

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

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EVALUATION OF THE DOW-SHELL GROUP

"REPORT TO THE STATE OF ALASKA--FEASIBILITY OF A PETROCHEMICAL INDUSTRY"

The overall purpose of this work has been to review the Dow-Shell Group (DSG) "Report to the State of Alaska--Easibility of a Petrochemical Industry"; to update the economic evaluation computer model applicable to natural gas liquids and petrochemical facilities in Alaska based upon the DSG report; and to provide an independent assessment of the DSG report.

The time limit for this work and necessary restrictions of proprietary data have not allowed an extremely detailed assessment of the DSG study and report. However, we feel that based upon this scope of work, together with our previous related study, the following observations are warranted.

- Capital investments and ethane feedstock cost are the cost-related determinants of economic feasibility for NGL-based petrochemical production in Alaska.
- An economically viable NGL project is a necessity for (but does not insure) an acceptable petrochemical project.
- The price of crude oil is the basic determinant of NGL values; however, the future NGL-crude oil pricing will be affected by many new factors which complicate a reliable prediction of this relationship.
- The economic evaluation procedure--20% before tax return on investment--is not a sophisticated economic evaluation criteria. However, this method of presentation is considered appropriate because (1) any more sophisticated criteria would have required such a complex presentation as to have significantly reduced the audience for the report; (2) this general procedure is an often used economic viability criteria which does relate to the investment decision-making economic evaluation criteria; and (3) the results of the more sophisticated evaluation methods based upon the values developed from the 20% before tax return are consistent with reasonable economic viability criteria.

- Based upon the capital investments stated in their report and considering the magnitude of uncontrollable pricing and market factors, our evaluations indicate that the DSG analysis of feasibility is appropriate.
- Due to the very large capital investment requirements and the long permitting, engineering, and construction schedule, the business risks are indeed great. Consequently, a positive investment decision almost requires the critical cost factors must, at the time of such a decision, be at or near those values required for economic viability.

In the course of this work we have (1) reviewed the Dow-Shell Group report; (2) provided various state officials a preliminary assessment of the study and established goals for further evaluation; (3) met with members of the DSG to discuss the report and obtain additional information used to develop the economic evaluations; (4) adapted the available information for use in the economic evaluation model; and (5) developed independent economic evaluations based upon these data.

NGL Project

Based upon the stated capital investments and operating cost, our economic evaluation indicates the \$947 MM/yr cost (1981 dollars) for the total NGL system would provide a real rate of return on investment (above inflation) of about 7% (see attachment I for comments on rate of return). The capital return component of the \$947 MM is assumed to remain constant in nominal dollars throughout the project in this analysis. This actually results in a negative real growth rate in the total cost, e.g. in the tenth year the total cost is about \$585 MM in constant 1981 dollars. This infers that with crude oil prices keeping pace with inflation and with NGL's priced at 100% BIU parity with crude oil, the potential revenue at Prudhoe Bay for NGL would be increased by about \$360 MM (in constant 1981 dollars) in the tenth year of the project. Over a twenty-year period the potential revenue at Prudhoe Bay for NGL would be increased by the equivalent of about \$340 MM per year in constant 1981 dollars. This overall method--20% before return--

does provide a relatively heavy front-end return on investment. It should be noted that the typical rate base return often utilized for regulated pipelines provides an even greater front-end return on investment.

Assuming that the return on investment portion of the total NGL cost were to keep pace with inflation, an initial total system cost of about \$682 MM/yr would provide the same overall rate of return on investment (i.e. 7% real return). This would also infer that the revenue at Prudhoe Bay for NGL would be increased by \$265 MM (1981 dollars) in the first and all subsequent years of the project. However, some of the basic operating parameters for these analyses have been stated optimistically. For example, at the base unit revenue for NGL, the rate of return on investment is reduced from 7.0% to 5.8% when considering the lower pipeline throughput, until the Phase II petrochemical project begins. Market conditions could prevent marketing of the total LPG stream. At an overall 90% throughput, the return on investment would be reduced to about 5.2% and at 80% throughput, the return would be reduced to about 3.2%.

Based upon the ever increasing investment estimates for ANGIS and the IAPS history, one must be concerned about the NGL pipeline investment. The DSG pipeline investment is about double that used in our previous work, which had been based upon escalation of the Pipeline Technologists report, which in turn was based upon their work for the El Paso proposed natural gas pipeline route. As a point of reference, a doubling of the NGL pipeline investment would increase the total cost for the NGL system from \$947 MM/yr to about \$1,466 MM/yr.

There are certainly factors which would indicate that NGL may be priced at greater than 100% BIU parity with crude oil. Due to past regulation of natural gas at less than oil parity, NGL has not experienced a significant cost-price squeeze. Deregulation of natural gas prices could be expected to result in an upward pressure on NGL prices. Although the non-US LPG ventures have been structured toward BIU parity between delivered crude oil and

delivered LPG, these projects could probably undercut LPG prices significantly if such actions were perceived to be in their best interest. Therefore, there is also the possibility that LPG prices could be less than BCU parity with crude oil.

The recent elimination of restrictions on LPG exports will certainly have some positive effects on the LPG project, e.g. a broader market coupled with cost saving foreign flagship shipments. However, this is perceived as a potential two-edged sword in that a secure supply in some of the potential LPG export market countries could also produce a negative influence on the potential petrochemical demand for these same countries. This would require considerably more study before any firm assessment could be made of the net effect of LPG export upon the overall project viability.

Petrochemical Project

Based upon the stated capital investment and operating cost and our estimate of working capital, the \$1,140 MM/yr cost (1981 dollars) would provide a real rate of return on investment of about 7.0%. When compared to a similar US Gulf Coast complex, the \$400 MM differential would decrease in constant 1981 dollars over the years to about \$225 MM in the tenth year, which would be equivalent to about a 5.6¢ per pound required ethane cost advantage. Over a twenty-year project period, the equivalent constant 1981 dollars differential would be about \$233 MM/yr, or about 5.8¢ per pound required ethane price advantage.

As before, this evaluation method is equivalent to a negative real growth in the return on investment component. Assuming that the return on investment portion of the total petrochemical cost were to keep pace with inflation, an initial total cost of about \$881 MM (1981 dollars) would provide the same overall rate of return on investment (i.e. 7% real return). The US Gulf Coast differential would be about \$285 MM, or about a 7.1¢ per pound ethane cost advantage required in Alaska. However, market factors are almost certain to result in less than 100% production year after year. The

return on investment, at the same contribution to return per unit of product, would be reduced to 5.8% at 95% operating rate, 4.6% at 90% operating rate, 3.0% at 85% operating rate, and 1.3% at 80% operating rate. At an 80% operating rate, the base contribution to return per unit of product would essentially have to keep pace with inflation to provide the 7.0% rate of return (see attachment II for additional information on operating rates).

Other factors not considered in these evaluations are the differences in timing of Phase I and Phase II facilities. Since the majority of the site costs are required for Phase I and there is a strong possibility that construction costs would increase at greater than inflation, the analysis procedure with Phase I and Phase II projects combined presents somewhat optimistic results. In addition there is no assurance that actual product prices would permit economic viability for the US Gulf Coast facilities used as a comparison basis in this study.

Overall Evaluation

Although the negative real growth rates for return on investment inherent in the analysis procedure used in the DSG report are questionable, we believe that consideration of other real factors results in essentially the same conclusion and that the DSG report is a reasonable presentation of economic feasibility.

It must be recognized that for such large capital requirements and with such a long permitting, engineering, and construction schedule, as well as future price and market uncertainties, a positive investment decision is indeed difficult. We are not aware of any available forecasting techniques or controls which would produce the results and assurance necessary for a positive investment decision at this time.

ATTACHMENT I
RATE OF RETURN

Part 1: Theoretical Analysis ^{1/}

- 1.) The required real rate of return is made up of three components.
 - Pure rate of return (no risk).
 - Liquidity risk premium.
 - Business risk premium.
- 2.) The capital requirements are essentially provided by two sources-- debt and equity.

Capital Source	After Tax Return, %			
	Pure Return	Risk Premiums		Real Return
		Liquidity	Business	
Debt	2.0	1.5	0	3.5
Equity	2.0	1.5	4.0-8.0	7.5-11.5

- 3.) The composite real return is dependent upon the capital structure.

<u>Equity</u>	<u>Composite Real Return</u>
100%	7.5-11.5%
75%	6.5- 9.5%
50%	5.5- 7.5%
25%	4.5- 5.5%

^{1/} Based upon analysis by Dr. Larry J. Merville, Professor of Finance, The University of Texas at Dallas, in connection with our initial Alaska petrochemical study.

Part 2: Capital Structure

A recent Chemical & Engineering News survey showed that for a composite of fifteen major chemical companies (sales in excess of \$1 billion annually) showed that equity provided 49-50% of the total capitalization of these firms in 1979 and 1980.

Part 3: Actual Return on Investment

We are not aware of any information on the real rate of return (as used in this analysis) actually experienced in the chemical industry. However, information is available on the net income as a percentage of total assets which is somewhat related to rate of return. These figures are for the same composite companies mentioned in Part 2.

Year	Net Income
	Total Assets, %
1980	6.22
1979	7.10
1978	6.33
1977	6.26
1976	7.09
1975	6.92

Note: Due to the dynamic nature of these data, differences in book and tax depreciation, etc., these data are not directly relatable to real rate of return and are presented only as general information.

ATTACHMENT II

OPERATING RATE HISTORY FOR U.S. PETROCHEMICAL INDUSTRY

Operating Rate ^{1/}
(Percentage of Nameplate Capacity)

Time Period		Product						
		Ethylene	Styrene <u>2/</u>	Vinyl Chloride <u>3/</u>	Polyethylene		Ammonia	Urea
					Low-Density <u>4/</u>	High-Density		
1981	1st Qtr.	68	82	66	92	75	83	88
1980	3rd Qtr.	63	55	63	62	58	75	91
	1st Qtr.	84	87	89	92	86	95	86
1979	3rd Qtr.	89	89	99	92	95	91	87
	1st Qtr.	85	88	90	82	75	74	80
1978	3rd Qtr.	80	80	71	NA	NA	88	82
	1st Qtr.	79	83	80	NA	NA	75	62
1977	3rd Qtr.	81	83	86	NA	NA	79	70
	1st Qtr.	82	84	82	NA	NA	78	66
1976	1st Qtr.	84	84	84	NA	NA	88	66

1/ Source: Chemical & Engineering News, various issues.

2/ Major end-use for ethylbenzene.

3/ Major end-use for ethylene dichloride.

4/ Does not distinguish between conventional low-density polyethylene and new linear low-density polyethylene, which is experiencing phenomenal market acceptance and growth.

MEMORANDUM

State of Alaska

TO: John Katz, Commissioner,
Department Of Natural Resources

DATE: October 12, 1981

Thru: Glenn Harrison, *GH*
Director, DMEM

FILE NO:

TELEPHONE NO: 276-2653

FROM: Sam Murray *SM*
Petroleum Economist, DMEM

SUBJECT: Dow-Shell Report

Please find attached DMEM's comments concerning the economic feasibility of petrochemical development in Alaska as outlined by the Dow Shell Group report of September 9, 1981.

CC: Kay Brown
Mary Halloran
Ed Phillips
Bill Van Dyke

The Economic Feasibility of Dow-Shell's Proposal for Petrochemical Development in Alaska

Introduction: The feasibility of petrochemical development in Alaska is a function of a variety of factors, many of which are interdependent and not subject to state influence. The uncertainties associated with many of the key facets of this question preclude a definitive answer. As presented by Dow-Shell, the path to economical petrochemical development in Alaska entails a series of critical junctures, the combination of which, like a tumbler lock, leads to a myriad of possible outcomes. There are few combinations which unlock the door to efficient petrochemical development in Alaska. This is not to say that sound petrochemical development is unlikely, since favorable probabilities can be attached to certain junctures. In addition, each juncture or decision point will be critically evaluated by both state and industry; the outcome at each node will not be left to chance or approached in a random fashion. As a general conclusion, however, a "positive" confluence of circumstances will be necessary to insure a feasible outcome.

This paper assumes that the reader is familiar with the Dow-Shell report and previous petrochemical studies contracted by the state. An indepth overview of the industry is therefore replaced by a brief discussion of the economic factors governing petrochemical development which pertain to the issues to be raised. Finally, the approach presented by Dow-Shell (also referred to as the Dow-Shell Group (DSG)) will be examined. As a result of time and information constraints, the latter task will be held to a general discussion and incorporate simplifying assumptions. The outcome array and uncertainties mentioned above have forced Dow-Shell into a similar approach despite considerable expenditures. In summary, the following will highlight the major areas of concern regarding the economic development of this industry in Alaska.

The Petrochemical Industry: An Overview of Specific Economic Factors

The long capital life of a petrochemical plant serves as a strong incentive for firms to seek assured long term markets and feedstock supplies. Vertical integration has therefore become a hallmark of the chemical industry. Hydrocarbon producers tend to integrate forward in an effort to secure markets and provide outlets for their feedstocks, which include crude oil, gas and natural gas liquids (NGL's). The control which oil companies have over long term feedstock supplies eliminates much of the risk associated with a petrochemical complex. It is for the same reason that chemical firms often integrate backwards in an effort to secure insured feedstock supplies.

Assuming Alaska natural gas could be delivered to market, its ultimate use as a fuel or a petrochemical feedstock will depend on the price of natural gas relative to crude oil. Should the deregulation of natural gas lead to a comparatively high price in the lower 48, North Slope producers would not be inclined to remove high value ethane from the Alaska-Canadian pipeline stream for the sake of a local, third party petrochemical industry. Conversely, a low natural gas price, brought about by either market conditions or pipeline regulation, would make producers more likely to sell gas liquids to Dow-Shell. The petrochemical industry, for its part, will seek the least expensive feedstock source and will choose between natural gas and petroleum based feedstocks accordingly. In general the physical availability of feedstocks does not seem to be a limiting factor to U.S. petrochemical production.

The petrochemical complex under consideration by Dow-Shell is fairly typical of most world-scale petrochemical complexes. As such, it is laid out like a large industrial park designed to expand in response to its anticipated market, technological change, an energy availability. Petrochemical plants can vary substantially in their capability, ranging from single product ethylene plants to a full product slate of primary, intermediate, and end use products.

The selection of a plant's product slate is often dictated by processing and transportation economics. In Alaska for instance, high processing costs suggest that no processing should occur in state and the feedstock should be shipped directly to a region of more acceptable costs. However this rule of thumb is outweighed by transportation considerations. The feedstock of interest to Dow-Shell is natural gas liquids. Natural gas liquids consist of ethane and the immediate group of heavier gases, (propane, butane, pentanes, and hexanes) in liquified form. Liquified petroleum gas (LPG) is NGL net of ethane. Ethane, when converted to ethylene, is an exceptionally versatile and desirable petrochemical feedstock. LPG is a less attractive feedstock. Although the various components of LPG can be cracked (broken down) into ethylene, cracking yields are relatively poor and produce a group of byproducts which have little current value. This factor, coupled with the fairly portable nature of LPG has led Dow-Shell to propose that LPG be shipped to the U.S. Gulf Coast as fuel/feedstock. Ethylene, on the other hand, requires extreme pressure and refrigeration to make it suitable for ocean transport. As a result, the ethylene would be effectively trapped in Alaska until it was converted into a slate of more manageable primary petrochemicals. Thus, the petrochemical plant under consideration by Dow-Shell would manufacture a group of ethylene-based primary petrochemicals.

Because petrochemical complexes strive to achieve the lowest possible manufacturing cost, their product slates and system designs are carefully coordinated to optimize the use of chemical by-products, provide for waste disposal systems, and minimize power and fuel input. The Dow-Shell group, being composed of several large companies with established markets for their respective products, would organize their complex as a series of independently owned plants, holding infrastructure, power, and transportation facilities in common.

