain if the system was more capital intensive, e.g., a 36-inch or

42-inch pipe was installed, the general direction would be the same. Cost overruns on the Dawson Spur will not have a significant impact on U.S. cost of service in any case where the 66 2/3 percent floor is not reached.

The case in Line 5 is the "base" case. There are no credits available from main line construction. The Dawson Spur overrun is 35 percent. The U.S. would pay 100 percent of the Dawson Spur.

In the example on Line 6, the U.S. share of the Dawson Spur is at 83 1/3 percent because of the 40 percent overrun on the main line.

In the case represented by Line 7, the base U.S. share is 83 1/3 percent, but the Dawson Spur adjustment operates since Dawson Spur overruns are above 35 percent. The result is:

$$\frac{733}{760} = .9645 \times .833 = .8034 \times .0629 = \$.0505$$

for the Dawson Spur cost of service, and $1.0432 overall.

In Case 8, the U.S. share of the Dawson Spur has declined to 66 2/3 percent (or a volumetric share) because of overruns on the main line.

In Cases 9, 10 and 11, the mainline overruns have caused the U.S. share of the Dawson Spur to decline to 66 2/3 percent. Since the 66 2/3 percent floor has been reached, the U.S. pays that percent of total Dawson Spur cost of service, or .667 x .0650 = $.0436 for the Dawson Spur cost of service in the 45 percent case. In the 50 percent case, the Dawson Spur cost of service would be .667 x .0717 = $.0480. In the 100 percent case, it would be .667 x .0869 = $.0582.

All of the above capital cost and cost of service data assume that the input volumes of gas will be 2.4 bcfd for the U.S. and 1.2 bcfd for Canada. On the basis of present geological information, 2.4 bcfd from Prudhoe Bay is more likely than 1.2 bcfd from the Mackenzie Delta. Deliverability from the presently proved reserves in the Mackenzie Delta more likely would be in the range of .7 to .8 bcfd. A reduction in Canadian volumes would, of course, substantially increase the U.S. share of the system in Canada. However, it would not materially alter the U.S. cost of service. If the joint system was designed for 3.1 to 3.2 bcfd, the capital costs would be lower by about $100 million, the U.S. operating expenses would be lower, fuel consumption would be lower in absolute and relative terms, and the delivered volumes would be higher. These cost reduction factors would offset the increase caused by the larger U.S. share of the base capital costs of the mainline system. For example, at 1.2 bcfd from Canada with a 40 percent overrun in Canada, the base U.S. cost of service would be \$.9927. With the system redesigned for .7 bcfd from Canada, the U.S. cost of service would be \$.9950.

The capital cost, operating expenses and delivery factors operate as well with respect to the cost-sharing on the Dawson Spur. To illustrate, the estimated overall U.S. cost of service at 3.6 bcfd (2.4 plus 1.2) in the overrun case is \$1.0432. With 3.1 bcfd (.07 bcfd of Canadian gas) the U.S. cost of service would be slightly lower, about \$1.035.

Net National Economic Benefit

The net national economic benefit (NNEB) to the United States of the Alcan project also substantially exceeds that from the El Paso project. The NNEB measures the desirability of a project from the public perspective. The NNEB of a project is the present value of the benefits derived less the present value of the resources employed in undertaking the project. The benefit is measured by the value of energy delivered to the lower-48 states. A value of $2.62 per mmbtu for natural gas in 1975 dollars was used throughout the FPC hearings and is based upon a study done for the Department of the Interior that was market oriented rather than resource oriented. This value also formed the basis of the NNEB calculation contained in the National Economic Impact Task Force Report of July 1977.

To ascertain the reasonableness of this value, the resource cost of the most probable substitute for natural gas, No. 2 distillate, was determined. Based upon a mid-1977 price of $14.50 per barrel for imported oil and plausible assumptions regarding producer taxes and the resource investment that is required to refine crude to obtain No. 2 distillate, $2.60 per mmbtu is a fair measure of the current resource cost of this substitute for natural gas.[23/]

Further, the real value of natural gas is likely to increase over time as the real cost of imported oil increases. If the real value of gas increases at a rate of only 2 percent per year, the value of the gross benefits

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23/ The value of gas is undoubtedly higher since the intrinsic value of gas is greater than that of oil (clean, efficient, etc.) and a continuation of gas supply avoids the capital costs of conversion.

determined herein would increase approximately 35 percent, and the NNEB would approximately double.

There are five general categories of resource costs used in the NNEB calculation: the Prudhoe Bay field costs of conditioning the gas and using water injection in place of reinjected gas to pressurize the field; the initial capital costs of the transportation systems; annual operating and maintenance costs; the costs of public services used to support the project (measured in terms of the property taxes the project will be required to pay); and, in the case of Alcan, the annual cost of service payments to Canada for transporting the gas.[24/]

The components underlying these benefit and cost factors are displayed in Exhibits 4 and 5, and the NNEB components are summarized in Exhibit 6 for El Paso and Alcan under the cost overrun case herein. Alcan's NNEB exceeds that of El Paso by over $1.1 billion, which is approximately 25 percent of the El Paso NNEB. Most of that difference is attributable to the reduced volumes of gas

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24/ Fuel costs are not included. The U.S. will supply its share of fuel used to transport the gas through Canada and that cost is reflected automatically in the benefit calculation.

Exhibit 4

ALCAN NNEB COMPONENTS

YEAR	DELIVERED GAS (TRILLIONS BTU'S)	FIELD GATHERING & CONDITIONING ($MILLION)	FIELD OPERATION & MAINTENANCE ($MILLION)	U. S. TRANSPORT. FACILITIES ($MILLION)	U. S. WORKING CAPITAL ($MILLION)	U. S. OPERATION & MAINTENANCE ($MILLION)	OTHER U. S. TAXES ($MILLION)	U. S. SHARE CANADIAN COSTS ($MILLION)
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	10.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0
1980	0.0	200.0	0.0	240.0	0.0	0.0	0.0	0.0
1981	0.0	344.0	0.0	828.0	0.0	0.0	0.0	0.0
1982	0.0	400.0	0.0	1497.0	0.0	0.0	0.0	0.0
1983	0.0	500.0	0.0	1259.9	0.0	0.0	0.0	0.0
1984	935.5	0.0	8.0	0.0	16.4	37.4	136.4	1330.4
1985	936.1	0.0	8.0	0.0	0.0	39.2	128.7	1239.8
1986	914.7	0.0	8.0	0.0	0.0	41.2	121.2	1174.4
1987	916.0	0.0	8.0	0.0	0.0	43.3	114.2	1109.6
1988	915.9	0.0	8.0	0.0	0.0	45.4	107.6	1051.8
1989	916.7	0.0	8.0	0.0	0.0	47.7	101.3	1019.4
1990	917.4	0.0	8.0	24.3	0.0	50.1	95.4	992.5
1991	918.0	0.0	8.0	18.4	0.0	52.6	79.7	967.7
1992	917.6	0.0	8.0	17.7	0.0	55.2	73.4	944.8
1993	918.3	0.0	8.0	14.1	0.0	58.0	68.2	923.4
1994	918.6	0.0	8.0	0.0	0.0	60.9	63.3	903.5
1995	918.9	0.0	8.0	0.0	0.0	63.9	58.5	885.0
1996	919.0	0.0	8.0	0.0	0.0	67.1	54.0	868.0
1997	919.6	0.0	8.0	0.0	0.0	70.5	49.6	852.2
1998	920.0	0.0	8.0	0.0	0.0	74.0	45.5	837.6
1999	920.6	0.0	8.0	0.0	0.0	77.7	41.4	825.3
2000	920.5	0.0	8.0	0.0	0.0	81.6	37.5	812.6
2001	920.5	0.0	8.0	0.0	0.0	85.7	34.5	812.8
2002	919.7	0.0	8.0	0.0	0.0	89.9	30.6	799.2
2003	919.4	0.0	8.0	0.0	0.0	94.4	26.8	767.1
2004	919.0	0.0	8.0	0.0	0.0	99.2	22.8	736.5
2005	919.0	0.0	8.0	0.0	0.0	104.1	19.0	707.0
2006	919.0	0.0	8.0	0.0	0.0	109.3	15.2	678.7
2007	919.0	0.0	8.0	0.0	0.0	114.8	11.5	651.6
2008	919.0	0.0	8.0	0.0	0.0	120.5	7.7	625.5
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	22998.0	1444.0	200.0	3949.4	16.4	1783.7	1544.0	22516.4