The energy requirements of a petrochemical complex are substantial. Of the total energy requirements of all U.S. manufacturing industries, chemicals account for more than one third. The industry's substantial energy consumption is explained by the need for steam, process fuel, pumps, compressors, refrigeration, electricity, etc. Energy is probably the overriding factor of a petrochemical plants design. Heat generating processes, for instance, are usually placed strategically near heat absorbing processes. The availability of cheap electricity can also influence the location and design of a petrochemical complex.

Basic Economic Considerations

Before proceeding with the economics of the project the following concepts should be defined:

fixed costs: The fixed costs of the contemplated project are essentially its construction costs with an imputed interest rate (or return on equity). These translate into a "fixed" periodic payment that does not vary with plant output.

variable costs: Variable costs are those costs which depend on the output of the plant. For our purposes labor, power, and feedstock costs would adequately define the variable costs of the project.

world scale petrochemical facility: A world scale petrochemical facility is one whose size is not constrained by feedstock supplies or market considerations. Being of optimal technical size, a world scale plant is able to achieve the lowest possible cost per unit of output. Under today's technology a world scale plant generally processes at least one billion pounds of feedstock per year.

Fundamental Considerations

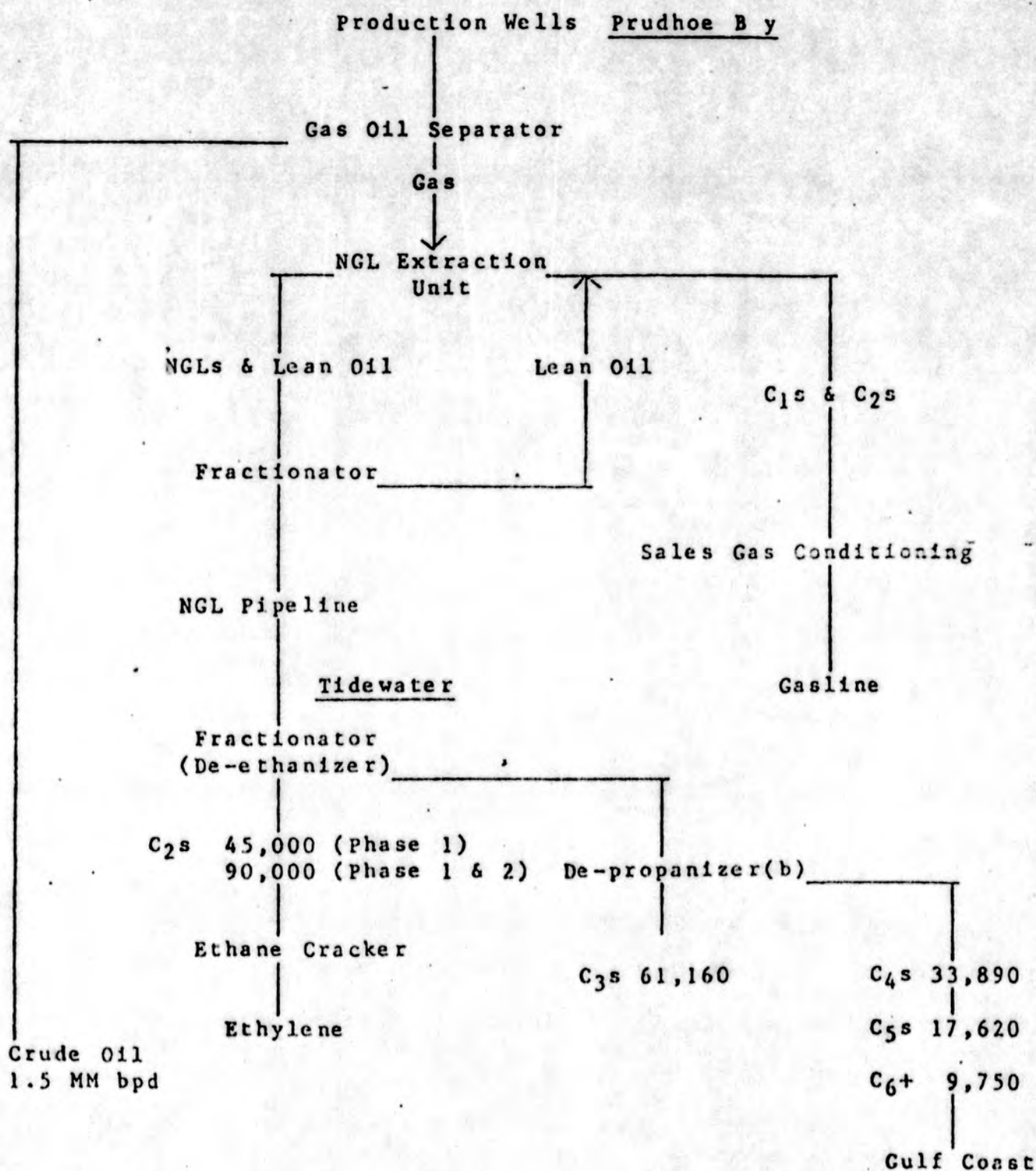
Transportation economics favor petrochemical development in Alaska. A petrochemical plant in Alaska would be well placed for the Pacific Rim markets. Consequently, an Alaskan plant would enjoy an advantage in market access over its competitors. The physically volatile nature of ethane implies that it should be processed in Alaska to enhance its mobility. This would be in keeping with the principle that can be observed in most Alaskan processing operations; the quest to reduce the weight, bulk, or perishability of any product whose transportation cost is otherwise prohibitive.

Construction costs disfavor petrochemical development in Alaska. As is well known to most Alaskans, in-state construction costs are often the prohibitive factor to development in Alaska. Dow-Shell estimates that the cost of building a petrochemical facility at tidewater in Alaska is 1.7 to 2.1 times greater than an equivalent U.S. Gulf Coast plant. The NGL extraction plant, NGL pipeline, and NGL fractionation plant require large capital outlays just to make feedstocks available at the complex. This raises a question as to whether or not ethane feedstock really is "cheap" in Alaska.

Fixed Costs are Sunk Costs. As a footnote it should be stated that although investors in a new plant expect revenues to cover total fixed and variable costs, once the plant is built fixed costs become sunk costs and do not affect operating decisions. Once established, a plant will operate at virtually full capacity provided its product sells for more than its feedstock and other variable costs, even if fixed costs cannot be covered. In general, any firm in this situation will stay in service so long as more money would be lost by shutting down than by continuing to operate.

"Figure 1"

DOW-SHELL GROUP PROPOSAL
DISPOSITION OF NORTH SLOPE GAS LIQUIDS (a)
(All figures in barrels per day)



(a) Source: The Dow Shell Group, Progress Report 8,
July, 1981.

(b) Possible location for a De-propanizer.

Evaluation of Major Assumptions

Figure 1 is a simplified schematic diagram of the Dow-Shell project as presently envisioned. As can be seen, a petrochemical plant could coexist with TAPS and ANGTS. The petrochemical branch of the diagram, beginning at the NGL extraction unit, can be traced to two general product categories; ethylene and LPGs. As mentioned, the ethylene would be converted into a product slate of primary petrochemicals and the LPGs would be sold to the U.S. Gulf Coast. Figure 1 implies a host of favorable and often interrelated assumptions which include but are not limited to the following:

- 1) North Slope producers will find it in their best interest to sell NGL's to Dow-Shell.
- 2) The costs of the gas liquids pipeline, and governmental regulations associated with this leg of the project will enable NGLs to be delivered to the plant at an acceptable price.
- 3) Dow-Shell has correctly estimated its on site capital construction costs, including the costs attendant to health, safety, and environmental regulations.
- 4) Dow-Shell will be able to secure adequate infrastructure facilities, and in its negotiations with the State, will not have to incur infrastructure costs that translate into unacceptable construction costs.
- 5) Dow-Shell will be able to secure sufficient quantities of suitably priced natural gas for its fuel and feedstock requirements.
- 6) There is a large enough market to absorb Dow-Shell's product slate at prices which cover all transportation costs, processing costs, and feedstock delivery costs and leave an adequate return on capital for all parties concerned.
- 7) Petrochemical developments in other low cost NGL regions will not seriously impinge upon Dow-Shell's target markets.

Numerous interrelationships between the above assumptions can be found. The feedstock delivery cost and netback (net of transportation) product prices are two prime examples. Either of these variables, when sufficiently favorable, can render the project feasible and dictate the amount of cost variance that can be tolerated in assumptions 2 thru 5. Of the remaining assumptions, feedstock delivery costs will strongly influence assumption 1 and netback product prices are key elements of assumptions 6 and 7. By linking netback product prices to the BTU value of world oil prices, and allowing world oil prices to increase at the rate projected by the Department of Energy, Dow-Shell has effectively set the prices necessary to cover total estimated project costs. It follows that if DOE's projection and the foregoing set of assumptions is true a petrochemical development will be feasible in the time period specified by Dow-Shell.

A more detailed discussion of the first five assumptions, which are of particular interest to the State, is provided here.

- 1) North Slope producers will find it in their best interest to sell NGL's to Dow-Shell.

This is the most complex and nettlesome uncertainty of the project. The outcome rests upon the alternatives which producers face. The presence or absence of ANGTS is a key determinant of those alternatives as is the regulatory structure attendant to ANGTS. These variables imply 3 possible scenarios on the North Slope. These are: a) No ANGTS; b) ANGTS without natural gas regulation; c) ANGTS with natural gas regulation.

To understand the likely behavior of the producers under each of these scenarios we must briefly recount the transportation and physical aspects of North Slope gas. The gas composition of the Prudhoe Bay field is approximately 74 percent methane, 13 percent NGL, and 13 percent carbon dioxide. Based on a gas production stream of 2.7 billion standard cubic feet per day, the forecast level of production, the reservoir life is estimated at 27 years. The daily NGL component of such a volume and Dow-Shell's proposed recovery rate is given by category in Table 1.

(Table 1)

Summary of Natural Gas Liquids Extraction Plant in Barrels Per Day

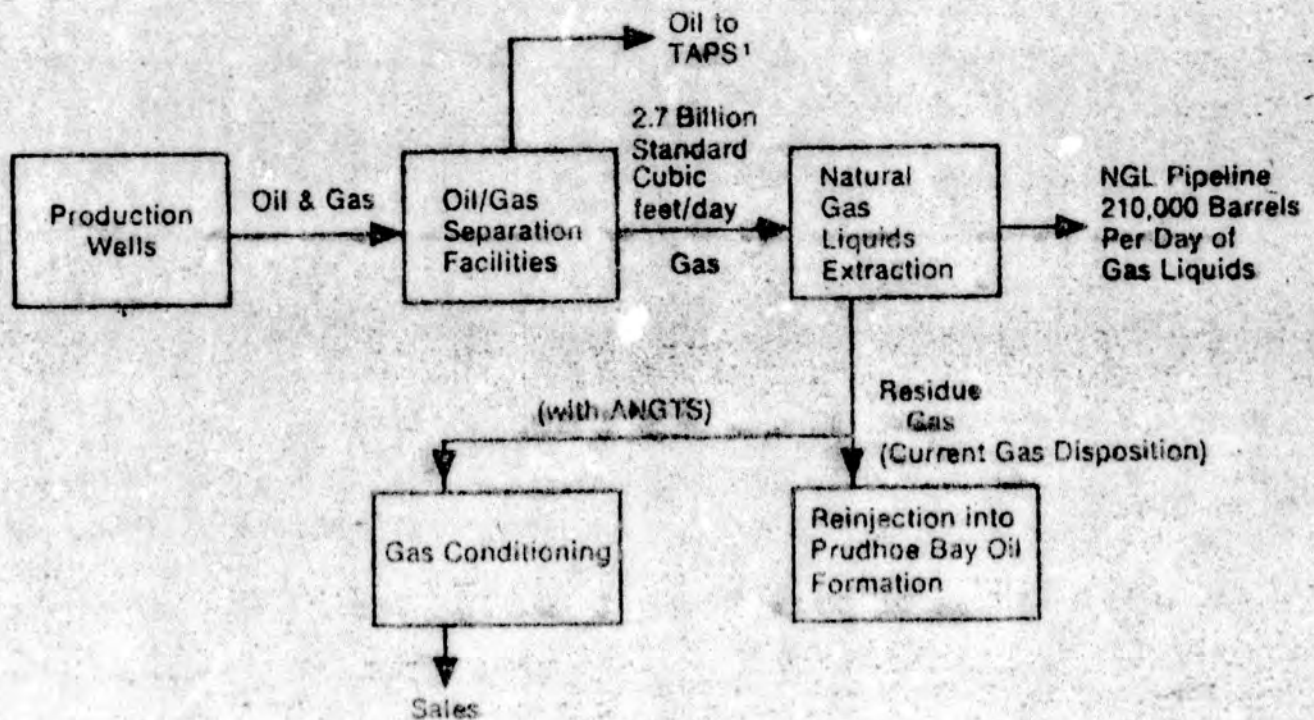
NGL Components	Entering Feed Gas Composition ¹	Phase 1 Initial Recovery ¹	Phase 2 Final Recovery ¹
Ethane (C ₂ H ₆)	110,000	45,000	90,000
Propane (C ₃ H ₈)	61,000	61,000	61,000
Butanes (C ₄ H ₁₀)	34,000	34,000	34,000
Pentanes (C ₅ H ₁₂) and higher	28,000	25,000	25,000
Total	233,000	165,000	210,000

¹Based on 2.7 billion standard cubic feet per day of entering gas

The high NGL recovery rate planned by DSG is a result of cost per unit considerations for (liquids line) transportation and the requirements of world-scale processing. Presently, oil and gas flowing from production wells are separated, with the oil entering TAPS and most of the gas reinjected back into the reservoir. Gas not reinjected is processed to meet most field fuel requirements. Should ANGTS be constructed, the raw gas producers now reinject would be separated from the NGLs and sent to a gas conditioning plant. To be compatible with ANGTS, carbon dioxide (CO₂) must be removed from the gas stream by further conditioning. The Dow-Shell Group may participate in the NGL extraction phase. Figure 2 schematically illustrates each phase leading to gas conditioning and ANGTS.

Figure 2

Proposed Natural Gas Liquids Extraction Schematic



Two related issues will be mentioned before moving on to the three aforementioned scenarios. These are the extent of carbon dioxide removal and the composition of the raw gas stream over time. ANGTS could tolerate a gas stream with a CO₂ content of up to 3% whereas the conditioning plant could bring the CO₂ content to as low as 1%. A lower level of CO₂ removal would hold down the costs of the conditioning plant but may be problematic for ANGTS maintenance. The converse holds true for maximum CO₂ removal. Since this aspect of gas conditioning is not seen as a major cost factor and does not affect the CO₂ content of the previously removed NGLs, it need not be considered. The same conclusion is drawn from the fact that the gas stream will become "leaner" over time. For physical reasons that will not be covered here, the gas stream is expected to grow leaner in the sense that the proportion of denser high BTU gases (butanes and pentanes plus) will decline. Considering the ample quantities available and prospects for additional North Slope discoveries, Dow-Shell has not expressed concern.

- a) ANGTS is not constructed: If ANGTS is not constructed North Slope producers would have fewer alternatives for their raw gas. They could reinject, expand field fuel consumption of gas, or even co-mingle all the heavier gases and as much as half the available butanes with crude oil for shipment thru TAPS. The latter two options would entail some degree of NGL extraction, as would sales to the Dow-Shell Group.

It will be instructive now to explain some of the rudiments of NGL extraction. Just as liquids can be converted to vapor by heat and low pressure, gas vapors can be liquified by the application of pressure and refrigeration. The amount of pressure and refrigeration needed to bring a gas to liquid phase depends on the gas. A relatively heavy gas, such as butane and heavier groups, can be held in liquid phase under modest pressure as a disposable butane lighter demonstrates. The lightest of the hydrocarbon gases, methane, must be subjected to extreme pressure and temperature reduction to liquify. The composition of the Prudhoe Bay raw gas stream is such that heavier gases will be the first to liquify (drop out) in the extraction process. Progressively intense refrigeration and pressurization would force ethane and finally methane to drop out.

The foregoing discussion suggests that the degree of liquids extraction depends on sales to the Dow-Shell Group. For instance under this scenario, if producers chose not to sell to Dow-Shell but wish to exhaust alternatives to reinjection, they could utilize TAPS by extracting some propane and all heavier gases. Some portion of the remaining raw gas might also be conditioned to meet expanding field use. Conversion of methane to methanol for shipment down TAPS has also been proposed. These options are limited since TAPS capacity to carry NGLs will decline with the flow of oil, and gas is used to handle most present field fuel requirements. Should producers consider that approach superior to total reinjection, the prospective benefits of such an arrangement would establish the floor price which the Dow-Shell Group would have to bid against.

Without ANGTS, sales to a petrochemical plant is the most promising outlet for North Slope gas liquids. With Dow-Shell collecting nearly all gases save methane, producers could reinject, convert to methanol, or meet their field needs. Since some degree of NGL extraction would occur under either event, the Dow-Shell Group argues that their arrangement is more efficient. Dow-Shell maybe willing to participate in the costs of its selected extraction process. The division of cost and management responsibilities depend greatly on producer preferences and price negotiations. The producers, for their part, would likely seek to control all North Slope operations and would surely demand a price and level of participation which exceeds all costs incurred to accomodate Dow-Shell. These would include any inconveniences encountered in handling field requirements, the functional and speculative value of forgone reinjection gas, the net value of shipping NGLs down TAPS, and possibly the merits of methanol conversion.

b) ANGST without natural gas regulation.

The presence of an unregulated ANGST would pose a competitive hurdle for DSG. Physically, ANGTS is capable of transporting methane, ethane, and some propane. Although methane reserves are sufficient to run ANGST at full capacity over its lifetime, the BTU value (and thus the price) of ethane and propane is greater. Without sales to Dow-Shell, the producers would likely pack ANGTS with all the high BTU gas it could carry. However the mechanics of raw gas conditioning is such that this option is hampered.

To date, the preferred gas conditioning process on the North Slope appears to be the one recommended by Parsons Company. The process chosen by Parsons, however, results in a waste gas that contains about half the ethane that enters the plant. Thus the producers would ship a methane-ethane-propane mixture down ANGTS and be left with an ethane rich CO₂ gas. This waste gas, when spiked with propane (or possibly butane) would be suitable for field use. For the balance of the NGLs, producers could exercise the same options outlined in the without ANGTS scenario.

To accomodate Dow-Shell, producers would have to condition primarily methane and forego the additional revenue which would otherwise accrue by a "richer" gas stream. In addition, any waste gas resulting from this arrangement would not be acceptable for field needs. Consequently, sales to DSG would be less attractive with the presence of ANGTS. Dow-Shell would find itself in heightened competition for Prudhoe Bay NGLs.

c) ANGTS with natural gas regulation.

If ethane and other NGLs are extracted before they enter an interstate natural gas pipeline, they are not subject to ceiling prices under the Natural Gas Policy Act. However, if ethane or other NGLs were co-mingled with methane destined for the Lower 48, federal law might treat them as "natural gas in interstate commerce" and subject to price regulation. This would dampen the producers incentive to spike the methane stream with higher BTU gases. Natural gas regulation would diminish the options available to producers and make them more disposed to negotiate with Dow-Shell.

In summary the outcome of assumption 1 hinges on a variety of indeterminant factors which the State is powerless to resolve. Until the disposition of ANGTS is known, producers cannot fully appraise their alternatives and they will be inclined to hedge their bets.

- 2) The costs of the gas liquids pipeline, and governmental regulations associated with this leg of the project will enable NGLs to be delivered to the plant at an acceptable price.

DSG has emphasized that they are not in the NGL extraction or transportation business. Consequently, they prefer that the ownership and management of those operations be left to other parties. Dow-Shell logically views the costs of NGL extraction and transportation as being imputed in the price of the NGLs which enter their plant. Although DSG is very cognizant of their markets, competition, product transportation costs, and on-site development, they appear to have a tariff mentality toward all activities upstream of the plant itself. Although such an approach is not inappropriate from Dow-Shell's perspective, the state should carefully scrutinize the costs of a gas liquids pipeline.

Dow Chemical assumed study responsibility for the northern half of the liquids line extending from Prudhoe Bay to Fox; Alaska Interstate Company studied the segment from Fox to tidewater. Assisting in the study were Williams Brothers Engineering Company for Dow Chemical and Delta Engineering Corporation, in cooperation with Brown and Root, for Alaska Interstate Company. Capital and operating cost estimates were made for a

liquids line leading to each of the six selected sites. These costs dictate the NGL delivery cost for each site. Key assumptions concerning easements, environmental considerations, engineering specifications, etc. have been briefly outlined in the DSG report. The state does not presently have the expertise to thoroughly evaluate Dow-Shell's assumptions; but for the reasons enumerated above, it is appropriate for the state to be more concerned about this segment of the project than (say) events downstream of the plant. The major uncertainty is cost which is in turn influenced by regulation, financing, and the timing of other projects.

It is commonplace for projects of this magnitude to greatly exceed their original cost estimate. In 1975 for instance, when TAPS construction was already underway, the Alyeska Pipeline Service Company estimated a peak construction work force of 14 thousand. By 1976, however, Alyeska reported 26,770 persons employed. Cost overruns for the TAPS project are well documented and only the quadrupling of world oil prices saved TAPS from financial disaster. In hindsight, TAPS sponsors were well advised to insist upon government loan guarantees.

If construction of other large capital projects, such as Susitna, ANGTS or new North Slope oil and gas development were to occur at the same time a liquids line was being built, the economic boom could surpass that of TAPS construction in 1974-6. In that case, cost overruns would be phenomenal and this timing consideration could easily postpone the project.

Regulation for environmental and financing/pricing purposes can also have a strong effect on pipeline costs. A regulatory framework addressing the environmental concerns of pipeline construction has yet to crystalize. Dow-Shell states that all environmental stipulations will be followed during both construction and operation of the liquids line. The question becomes "at what cost?" Be it by more stringent engineering specifications, rerouting, or operations constraints, regulations nearly always translate to additional costs from the firms perspective. Consequently, Dow-Shell cannot make definitive estimates for either plant or pipeline construction costs until this matter is clarified.

The DSG report makes little mention of federal pipeline regulation. While the NGL liquids line would be entirely in-state, the federal government could conceivably assert authority over the pipeline. This might be done by interpreting LPG shipments to the U.S. Gulf Coast as inter-state commerce. The affect of such an interpretation is again manifest by cost. Without going into detail, it is safe to assume that the problems entailed by federal regulation are similar to those facing ANGTS. That is, some set of restrictions governing the pricing and financing practices of the project sponsors.

Finally, the issue of financing may become an inhibiting factor. Like TAPS, the construction of a gas liquids line involves a great deal of risk which financing sources are traditionally adverse to. To date, only the Alaska Interstate Company has expressed interest in constructing the pipeline. Moreover, that interest is restricted to the southern leg of the project. Who then will build the northern half of the line? The only certain statements that can be made is: a) that party will seek a substantial return for their risk; b) they may seek some form of loan guarantee or; c) they may seek both. The jest of the above paragraph is

that the financing scheme envisioned by Dow-Shell, with pipeline owners holding a 10% equity position, is optimistic in light of the risks. Aside from the obvious concerns raised by these financing questions, it should be noted that the State has an uncomfortably high profile as a prospective equity participant/loan guarantor.

- 3) Dow-Shell has correctly estimated its on-site capital construction costs, including the costs attendant to health, safety, and environmental regulations.

The discussion relating to pipeline construction costs can generally be applied to plant construction costs. Given that Dow-Shell is intimately familiar with their construction requirements, and would be placing substantial capital at risk, their figures probably represent the most authoritative estimate available. Again, a delineation of the state's health, safety, and environmental regulations is imperative to establishing final costs. Moreover, even the most informed cost projection cannot escape the hazards of the Alaskan construction environment. Fortunately the state need not be overly concerned with DSG's construction costs. Once begun, the complex is almost certain to be completed despite overruns. Even if Dow-Shell were to suffer the fate of the sunk cost principle, the state would reap all the benefits anticipated.

- 4) Dow-Shell will be able to secure adequate infrastructure facilities, and in its negotiations with the State, will not have to incur infrastructure costs that translate into unacceptable construction costs.

This paper will not attempt a cost-benefit analysis of prospective state infrastructure costs. That task will be left to those who have intimate knowledge of State tax laws and community development. It is clear however that infrastructure costs must be defined before the state can begin rational deliberations.

Dow-Shell states that their calculations have been done on the basis that the state will not provide financial assistance in the funding of the project, except in "the normal areas of infrastructure ownership and financing". The DSG study anticipates a total project cost of nine to ten billion 1981 dollars, depending on the site. The level of world oil prices that Dow-Shell requires for feasibility would yield a 20% before tax rate of return on capital with a 15% rate of return applied to state capital expenditures. This implies that Dow-Shell would, over time, reimburse the state's outlays through taxes and user fees provided those outlays have been assessed accurately. Any miscalculations in this area will not change Dow-Shell's prospective revenues or their ability to reimburse the state.

The state will need to know: a) what costs Dow-Shell has calibrated at a 15% rate of return; b) the portion of those costs the state would finance. State decision makers should also bear in mind that Dow-Shell will not likely pay for infrastructure cost differentials from site to site and they are inherently more interested in appraising their own costs vis-a-vis state costs. Dow-Shell's analysis suggests that some fraction of the projects revenue is earmarked for payments toward infrastructure services. Those payments in turn form the states infrastructure budget which when exceeded, constitutes a subsidy.

- 5) Dow-Shell will be able to secure sufficient quantities of suitably priced natural gas for its fuel and feedstock requirements.

The plant under consideration by Dow-Shell would use feedstock hydrocarbons and byproducts for most of its internal needs. But despite the high energy value of its NGL feedstock, the complex would have a net energy requirement, in the form of electricity, of 75MW in the first phase of operation. The additional products planned for phase two would consume prodigious amounts of electricity, raising overall demand to 245MW. This compares to an average consumption of 600MW by the Municipality of Anchorage. The Dow-Shell group has determined that a combined cycle gas turbine co-generation system is optimal under most conditions. The details of this system as well as the others considered are covered in the energy section of Dow-Shell's report. For this analysis it is sufficient to say that the Dow-Shell Group would seek natural gas (methane) as fuel.

Project sponsors expect to purchase natural gas at \$3 to \$4/MCF. The source or wellhead price of the gas is unclear. For any of the tidewater sites an obvious source is Cook Inlet. The cost of delivery would vary considerably from site to site. With ANGTS, for example, gas would be available in Fairbanks at a minor delivery cost. The volume of gas involved is estimated at about 18.3 bcf. annually. The state will need to investigate the impact of such withdrawals from prospective reserve sources and possibly look into delivery costs for each site. The views of gas producers concerning Dow-Shell's price expectations would be useful. It should also be mentioned that DSG will seek feedstock methane during phase 2 of the project for their ammonia/urea operations.

Conclusions

As for assumptions 6 and 7, it is doubtful that state inquiries into world markets and competition would be very instructive. The petrochemical industry's expertise in this area, coupled with the tremendous risks that they would incur by such a project, effectively precludes the need for second guesses by the state. There is one area, however, in which the state's interests may be directly affected. The DSG study indicates that processes involving high ethane/low energy consumption are well suited for Alaska, but some of the products slated for phase 2 do not meet this description. The study further states that maximum production of the most favorable products is constrained by market considerations. Should Dow-Shell encounter unexpected methane/electricity costs, they may choose to drop certain items from their product slate and bypass Alaska by shipping out feedstocks earmarked for those items. Even the high cost of shipping ethylene (the first ethane derivative) may be preferred to processing energy intensive chemicals in Alaska. In the extreme, all NGLs might be shipped out with virtually no processing in Alaska save the conversion of ethane in ethylene. Given that this possibility is mentioned in the DSG report, the state should examine the economic viability and consequences of that option.

To recap the issue of economic feasibility, the state should recognize that:

- 1) North Slope producers will not necessarily find it in their best interests to sell to Dow-Shell.

- 2) Until a regulatory structure is established all cost estimates should be considered highly tentative. Particular caution should be taken with cost estimates made by parties whose welfare is not directly linked to those estimates.
- 3) Any cost/financing difficulties arising outside of Dow-Shell's jurisdiction (e.g. the pipeline or state infrastructure) could end up at the state's doorstep.
- 4) It is not clear that Dow-Shell will commit itself to the degree of in-state processing presently contemplated.

The concerns enumerated in this paper suggest that the DSG report represents the most optimistic confluence of events. Even if world oil prices attain their expected level, the potential for "slippage" in some other area remains high. While the long term fundamentals for in-state petrochemical processing are good, one should not attach a high probability to sound development in the coming decade.

MEMORANDUM

State of Alaska

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF FOREST, LAND AND WATER MANAGEMENT

TO: JOHN KATZ
Commissioner

DATE: October 14, 1981

FILE NO:

DICK LEFEBVRE, Deputy Director

TELEPHONE NO: 276-2653

FROM: DEAN N. BROWN, Chief
Water Management Section

SUBJECT: State Review of Dow/Shell
Feasibility Study

Attached is a detailed response to Mary Halloran's memo of 9/27/81. The following is a brief summary of water resource concerns for each proposed Dow/Shell tidewater site:

Fire Island: Surface water unavailable. Insufficient groundwater information however data available shows salt water intrusion problem in existing well and suggests insufficient quantities available on island. Impact of water demand on Anchorage system would be extensive, doubling present capacity, enlarging treatment plant, building one larger and one new pipeline. The timing to incorporate changes is good since Anchorage is presently locating a new water source for development to be at either Eagle River or Eklutna.

Pt. MacKenzie: Surface water unavailable. Insufficient groundwater information, but two exploratory wells show water levels fluctuate with tides in Cook Inlet which raises serious concerns of salt water intrusion potential into aquifer with prolonged pumping.

Seward: Surface water insufficient year-round for project. Again insufficient groundwater information. Smaller glacially formed aquifers such as this is usually are of discontinuous and limited extent hydrologically and geologically. Depending on well location consideration should be given to creating salt water intrusion into aquifer during winter months.

Kenai: This is already an existing groundwater mining problem from industrial usage, which has lowered lake levels and affected domestic wells. Situation is believed to be mitigated, however Union Chemical had one well fail last month and is having to redrill it to reestablish water supply. Extensive aquifer testing needed before further large water uses permitted. Definite problem area. Surface water unavailable on site, but Kenai River could be source requiring tertiary water treatment facility and pipeline. Long term solution needed in Kenai with Borough, industry and State.

Valdez: Surface water insufficient. Groundwater source more than adequate for project if wells located based on ALPETCO drilling data results.

In all cases, the water cooling method proposed by Dow/Shell is the

most resource wasteful and other (more costly) alternatives such as air cooling are recommended by Water Management.

Additionally, you may wish to review page 7 of the attached document for potential State or Borough financial impact considerations.

cc: Dow/Shell Special Projects File

Question 1: Statement of the known water resources at each of the proposed tidewater sites.

I. FIRE ISLAND

1. No surface water is available on the island for this magnitude project.
2. Insufficient ground water anticipated. There is a water well on the island which has been monitored by U.S.G.S. The water was used for a small military outpost on the island, but when the well was pumped for a long period of time salt water entered the well.
3. Water from the municipality of Anchorage water and sewer system could be used. The present capacity is 20 MGD and would require doubling the system to meet the demands of the Petrochemical project.

Little information is available on Fire Island groundwater resources. Well pumping report located in the U.S.G.S. Water Resources System.

II. POINT MACKENZIE

1. No surface water is available at the site which could meet industrial demands.
2. Ground water is available, whether or not sufficient supply exists is not determined. Two test wells on the site, strong indication of potential salt water intrusion with prolonged pumping from these sources. The water level in the wells does fluctuate with the tides.
3. Sea water is available but would require a desalinization plant, and extreme tidal fluctuation and sedimentation would make this a poor site.

One technical report for two wells on the site by DGGS.