Exhibit 5

EL PASO NNFB COMPONENTS

YEAR	DELIVERED GAS (TRILLIONS BTU'S)	FIELD GATHERING & CONDITIONING ($MILLION)	FIELD OPERATION & MAINTENANCE ($MILLION)	U. S. TRANSPORT. FACILITIES ($MILLION)	U. S. WORKING CAPITAL ($MILLION)	U. S. OPERATION & MAINTENANCE ($MILLION)	OTHER U. S. TAXES ($MILLION)	U. S. SHARE CANADIAN COSTS ($MILLION)
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	80.0	0.0	0.0	0.0	0.0
1979	0.0	0.0	0.0	180.0	0.0	0.0	0.0	0.0
1980	0.0	200.0	0.0	530.0	0.0	0.0	0.0	0.0
1981	0.0	344.0	0.0	1275.0	0.0	0.0	0.0	0.0
1982	0.0	400.0	0.0	2375.0	0.0	0.0	0.0	0.0
1983	0.0	500.0	0.0	1880.0	0.0	0.0	0.0	0.0
1984	444.0	0.0	4.0	480.0	0.0	130.3	125.6	0.0
1985	888.0	0.0	8.0	0.0	0.0	273.6	270.8	0.0
1986	888.0	0.0	8.0	0.0	0.0	287.3	260.3	0.0
1987	888.0	0.0	8.0	0.0	0.0	301.6	249.8	0.0
1988	888.0	0.0	8.0	0.0	0.0	316.7	239.3	0.0
1989	888.0	0.0	8.0	0.0	0.0	332.5	228.8	0.0
1990	888.0	0.0	8.0	0.0	0.0	349.2	218.3	0.0
1991	888.0	0.0	8.0	0.0	0.0	366.6	207.8	0.0
1992	888.0	0.0	8.0	0.0	0.0	384.9	197.2	0.0
1993	888.0	0.0	8.0	0.0	0.0	404.2	186.7	0.0
1994	888.0	0.0	8.0	0.0	0.0	424.4	176.2	0.0
1995	888.0	0.0	8.0	0.0	0.0	445.6	165.7	0.0
1996	888.0	0.0	8.0	0.0	0.0	467.9	155.2	0.0
1997	888.0	0.0	8.0	0.0	0.0	491.3	144.7	0.0
1998	888.0	0.0	8.0	0.0	0.0	515.8	134.1	0.0
1999	888.0	0.0	8.0	0.0	0.0	541.7	123.6	0.0
2000	888.0	0.0	8.0	0.0	0.0	568.7	113.1	0.0
2001	888.0	0.0	8.0	0.0	0.0	597.2	102.6	0.0
2002	888.0	0.0	8.0	0.0	0.0	627.0	92.1	0.0
2003	888.0	0.0	8.0	0.0	0.0	658.4	81.6	0.0
2004	888.0	0.0	8.0	0.0	0.0	691.3	71.1	0.0
2005	888.0	0.0	8.0	0.0	0.0	725.9	60.5	0.0
2006	888.0	0.0	8.0	0.0	0.0	762.2	50.0	0.0
2007	888.0	0.0	8.0	0.0	0.0	800.3	39.5	0.0
2008	888.0	0.0	8.0	0.0	0.0	840.3	29.0	0.0
2009	444.0	0.0	4.0	0.0	0.0	441.2	9.2	0.0
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	22200.0	1444.0	200.0	6800.0	0.0	12746.2	3732.8	0.0

EXHIBIT 6 - NNEB COMPARISON
($ Billions 1975)

	El Paso[a/]	Alcan[a/]
Value of Gas	$10.849	$11.791
Less:		
Field Capital Costs	.873	.873
Transport Facilities	4.074	2.334
U.S. Working Capital	0	.008
U.S. O & M (field and system)	.820	.157
U.S. Other Taxes	.456	.222
Canadian Cost of Service	0	2.431
NNEB	$ 4.626	$ 5.766

a/ Based upon 2.4 bcfd input at 1137.8 Btu/cf.

that El Paso would deliver because of its high fuel consumption. The real resource costs associated with the transportation are nearly equal, with the higher sum of the Alcan facilities, plus Canadian cost of service for Alcan, being offset by El Paso's large operating and maintenance expenditures.

While both projects exhibit the ability to absorb substantial cost overruns without becoming uneconomic, Alcan's ability is greater than that of El Paso. Assuming that the elasticity of cost of service with respect to direct cost overruns is about 0.8, Alcan's direct costs could increase almost 124 percent over the cost overrun case before it would become socially uneconomic; the comparable figure for El Paso is 114 percent.

In conclusion, the economic considerations overwhelmingly favor the Alcan overland pipeline measured against the El Paso LNG transportation system. The cost of service will be significantly less; the net national economic benefits will be significantly higher; the amount of energy delivered will be significantly higher; and the ability to absorb cost overruns is greater.

CHAPTER V - SAFETY, RELIABILITY AND EXPANSIBILITY

Considerations of safety, reliability and expansibility avor the Alcan overland pipeline system in comparison to the LNG system proposed by El Paso.

The safety record for LNG storage and transportation has been excellent during the past quarter of a century. Nevertheless, LNG facilities present marginally higher risks of a major accident than overland pipelines. An LNG project requires a careful approach to facility siting. The United States may need to rely more upon LNG in the future. However, the use of LNG should be chosen where there is no economically and environmentally feasible alternative.

The greater reliability of the Alcan system should be emphasized. The El Paso system is a multiple-mode system that would be sized and operated at very close capacity and operational tolerances, a factor that tends to decrease reliability. Further, the El Paso pipeline would cross several major geologic faults--the Alaska LNG facility and the California regasification facility would be sited in some of the most seismically active areas in the world. Although the faciliites can be designed and constructed to survive structurally a major seismic event, there inevitably would be interruption in service during repair. By contrast, the seismic risk to the Alcan system is very small. It will approach relatively few seismically active areas and will cross no known active faults in Alaska.

Finally, expansibility of capacity also weighs in favor of the Alcan system. The capacity of a properly designed all-pipeline system can be expanded incrementally up to a point simply by the addition of compression at relatively low capital cost. The capacity of an LNG system, on the other hand, must be expanded in large increments that may be excessive in relation to the actual need.

The specific safety and design areas which have been addressed by U.S. and Canadian authorities and to which Alcan must now properly respond as the project moves forward include:

- Safety of Design and Operation
- Potential for Service Interruption -- Reliability
- Efficiency of Design and Capability of Expansion
- Monitoring Construction and Joint U.S./Canadian Coordination

These safety and design issues, involving new technologies for the Alaska gas system, were reviewed by an Interagency Task Force under the lead of the Department of Transportation (DOT), with participation by the Departments of the Interior and Commerce, the Federal Energy Administration, the Energy Research and Development Administration, and the Environmental Protection Agency.

Safety of Design and Operation

The technical problems in operating a pipeline at high pressures and the transportation of natural gas at chilled temperatures have been carefully considered by government and industry officials. Specific issues include:

- high strength pipe metallurgy,
- the possibility of frost heave effects on the pipeline in permafrost soils,
- the choice of pressure testing methods, and
- development of advanced valve designs.

Final resolution of these technical issues will be needed before there can be site specific approvals of system design and initiation of construction.

<u>Pipe Metallurgy</u>. The principal factors that affect safety of the pipeline system are the type, design, physical properties, the metallurgy of the pipe used, and quality control for the pipe.

Alcan initially proposed to operate its 48-inch system at 1260 psig pressure with the pipeline buried and the gas chilled below 32^{o}F before shipment through permafrost regions. It is probable that Alcan will redesign its system between Whitehorse, Yukon, and Caroline Junction, Alberta, to increase capacity and allow for the economical transportation of Canadian gas from the Mackenzie Delta. The principal alternatives are a 48-inch, 1680 psi system or a 54-inch, 1120 system. In addition, if a 1680 system is installed south of Whitehorse, consideration will be given to installation of a 1680 psi system in Alaska, perhaps with a pipe diameter less than 48-inch. The higher pressure system is generally more economically efficient than lower pressure designs.

To date, the highest pipeline operating pressure has been approximately 1000 psi. From the evidence submitted at the FPC hearings, the DOT and the Safety and Design Task Force tentatively have concluded that the higher operating pressures (1670 to 1680 psi) could be safely achieved with adequately designed pipe. However, further testing and evaluation will be required. The Agreement on Principles between the United States and Canada provides for a jointly conducted testing and evaluation program to determine which system would offer the highest degree of safety, reliability and efficiency. Upon completion of the testing program, the respective regulatory authorities of each country will make a final decision as to which type of system might be installed in each country.

Another issue pertaining to high pressure pipe is whether special "crack arrestors" will be required to stop fracture propagation in the event a fracture should occur. The Safety and Design task force concluded that the fracture toughness properties designed into the pipe specified by the various operators should be sufficient to prevent the initiation of a propagating crack even at arctic temperatures. It therefore concluded that crack arrestors were merely a precaution to ensure that in the remote chance a crack were to initiate, any resulting propagation would be controlled. The task force also reported that with proper

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design and installation, the arrestors would introduce no problems of corrosion control or stress concentration.

However, if Alcan uses crack arrestors, the particular design and installation plans will be reviewed on a site-specific basis by the DOT to assure that they are consistent with the Federal gas pipeline safety standards.

Alcan plans to use high-strength, grade X-70 pipe. The grade has been rated acceptable in the most recent survey of pipe specifications published by the American Petroleum Institute (API). However, a reference specification for X-70 pipe is not presently incorporated in the Federal gas pipeline safety regulations. Reports of operating experience with X-70 pipe and its approval under liquid pipeline safety standards, as well as in the standards and regulations of many other countries, make it probable that the DOT will incorporate the API X-70 pipe specifications into its regulations before commencement of the construction on the Alaska portion of the system. The economic benefits from the use of X-70 pipe provide an incentive to incorporate it into the design of the Alaska gas system.

Potential for "Frost Heave." The problem of frost heave (i.e., the upward movement of a buried pipeline resulting from freezing and thawing conditions), which pipelines can experience when buried in areas of discontinuous permafrost, must be adapted for the particular conditions encountered on a site-specific basis. Depending upon soil characteristics, some discontinuous permafrost areas are more subject to frost heave than others. Given the time to finalize the route survey, field testing to determine soil conditions, and engineering design capability, Alcan should be able to solve the frost heave problem satisfactorily although costs for doing so may vary from initial estimates.

Alcan has stated that it expects to encounter 80 miles of frost-susceptible soil along its right-of-way. It plans to use a passive system which consists of loose fitting insulation and select backfill. This will be supplemented by cycling flowing gas temperatures, thermistor monitoring of the pipeline to detect frost heave problems for corrective action, and periodic patrol and visual inspection based upon accessibility of its right-of-way.

The DOT will review the frost heave site-specific design approach for the Alaska section to assure that the final design will provide the required pipe support, and meet the other pertinent provisions of the Federal gas pipeline safety standards in 49 CFR Part 192. Because frost heave problems occur over a period of time, monitoring of the design, construction, and operation of the Alaska gas transportation system by Alcan and government agencies should detect problem areas early and provide the high level of safety and reliability required.

Pressure Testing. Once the pipeline is installed, Federal pipeline safety standards require that pipeline systems be pressure tested before initial operation. Alcan proposes to use a hydrostatic test and preheat the test water to prevent its freezing in the line where buried in permafrost areas. This procedure proved workable on the Alyeska crude oil pipeline. However, the Alyeska pipeline was buried only in areas of thaw-stable material and was designed, from a thermal expansion standpoint, to carry warm oil. The Alcan pipeline, on the other hand, will be buried in varied types of soil conditions and designed to carry chilled gas.

The Task Force on Safety and Design concluded that "the proposed Alcan procedure for hydrostatic testing with heated water would not be appropriate in sections traversing permafrost or discontinuous permafrost unless stringent control of test water temperatures is maintained and adequate temperature sensing devices are installed adjacent to the buried pipe." That report also concluded that an approach similar to the one proposed by Arctic Gas, i.e., a hydrostatic test using a water/methanol freeze-depressant solution at stress levels approaching 100 percent specified minimum-yield strength, provided the best assurance that any defects present in the pipe will be disclosed prior to placing the line in service.

Extensive studies were performed by Arctic Gas on the procedures to be used, the manpower to be expended, and the equipment and costs associated with both air and methanol/water testing. The proposed Arctic Gas test plan included procedures for disposing of the methanol after testing and safeguards to be used in the event of a pipeline test failure. Reports to the DOT confirm that there are very few test failures on newly constructed gas pipelines. In the remote event of failure, environmental concerns can be alleviated through development of a spill containment contingency plan and proper method of methanol disposal. Alcan should utilize hydrostatic testing research data developed by Arctic Gas; such information should be made available to Alcan.

Valve Design and Performance. If Alcan constructed a 1260 psi system, it would face few problems with regard to design of valves for chilled service. However, if Alcan increases pressure to 1680 psi, either for the Alaska segment of its line alone or for sections in Canada, additional valve design evaluation will be necessary. Valves currently installed in operating pipelines have not had service experience at those higher pressures with chilled gas temperature conditions even though some development and test work has been done at the ranges of pressure which were anticipated for the Arctic Gas and El Paso systems. If higher-pressure service is used, valving plans will be reviewed by DOT on a site-specific basis to assure that the designs are consistent with Federal gas pipeline safety standards.

Correlation Between Canadian and U.S. Gas Pipeline Safety Standards. To assure the overall integrity of the Alaska natural gas transportation system and the continued reliability of service to the U.S., it will be necessary to coordinate specific elements of the Canadian and U.S. gas pipeline safety standards. A review is underway to identify and correlate the various specific features of the Canadian and U.S. standards, and with effective technical liaison between the U.S. and Canadian regulatory agencies, these slightly differing standards should not create any problems. It will be necessary for those regulatory officials monitoring construction of the U.S. pipeline system to be aware of and resolve differences in design, particularly as they relate to acceptable levels of safety and reliability of service.

Design and Active Seismic Areas. The proposed Alcan route encounters relatively few active seismic areas and the risk of damage to the Alcan system from earthquake activity is small. Alcan crosses no known active faults in Alaska. The Denali fault is approximately 30 miles away at its closest point. In Canada, Alcan traverses the Shakwab fault which is large but not likely to be active. Alcan plans to provide for earthquake protection by wide-shallow ditch design and granular backfill to provide support for the pipe to an 8.5 Richter scale, and to install valves at either side of the fault.

Compressor stations for the Alcan system will incorporate structural design for anticipated earthquake stresses and utilize heavier wall pipe where appropriate.

Potential for Service Interruption -- Reliability

Accessibility of the Alcan route by the Alyeska haul road and existing highways in Alaska and in Canada will facilitate proper maintenance of the pipeline system. In certain tundra areas where conflicts may arise between requirements of the Federal gas pipeline safety standards and the environmental protection rules of Federal or State agencies, trade-offs between environmental considerations and pipeline safety and reliability will need to be carefully weighed in specific instances.

The FPC concluded earlier that each of the three systems originally proposed could be operated with a reliability acceptable to the gas consumers of the United States. The record of pipelines generally shows that their continuity of service is by far the best of any mode of transportation in the United States, and Canadian experience, including experience with the pipelines, in the far north is comparable.

The FPC and the Task Force on Safety and Design also concluded that repair of a pipeline outage on any of the systems as originally proposed would normally be very rapid. Again, the accessibility of the Alcan route to haul roads, work pads, and existing highways would facilitate rapid repair. Special techniques and equipment will be required for repairs in remote tundra areas during the period of summer thaws. Techniques originally planned to be used by Arctic Gas for such repair should be considered by Alcan in its maintenance and repair plans.

Efficiency of Design and Capability of Expansion

It was also suggested in the safety and design report that for economic reasons, Alcan should consider increasing the operating pressure and wall thickness of its 48-inch diameter pipeline in order to allow for more efficient increases in throughput rate for additional reserves which might be committed to the system from either Alaska or Canadian sources.

These physical factors determine the capacity of a gas pipeline:

- diameter of pipe,
- operating pressure,
- the rate (velocity) at which gas moves through the line.