III. SEWARD

1. Surface water from Fourth of July Creek, a glacial stream may not be sufficient for requirements and does decrease flow substantially during winter months. Additional data is needed. The water will require treatment to remove silt and rock flour.
2. There is insufficient data to determine if the ground water from this valley would be an adequate supply. Similar glacial deposits frequently form discontinuous aquifers of limited hydrologic and geologic extent.
3. Sea water is available but would require a desalinization plant.

A report on water resources by U.S.G.S. and Quadra. There is very little information on groundwater resources at this site.

IV. KENAI

1. Groundwater is available in this area but present industrial usage has strongly impacted domestic users near existing wells. The site is in an industrially developed area. Tesoro - Alaskan Refinery, Phillips Petroleum Kenai Plant, Standard Oil of California are using ground water sources. Union Chemical Company is a major ground water user. Industrial ground water use is 4.2 MGD and domestic use is 0.35 MGD. Extensive aquifer testing is recommended prior to further industrial development from groundwater sources.
2. Surface water from the Kenai River would be able to supply 25 MGD for this project but tertiary pretreatment will be required before the water meets industrial standards.
3. Sea water useage would require a desalinization plant.

The Kenai area has been the subject of several technical reports since 1968. U.S.G.S. and DGGs have been monitoring groundwater supply for several years. A computer groundwater model has been developed by U.S.G.S. It is considered a water problem area by Water Management.

V. VALDEZ

1. Ground water: there has been a series of shallow test wells drilled on the ALPETCO Plant site and pump tests have been conducted on two deep wells. There should be adequate groundwater for this project.
2. Surface water: This source will not deliver the necessary quantities of water all year or the quality desired.

The area has been studied for industrial water use by ALPETCO. Department files have the pump test data and well logs.

Question 2: Review of Dow/Shell's potential usage, identifying the potential impacts of the project on water resources at each site.

At all sites, the amount of potential water use could be significantly decreased by use of other cooling methods.

Fire Island: Development of water from wells on site, if possible, is likely to cause salt water intrusion. Water from the Municipality of Anchorage would require doubling present capacity of Municipal system. Eagle River water via pipeline would require pretreatment to remove silt and glacier flour. Desalinization of sea water is expensive and tidal fluctuation and sediment load would not make this an ideal site.

Point MacKenzie: Pumping at present plant needs could possibly cause salt water intrusion. Impact of plant on amount of water available for urban development is undetermined. Surface water from the Susitna River may be an acceptable alternate but pipeline impact, need for treatment, and possible fisheries impact would need to be studied.

Seward: Impact is indeterminant due to groundwater data needs, however it could impact the industrial park development area the city is considering as well as fresh water needs for the port facility being considered.

Kenai: Ground water at this site is being used by other industries in the area. The lake levels in the Kenai area have been shown to fluctuate because of pumping from existing wells and further development of this magnitude is anticipated to effect domestic wells in the area.

Valdez: The impact of 25 MGD withdrawal from this location would not negatively impact the aquifer or other users. Bedrock ridges are known to extend under the site and wells would need to be located in the deepest part of the valley to avoid problems.

Question 3: Identification of major studies needed or additional information needed by the State in order to make decisions regarding water allocation.

Fire Island: Need exploration wells to determine amount of groundwater available on the island. Need study to determine effect and cost of using Anchorage water system as a source of water, including costs of a pipeline from Eagle River and one to Fire Island. Long range effect of this quantity of usage on the Municipal water reserves and demand should be determined.

Point MacKenzie: Need more test wells, pump tests, and peizometer installation to determine the amount of ground water available on the site. Hydrologic study of the ground and surface water potential in this area of the Susitna River Valley should examine aquifer extent, capacity, potential for salt water intrusion, effect of tidal fluctuations on aquifer and wells, and potential of using Rivers.

Seward: Need test wells and pump tests to develop aquifer information for this location. Stream gaging of Fourth of July Creek needed to determine minimum and maximum flows, duration, and recharge effect on aquifer.

Kenai: Additional drilling, pump tests and observation wells are needed on the actual site to determine possible effect on existing domestic wells, lake levels, existing industrial water withdrawals (Union Chemical's last well has gone dry and they are having to redrill

now) and possible salt water intrusion. Feasibility of developing a water source from the Kenai River should be reexamined from the aspects of water treatment necessary, cost of treatment plant and pipelines, location, in-stream flows and affect on canneries located on the river (navigability).

Valdez: May need to determine availability of groundwater at the specific proposed well sites on the Dow/Shell site location. Water data generally sufficient for the location from ALPETCO studies. Should have an on-going monitoring program in existing wells on site.

Question 4: Recommendations, if any, for future action by the State or Dow/Shell or the local communities re water availability.

Dow/Shell - at all sites: develop cost, feasibility, and quantities needed for using a more conservative method of water use for cooling, such as air cooling. Prepare list of alternative options.

develop list of anticipated ancillary industries with related water usages.

Fire Island

Local - Municipality of Anchorage is presently developing a comprehensive water development plan which needs to consider impact of extension of a system to the island. Determine the cost of increasing water treatment plant capacity for use on the island.

Dow/Shell - cost of water from Eagle River via pipeline to the island. Cost of a desalinization plant on the island.

Point MacKenzie

Borough - develop a groundwater resource assessment program consisting of well drilling, pump testing, aquifer definition. Gather data on the effects that continuous pumping will have on the fresh water - salt water interface. Assess groundwater needs for projected urban-industrial-agricultural development and plan water development for the area.

Dow/Shell - develop cost of other water source options such as off-site wells, Susitna River, etc. including pipeline costs.

Seward

City - determine if water resources in this area can supply all their planned development and a petrochemical industry. Develop an information base of available ground and surface water for industrial development.

Kenai

State - reestablish funding for update of U.S.G.S. groundwater modeling system, undertake joint DGGs/USGS drilling program on-site to monitor water usage in this location, work with city and industry to develop a plan for water control.

City and Borough - Assess the impact that promotion of increased industrial development will have on existing water usages and determine a course of action for securing funding for a water source to meet present expansion and future needs.

Valdez

City - initiate groundwater monitoring of existing ALPETCO wells in this area.

Additional specific concerns that should be considered and may affect feasibility and cost of project:

1. Water pipeline construction funding -

Possible pipeline construction for water has been mentioned for Pt. MacKenzie, Fire Island, and Kenai. In conversations, the question of funding has been nebulous with at least one indication that the State or Boroughs would be expected to fund and build one, and Dow/Shell would pay a water user charge commensurate with that charged domestic water users, but not any capital charges. Costs, alternative options, and impact on public, state, Borough should be evaluated.

2. Development of increased or new water supplies affecting existing municipal systems.

Expansion of the Anchorage system due to population increases has necessitated the studies underway to identify and develop new water sources affecting Eagle River and possible Eklutna. Impact of the Dow/Shell project would be substantial, affecting quantities of water needed, treatment plant expansion, pipeline capacity increase to Anchorage and new pipeline possible to supply site. At Kenai existing industrial uses affect groundwater adversely in local areas. If Kenai continues to attract industries a new water supply system and source will need to be located, financed and developed. Again, funding, cost to be borne by a petrochemical plant, and effect on existing water supply reserves should be examined as well as Dow/Shell's implied position of not becoming involved in problems of construction, expansion or development of water supply that would serve other users.

3. Water conservation methods should be utilized by any petrochemical plant.

Alternate cooling methods which will not use or minimize use of water are utilized in many areas, but are more expensive which would affect ultimate feasibility.

4. At some point the cost and feasibility of desalinization, which would be further impacted by sediment load in waters, should be investigated for the Kenai area. Water resources will continue to become an increased deterrent to industrial development.

TO: [John W. Katz
Commissioner
Department of Natural Resources

DATE: October 7, 1981

FILE NO:

TELEPHONE NO:

465-4347

FROM: William R. Nix *by Sydney*
Commissioner
Department of Public Safety

SUBJECT: State Agencies'
Recommendations & Policy
Development; Petrochemical
Technical Team

It is the recommendation of the Division of Fire Prevention that all six Fire Prevention Recommendations (copy attached) should be initiated during the next one to three years.

Reference Item #1. Planning must focus on both the fire protection needs of the petrochemical complex and the surrounding community, with decisions being made by the local government as to the level of desired fire protection (degree of acceptable risk).

The Feasibility Study is less than clear in its definition of responsibilities for response to emergencies at the complex. On one hand the report portrays an in-house fire protection capability, and later suggests that major fires or natural disasters would trigger the call-up of the community's emergency services. The report expresses reservations with the Pt. Mackenzie site in that there is considerable distance between the site and the community's emergency services.

In reference to the required plan checks of the complex design, the division has requested two additional staff positions (a fire protection engineer and a secretary/typist) plus contractual monies for technical reviews to meet the impact of the natural gas pipeline construction. It would be logical to carry these over for the subsequent NGL line and complex construction. Of key concern are the design features for which there are no regulations. It would be short-sighted to regulate the construction of the complex in only those aspects for which we now have regulations.

The division proposes to assess the risk to the safety of the population by verifying the stated safety record of the petrochemical industry in general and by specific companies through the National Safety Council. Additional data gathered by the National Fire Incident Reporting System, the National Fire Protection Association, and other sources will be examined. Research and data about known physical characteristics of materials will also be checked.

Substantial effort must also be directed to the transportation aspects of the project, both input (NGL) and output (Products) of the complex. There is insufficient information on the expected behavior of hazardous materials in emergencies for pre-planning and tactical decision making.

John W. Katz
October 7, 1981
Page 2

The report expresses a high safety record for the petrochemical industry, however, this is not specifically defined. The array of potential variables which affect the decision making process at a hazardous materials incident cannot be reduced to one simplistic answer. Therefore, the industry and communities must prepare for the catastrophic as well as the routine incidents.

Attachment

Recommendations - 16

DEPARTMENT OF PUBLIC SAFETY

Fire Prevention

1. Need fire protection planning which involves both industry and public services where available, and also security measures planning.
2. Establish clearcut definition of responsibilities among the industry, state and local governments concerning fire protection systems.
3. Encourage Dow/Shell to examine the potential of the State's regional fire training centers, backed by the Department of Education's Fire Service Training Program.
4. Anticipate requests for grants or loans to finance local government fire protection equipment, apparatus and stations.
5. Investigate the appropriateness of a waiver of the local building code enforcement program in those communities which have both a local code and the state code plan requirement to avoid regulatory redundancy.
6. Consider the following statutory deficiencies:
 - (a) Certain aspects of the petrochemical facilities may be of such a scale that no nationally known recognized codes or standards may be written to meet the scope of the project. Should the State Fire Marshall develop independent codes or accept industry standards?
 - (b) If the plants are constructed in a political subdivision that does not exercise any building regulations, there will be no check on the structural integrity of buildings, such as the structures' ability to resist wind, snow or earthquake loading (as no state agency provides such a check).
 - (c) Consider establishment of followup field inspections of facilities whose plans have been reviewed by the Division of Fire Prevention.

MEMORANDUM

State of Alaska

Department of Revenue

TO: John W. Katz
Commissioner
Department of Natural Resources

DATE: November 2, 1981

FILE NO:

TELEPHONE NO:

FROM: Joseph K. Donohue
Deputy Commissioner, Taxation

SUBJECT: Dow-Shell Petrochemical
Industry Feasibility
Study

The attached memorandum outlines the possible state and local revenue impacts to be considered relative to a petrochemical operation like that envisioned by Dow-Shell. I believe, as the memorandum indicates, that major contractual, financial, and locational decisions on the part of prospective participants to the project must be made before the state can commence quantitatively assessing such impacts.

The attached memorandum does, however, discuss the primary areas impacting the state in terms of revenue.

MEMORANDUM

State of Alaska

Department of Revenue

TO: Vince Wright
Chief of Research

DATE: October 15, 1981

FILE NO:

TELEPHONE NO:

FROM: John Larson
Economist

SUBJECT: Review of Dow-Shell
Petrochemical Industry Feasibility Study -
Potential Impacts on State and Local Govern-
ment Revenues

The purpose of this memo is to examine the potential effects of the Dow-Shell proposed projects on state and local government revenues. The discussion of revenue impacts at the state level will deal with the sale of the state's royalty share of natural gas liquids (NGL), the corporate income tax, the oil and gas property tax and other potential state government revenues. At the local level property taxes, sales taxes and other local government revenues will be discussed. An attempt will be made to identify areas where there is a need for additional information or clarification due to uncertainty about future events relative to the projects. An overall governmental fiscal impact analysis of the projects would involve also examining potential state and local government expenditures and means of finance for infrastructure, regulation and services relative to the projects and their induced activity. This is however beyond the scope of this memo and probably not possible given the level of information and uncertainties contained in the Dow Shell study.

The sale of the state's royalty share of Prudhoe Bay Natural Gas Liquids (NGL) to this project would represent one source of revenue at the state government level. The amount the state would receive for its NGL would be subject to negotiation but in no case would it be lower than the amount received had the state taken its royalty share of these NGL's in value from the producers rather than in kind and sold to this project. The advantage of this project depends on what alternative markets and means of transportation exist for Prudhoe Bay natural gas and NGL's. That is will the Alaska Natural Gas Transportation System (ANGTS) pipeline ultimately be built providing a market for these NGL's.

The Dow Shell project is really two separate projects. The first project would be a NGL extraction and transportation project where, given certain market conditions, producers at Prudhoe Bay would find it advantageous to extract NGL from natural gas at Prudhoe Bay, ship the NGL into its two major components Liquid Petroleum Gas (LPG) and ethane and then ship the LPG to market via cryogenic LPG tankers. The second project which depends upon the first for its feasibility would be the construction of ethane based petrochemical derivative plants probably at a tidewater site using the ethane from the LNG project as a feed stock. In addition to favorable market conditions and cost factors, the feasibility of the petrochemical project would depend on the availability of ethane from the NGL project.

Whether the producers eventually find a NGL project in their best interest will depend on what alternatives exist for marketing those NGL's. If ANGTS is not built, there will be no means to market the NGL and thus it will have no value to the producers unless they find an alternative means of bringing it to market such as a NGL project. This also means that the state's royalty share of these NGL will have no value unless alternatives are developed. If, however, ANGTS is built then the relative advantage to the producers and the state of this project, at least insofar as additional value for NGL's is concerned, will be reduced.

Corporate income tax levied on the income project sponsors derive from participation in the LNG or petrochemical projects and on the additional corporate activity and income induced as a result of these projects would represent another potential source of state government revenue.

The amount of corporate income tax the state would collect from direct participants in these projects would depend upon the financial structure of the project. That is, which corporations would own an interest in what portions of the projects and how would they be financed?

The corporate income tax would be collected under provisions of AS 43.20, the Alaska Net Income Tax Act as modified during the 1981 legislative session by SB 524 and HB 460. Under AS 43.20 corporations are separated into two types, "those doing business in the state which derive income from the production or pipeline transportation of crude oil or natural gas in the state," and those which do not. Oil is further defined as "crude petroleum oil and other hydrocarbons regardless of API gravity which are produced in liquid form, including the liquid hydrocarbons sometimes known as distillate or condensate which are recovered from gas other than at a gas processing plant," this would appear to include NGL's. The determination of income and apportionment factors for each type of corporation is different. Corporations which fall under the oil and gas provisions determine their Alaska taxable income by starting with their federal taxable income making certain adjustments and multiplying by an apportionment factor which is the average of the ratio of their Alaska divided by their worldwide property, extraction and sales. Corporations which are considered non oil and gas determine their Alaska taxable income by starting with their federal taxable income, making different adjustments and multiplying by an apportionment factor which includes property, payroll and sales ratios. Both types of corporations are subject to the same tax rates on their Alaska taxable income in determining their tax liability. A major difference aside from the use of an extraction factor in place of a sales factor for oil and gas corporations, is that oil and gas corporations may only use methods of depreciation in effect as of June 30, 1981, in computing their adjusted federal taxable income to be apportioned. This means that these corporations will not be able to take advantage of recently enacted federal tax legislation allowing for greatly accelerated cost recovery (depreciation) in computing their Alaska tax liability. Non oil and gas corporations on the other hand would be allowed to use the new depreciation methods in computing their tax liability under AS 43.20.