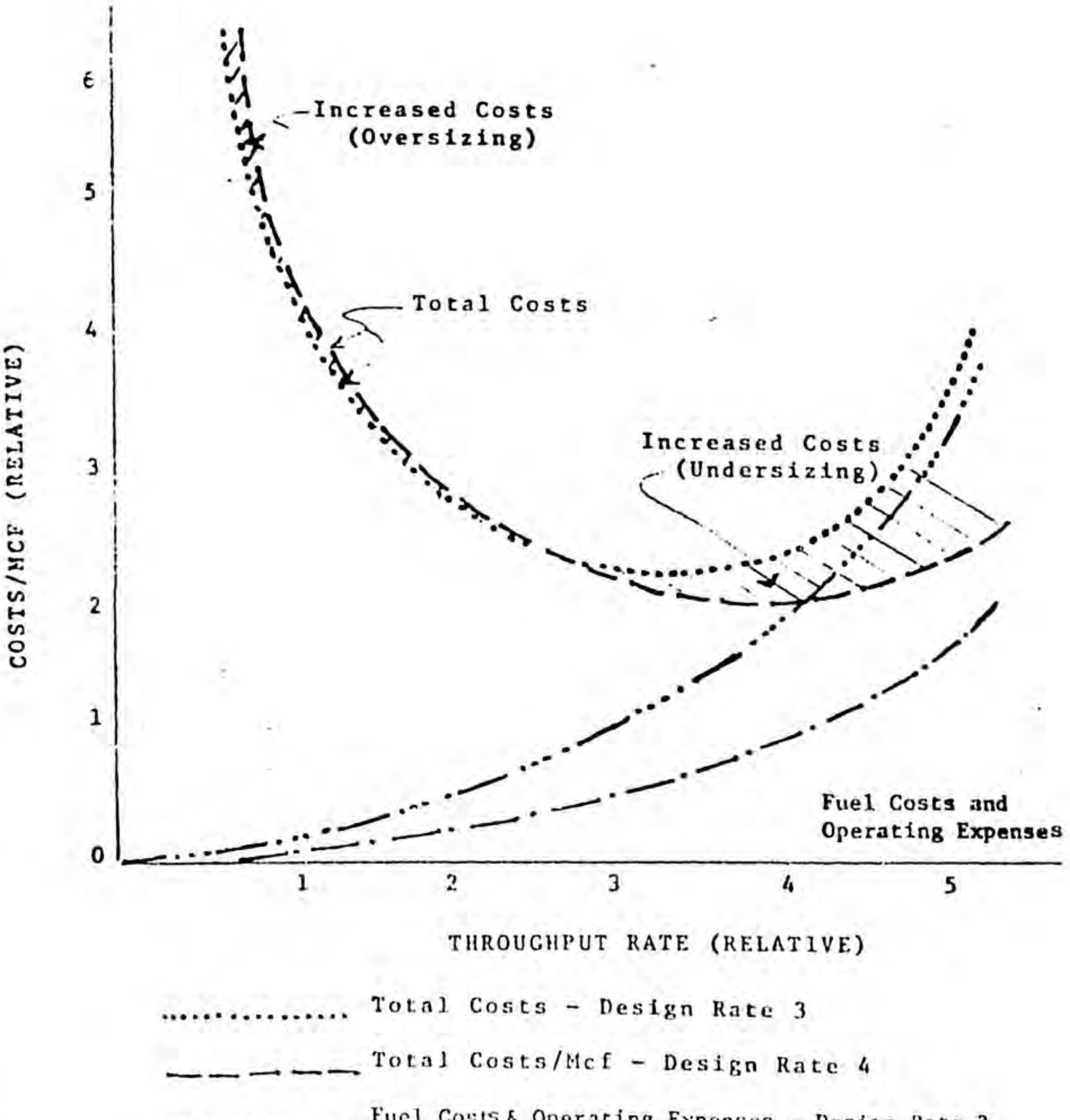
For any new system the first two items are selected in relation to the expected "throughput" of the gas and are then fixed. Any subsequent increase in the capacity of that pipe requires movement of gas at a higher rate. The velocity of gas is increased by adding compression to the pipeline. Compression requires fuel essentially in proportion to the horsepower added. Thus, as more throughput is required in an existing pipeline, horse power (capital cost) and fuel use (operating cost) will increase.25/

The introduction of the additional gas also allows the division of fixed costs by more units of throughput. If the line is operating at less than optimal capacity, the decline in unit fixed costs will be greater than the increase in unit costs for additional horsepower and fuel, and the overall unit cost will decrease. On the other hand, if the pipeline is forced beyond its optimal capacity by addition of yet more compression, the reverse is true: horsepower and fuel increases faster than the declini. unit fixed costs, resulting in an increase in overall unit cost of service. Exhibit 4 illustrates the problem.

Overall, considering the arctic construction, inflationary impacts, and environmental impacts, the ultimate cost to consumers of providing capacity for increased gas throughput would be much lower if the capacity is provided initially by increasing the diameter or working pressure of the pipe, than if it is provided later by adding compressor horsepower or looping the pipeline.

25/ Horsepower and fuel requirements increase roughly as the the difference between the squares of the relative throughputs. Doubling the throughput would require about 4 times as much fuel.

RELATIVE COST vs RELATIVE RATE
DIFFERENT DESIGN CAPACITY



The routing of the Alcan system provides future access to reserves which might be discovered in the Beaufort Sea or eleswhere on the North Slope. Alcan similarly could transport gas from other areas of Alaska or even from the Gulf of Alaska by means of somewhat longer supply laterals. Further, the Agreement with Canada provides for the use by Canada of the Alcan main line at a throughput up to 1.2 bcfd. Therefore, redesign of the system to enable inexpensive expansibility up to 3.9 to 4.0 bcfd south of Whitehorse, Yukon Territory, is essential.

CHAPTER VI - ORGANIZATION OF FEDERAL INVOLVEMENT AFTER SYSTEM SELECTION

Introduction

A frequently cited problem with construction of the Alyeska pipeline was the multitude of Federal Government agencies that severally prescribed and enforced terms and conditions with only minimal coordination of purpose or effort. Uncoordinated government actions can cause needless construction delays and cost increases. Coordinated Federal oversight of project management and construction would:

- provide coherent and uniform rules, and make them clear to the applicant;
- provide consistent enforcement of the rules;
- avoid rules and bureaucractic procedures that are merely cumulative and would be sources of delay.

ANGTA provides for creation of a new Federal officer, the Federal Inspector for construction of an Alaska natural gas transportation system. Under Section 7(a)(5) of ANGTA, this Federal Inspector shall-

> (A) establish a joint surveillance and monitoring agreement, approved by the President, with the State of Alaska similar to that in effect during construction of the trans-Alaska oil pipeline to monitor the construction of the approved transportation system within the State of Alaska;

(B) monitor compliance with applicable laws and the terms and conditions of any applicable certificate, rights-of-way, permit, lease, or other authorization issued or granted;

(C) monitor actions taken to assure timely completion of construction schedules and the achievement of quality of construction, cost control, safety, and environmental protection objectives and the results obtained therefrom;

(D) have the power to complete, by subpoena if necessary, submission of such information as he deems necessary to carry out his responsibilities; and

(E) keep the President and the Congress currently informed on any significant departures from compliance and issue quarterly reports to the President and the Congress concerning existing or potential failures to meet construction schedules or other factors which may delay the construction and initial operation of the system and the extent to which quality of construction, cost control, safety and environmental protection objectives have been achieved.

While the Federal Inspector can "monitor" the enforcement and compliance actions of the various Federal agencies, he does not have any specific enforcement powers. A coordinated regulatory approach will be elusive unless the Federal Inspector has the necessary supervisory authority at the field level over enforcement of terms and conditions to ensure that coordination occurs.

Therefore, as set forth in the Presidential decision, the President will submit to Congress upon approval of the

Decision a limited executive reorganization plan for the very specific purpose of transferring to the Federal Inspector field-level supervisory authority over the enforcement of stipulations and terms and conditions from those Federal agencies having statutory responsibilities over various aspects of an Alaska natural gas transportation system. This coordinated field level authority over compliance and enforcement activities of the respective Federal agencies is essential to avoid project delays and minimize cost overruns.

However, the Federal Inspector will be subject to the ultimate policy direction and supervision of an Executive Policy Board, made up of the Secretaries of Interior, Energy, and Transportation, the Administrator of the Environmental Protection Agency and the Chief of the Army Corps of Engineers. Furthermore, all Federal agencies will retain their existing authorities, pursuant to section 9(a) of ANGTA, to issue original certificates, permits, rights-of-way and other authorizations, and to prescribe any appropriate stipulations and terms and conditions to such authorizations that are permissible under existing law. Finally, the Agency Authorized Officers, who will exercise the delegated authorities of their respective agencies, will directly enforce the stipulations and terms and conditions--subject to the field-level supervisory direction of the Federal Inspector.

With these organizational proposals, and with the general terms and conditions set forth in the Decision, the Federal Government will have an expanded role in the oversight of project management and construction. The oversight authority conferred by the terms and conditions set forth in the Decision will be far more comprehensive than the limited Federal monitoring effort over Alyeska's project management. If these general terms and conditions are effectively enforced, most of the management abuses associated with the Alyeska project should not recur. The general terms and conditions, however, do not hold the successful applicant to any specific management approach, but merely provide certain minimum standards for cost and quality control and timely completion of construction, which reflect the collective experience and knowledge gained by the various Federal agencies from involvement with the Alyeska project.

The Organization of Federal Involvement with the Alcan Project

As noted above, the Federal Inspector will have the field-level supervisory authority over the Agency Authorized Officers who will be assigned on a full-time basis to administer the authorities of their respective agencies over various aspects of the Alcan project. The Federal Inspector and the Agency Authorized Officers will constitute an Alaskan Natural Gas Pipeline Office.26/ This Office will consist of administrative and field inspection and monitoring staff working under the direction of the Federal Inspector. The Executive Policy Board will approve the level of staff support, and determine Agency Authorized Officer participation in providing such staff support to the Federal Inspector.

Essentially, the organization of Federal involvement with the Alcan project has three elements:

1. The Federal Inspector. The Federal Inspector will be a Presidential appointee confirmed by the

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26/ The Office should be located in Alaska, at least for the construction phase of the project, and later in reduced form for the operational phase. It is probable that preconstruction planning and design will necessitate an Alaska-based pipeline office (e.g., to coordinate site-specific terms and conditions) even though the size of the Washington, D.C.-based staff will be larger in the earlier phases of the project.

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Senate and is an officer independent of other existing Federal agencies. In addition to his statutory duties under section 7(a)(5), the Federal Inspector will have supervisory authority at the field level over enforcement of terms and conditions, and will otherwise coordinate Federal involvement with the pipeline operator during the design and construction phases of the project. The Federal Inspector is designed to be the principal point of contact with the pipeline owners, the contractors, State agencies, and Canadian entities on matters pertaining to Federal oversight of the project. As chairman of the Executive Policy Board, he should be the executor of its policy decisions. The Federal Inspector also has the power to compel information by subpoena and to issue quarterly reports to the President and Congress concerning existing or potential failures to meet construction schedules and other matters.

2. The Executive Policy Board. Presidential supervision over the Federal Inspector will be delegated to an Executive Policy Board. The Board would be made up of the Secretaries of Interior, Energy, Transportation, the Administrator of the Environmental

Protection Agency, and the Chief of the Army Corps of Engineers, or their Deputies (or senior officers who have been delegated authority over gas pipeline matters). The Federal Inspector shall serve as the non-voting chairman of the Board.

The Board will provide policy guidance <u>through</u> the Federal Inspector to the Agency Authorized Officers and will be paramount in all policy matters. It will also act as an appellate body to resolve any differences between the agencies and the Federal Inspector, including differences that may arise when the Federal Inspector overrules an enforcement action of an Agency Authorized Officer. In such cases, the Board shall expeditiously resolve any appeal within a specified time period. Otherwise, the Board shall confine itself to policy-making matters, and the Federal Inspector will be the conduit of the Board in carrying out policy.

3. <u>The Agency Authorized Officers</u>. These officers will represent and exercise the internally delegated authorities of their respective agencies in matters pertaining to the project. Although these authorities can be exercised only by the

respective Agency Authorized Officers, they will be subject to supervision of the Federal Inspector at the field level, and receive policy direction from the Executive Policy Board through the Federal Inspector on enforcement matters.

The Agency Authorized Officers should have no other administrative duties that would require less than full attention to the project, unless the Executive Policy Board consents to waive this requirement in a particular case. It is hoped that the use of Agency Authorized Officers to represent the various agencies will minimize coordination problems between the project applicant and the Federal Government.

Implementation of Organizational Plan

The proposed transfer of field-level supervisory authority to the Federal Inspector should be submitted for approval by Congress in a government reorganization plan, ratner than implemented by executive order. This plan will propose a limited, single-purpose transfer of field-level supervisory authority over enforcement of terms and conditions for the duration of the preconstruction and construction phases of the Alcan project. No other transfer of existing authority, or transfer of ary coordination function, will be proposed in the reorganization plan.

To avoid the possible overlap with Congressional action on the Presidential decision itself, the reorganization plan will not be submitted to Congress until that decision has been approved. Congress would then have 60 legislative days in which to consider the merits of the plan under the special parliamentary procedures provided by the Reorganization Act of 1977, 5 USC 901 et seq.

The President can immediately issue an executive order creating the Executive Policy Board and by his power pursuant to Section 301 of Title 3, delegate the necessary authority to the Board to carry out its functions. The Board can then make certain initial administrative decisions regarding the Office of Federal Inspector--e.g., the level of staff support for the Federal Inspector, and the possible use of the Army Corps of Engineers for such staff support. In the interim, the Federal Inspector can immediately exercise his responsibilities under existing ANGTA authority to "monitor" compliance by Alcan with applicable laws and authorizations.

Coordination with the States

In addition to the duty of organizing Federal involvement, the Federal Inspector has the substantial responsibility under ANGTA to establish a joint surveillance and monitoring agreement with the State of Alaska and other affected States. The strengthened field level supervisory authority proposed for the Federal Inspector will be of great assistance in the performance of this statutory responsibility.

The Alcan system will pass through hundreds of miles of land owned by the States, particularly by the State of Alaska. Officials of the State of Alaska have previously declared that the State will issue a right-of-way lease to the gas pipeline for crossing these lands, regardless of which project is approved, and have indicated that environmental terms and conditions will be part of this lease.

The States and the Federal Government share responsibility to ensure that lands, water and wildlife are not unnecessarily disturbed by the gas pipeline and that where disturbed, maximum restoration is carried out. The Federal Inspector and Agency Authorized Officers will therefore work with the State of Alaska and with other States in a cooperative fashion both for the protection of the environment and for the expeditious construction of the pipeline. The terms and conditions and stipulations which pertain to State and Federal lands should be as similar as possible. A reasonable accommodation of State and Federal interests is expected with the Federal Government having primary responsibility where the pipeline crosses Federal land and private lands, and with the State Governments having primary responsibility where the pipeline crosses State lands. Cooperative agreements based on these principles have been successful in the recent past, and should be the point of departure for further strengthening the Federal and State cooperation during construction of the gas pipeline.

CHAPTER VII - IMPACT ON COMPETITION IN THE NATURAL GAS INDUSTRY

The antitrust and competitive impact effects of an Alaskan natural gas system have been thoroughly studied by the Federal Power Commission and by the Justice Department under Sections 6 and 19 of the Alaska Natural Gas Transportation Act of 1976. Under section 19, the Attorney General prepared and submitted to Congress on July 14, 1977, a detailed analysis of potential antitrust issues and problems. Under Section 6, the Attorney General submitted that same report to the Alaskan Natural Gas Task Force, along with a commentary on the FPC's findings with respect to competitive impact. In addition, the Justice Department submitted a letter on August 9, 1977, which elaborated its views concerning possible participation by the gas producers in financing the transportation system. A copy of the letter is appended to the end of of this Chapter.

Based on these studies, it can be concluded that the Alcan project will have no harmful effect on regional or national competition in the natural gas industry, and that any potential of competitive abuse can be cured by proper proper federal regulation. In addition, consistent with the Administration's antitrust objectives, producers of Alaskan gas could participate in financing this expensive transportation system through guaranteeing some portion of the project debt.

Gas transmission and distribution industry

The Federal Power Commission and the Justice Department agreed that certification of a transportation system for Alaskan gas will not have a significant impact upon competition in the natural gas transportation and distribution industries.

Based on statistics presented in the Justice Department's Report to Congress, the American sponsors of the Alcan project, including PGT, PGE and the Northern Border companies, transport approximately 40 percent of all the interstate natural gas shipped in the U.S. However, in an industry as heavily regulated as natural gas, indices of concentration tend to overstate the potential for anticompetitive behavior. In the presence of effective regulation, the actual prospect of anticompetitive behavior is minimized, and there is only a small risk that the Alcan sponsoring companies could control national or regional gas markets.

Gas producers

Alcan has no oil companies or subsidiaries of oil companies among its sponsors. This fact in itself sharply reduces potential antitrust concerns.