Vince Wright
October 15, 1981
Page 3

It appears from the Dow Shell study that various portions of the projects would be owned and operated by different types of corporations and those would be subject to different provisions of the corporate income tax. For example, if the Prudhoe Bay producers, ARCO, EXXON and SOHIO, owned and operated the NGL portion of the project, the income derived from that project would probably be taxed under the provisions of AS 43.20 as they apply to oil and gas production and transportation corporations. If the chemical corporations Dow and Shell owned and operated the petrochemical portion of the project, they would probably pay tax under the non oil and gas provisions of AS 43.20.

Due to uncertainty about future product and financial market conditions as well as potential participants in these projects the Dow Shell study does not specify the exact financial structure or amounts of income to be derived from the various portions of the project. It is thus not possible to determine at this time, with potential development so far in the future, the amount the state would collect under the corporate income tax from these projects.

Another source of revenue at the state level would be the tax collected under AS 43.56, the Oil and Gas Exploration, Production and Pipeline Transportation Property Tax. Under the provisions of AS 43.56, an "annual tax of 20 mills (2 percent) is levied on the full and true value of taxable property." Taxable property is further defined as "real and tangible personal property used or committed by contract or other agreement for use within this state primarily in the exploration for, production of or pipeline transportation of gas or unrefined oil (except for property used solely for the retail distribution or liquifaction of natural gas) or in the operation or maintenance of facilities used in the exploration for, production of" Unrefined oil includes "crude petroleum and other hydrocarbons regardless of gravity which are produced at the well head in liquid form and the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas . . .," which would seem to include NGL.

Based on the above definitions, it appears that the NGL portion of the project which would include an extraction plant, a NGL pipeline, a fractionation plant and an LPG terminal facility would be subject to the property tax under AS 43.56 since they are used in the production of and pipeline transportation of NGL. It is questionable whether the petrochemical derivative plants which would use the ethane from the LNG project as feedstock would be subject to the property tax. This is an area which would require additional legal clarification.

It should also be noted that under the provisions of AS 43.56 and AS 29.53 Municipal Assessment and Taxation, municipalities may also levy property taxes against property which is taxable by the state under AS 43.56 subject to certain limitations. The tax paid to a municipality is credited against the state tax and thus would reduce state tax revenue. Limitations on municipalities' property taxing power relate to population, existing tax base and rates and whether the tax is to pay for bond debt

service. Since a definite site or sites for these projects has not been selected, it is not possible to determine the amount of municipal property tax which could be collected on project property. Due to uncertainty about the project and the interaction between state and municipal property taxes, it is not possible to determine the amount the state would collect under AS 43.56.

There are a number of other sources of revenue at the state level which would conceivably increase as a result of increased direct and induced employment and business activity resulting from these projects. These revenues would be certain gross receipt and sales and use type taxes as well as business and non business license and permit revenues and facilities and service-related charges. These revenues make up a very small portion of total revenues at the state level and the impact of these projects would not be very significant. Since Alaska no longer has an individual income tax, employment and payrolls resulting from the projects would not generate much revenue at the state level.

At the local level, property taxes on the facilities associated with these projects would probably represent the most significant source of addition of revenue. In addition to facilities used directly in the projects, support facilities and residential housing induced by the project could also be taxed at the local level. Municipalities are given the power to levy property taxes under the provisions of AS 29.53. There are, however, limits as to the amounts they may collect through the property tax determined by the population of the municipality and various per capita limits. There are also maximum rate limitations. These limits, however, do not apply to "taxes levied to pay or secure payment of bond principal or interest" regardless of whether the bonds are in danger of default for boroughs and first class cities and only to avoid default on payment of principal and interest on bonds for second class cities. Thus, if a municipality which is a borough or first class city sold bonds to finance infrastructure for these proposed projects, they could levy property taxes without limit if necessary to repay the bonds whereas a second class city could only levy unlimited property taxes if the bonds were in danger of default.

To determine the amount of additional local property tax that would result from these projects, it would be necessary to know the population of the municipality where they would be located, the type of municipality, the amount of tax base already subject to property taxes and the use to which the taxes would be put. Since no definite site has been selected, this is not possible at this time.

Sales taxes would be another possible source of revenue at the local government level. Municipalities are given the power to levy property taxes under AS 29.53 subject to the limitation that the rate may not exceed six percent. Also, if the municipality levies a property tax on property which is subject to the state oil and gas property tax AS 43.56 that property tax is in place of any sales taxes associated with that property.

Vince Wright
October 15, 1981
Page 5

Thus a municipality could not levy both a sales and property tax on activity associated with facilities which would be subject to the state property tax, which in the case of these projects would most likely include at least the LNG project facilities. Sales taxes could be levied on induced economic activity and sales. Again more specific information is needed to make any quantitative estimate of the amounts which would be collected.

Various license and permit fees at the local level would be an additional but minor source of revenue resulting from these proposed projects.

In conclusion, there is a potential for significant additional revenues at both the state and local level to result from these projects. Additional specific information as outlined above will be required before any quantitative estimates can be made. It is likely, in light of all the uncertainties which surround these projects in terms of timing, economic feasibility and financing that this information will not be available for some time.

MEMORANDUM

State of Alaska Department of Transportation & Public Facilities

TO: John W. Katz
Commissioner
Dept. of Natural Resources

DATE: November 2, 1981

FILE NO:

TELEPHONE NO: 465-3900

FROM: John Bates 
Deputy Commissioner
Planning and Programming
DOT/PF

SUBJECT: Dow/Shell Petrochemical -
Final Report

I have had my staff review the Dow/Shell final feasibility study. We found it to be a very professional product and have only two specific comments to offer on the report.

I would like to emphasize that certain segments of the proposed transportation facilities should not be considered as appropriate for public financing. Even though the report refers to significant infrastructure requirements and indirectly suggests that these facilities are a public responsibility, our traditional definition of "infrastructure" includes only those facilities that are developed to serve the general public and are open to all on an equal basis. It's obvious that improvements such as the liquids docks, and possibly others, will not fall within that definition.

We have also reviewed the cost estimates of transportation facilities that were transmitted to Mary Halloran earlier this year. We feel that the estimates are still valid and need no revision.

Given that the State is considering the option of acquiring the Alaska Railroad, it is reasonable to assume a greater responsiveness might exist with respect to those development scenarios involving use of the rail system. This situation should be particularly true in the case of any needed expansion of that system. Without attempting to estimate the levels of proposed traffic that would potentially be generated by the project, our recent assessments indicate a under-utilization of the capacity of the existing physical plant. Moreover, those same assessments have indicated a potential for a large increase in that capacity with a modest amount of investment.

Please be assured that DOT/PF will continue to participate in the assessment of industry proposals. If there is any further information that I can furnish, Please let me know.

Attachment

ESTIMATE OF COSTS - TRANSPORTATION ELEMENTS

DOM/SHELL PETROCHEMICAL DEVELOPMENT

KENAI

Dock Facilities

Order of Magnitude Cost
Millions of Dollars

- | | |
|-----------------------|---------|
| 1. Dry Cargo Dock | 20-25 |
| 2. Liquids Dock | 175-250 |
| 3. Barge Dock | 40-60 |
| 4. Bulk Material Dock | 40-60 |

Highway & Industrial Access

- | | |
|---|------|
| 1. Spur highway Wildwood to Nikiski (5 miles) | 5-10 |
| 2. Main Site access (1/2 mile) | 1-2 |

TOTAL TRANSPORTATION ELEMENTS, KENAI

281 - 407

PT MACKENZIE

Dock Facilities

- | | |
|-----------------------|---------|
| 1. Liquids Dock | 200-250 |
| 2. Barge Dock | 50-75 |
| 3. Bulk Material Dock | 50-75 |

Railroads

- | | |
|--------------------------|-------|
| 1. Railroad from Houston | 50-75 |
|--------------------------|-------|

Highway & Industrial Access*

- | | |
|-------------------------------------|---------|
| 1. Pt. Mackenzie Highway (20 miles) | 10-15 |
| 2. Causeway to Anchorage | 500-750 |
| 3. Access road to dock | 5-10 |

TOTAL TRANSPORTATION ELEMENTS, PT. MACKENZIE

665-1,250

FIRE ISLAND

Dock Facilities

- | | |
|-----------------------|--------|
| 1. Liquids Dock | 75-150 |
| 2. Bulk Material Dock | 50-75 |

Railroad

- | | |
|---------------------------------|-------|
| 1. Rail via causeway (12 miles) | 15-20 |
|---------------------------------|-------|

*\$5.5 million for Knik Arm Crossing in FCCSHB 50

FIRE ISLAND (Cont.)

Highways & Industrial Access

- | | |
|--|-------------|
| 1. Causeway | 300-500 |
| 2. Highway connecting with Seward Hwy (12 miles) | 10-15 |
| 3. Access on Fire Island | <u>5-10</u> |

TOTAL TRANSPORTATION ELEMENTS, FIRE ISLAND - 455-770

VALDEZ

Dock Facilities

- | | |
|-------------------------|--------------|
| 1. Liquids Dock | 100-200 |
| 2. RR Barge Dock | 25-50 |
| 3. Container Barge Dock | 25-50 |
| 4. Bulk Material Dock | <u>25-50</u> |

Railroad

- | | |
|-----------------------|------|
| 1. Dock to plant site | 5-10 |
|-----------------------|------|

Highways & Industrial Access

- | | |
|---|------------|
| 1. Access to road to Alpetco site (1 1/2 miles) | 1-2 |
| 2. Municipal Dock to site | <u>1-2</u> |

TOTAL TRANSPORTATION ELEMENTS, VALDEZ - 182-364

SEWARD

Dock Facilities

- | | |
|-----------------------|--------------|
| 1. Liquids Dock | 75-100 |
| 2. RR Dock | 25-50 |
| 3. Dry Cargo Dock | 25-50 |
| 4. Bulk Material Dock | <u>25-50</u> |

Railroad

- | | |
|--------------------------|-------|
| 1. RR Dock to plant site | 10-15 |
|--------------------------|-------|

Highway & Industrial Access*

- | | |
|----------------------------------|--------------|
| 1. Nash Road Extension (6 miles) | 2-5 |
| 2. Seward Highway Upgrade | <u>50-75</u> |

TOTAL TRANSPORTATION ELEMENTS, SEWARD - 212-345

*Currently authorized projects for FY '81 include \$15.8 million for Seward Highway upgrade and \$3.0 million for Nash Road - 4th of July Creek improvements.

BONANZA CREEK ALTERNATE

Railroad

- | | |
|-------------------------------|-------|
| 1. Spur to site (9 1/2 Miles) | 15-25 |
|-------------------------------|-------|

Highway and Industrial Access

- | | |
|--|------------|
| 1. Access from Parks Highway (2 miles) | <u>1-2</u> |
|--|------------|

<u>TOTAL TRANSPORTATION ELEMENTS, BONANZA CREEK ALT.</u>	16-27
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**PLEASE NOTE: THE PRECEDING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.**

**PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT**

SEP 26 1980

Alaskan Northwest Natural Gas)
Transportation Company) Docket No. CP80-435

**INTERIM REPORT TO THE COMMISSION
BY THE ALASKAN DELEGATE
AND THE DIRECTOR, AUDIT AND COST ANALYSIS,
OFFICE OF THE FEDERAL INSPECTOR**

In its order of August 1, 1980 in the above captioned proceeding, the Commission directed the Alaskan Delegate, assisted by the OFI Division Director, to commence a series of technical conferences on the project sponsors' cost estimate for the Alaska segment of the ANGTS and related incentive rate of return (IROR) issues. The order inter alia offered the parties an opportunity to file comments on procedures for the conferences, and directed the Delegate to consider those comments with the parties at the first conference.

The first round of conferences was held on September 3 and 4, 1980, and dealt mainly with procedural issues. Prior to the conferences, procedural comments were received from the project sponsors and the Commission's trial staff. The comments, and the discussion that ensued, focussed primarily on the scheduling and location of the conferences, transcription of the conferences, and procedures for exchanging information. These matters were discussed at length in the morning session of September 3 and the afternoon session of September 4; the results of those discussions are summarized below.

Cost Estimate Formats

The afternoon session of September 3 was scheduled to consider cost estimate formats. That session was very brief in that no party indicated any disagreement with the cost estimate formats previously submitted by the project sponsors. We expect the sponsors' formats to be agreed to by the parties at next week's conference.

IROR Methodology Issues

The conferences opened with (and later returned to) a discussion of the concern expressed by the Commission in its August 1, 1980 order (at page 10), namely that:

The Commission's orders establishing the IROR mechanism contemplated that all such [design] issues would have been resolved prior to the filing of the CCSE.

The design issues identified in the conferences as having some potential for resolution on a basis other than that contemplated by Alaskan Northwest's July 1 filing were:

1. Separation distance between the ANGTS and the Trans-Alaska (oil) Pipeline System (TAPS);
2. The possibility of utilizing a tunnel of approximately two and one-half miles in length to bypass the most difficult portion of the Atigun Pass in the Brooks Mountain Range in northern Alaska;
3. Burial of the pipeline in a shallow or embankment mode, rather than in a trench; and
4. Access roads and work pads constructed of snow, with increased emphasis on winter construction, as opposed to access roads and work pads made of gravel, with emphasis on summer and "shoulder" months for the construction period.

The first of these issues, the separation or alignment question, was left open to some degree by Congress and the President in selecting the approved transportation system. 1/ On this basis, the Commission in its orders in Docket No. RM78-12 expressed its intention to consider establishing the Certification Cost Estimate (CCE, or occasionally referred to as the Certification Cost and Schedule Estimate, or CCSE) upon appropriate resolution of this issue. 2/ The issue has now been resolved by the Department of the Interior (DOI), on a basis slightly different from that on which the July 1 filing was based. DOI's proposed right-of-way grant allows for the possibility, upon completion of considerable further study, of authorizing the alignment originally proposed by Alaskan Northwest, 3/ but Alaskan Northwest suggested in our conferences that they would likely accept DOI's

1/ The nature and route of the approved system was specified in Section 2 of the Decision and Report to Congress on the Alaskan Natural Gas Transportation System (Executive Office of President, Energy Policy and Planning, September 1977). Approved by Joint Resolution of Congress, the Decision has the legal force and effect of a Federal statute. The Decision states (at page 7):

From Prudhoe Bay to Delta Junction, Alcan expects to construct its line approximately eighty feet from the Alyeska oil pipeline. As proposed by Alcan, construction will be carried out by extending the existing Alyeska work pads. However, Alyeska advised that the Alyeska and Alcan lines must be separated by 100 to 200 feet where blasting to build the pipeline trench would occur (approximately 350 miles of pipeline length). Additional studies will determine the minimum distance between the Alyeska oil pipeline and the Alcan line that is necessary to permit safe construction and operation.

2/ See, e.g., Order No. 17-A, "Order Confirming the Incentive Rate of Return Mechanism and Denying Petition for Reconsideration and Classification," Docket No. RM78-12 (issued January 17, 1979).

3/ The proposed grant with its terms is contained in a letter, dated August 20, 1980, from Guy R. Martin, Assistant Secretary for Land and Water Resources, Department of the Interior, to Mr. John McMillian, Chairman of the Board of Directors for Alaskan Northwest Natural Gas Transportation Company, the sponsor of the Alaska segment. As mentioned later in this interim report, we have asked that this letter with its attachments be filed and served on the parties to this proceeding.

preferred routing. Accordingly, we believe it is appropriate to try to develop a recommended CCE value based on the revised alignment.

With respect to the other issues identified in our initial conferences, Alaskan Northwest characterized the burial mode and access road/work pad issues as ones for which the July 1 filing contained their preferred resolution, but for which agencies of the Federal Government, principally the Federal Inspector and various of his advisory bodies, had requested that alternatives be explored. Alaskan Northwest reported that the alternatives are being explored in good faith, but that Alaskan Northwest believes in the superiority of the preferred alternatives contained in the July 1 filing, and expects those alternatives to be selected when consideration is complete. On the other hand, the tunnel alternative for passage over the Brooks Range is being evaluated as a potentially preferable alternative to the use of Atigun Pass.