Nevertheless, since elsewhere in this Report it is urged that the gas producers participate in financing this project, it is necessary to examine the competitive considerations associated with producer participation. The Attorney General concluded that "present Federal Power Commission regulation appears to preclude an opportunity for competitive abuse by the gas producers." However, the Department warned that if wellhead prices were decontrolled or substantially relaxed, some opportunity might arise for producers, if they owned or controlled the transportation system, to transfer profits from the regulated transportation operation to their unregulated upstream production operations.

The Department of Justice indicated that its concern about producer ownership or control of the pipeline <u>does not preclude producer participation in financing the system</u>. For example, consistent with antitrust objectives, producers could be involved in guaranteeing a portion of the project's initial debt or cost overrun debt. To assure antitrust insulation, any producer role in the management of the transportation system prior to its becoming operational should be the minimum necessary to protect the producers' investment interest but in any event should not permit producers to engage in anticompetitive conduct. In addition, producer debt guarantees should terminate upon completion of the project and commencement of the tariff. Finally, the Federal Power Commission should utilize its approval power over gas purchase contracts, and more generally, over project financing plans, to ensure that any conditions producers impose in exchange for debt guarantees do not create situations which might permit abuses of competition.

Thus, as is urged elsewhere in this report, gas producers could guarantee portions of the project debt consistent with this Administration's antitrust objectives.

* * * * * *

Overall, we conclude that the potential for anticompetitive abuse by either the gas transmission and distribution industry or the gas producers (to the extent they might participate in guaranteeing project debt) is small, especially under a continuing system of price regulation.

Any potential competitive problems can be guarded against through (1) imposing proper conditions in the license to construct the transportation system (including the nondiscriminatory conditions under section 13(a) of the Act); (2) monitoring gas purchase contracts between gas producers and gas transmission companies; (3) requiring the disclosure of any collateral agreements between producers and transmission companies; (4) requiring government scrutiny and approval of any plans for gas reallocation or displacement, and government monitoring of any industry discussions to derive such plans; and (5) imposing regulatory sanctions in any specific cases of abuse that may arise.

EXHIBIT

ASSISTANT ATTORNEY GENERAL
ANTITRUST DIVISION

Department of Justice
Washington, D.C. 20530

August 9, 1977

Mr. Leslie J. Goldman
Assistant Administrator
Energy Resources Development
The White House
Washington, D. C. 20500

Dear Mr. Goldman:

The Attorney General submitted his Reports on the competitive aspects of the Alaska natural gas transportation system to the President and to the Congress on July 14, 1977. One of the conclusions drawn in those Reports was that producers of substantial amounts of natural gas should not be permitted to own any portion of or participate in any manner in the selected Alaska natural gas transportation system.

The Department has been requested by the Alaska Natural Gas Task Force to consider whether this recommendation precludes the participation of the Alaskan natural gas producers in the financing of the selected project. We have been requested to focus our attention on the two routes still under active consideration -- the all-pipeline route proposed by Alcan Pipeline Company and the pipeline-LNG route proposed by El Paso Alaska Company.

The Department's recommendation concerning gas producer ownership and participation was based on the premise that such ownership or participation under a regime of deregulated or relaxed wellhead price regulation could lead to the evasion of effective pipeline regulation and create the opportunity for the earning of monopoly profits through anticompetitive activity. Despite the continuation of wellhead price regulation and the present lack of gas producer ownership or participation in either the Alcan or El Paso projects, we continue to express our concerns on this important issue, since the long term status of wellhead price regulation appears uncertain and it is not now clear who will be the ultimate owners of these projects. However, our concern about gas producer ownership of the projects does not mean that there would necessarily be antitrust objections to participation in project financing on the part of Alaskan gas producers.

From consultation with other members of the Alaskan Natural Gas Task Force, we understand that gas producer participation in the financing of the selected project may be essential to the success of the project. We believe, therefore, that consistent with our recommendations producers could be involved in the guarantee of a portion of the project debt. We view this guarantee as consistent with our recommendations so long as the gas producers would not be equity members of the sponsoring consortium, would not have any voting power, would not have any role in the management or operations of the transportation system once the system would become operational and would be obliged to terminate their guarantor roles upon completion of the project and the tariff's going into effect. Any role in the management of the transportation system prior to the system becoming operational would be minimal and consistent with the size of the guarantee and would not lead to the types of anticompetitive conduct indicated in the Attorney General's Report on the Alaskan natural gas transportation system and in this letter.

Although not opposed to some financial backstopping under these conditions, we reiterate our opposition to any type of financial participation by producers that would enable them to engage in any form of anticompetitive conduct, such as the restriction of pipeline throughput, the denial of access to nonowners, or the resistance or denial of future expansion of pipeline capacity.

The Department recognizes that if the gas producers were to act as debt guarantors they would have the right to request conditions to protect their financial involvement. The Department would not oppose conditions to this effect so long as the conditions would not give rise to the potential for competitive abuse, including the power to veto procompetitive policies, referred to above. In this regard, we would expect to urge the Federal Power Commission, or its successor agency, at the appropriate time, to utilize its approval power over gas purchase contracts and, more generally, over project financing plans, to ensure that producer-imposed conditions do not conflict with the antitrust objectives outlined in the Attorney General's Reports.

In addition, as a further safeguard, the Department suggests that it review all the terms and conditions of any financial guarantee of a portion of the project debt negotiated with the Alaskan gas producers. You are assured of our willingness to assist in exploring and developing an appropriate method of gas producer financial participation in an Alaskan natural gas transportation system that will not subvert the competitive spirit and intent of the recommendations contained in our Reports.

Sincerely yours,

Hugh P. Morrison Jr

Hugh P. Morrison, Jr.
Acting Assistant Attorney General
Antitrust Division

cc: Roger C. Altman
Assistant Secretary
(Domestic Finance)
Department of the Treasury
Washington, D. C. 20220

CHAPTER VIII - NATIONAL SECURITY

The Department of Defense (DOD) provided a study on the national security implications of the proposed Alaska gas transportation systems both to the Department of Interior, for its report required by the Trans-Alaska (Oil) Pipeline Act (P.L. 93-153)[27/], and to the Federal Power Commission (FPC) for its use in evaluating the proposals. The conclusions of the DOD study were that analysis of military factors alone would not indicate an overriding preference for one route over another.

A DOD representative testified on the study before the FPC and was cross-examined by representatives of both El Paso and Arctic Gas, after direct examination by the FPC's Administrative Law Judge Litt and a staff attorney. As reported by Judge Litt:

> ....the evidence shows each system has its advantages and disadvantages. El Paso's entire pipeline portion of its system is under U.S. control, and thus defense strategy may be facilitated. However, El Paso's project tends to concentrate potential targets, like its liquefaction and regasification plants, whose destruction would present major, long-term outage problems. Similarly, both the oil and gas pipelines would be susceptible to concentrated attack or sabotage on the Yukon River

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27/ "Alaska Natural Gas Transportation Systems, A Report to the Congress Pursuant to P.L. 93-153," U.S. Department of the Interior, December, 1975.

> Bridge. Arctic Gas and Alcan, while not concentrating vulnerable facilites at single locations or subjecting their systems to interdiction at sea, suffer somewhat from the length and location of their pipelines. Moreover, these projects must rely on Canadian security forces for defense over much of their pipeline lengths.[28/]

The consensus was that each of the proposed systems has some national security problems which are peculiar to that system, and that the extremely modest danger due to hostile acts is of some concern, whether such acts are in wartime or are acts of sabotage. However, such danger was considered to to be far less likely to disrupt pipeline operations than system failures of a purely natural or mechanical nature.

DOD also submitted a report to the President on July 1 commenting on the national security implications of the FPC's Recommendation to the President.[29/] In that report, DOD reiterated its conclusion that there is no overriding preference for one route over another when analysis is based on military factors alone. However, the report pointed out that dependence on imported oil presents a grave danger to the national security, and stressed that completion of a transportation system for delivery of Alaska North Slope

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28/ Initial Decision on Proposed Alaska Natural Gas Transportation Systems, Federal Power Commission, February 1, 1977, p. 411.

29/ Recommendation to the President, Federal Power Commission, May 1, 1977.

natural gas to the contiguous 48-states must be considered an important national security objective.