The Commission's Alaskan Delegate 4/ and the Commission itself 5/ have stated that the ANGTS approved by the President and the Congress is the system described in the Alcan filing submitted to the Federal Power Commission in March of 1977. 6/ It would seem, then, that the Commission's Order Nos. 31 and 31-B would have been written in the contemplation that it was basically that system (save for the separation issue as discussed above) which was to be constructed and for which the IROR mechanism as adopted by the Commission was to apply.

4/ See, e.g., "Report of the Alaskan Delegate on the System Design Inquiry" (especially at page 51), attached to "Notice of Delegate Report and Order Inviting Comments," issued by the Commission in Docket No. CP78-123, et al., on May 17, 1979.

5/ See, e.g., "Notice of Proposed Rulemaking and Statement of Policy," Docket No. RM79-19 (issued February 2, 1979) at page 7, and Order No. 45 (issued in that proceeding on August 24, 1979) at page 5 (rehearing pending).

6/ "Alcan Pipeline Project 48-inch Alternative Proposal," Docket No. RM77-6, filed on March 8, 1977.

Section 9 of the Alaska Natural Gas Transportation Act (ANGTA) limits changes to the approved system to those which would not

... compel a change in the basic nature and general route of the approved transportation system or . . . otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system.

The question which arises for exploration in our proceeding is whether all changes such as would meet this test, including presumably any of the additional three mentioned above if ordered by the Government, 7/ are within the contemplation of Order Nos. 31 and 31-B.

Alaskan Northwest's proposal is to treat all such changes as "design changes" as allowed for by the Commission in Orders Nos. 31 and 31-B. As postulated in the Commission's August 1, 1980 order (at page 10), we think an alternative value of the CCE is appropriate for the new resolution of the separation issue, because of the referenced language regarding the separation issue in Order Nos. 17 and 17-A. In this proceeding, we will attempt to determine whether additional alternative values of the CCE are appropriate for alternative resolutions of other outstanding design issues, and, as requested, will address development of guidelines to govern the design change process envisioned by the Commission's orders.

With respect to procedure, it seems apparent that Alaskan Northwest's July filing is based on the same design concepts as the March 1977 filing, although those design concepts have been greatly refined since that time through expenditure of considerable time

7/ Condition No. I.5. at page 29 of the Decision requires that the project sponsors develop a final design, design cost estimate, and construction schedule for submission to and approval by the Federal Inspector prior to the initiation of construction. At that stage, the Inspector could order changes as a condition of his approval.

The Commission provided a discussion of its understanding of the design change problem as part of its change in scope discussion at pages 120-138 of Order No. 31 (issued June 8, 1979).

and effort. Alaskan Northwest suggests, and we concur, that the July 1 filing is an appropriate base from which to begin development of CCE and Center Point (CP) values for the Alaska segment. The cost consequences of any alternative resolutions of outstanding design issues would be developed by Alaskan Northwest as variations off of the basic cost information presented in that filing, and could best be evaluated by the Commission and the parties as variations from that base. Detailed evaluation of the basic estimate could thus be a step in evaluating estimated costs of any alternatives, even if our report to you ends up recommending CCE values for alternative designs.

Another aspect of the Commission's concern in this area was also addressed during our conferences. We raised the question of whether the recent agreement between the project sponsors and the North Slope producers on a cooperative study for design and engineering of the pipeline and conditioning plant would not result in some further changes to the design of the pipeline beyond those currently being studied. We were assured that that agreement did not contemplate such further changes. We requested that the agreement be filed and served on all parties to this proceeding, and that a statement on behalf of the parties to that agreement be filed and served on all parties to provide some idea of the agenda and timetable for the design review being conducted pursuant to that agreement.

As regards further proceedings on the IROR methodology issue, we agreed on the following additional steps:

1. In addition to filing and serving the cooperative study agreement, we asked that the sponsors file and serve the communication from DOI regarding the right-of-way grant.
2. We have developed a working paper on IROR concepts which is being circulated as an attachment to this report.

3. The Federal Inspector's report requested by the Commission to identify the major outstanding design issues from his perspective is expected to be submitted by the end of September. At approximately the same time, the project sponsors will submit the above-mentioned statement from the producer-sponsor study group, plus any further thoughts they may have with respect to (a) other outstanding major design issues, and (b) a more complete statement of their views regarding how such changes should be handled for purposes of the IROR mechanism.

4. At the same time, any other party may also submit its own comments on design issues, including any design changes that such party wishes to propose for consideration. (In this regard, Exxon, ARCO and Sohio took the position that the design should include the conditioning and processing facilities required to prepare the gas for pipeline entry.) Reports and comments on design issues, as submitted by the project sponsors and the parties, should also address the IROR implications of those issues.

5. The project sponsors expect to file by October 15 appropriate revisions to their proposed CCE to account for the changed separation from the oil pipeline. They indicated that they expect to have information available on the cost consequences of other design alternatives by the end of October.

Several parties (including, in particular, the trial staff) expressed reluctance to consider the IROR issues until after the parameters of the outstanding design issues had been clarified in the conferences. On the other hand, we felt that it was important to begin exploration of IROR questions early in the conferences, as application of the IROR mechanism is an important element of the context in which the Commission and the

parties consider the sponsors' cost estimate filings. The compromise that we struck was to begin exploration of the IROR topics in a special conference in the week of October 6, 1980, then return to it at the end of the conferences.

Schedule of Future Conferences

Williams Brothers Engineering Company, the consultants recently retained by OFI, indicated a need to spend several days at the offices of the sponsors' project management contractor in California meeting with the project sponsors to familiarize themselves with the organization and methodology of the sponsors' filing. Those informational sessions were held on September 16-18. All parties were invited to participate. No decisions were reached at these sessions, and no transcript was prepared. The Alaskan Delegate and the OFI Division Director did not attend these sessions.

Further technical conferences will commence in the last week of September. We originally announced our intention to hold the conferences on alternate weeks pursuant to the following schedule:

September 30

October 14

October 28

November 11

November 25

However, inasmuch as several of these weeks involve Federal holidays our present intention is to reevaluate the schedule through discussion with the parties at the September 30 conference.

Each conference will commence on a Tuesday, and will continue for as many days as the parties consider useful and appropriate, but will terminate no later than the Friday of

the week in which it commenced. The Alaskan Delegate or the OFI Division Director will preside at each of these conferences, and a limited transcript will be kept (as discussed below).

The first conference will be held in California. The location of the ensuing conferences will be determined at a later date, taking into consideration the subject matter to be discussed.

The following subjects will be taken up at the conferences, in this order:

1. Estimate format
2. Pipeline
3. Compressor and metering facilities
4. O & M facilities
5. Temporary facilities and services
6. Communications and supervisory systems
7. Project directorate
8. Potential design changes and P/L adjustments
9. Center Point and contingency and finance charges

The first conference will start off dealing with all subject areas to determine, to the extent possible, general areas on which there is substantial agreement or disagreement. The conference will then concentrate on subjects no. 1 and no. 2 above. At the conclusion of each conference, the parties will determine the scope and agenda of the next scheduled conference.

The conferences will continue until we and/or the parties conclude that they are no longer productive. We have tentatively scheduled them through the end of November, anticipating that they can usefully continue at least that long. At about that time, we will advise the Commission regarding our expected schedule for any further proceedings.

In addition, as mentioned above, a conference will be held in Washington on October 7, to consider design issues and their IROR implications.

The Delegate will issue a notice of each conference, identifying the date, place and subject matter of the conference. A copy of the notice announcing the September 30 and October 7 conferences is also attached to this report.

Transcripts

The project sponsors and the trial staff recommended that no transcripts be kept of the conferences, contending that the discussions would be faster, freer and more productive without them. Alaska, Exxon, and ARCO, on the other hand, recommended that verbatim transcripts be kept, contending that they would be needed to accurately record the results of the conferences as well as to keep all parties fully informed. After lengthy discussion, the Delegate established a compromise procedure designed to balance and accommodate all of these legitimate concerns to the extent feasible.

A court reporter will be present at all of the technical conferences (i.e. except for the pre-conference informational sessions during the week of September 16). All agreements by the parties present at the conference will be transcribed. When the parties disagree, but have discussed a subject at sufficient length to crystallize the nature of their disagreement with some degree of precision, their respective positions will be transcribed. In addition, the transcript will include a summary of the topics discussed, and a description of the agenda for the next conference. The transcript will also include a description of all informal exchanges of information between a party and a decisional person (generally, Williams Brothers personnel) that have occurred prior to the conference and subsequent to the last such transcription (see discussion below). Parties present at the conference may also include in the transcript any other procedural or substantive matter that is reasonably pertinent to the proceeding. Within these general parameters, the conferences

will make very liberal use of "off the record" discussions, including simultaneous meetings in smaller groups, and free flowing consideration of thoughts, ideas and questions as they occur.

After careful consideration of the views expressed by the parties, it is our conclusion that this procedure will satisfy the legitimate needs of the parties (and of the OFI and the Commission) for an accurate record of the progress of the conferences and the conclusions reached (including conclusions in the nature of sharpened, articulated disagreements), without inhibiting the free flow of discussion. Parties who wish to be informed of the processes by which these positions and conclusions are reached will in any event have full opportunity to participate directly in the conferences themselves. In reaching this conclusion, we also note that the conferences are not formal evidentiary hearings, and that there will be no testimony under oath or cross-examination of witnesses. The purpose of the conferences is to assist the Alaskan Delegate and the OFI Division Director in the preparation of their report to the Commission by organizing the information and clarifying the issues; all parties will have ample opportunity to file comments and reply comments on the report itself.

In this regard, several parties inquired as to whether the conferences would be deemed part of the Commission's "record" of the proceeding. It is our conclusion (and we so stated) that the record of the conferences would be part of that "record" in the sense that they constitute preliminary, informal consideration of the subject matter designed to culminate in the issuance of a formal notice inviting comments and reply comments.

Finally, in the course of discussion of the transcript procedure, one party referred us to the following sentences on page 9 of the Commission's August 1, 1980 order:

Stipulations and other agreements are encouraged, and will be included in the final report to the Commission. Unanimous agreement among the participants at a conference shall be deemed to constitute unanimous agreement among the parties. Objections to stipulations must be supported by substantial rationale.

It is our understanding (and we so stated) that the Commission's intent was to maintain steady progress at the conferences by precluding parties at a later conference from re-opening agreements and stipulations reached at earlier conferences. As we understand it, however, the above quoted passage was not intended to preclude the Alaskan Delegate and the OFI Division Director from exercising their independent judgment in the preparation of their report in the event that they reach a conclusion different from one stipulated or agreed upon by the parties. (In such event, the report would set forth the agreement or stipulation, and state why the Delegate and Division Director disagree with it.) Similarly, it is our understanding that the Commission did not intend to preclude any party (whether or not it participates in the technical conferences) from raising any issue in its comments and reply comments on the Delegate and Division Director's report to the Commission, regardless of any stipulations and agreements upon which the report may have been premised.

Exchanges of Information

The delegate first noted the August 15, 1980 comments from the Commission's trial staff, dealing, in large part, with the area of discovery. The Delegate pointed out that the technical conferences were intended to deal with the CCE, CP and related IROR matters only. To the extent that trial staff or other parties seek information that is to be dealt with in the final FERC certification proceeding (e.g., information relating to the financing plan or the marketability of Alaskan gas) or that relates to matters which are the responsibility of the OFI (e.g., the project sponsors' management plan), they must rely

on methods of access available to them through means other than the technical conferences. The parties should deal directly with each other in obtaining access to documents and other information. The Delegate or the Division Director will rule on the production of documents directly relevant to this proceeding when the parties cannot reach agreement among themselves.

Williams Brothers, OFI's consultant assisting the Alaskan Delegate and the OFI Division Director in the preparation of their report, indicated a continuing need to obtain information informally from the project sponsors on their cost estimate. Similarly, the trial staff and their consultants indicated an occasional need to consult with Williams Brothers on questions of common interest. Both the project sponsors and the trial staff indicated that their respective rights would not be prejudiced by such private oral communications between conferences provided that the communications were fully disclosed at the next conference. No other party objected to this procedure, and all parties who expressed an opinion agreed that this procedure would expedite the conferences by enabling all participants (including Williams Brothers) to be better prepared for them.

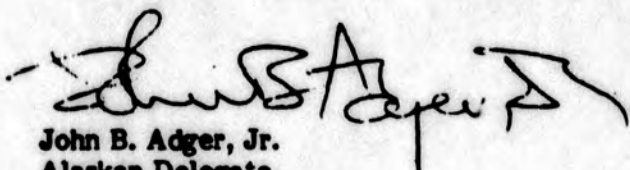
Accordingly, any party may communicate privately with Williams Brothers personnel between conferences (or prior to the first conference). At the next conference subsequent to such communication, the contents of the communication will be disclosed and will be recorded in the transcript. Williams Brothers will maintain a log of all such communications, which will be reproduced as part of the transcript (or, if it is voluminous, will be circulated separately by the Delegate to all parties on the restricted service list).

The trial staff also indicated a possible need to obtain oral information from OFI on occasion. In such event, the OFI Division Director will record and report on the communication. Similarly, in the event of a need for communication between any party and

James McCullough, the Alaskan Delegate's IROR consultant, Mr. McCullough will record the communication and disclose it at the next conference.

In the event that information is communicated in written form between a party and either the Delegate, OFI or Williams Brothers, the sender of the written communication will serve copies of it on all parties on the restricted service list. If the information is voluminous and appears to be of limited interest, the party communicating it may circulate instead a short description of the material and an offer to provide copies to any parties indicating a desire for such.

The Alaskan Delegate will establish a public file in his office containing all of the transcripts and other materials generated by the conferences. The trial staff will ensure that the Commission's central filing system contains the same material, under Docket No. CP80-435.



John B. Adger, Jr.
Alaskan Delegate



J. Richard Berman
Director, Audit and Cost
Analysis, Office of the
Federal Inspector

**UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION**

**Alaska Northwest Natural Gas
Transportation Company**

Docket No. CP80-435

Notice of Technical Conferences

(September 23, 1980)

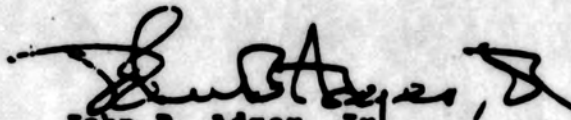
Notice is hereby given of the resumption of the series of technical conferences convened to consider for rate of return purposes the materials filed by the sponsors of the Alaska segment of the Alaska Natural Gas Transportation System in this docket on July 1, 1980. These conferences are being held pursuant to the Commission's order issued in this proceeding on August 1, 1980.

Two additional conferences are being scheduled at this time. The first will attempt an inventory of contested issues in all topic areas addressed by the July 1 filing, then focus on a discussion of any issues with regard to (1) the sponsors' cost estimate format, and (2) the pipeline construction component of the total cost estimate. The conference will also reconsider certain aspects of the conference schedule discussed previously. This conference will take place at the Fluor Corporation headquarters at 3333 Michaelson Drive, Irvine, California, and will begin at 1:00 p.m. on Tuesday, September 30, 1980, and continue until adjourned, in any event no later than Friday, October 3, 1980. The precise location of the conference will be posted at Fluor's headquarters on the day of the conference, and can be obtained in advance by calling Frieda Whiteside at (714) 975-6032.

The next succeeding conference will be held at the Commission's offices in Washington, D.C., beginning at 10:00 a.m. on Tuesday, October 7, 1980. This conference will consider a report from the Office of the Federal Inspector on major outstanding design issues, certain additional submissions regarding potential design changes from the project sponsors, and any further submissions from any other parties, in beginning to address the issue of the treatment of major design changes under the incentive rate of return (IROR) mechanism prescribed for the ANGTS by the Commission, and to address the development of guidelines to govern the design change process called for by that same IROR mechanism. That conference will also continue until adjourned, in any event no later than Friday, October 10. The precise location of this conference at the Commission's offices

will be posted on the day of the conference, on the second floor bulletin board at 825 North Capitol Street, Washington, D.C. Further information about this conference can be obtained from Miss Jeanne Barrie at (202) 357-8900.

In accordance with the agreement reached at the conference of September 3-4, 1980, summary transcripts will be prepared for both the Washington and Irvine conferences. Information about obtaining copies of those summary transcripts is available from Miss Jeanne Barrie at (202) 357-8900.


John B. Adger, Jr.
Alaskan Delegate

WORK PAPER WP-1
THE FERC REGULATORY FRAMEWORK OF THE CENTER POINT
OF THE IROR MECHANISM

James D. McCullough
September 22, 1980

Prepared for
"Comparative Cost Analysis for the Alaskan Segment, ANGTS Task"
Federal Energy Regulatory Commission
Contract DE-AC39-80RC-10477

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The FERC Regulatory Framework of the Center Point of the IROR Mechanism

I. Introduction

The purpose of this brief paper is to compile FERC's published regulatory comments on the Center Point established for the Incentive Rate of Return Mechanism (IROR) - its definition and scope. Of particular interest are the types of events contributing to cost uncertainty which are to be included in - and excluded from - the Center Point. A separate paper will explore the technical statistical aspects of the Center Point (CP).

II. Center Point Definitions

(a) "Center Point -- The value of the Cost Performance Ratio which would be achieved at the expected or most likely level of construction costs for the pipeline. The difference between the Center Point and 1.0 is a measure of the likely or expected level of cost overruns from the Projected Capital Costs of the project."¹

(b) "Cost Performance Ratio -- The ratio of deflated Actual Capital Costs to Projected Capital Costs. This ratio is used to measure the performance of the project sponsors in achieving the budgeted cost of construction and reducing cost overruns."¹

The ratio is adjusted for inflation and for design and other scope changes.

¹Federal Energy Regulatory Commission, Order No. 17, "Order Attaching Incentive Rate of Return Conditions to Certificates of Public Convenience and Necessity," Docket No. RM 78-12, December 1, 1978, pg. 20.

(c) "Deflated Actual Capital Costs ... the sum of direct construction costs actually incurred in the construction of the pipeline after conversion into base-year prices ... plus a Finance Charge calculated from the Real Rate of Return ..."¹ The Finance Charge is based on the Real Rate of Return (set at 5 percent).

(d) "Projected Capital Costs ... the sum of direct construction costs included in the Certification Cost and Schedule Estimate approved by the Commission pursuant to Condition 7, ... and after any adjustments for Changes in Scope ... or resulting from design changes prior to the Final Design ... plus a Finance Charge calculated from the Real Rate of Return."¹

Design Changes and Scope Changes will be discussed below.

III. Center Point Relationship by Formula to IROR Schedule

a. Definitions

1. "Incentive Rate of Return (IROR) -- The rate of return on equity that shall be decreased as the Cost Performance Ratio is increased in order to provide an incentive for project sponsors to keep construction costs as low as possible. This rate of return is referred to as a variable rate of return in the President's Decision."²
2. "Incentive Rate of Return Schedule -- A table or formula establishing a value of the Incentive Rate of Return for each value of the Cost Performance Ratio."²

b. Center Point Relationship to Center Point

"One of the Cost Performance Ratios must be chosen as the starting point for constructing the IROR schedule. Once that point has been assigned a rate of return, and the marginal rate has been chosen, the entire schedule can be determined.

¹FERC, Order No. 31, "Order Setting Values for Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisions," Docket No. RM 78-12, June 8, 1979, pages 241-242.

²Order 17, op. cit., pages 20-21.

The Center Point is that Cost Performance Ratio which is associated with the Center Rate of Return. Ratios above the Center Point will yield rates of return below the Center Rate. Ratios below the Center Point will be rewarded as underruns, with rates of return greater than the Center Rate.

In order for the Center Rate to be perceived by investors as adequate compensation for risk, it should be the rate of return that they can realistically expect their investment to yield. As a result, the Center Point should be set at the most likely Cost Performance Ratio. Then, if the final costs are at the expected levels, the Center Rate will be earned."^{1,2}

c. Formulas to Relate Center Point to IROR and to Determine Center Point

The IROR formulas established for Northern Border and Northwest Alaskan (NWA) are:

"The Incentive Rate of Return shall be set equal to $[(17.5)(CP) + 8(A - CP)]/A$ for the Alaska segment and $[(15)(CP) + 8(A - CP)]/A$ for the Northern Border segment, where A is the Cost Performance Ratio and CP is the Center Point."³

Formulas for the establishment of the Center Point were set forth in Order 31 as follows:

"Based upon the findings of the President's Decision, the Center Point (CP) for the Alaska segment shall be calculated from the following formula:

¹FERC, "Revised Notice of Proposed Rulemaking," Docket No. RM 78-12, September 15, 1978, page 14.

²The IROR will be earned on equity capital in accordance with Condition 16, "Cost of Service Calculations," of Order 31, page 250. A one-time adjustment to the rate base will be made, per Condition 17 (page 251) to permit an "Operation Phase Rate" of 14 percent to be earned on that adjusted amount, per Condition 13 (page 249). The rate base for debt capital funds will include the actual cost of borrowing funds used during construction (AFUDC). The Commission assumed a 25 percent equity capitalization and a 75 percent debt capitalization in determining the Real Rate of 5 percent (see Order 31, page 38).

³Order 31, op. cit., page 249.

Center Point = $[1.3 \times (\text{March 1977 Cost Estimate} + \text{Finance Charge})] / [\text{Certification Cost Estimate} + \text{Finance Charge}]$

where the March 1977 Cost Estimate is in base-year prices.

The Center Point for the Northern Border segment will be calculated from the following formula:

Center Point = $[1.1 \times \text{March 1977 Cost Estimate} + \text{Finance Charge}] / [\text{Certification Cost Estimate} + \text{Finance Charge}]$

where the March 1977 Cost Estimate is in base-year prices."¹

The Commission gave the sponsors the option to elect to not use the formula provided that:

"If the project sponsors believe that a major change in the basic nature of the project from that assumed in the Decision has occurred, and thus, the above procedure [the formula] for setting the Center Point is no longer applicable, then the sponsors, as part of their respective submissions of certification cost estimate, must at a minimum present evidence to the Commission on the following subjects:

- (1) The nature of the changes in the project from that assumed at the time of the Decision.....
- (2) The value or benefit to the Nation and gas consumers of construction of this project in light of the revised cost estimates.....
- (3) The cost increases or cost overruns above the Certification Estimates that may reasonably be expected to occur....."²

¹Ibid, page 247.

²Ibid, pages 52-53

Northern Border elected to follow the formula, and the Commission determined that their Center Point is 1.0758.¹ The Northern Border IROR schedule is shown on Figure 1.

"The Commission, in Order 31, gave the project sponsors two choices or options as to how the Center Point would be determined. The first option was to utilize a formula based upon a comparison of the Certification Cost and Schedule Estimate and the estimates in the President's Decision. In its Motion for Rehearing, Alaskan Northwest objects to this formula approach. Under the second option, the project sponsors could request a Center Point without reference to the formula as part of the Certification Cost and Schedule Estimate submission if a major change had occurred in the project, including likely overruns, that exceeded the estimates in the Decision.

Alaskan Northwest's motion states that '...it now appears very clear that a reasonable cost estimate for the Alaska Segment of the project will exceed the March 1977 cost estimate by more than 30 percent.' The Commission interprets this statement to mean that a major change in the Alaskan segment of the project has occurred since the President's Decision, and thus that Alaskan Northwest has rejected the option of setting the Center Point using a formula approach. Consequently, the Commission will not require that the formula approach be used for the Alaskan segment."²

IV. Minimum Value of Center Point

Upon petition by NWA, the Commission ruled that:

"...the Center Point will not be set at a value less than one. However, the Commission will carefully review the Certification Estimate to determine if it is based upon normal or probable conditions and assumptions, and is an otherwise reasonable estimate, and will adjust the estimate if necessary before approval is granted."³

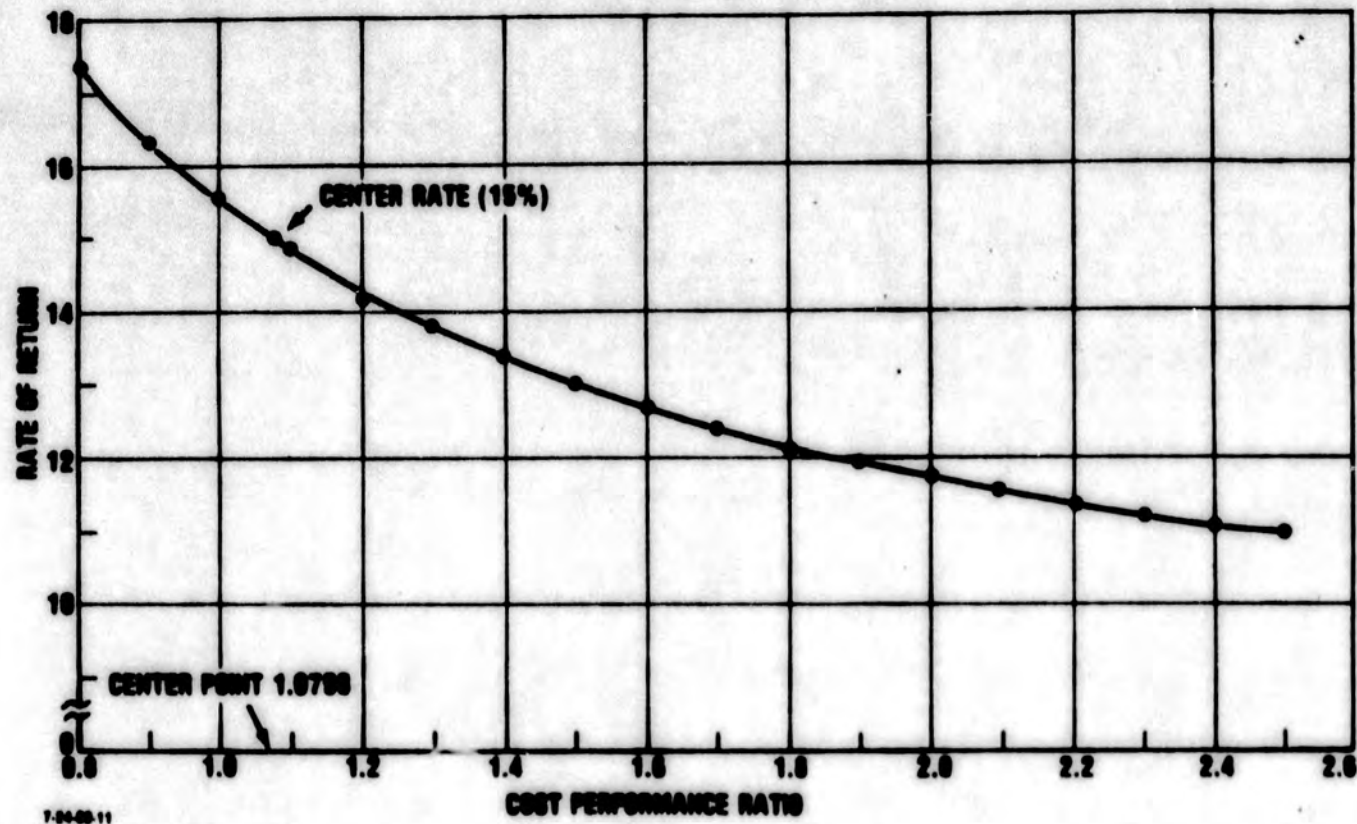
¹FERC - Findings and Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas, Docket Nos. CP78-123, et. al., April 28, 1980, page 103.

²FERC, Order No. 31-B On Rehearing - Docket No. RM 78-12, September 6, 1979, page 4.

³Ibid, page 5.

Figure 1

**NORTHERN BORDER IROR SCHEDULE AS
DETERMINED BY COMMISSION ORDER OF
APRIL 28, 1980**



V. Events to be Included in or Excluded From the Center Point

a. Abnormal Events to be Excluded from the CCE.

"The Commission expects that the Certification Estimates will only include costs resulting from normal conditions to be expected during construction. Abnormal or unlikely events that could increase costs will be analyzed as part of the sponsors' submission concerning potential cost overruns from the Certification Estimate."¹

b. Categories of Abnormal Events

The Commission further clarified the categories of abnormal events in its Order to Northern Border.²

"The Commission has previously dealt with the relationship between normal contingencies and the Center Point of the IROR schedule in its orders defining the IROR mechanism.¹¹⁹ In those orders, the Commission has distinguished among Change in Scope events, abnormal events and the conventional approach to estimation. These references may be categorized into three sets of "events" as concerns the Center Point:

- (1) Abnormal or unlikely events of such importance and consequence that the Commission has designated them as "Change in Scope" events.¹²⁰ The cost consequences of these events are to be excluded from the cost estimates submitted for use in determining the Center Point. The project sponsors will be permitted to increase the Projected Capital Costs, which serve as the target for assessing cost and schedule control performance, by the estimated costs of Change in Scope Events as approved by the Federal Inspector.

¹¹⁹ See, especially, Order No. 31-B at pages 6-7.

¹²⁰ See Condition 10, Order No. 31-B at page 73.

¹Order 31, op cit., page 54.

²NB Order of April 28, 1980 op. cit., pages 96-97.

- (2) Normal or likely events of a routine nature but of an unknown (but not significant) cost impact, such as are normally included in pipeline construction cost estimates as contingency or management reserve at rates, for example, of 5-7 percent. The cost consequences of these "anticipated unknown" events are to be included as contingencies in estimates submitted for use in determining the Center Point.
- (3) Abnormal or unexpected events that could substantially increase costs but which are not included in the list of Change In Scope events. Examples of such events are 100 year storms, major fires and floods. The cost consequences of these "un-anticipated unknown" events are to be excluded from the normal contingency allowance discussed above, but because these events are not Change In Scope events they are covered only by the Center Point mechanism itself."

VI. Change in Scope Events

The estimated costs of events qualifying as Change-In-Scope Events are to be excluded from the Center Point determination. Order 31-B defined these as:¹

"Such Change in Scope events shall be limited to:

- (1) declared or undeclared war, including civil war or a formally declared blockade,
- (2) any emergency or major disaster which either
(a) is determined, by the President of the United States, pursuant to the Disaster Relief Act of 1974, Pub. L. 93-288, 88 Stat. 143 (as it may be amended) to have occurred in the United States or its territories or possessions, or (b) is determined by the Federal Inspector (i) to have occurred outside the United States or its territories and possessions and (ii) to be of such consequence that, had it occurred in the United States, it is reasonably probable that it would be determined to constitute an emergency or major disaster pursuant to clause (a) above,

¹Order 31-B, op. cit., pages 74-75.

- (4) major changes in pipeline routing or capacity ordered by Federal or State Governments for the Alaska Natural Gas Transportation System from that approved by the Federal Inspector in the Final Design of the pipeline, and
- (5) delay in the issuance of a government permit or certificate necessary for completion of the pipeline system, when such delay (a) occurs subsequent to approval of the Final Design, (b) occurs through no fault of the project sponsors and (c) causes significant cost increases."

VII. Normal Contingencies

NWA expanded upon the Commission's definition of normal contingencies in its Certification Cost Estimate submission:¹

"In-scope estimating uncertainty was carefully defined to separate its impact on project costs from the impact of unexpected events, design changes, and changes in scope. In-scope estimating uncertainty was explicitly defined as the variation in project costs and schedules resulting from:

- Accuracy of material quantity estimates.
- Accuracy of material price estimates.
- Human productivity assumptions.
- Equipment reliability assumptions.
- Engineering/design development.
- Accuracy of scheduled durations.
- Accuracy of bid specifications based on current project definitions."