With the Alcan joint project with Canada, we believe Canada will have a major interest in maintaining a uninterrupted flow of gas through the pipeline as well as a treaty obligation to do so under the recently ratified pipeline treaty. First, the Canadian companies which will be the owners of the Pipeline in Canada will have a substantial investment which they will want to have protected. Canadian investors would be adversely affected by any interruption in throughput. Second, remote communities in both the Yukon Territory and the western provinces will be served by the Pipeline, and any interruption in flow will directly affect availability of gas to those communities. Finally, a much larger number of Canadian gas consumers will have a direct interest in uninterrupted throughput when the Dempster Line comes into service from the Mackenzie Delta. The Canadians expect the Dempster Line to be built within several years of initiation of service on the main line.

Provision for access to the Mackenzie Delta reserves will have beneficial effects on the national security of both countries due to decreased dependence on imported oil. Canadian oil import requirements will be directly reduced by availability of gas to Canadian consumers. Access to frontier gas reserves will allow Canada to fulfill its current gas export commitments, preventing an increased degree of U.S. oil import dependence due to curtailment of Canadian gas supplies. Attaching Canadian frontier gas and providing a stimulus to the Canadian oil and gas producing industry may ultimately allow some increase in the level of Canadian gas exports, which would allow even further reduction in oil import dependence.

CHAPTER IX - THE WESTERN LEG

The Authorization of Facilities

There are two basic methods for delivering Alaskan natural gas to the West Coast. The first method is to construct a "Western Leg" to the Alcan system by constructing a new pipeline and some looping in Canada from Caroline Junction to Kingsgate, and by increasing the capacity of the existing Pacific Gas Transmission (PGT) and Pacific Gas and Electric (PG&E) pipeline, also through looping. A fully looped system would cost about $770 million (1975 dollars).

The second method is to deliver the gas to the West by "displacement." The Northern Border section of the Alcan project to Chicago could be sized to deliver all Alaska gas to the Midwest. Natural gas from West Texas and New Mexico that otherwise would flow to the Midwest could then be diverted to the West Coast through the El Paso, Transwestern and Northwest pipeline systems.

As set forth in the Presidential Decision, construction of a Western Leg will be authorized for direct delivery of Alaskan gas to the West Coast. See page 20 of the Decision. The Western Leg facilities proposed by the sponsors in the FPC hearings (i.e., the "1580 Design") will be authorized for "construction and initial operation." All such facilities will be entitled to the special mandatory certification and expediting procedures provided by ANGTA.

However, the facilities proposed in the "1580 Design" will be subject to a final review and possible adjustment prior to final certification by the FPC. As in the case of the Northern Border system, the Secretary of Energy shall determine at the time of certification whether the facilities proposed in the "1580 Design" are larger or smaller than necessary to handle the contracted supplies of Alaskan gas and Canadian exports and whether "pre-construction" is necessary to accommodate short-term excess deliveries of Canadian gas from Alberta. The "1580 Design" facilities would be needed to handle exports from Canada continuing beyond current contract expiration dates or if new gas supplies from Alaska are developed. Furthermore, complete delivery by displacement would not be feasible if Mexican gas becomes available and the 30 inch gas pipeline that is part of the El Paso system between Texas and California is converted to an oil pipeline for use in the Sohio project to transport surplus Alaskan crude oil.

At the time of certification, however, when there will likely be better information upon which to project future gas supplies, the "1580 Design" may prove not to be the appropriate size. Therefore, the Decision does not make an irrevocable commitment to construct new capacity that is either too small or too large for the projected needs. Prior to final certification of a Western Leg, the Secretary of Energy shall make the precise determination of facility size and volume to account for material changes in the facts, if any, since the Presidential decision. The Western Leg may also be utilized in connection with short-term deliveries from Canada.

The Western Leg facilities required for direct delivery will depend on several estimates -- the estimated Western share of Alaskan gas, the estimated volume of Canadian exports, the amounts of Mexican gas, and the abandonment of the El Paso gas line in favor of the Sohio oil transport system. These estimates provide the basis for the decision to authorize the Western Leg.

The Western Share of Alaskan Gas

The proportion of natural gas that is distributed to a particular region of the country is ordinarily determined by private contract between the producers, on the one hand,

and the purchasers which are usually interstate pipeline or local distribution companies, on the other.

There is no reason to change these rules for Alaskan gas. A region of the country that is arbitrarily and inequitably deprived of its share of Alaskan gas will have the opportunity to seek relief from the FPC. But, in the absence of such discrimination, regional distribution of Alaskan gas will be made by the usual means of private agreement.

Since contracts for the purchase and sale of Alaska North Slope gas have not yet been executed, it cannot now be determined with precision how much of that gas will eventually be destined for the western states. However, in the absence of sales contracts, it is reasonable to assume that 30 percent of the Alaskan gas will be purchased by parties served by the Western Leg. It is also assumed that deliveries of Alaskan gas to the lower 48 States will begin at 2 bcfd in 1983 and increase to about 2.4 bcfd within a few years. For purposes of this analysis, then, approximately 700 mmcfd will be considered the maximum Western share of Alaskan gas through this period.

Increased and Accelerated Canadian Exports

In its July 4th decision authorizing the Alcan proposal, the Canadian National Energy Board (NEB) assured the continuation of current Canadian supplies to the West. It rejected outright any suggestion that existing Canadian agreements to export gas to U.S. markets not be honored. The NEB also concluded that gas production from the established fields of Alberta and British Columbia would exceed total demand, including exports, by as much as 400 bcf in 1978, and had created a temporary excess supply.

It proposed that the current Canadian "gas bubble" be sold to export customers, either as "predeliveries" on contract volumes that would otherwise be delivered in the 1984-90 period, or under an "ironclad" guarantee that it would be replaced later by Alaskan gas delieved in Canada. And finally, in order to assure the delivery of these additional volumes, it recommended the "preconstruction" of that portion of the total system that would be located in southern Canada.[30/]

30/ See NEB, Reasons for Decisions: Northern Pipelines, Vol. 1 pp. 1-69 to 1-83, 1-161, June 1977.

The recently signed Agreement on Principles makes it even more likely that there will be an increase or acceleration of gas exports from Alberta. By providing Canada with access to frontier gas reserves in the Mackenzie Delta, the Alcan proposal stimulates the gas industry in Canada, and enhances the availability of Canadian supplies for absolute increases in exports to the United States.

The following sections set forth the analysis of the capacity available in existing pipeline systems to transport these additional volumes of Alaskan or Canadian gas directly or by displacement to the Western States.

Estimated Excess Pipeline Capacity in Existing Systems

Existing Facilities of the Western States

At the present time, the West is provided with most of its natural gas via interstate pipelines from two major producing areas -- the established gas fields of the southwestern United States, particularly in the Permian and San Juan Basins, and the Alberta and British Columbia reserves in Canada. For purposes of this analysis, there are two principal interstate pipeline systems that should be considered in evaluating the capacity requirements of Western States. They are: (1) the Pacific Gas Transmission and

Pacific Gas & Electric systems from Kingsgate, B.C. to Antioch, California, which supply Washington, Oregon and Idaho markets, as well as California, with Canadian gas, and (2) the El Paso and Transwestern systems in the Southwest (referred to collectively hereafter as the Southwest pipeline system), which deliver gas from the Permian and San Juan Basins to California, Arizona and New Mexico. As will be seen below, the full share of Alaskan gas plus additional Canadian supplies could not be delivered directly by the PGT and PG&E systems for at least several years and in the interim might well use up and exceed the capacities of the El Paso and Transwestern systems that would be used for displacement.

Direct Delivery

As noted, the Western Leg proposal would amount principally to looping of the existing pipeline facilities from Alberta to California. The existing system could not itself be utilized for direct deliveries of any Alaskan or additional Canadian gas because it is now being utilized to capacity and will be until at least later 1985.

There are four principal contracts pursuant to which Canadian gas is now delivered via the PGT and PG&E systems directly to California, their volumes and the expected expiration dates are as follows:

Authorized Average Daily Volume (in mcfd)	Expiration Date
184.9	10-31-85
419.9	10-31-86
205.0	10-31-89
213.0	10-31-93

Thus, even if none of these contracts is renewed -- the likelihood of which is reduced as a result of the Agreement on Principles -- direct delivery of substantial volumes in existing facilities will be impossible for the first three or four years of an Alaskan gas transportation system.

Displacement

Under the "displacement" option, the Western share of Alaskan gas would not be directly delivered to the West but moved there indirectly through exchange arrangements with customers of the Northern Border system.