VIII. Design Changes Prior to Final Design Approval

It should be noted that neither the Certification Estimate nor the Center Point should include an allowance for design changes made prior to approval of the Final Design. Condition 9 of Order 31 permits the Projected Capital Cost baseline to be modified by the addition of the estimated costs of design

¹NWA submitted an estimate for normal contingencies of 12.0 percent of Direct Capital Costs exclusive of Finance Charges, Volume XXXIII, "Normal Contingency, Contingency Methodology and Breakdown, WP-14," July 1, 1980, page 7.

changes incorporated into the Final Design approved by the Federal Inspector.¹ Thus, there is no need to allow for this in the Certification Estimate or Center Point. However, minor Design Changes due to pipeline rerouting subsequent to the Final Design approval, but prior to actual construction, are to be included. See item IX(2) below.

Further, the Projected Capital Costs may not be reduced for design changes that reduce costs.² This is to provide sponsors an incentive to propose design changes that reduce the ultimate costs to consumers. The Commission ruled that changes in design which reduce capital costs at the expense of increased operating and maintenance costs will not be allowed.

The Commission further clarified this ruling in a lengthy footnote to the Northern Border Order:³

"The Commission takes this opportunity to clarify one aspect of Order No. 31-B, regarding revisions to the Projected Capital Costs target for the IROR mechanism. At pages 41 and 42 of Order No. 31-B, the Commission expressed a willingness to accept Northern Border's proposal that Projected Capital Costs should not be reduced for design changes that reduce costs. It has occurred to us that, in theory at least, abuses could arise in the following two types of situations:

- (1) Project sponsors were aware of cost-saving design changes at the time of consideration of the CCSE, but postponed them until after CCSE approval in order to retain a high CCSE and thus improve their expected cost performance ratio, and consequently their IROR; or
- (2) Certain optional assumptions (of which the project sponsors had knowledge at the time of preparation of the CCSE), such as alternate (cheaper) sources or (lesser) specifications for materials or equipment, were omitted in preparing the CCSE for the purpose of increasing its value, only to be changed once the CCSE had been approved.

¹Order 31, op. cit., pages 244-245.

²Order 31-B, op. cit., pages 41-42.

³Northern Border Order of April 28, 1980, op. cit., pages 100-101.

The Commission still believes that Northern Border's basic suggestion is valid. To eliminate any potential for abuse, the Commission states that neither of the two above described situations were intended to result in design changes without adjustment in Projected Capital Costs. Orders No. 31 and No. 31-B were premised on the following assumptions:

- (1) Project sponsors did not know about cost-saving design changes at the time of preparation of the CCSE if such design changes are to be approved without lowering Projected Capital Costs; and
- (2) If optional assumptions were made in preparation of the CCSE, cost-saving design changes will continue to utilize those same assumptions unless the assumption made was the correct one at the time of preparation of the CCSE but had since become inappropriate.

The Commission's intention in accepting Northern Border's suggestion was exactly the reason that led Northern Border to propose it, namely, to give the project sponsors an incentive to propose design changes that reduce costs. The Commission recognized that implementing such an intention will be difficult, and will inevitably depend on the exercise of administrative judgment. The Commission intends that the Federal Inspector will be the one to exercise such judgment as he sees fit, and the Commission believes that it has structured the IROR mechanism in a manner which fully authorizes him to do so."

IX. Commission Comments on Abnormal Events not Covered by Change in Scope Rules

The Commission, in Orders 31 and 31-B, commented upon various abnormal events which are not covered by Change In Scope rules and hence, are covered only by the Center Point.

(1) Exclusion From "Wars":

"As to 'wars,' 'we do not include riots, insurrections, actions of public enemy, and civil or military disturbances or other interferences' either because such events are clearly of lesser magnitude than 'war' or because they are inherently vague and ambiguous in meaning."¹

¹Order 31-B, op. cit., page 33.

(2) Design Changes:

"In this instance, the adjective 'major' is essential to the basic structure of the Change in Scope mechanism. Any change in the capacity of the pipeline would probably constitute, on its face, a 'major' change, but that is not true of changes in the route. It is likely that, subsequent to approval of the Final Design but prior to the actual laying of the pipe into the ground, there may well be numerous minor deviations in the precise routing of the pipe - deviations made to accommodate particular terrain conditions as they are encountered. That process is inherent in pipeline construction, and the project sponsors can and should plan for it in their cost estimates."¹

(3) Abnormal Weather, Fires, Floods, "Acts of God":

"The project sponsors should evaluate weather problems realistically (including a factor for delays caused by abnormal weather) when preparing their Certification Cost Estimate (including the Center Point). Then, when abnormal weather occurs, the efforts of all concerned can be focused exclusively on coping with it.

Similarly, fires, floods, landslides and other "acts of God," as well as "terrorism, sabotage, riots, and civil disturbances, and embargos, strikes, work stoppages and slowdowns" are all risks that the project sponsors can evaluate in advance, in the sense of considering a reasonable cost factor for some level of unanticipated and undesirable events that may occur during the course of the project."²

¹Ibid, page 39.

²Order 31, op. cit., page 128.

(4) Delays Due to Non-Completion of Other Segments:

"The IROR mechanism fully protects the project sponsors from one other form of delay that could otherwise have a potentially serious impact on the rate of return. The project sponsors or investors in any one segment, Alaskan or Northern Border, of the pipeline will not be responsible for cost increases resulting from construction delays in the other segments, or from a delay in the initiation of gas production at Prudhoe Bay. This is accomplished by defining the Actual Capital Cost for a segment as those costs incurred up to the point that that segment is capable of rendering service, even though other segments are not yet capable of delivery from Prudhoe Bay. In other words (for IROR purposes only), AFUDC will cease to be added to the Actual Capital Costs for a segment when that segment is complete and ready to begin transporting gas even if, for whatever reason, it is not actually transporting gas. (AFUDC will, of course, continue to accrue for rate base purposes.)"¹

(5) Field Conditions and Right-of-Way:

"With respect to field conditions there is an economic trade-off. Field conditions can be ascertained in advance through sampling and other scientific techniques. On the other hand, there comes a point at which the cost of elaborate advance ascertainment would exceed the cost of coping with whatever unexpected conditions may eventually be encountered. The project sponsors are in the best position to strike the proper balance between incurring the cost of totally comprehensive ascertainment in advance versus coping later with unanticipated conditions that had not been fully ascertained. The project sponsors should be the ones to make the judgement, to estimate their costs accordingly, and to bear the responsibility for whatever unanticipated conditions they eventually encounter. Similarly, right-of-way acquisition is a problem that the project sponsors can and should evaluate when preparing their Certification Cost Estimate (including the Center Point.)"²

¹Ibid, page 133.

²Ibid, pages 128-129.

X Recap of Key Points Related to the Alaska Segment

The Center Point is the Cost Performance Ratio which is associated with the Center Rate of Return. The value of the Center Point is the expected or most likely level of the actual construction costs of the pipeline. The difference between the Center Point and 1.0 is a measure of the expected level of cost overruns from the Projected Capital Costs (PCC) of the project. For the Alaska Segment, the Center Point will be established by review of NWA's Center Point justification paper and not by a formula.

The PCC's initial value is that of the approved Certification Cost Estimate. The PCC may be increased (but not decreased) by the cost of design changes approved by the Federal Inspector prior to the approval of the final design and construction go-ahead. Subsequently, the PCC may be increased by the cost of Change-In-Scope Events as approved by the Federal Inspector.

The abnormal events excluded from coverage by the Center Point are 1) design changes, 2) scope changes, 3) those events covered by the normal contingency allowance (in-scope estimating uncertainty). The abnormal events covered by the Center Point include weather (such as 100 year storms, landslides, major fires and floods), riots, insurrections, terrorism, sabotage, actions of a public enemy, civil disturbances, design changes made subsequent to the Federal Inspector's approval of the Final Design (but prior to the actual laying of the pipe), embargos, strikes, work stoppages and slowdowns.

The IROR will be earned on equity capital and AFUDC earned on borrowed capital. A 25 percent equity capitalization and a 75 percent debt capitalization is assumed.

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AS A UNIT IN THE ORIGINAL DOCUMENT.**

**PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT**

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Georgiana Sheldon, Acting Chairman;
Matthew Holden, Jr., George R. Hall
and J. David Hughes.

Northwest Alaskan Pipeline Company) Docket No. CP78-123, et al.
Northern Border Pipeline Company) Docket No. CP78-124
Pacific Gas Transmission Company) Docket No. CP79-60

ORDER PROPOSING CONDITIONS TO CERTIFICATES

(Issued December 19, 1980)

The Commission is proposing the adoption of a condition to be appended to the final certificates of public convenience and necessity (for construction and operation of the Alaska Natural Gas Transportation System) issued by the Commission to Pacific Gas Transmission Company (PGT) and Northern Border Pipeline Company (Northern Border) in its orders of January 11 and April 28, 1980 in Docket No. CP78-123, et al., 1/ as well as to the conditional certificates issued December 16, 1977 in the same docket.

In light of the limited number, nature and scope of the proposed conditions, as well as the statutory mandate of Section 9 of the Alaska Natural Gas Transportation Act (ANGTA), 15 U.S.C. §719g, that certification of the Alaska Natural Gas Transportation System (ANGTS) be expedited, the Commission has decided to use notice and comment procedures to consider the condition. In addition to other applicable law, this order is issued pursuant to Section 7(e) of the Natural Gas Act, 15 U.S.C. §717f(e), Section 9 of the ANGTA, the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System (Decision), 2/ Paragraph 7 of the Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline, and Section 402(a) of the Department of Energy Organization Act, 42 U.S.C. §7172(a).

A. Background

The ANGTS is designed to transport natural gas from the North Slope of Alaska to the lower 48 states. The pipeline will be

1/ 10 FERC ¶61,032 and 11 FERC ¶61,088.

2/ Executive Office of the President, Energy Policy and Planning, September 1977.

constructed through Canada, and will separate into two legs (Western and Eastern) just north of Calgary, Alberta. The Western Leg will enter the United States near Kingsgate, British Columbia and terminate at Antioch, California. The Eastern leg will enter the United States near Monchy, Saskatchewan and terminate at Dwight, Illinois.

The April 28, 1980 3/ order authorized Northern Border to "pre-build" a portion of the Eastern Leg of the ANGTS, consisting of 909 miles of 42-inch pipeline from Monchy to Ventura, Iowa. The January 11, 1980 order 4/ authorized, inter alia, the early construction of a portion of the ANGTS by PGT, consisting of 160.5 miles of the Western Leg from the point of importation near Kingsgate, British Columbia to Stanfield, Oregon.

The Commission has found that the ANGTS is not a purely domestic project, but is an international project undertaken jointly by the U.S. and Canada. 5/ The Agreement between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline (the Agreement on Principles) was signed by representatives of the two governments on September 20, 1977 (TIAS 9030). It was then incorporated into the Decision (at pages 47-83); inasmuch as the Decision was approved by a Joint Resolution of the Congress (on November 8, 1977), the Agreement on Principles, as a part of the Decision, has the legal force and effect of a federal statute.

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- 3/ 11 FERC ¶61,088. The April 28 order became effective June 20, 1980 when the Commission issued its Order Granting Applications for Rehearing in Part, in the above-referenced docket. 11 FERC ¶61,302.
- 4/ The January 11 order became effective June 13, 1980 when the Commission issued its "Supplemental Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas, and Order on Rehearing," in the above-referenced docket.
- 5/ "Supplemental Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas, and Order on Rehearing," Northwest Alaskan Pipeline Company, Docket No. CP78-123, et al., June 13, 1980, 11 FERC ¶61,279, mimeo at p. 45.

The Agreement on Principles states, in Paragraph 7(a), that "having regard to the objectives of this Agreement each Government will endeavor to ensure that the supply of goods and services to the Pipeline project will be on generally competitive terms." In weighing competitiveness, the elements to be considered include price, reliability, servicing capacity and delivery schedules. Paragraph 8 of the Agreement provides for consultation between senior officials of the two governments on the implementation of principles relating to the construction and operation of the pipeline.

The responsible U.S. ^{6/} and Canadian officials have been discussing methods of implementing Paragraph 7 of the Agreement on Principles. The result is a reciprocal arrangement between the United States and Canada on a procedure to govern the procurement of certain designated items by the pipeline companies before contracts are awarded. That agreement between the two governments is embodied in a formal exchange of diplomatic notes, signed June 10, 1980, and is effective subject only to the necessary regulatory action in each country.

By a letter dated August 4, 1980, the Federal Inspector has forwarded to the Chairman of the Commission an official copy of the diplomatic notes. A copy of the letter, including the diplomatic notes, is attached to this order for reference. In his letter, the Inspector requests the Commission to implement the notes by attaching appropriate conditions to the project sponsors' certificates.

In this regard, the exchange of notes provides that the agreed procurement procedures are subject to approval through regulatory processes of the two countries. Within the U.S., such approval is defined in terms of amending the project sponsors' certificates:

"In fulfillment of this agreement, the United States agrees to adopt the procurement procedures contained in the Annex to this note. It is understood that the procedures in the Annex are subject to regulatory approval in the United States, specifically the amendment of the conditional certificates of the Alaskan Northwest Natural Gas Transportation Company, of the Pacific Gas Transmission

^{6/} The responsible U.S. Official is the Office of the Federal Inspector (OFI). The OFI was created by Reorganization Plan No. 1 of 1979, which became effective July 1, 1979, pursuant to Executive Order 12142 of June 21, 1979, 44 F.R. 36927 (June 25, 1979).

Company, and of the Northern Border Pipeline Company by the Federal Energy Regulatory Commission of the United States. It is further understood that Canada will also adopt the procurement procedures contained in the Annex to this notice, and bring them into force with Canadian regulatory process."

Thus, attaching the proposed condition to the certificates would complete the process envisioned in the exchange of notes, thereby implementing the executive agreement set forth in the notes.

B. Proposed Condition

The text of the agreement set forth in the diplomatic notes is self-explanatory, and is the product of extensive deliberations and negotiations by the two governments. Accordingly, the Commission is reluctant to attempt to recast that language into detailed conditions of the style and form generally used in drafting certificate conditions. Instead, the Commission proposes to attach to the certificates a shorter and more generalized condition that simply requires the certificate holders to comply with all requirements in the agreement that are applicable to them, and to co-operate fully with the Federal Inspector in his interpretation and implementation of the agreement.

C. Comment Procedures

The Commission invites the parties of record in Docket Nos. CP78-123, et al., to submit written data, views, comments and other information concerning the matters set forth in this order. An original and 14 conformed copies should be filed by January 16, 1981, with service of copies on all parties. Parties of record may also file reply comments, pursuant to the same procedure, by February 6, 1981. Comments and reply comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D. C. 20426, and should reference Docket Nos. CP78-123, et al. All written submissions will be placed in the Commission's public files and will be available for public inspection in the Commission's Office of Public Information, 825 North Capitol Street, N.E., Washington, D. C., during regular business hours.

The Commission orders:

(A) Parties of record in Docket No. CP78-123, et al., may submit comments and reply comments on the condition that the Commission proposes to append to the certificates of public convenience and necessity issued (for construction and operation of the ANGTS) by the Commission to the ANGTS project sponsors in the Commission's orders of January 11 and April 28, 1980, as well as to the conditional certificates of public convenience and necessity issued December 16, 1977 in that docket, as described more fully above. The proposed condition is set forth in an attachment to this order. Comments may be filed on or before January 16, 1981, and reply comments may be filed on or before February 6, 1981. Copies of all comments and reply comments should be served on all parties of record in Docket Nos. CP78-123, et al.

(B) Copies of this order shall be served on all parties in Docket No. CP78-123, et al.

By the Commission.
(S E A L)

Kenneth F. Plumb
Kenneth F. Plumb,
Secretary.

Docket No. CP78-123, et al.

APPENDIX

PROPOSED CONDITION

The certificate holder shall comply with all of the requirements imposed on ANGTS project sponsors by the executive agreement set forth in the exchange of diplomatic notes between the United States and Canada, dated June 10, 1980, as those requirements are set forth in the "Procedures Governing the Procurement in Canada and the United States of America of Certain Designated Items for the Alaska Highway Gas Pipeline" adopted in said agreement. The certificate holder shall co-operate fully with the Federal Inspector in his interpretation and implementation of the agreement.