In order to carry out the displacement scheme, the capacity of the Northern Border system would have to be such as to accomplish the direct delivery of both the East's and West's share of North Slope gas. Full displacement would require either that the proposed 42-inch Northern Border line south of Empress, Alberta, be fully-powered or that a 48-inch line be constructed over this segment to carry the same volume of gas, at an additional capital cost but with the flexibility to increase capacity.

On the surface, displacement appears to be the most cost effective method. The $770 million (in 1975 dollars) cost of a fully looped Western Leg could be avoided. Increasing the capacity of the Northern Border system would be much less capital intensive; $258 million for fully powering the 42-inch Northern Border System, and $404 million for increasing the pipe diameter to 48-inch. In either case the cost of service for the displacement plan would be about $50 million per year less than direct delivery. However, there are several reasons why displacement is not a desirable long term method in this situation.

(a) Any displacement plan would consume more energy than direct delivery to the West. The West's Alaska gas essentially would move east to Chicago and then back west from the Permian or San Juan basins. By contrast, the looping of the PGT and PG&E systems would increase the overall fuel efficiency for those systems. The difference is about 25 bcf of gas per year, worth $68 million at $2.60 per mmbtu.

(b) Use of displacement to transport all of the West's Alaskan gas would create capacity constraints on the existing El Paso and Transwestern lines if:

- o one El Paso 30 inch line is converted to an oil line by the Sohio Project;
- o substantial volumes of Mexican gas become available for transportation to the West Coast;
- o there are any advanced or increased deliveries of Canadian gas to the U.S. which would also have to be moved West by displacement; and
- o the Algeria II LNG project is completed on schedule.

For purposes of analysis, all four of these conditions should be regarded as reasonably likely to occur.

While the Federal Government has not specifically endorsed the Sohio Project, it has endorsed generally the need for the expeditious construction of a pipeline to transport surplus Alaskan crude oil from the West Coast to refining markets east of the Rocky Mountains.[31/] Such a system is needed to provide economic and efficient transportation of Alaska North Slope oil to markets in the

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31/ See Executive Office of the President, The National Energy Plan, April 29, 1977, p. 55.

U.S. The conversion of the El Paso pipeline by the Sohio Project, which is assumed in the present analysis, will result in a substantial decrease in overall capacity of the Southwest gas pipeline system.

Recent events have given cause for considerable optimism about increased exports from Mexico which would enter through the Southwestern and El Paso system. Petroleos Mexicanos (Pemex), the government-controlled oil and gas monopoly in Mexico, has recently expressed its intention to construct a 48-inch, 850-mile pipeline from the Reforma fields in Chiapas and Tabasco to the U.S. border near McAllen, Texas. Pemex expects initially to deliver 1 bcfd to the U.S. upon completion of the pipeline (probably not before 1980), and to increase the flow to 2 bcfd by about 1982. On August 3, 1977, Pemex and six U.S. companies signed a memorandum evidencing their intention to enter into supplier-purchaser relationships for 6 years, renewable for another 6-year term if the purchasers meet the best tender Pemex may have for the gas at the end of the first term.

Notwithstanding several remaining uncertainties, it now appears likely that the Mexican Project will soon become a significant new source of gas supply in the Southwest.

Between El Paso and Transwestern, the West could reasonably expect to receive about 220 mmcfd of Mexican gas by 1980 and a total of 440 mmcfd beginning in 1982.

As discussed above and throughout this Decision and Report, the Alcan system will offer the potential for accelerated delivery of Canadian exports under existing contracts; it will also enhance the overall availability of Canadian gas for absolute increases in exports. Since these additional volumes of Canadian gas could not be delivered directly in the PGT and PG&E systems, as noted above, they would also have to be displaced through the El Paso and Southwestern systems for delivery to the West.

Finally, the Algeria II project, El Paso's application for which is pending before the FPC, would deliver up to 325 mmcfd of regasified LNG from the Texas Gulf Coast to the Southwest by as early as 1983 and could deliver a total of 650 mmcfd by the following year.

Under these conditions, delivery of Alaskan gas through the Northern Border system for displacement to the West would preempt all the excess capacity now available in the existing Southwest pipeline system from the Permian and San Juan Basins. Any substantial new supplies from the deep Permian formations -- or increased supplies from coal gasification projects -- would compound the problem.

Indeed, under optimistic assumptions about future gas supplies to the West and the existing capacity to California which would be utilized, there is a serious risk of a capacity shortage for the years 1983-87. This shortage can be determined from the data set forth in Exhibit 1.

The Exhibit indicates that without a Western Leg, a displacement scheme capacity shortage could exist in 1983-85 and would be uncomfortably close in 1986. If current Canadian supply contracts are renewed, as it is hoped they will be, a capacity shortage could exist in 1983 and later years as well.

Finally, it should be noted that full utilization of the Northern Border system for a displacement scheme would preclude the ability to expand the Northern Border system at a low capital cost for additional deliveries to the East if more Alaska gas becomes available.

The Nation's gas delivery system must have the overall flexibility to make a rapid and economic response to many variables - the level of future exports from Mexico, the level of future exports from Canada, the rate at which new supplies of Alaskan gas can become available, and the rate at which LNG and coal gasification projects are developed. Therefore, to ensure sufficient capacity

Exhibit 1

	1981	1982	1983	1984	1985	1986	1987
Capacity (mmcfd)							
El Paso (after abandonment)	3,274	3,272	3,274	3,274	3,274	3,274	3,274
Transwestern	785	785	785	785	785	785	785
Total Capacity	4,059	4,059	4,059	4,059	4,059	4,059	4,059
Supply (mmcfd)							
Permian Basin	1,551	1,448	1,358	1,271	1,190	1,114	1,042
San Juan Basin	1,253	1,247	1,209	1,176	1,144	1,113	1,083
Canadian Short-Term (by displacement)	221	167	112	56	--	--	--
Mexican	220	440	440	440	440	440	440
Algeria II LNG	--	--	325	650	650	650	650
Coal Gas	--	--	--	--	70	140	280
Total Supply	3,245	3,302	3,444	3,593	3,494	3,457	3,495
Excess Capacity	814	757	615	466	565	602	564
Less Alaskan Gas by Displacement	--	--	700	700	700	522[a]	120[a]
Capacity Excess (Shortage)	954	757	(85)	(234)	(135)	80	444

a/ Assumes that existing Canadian contracts will not be renewed.

for future supplies to California and other Western States, provision should be made for direct delivery of Alaska gas to the West.

Size and Volume of a Western Leg

The approved facilities for the Western Leg are embodied in the so-called "1580 Design." It would require a 36-inch, 176-mile pipeline, to be constructed by the Alberta Gas Trunkline Ltd. (AGT), from James River Junction in Alberta to Coleman on the British Columbia border, where it would connect with the existing Alberta Natural Gas Company Ltd. (ANG) line in British Columbia. One-hundred and five miles of the existing ANG line, from Coleman to Kingsgate on the U.S. border, would be looped with 36-inch pipe. In the U.S., 612 miles of the PGT line from the Canadian border to Malin, Oregon, and 297 miles of the PG&E line from Malin to Antioch, California, would also be looped with 36-inch pipe. No new compression would have to be added to the existing systems.

With this project, 659 mmcfd of North Slope gas could be delivered directly to the western U.S, which is roughly the total expected volume of Alaskan gas delivered to the West. PGT intends to deliver 22 mmcfd of this amount to Northwest Pipeline Company for distribution in the Pacific Northwest, and the remainder would be delivered to California, where 200 mmcfd would be distributed by PG&E in the North and 437 mmcfd would be distributed by the Southern California Gas Company in the South. Any share of Alaskan gas or additional Canadian gas greater than 659 mmcfd would not require a new facility but could readily be delivered to the West by displacement. There would easily be sufficient capacity in the Southwest system to absorb this relatively small volume of Western gas.

Conclusion

The evidence clearly suggests that the natural gas pipeline capacity available at present will not be adequate to accommodate both the Sohio Project and the movement of Alaskan gas to the West in the mid-1980's and perhaps beyond. While this conclusion is based on optimistic supply projections, it nevertheless is a significant probability on the basis of which a Western Leg Facility should be planned.

There is some risk in authorizing a Western Leg that it or other existing pipeline systems to the West could at some time become somewhat underutilized, perhaps resulting in some increase in per unit costs to gas consumers. But the consequences of not authorizing a Western Leg are even greater. Not only could failure to build a Western Leg under the most reasonable supply projections cause higher direct