SCOMM

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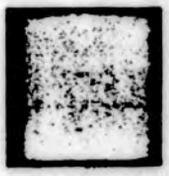
NORTHWEST ALASKAN PIPELINE COMPANY

1120 20th Street, N.W.
Suite S 700
Washington, D.C. 20036
(202) 872-0780

REA-80-1083

October 27, 1980



John B. Adger, Jr.
Alaskan Delegate to the Federal
Energy Regulatory Commission

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

Re: ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY,
DOCKET NO. CP80-435

Gentlemen:

On July 1, 1980, Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest") filed with the Federal Energy Regulatory Commission ("FERC") its application for a final certificate of public convenience and necessity authorizing construction and operation of the Alaskan segment of the ANGTS. On that same day, Alaskan Northwest filed its request with the Department of Interior for issuance of a right-of-way grant over Federal lands along the route proposed by Alaskan Northwest. Both applications assumed a minimum 80 foot spacing requirement between the Alaskan segment of ANGTS and the TAPS oil pipeline.

On August 20, 1980, the Department of Interior notified interested Congressional Committees of its intent to issue a Right-of-Way to Alaskan Northwest. The proposed grant would impose a condition that, with certain exceptions, there would be a 200 foot minimum spacing between the Alaskan segment of ANGTS and TAPS. Alaskan Northwest concluded that it would accept this condition, provided that its Certification Cost Estimate and Center Point request be appropriately modified to reflect increased costs and the variation in risk resulting from this change in spacing. At the technical conferences of September 3 and 4, 1980, Alaskan Northwest stated it would file the necessary cost revisions to its July 1, 1980 Certification Cost Estimate on or before October 27, 1980.

In order to comply with this increased spacing, Alaskan Northwest was required to select a new route along the total affected distance of about 300 miles. This revised route is essentially adjacent to the existing Haul Road, except for certain areas where virgin routing is merited. A completely new cost estimate of the revised route was then made in the same detail, using the same design criteria and following the same methodology as was utilized in the original estimate. The original estimate was then compared with the new estimate for the purpose of identifying variations in cost. The new estimate results in a total cost increase of $252 million, excluding contingency and finance charges. Preliminary estimates of normal contingency and finance charges are $30 million and $32 million, respectively. The increase in the contingency is due solely to applying the contingency factors established in the original filing, to the increased Certification Cost Estimate before contingency. The increase in finance charges is due to applying the original filing finance factors to the increased Certification Cost Estimate. If these estimates of normal contingency and finance charges prove to be correct, the total increased cost will be $314 million.

Shown below are the major elements of the filing and the cost effect of the route change on each of them:

COMPARISON OF FERC CERTIFICATION COST ESTIMATE
AS FILED JULY 1, 1980 WITH FERC CERTIFICATION COST ESTIMATE
AS REVISED FOR REROUTING OCTOBER 27, 1980
(1980 Dollars in Millions)

WBS Level 3 Element	FERC CCE as filed 7/1/80	FERC CCE as Revised 10/27/80	Differential
Compressor & Metering Stations	$ 693	$ 693	$ ------
Operation & Maintenance Facilities	53	53	------
Temporary Facilities and Services	887	927	40
Communications and Supervisory Systems	97	97	------
Pipeline	4,086	4,285	199
Project Directorate	1,234	1,247	13
Subtotal	7,050	7,302	252
Normal Contingency	846	876	30
Subtotal	7,896	8,178	282
Finance Charge	894	926	32
TOTAL	$8,790	$9,014	$ 314

The major increase in the pipeline and civil work estimate occurs as a result of: an increase in pipe hauling costs; an increase in the mineral material quantity by 8 million cubic yards; additional field programs (primarily borehole drilling); additional drilling and shooting; increased workpad embankment; a decrease in productivity due to both a narrower workpad necessitating shorter turns and lower travel speeds because of the proximity of the haul road; an increase in workpad culverts both in number and length; an increase in workpad crossings; an increase in restoration costs; an increase in pipe length and additional low water crossings. The increase in temporary facility costs is due primarily to an increase in the man-hours spent in the work camps which results from the need to deliver more materials for the increase in the workpad embankment. The increase in project directorate is due to an increase in taxes, insurance, permits and fees which are directly correlated to the increase in facility costs utilizing the same factors employed in the original filing.

Enclosed herewith are supplements to Exhibits K, Z-9.0 and Z-9.1 of the July 1, 1980 filing, and the work papers, which set forth the required revisions to the July 1, 1980 Certification Cost Estimate.

Alaskan Northwest is reviewing the preliminary estimates which have been made for the normal contingency and finance charge and is also determining what effect the pipeline rerouting will have upon the Center Point request. Alaskan Northwest will provide the results of this final review and determination to the parties on the restricted service list on or before November 7, 1980.

If you have any questions with respect to these revisions, please do not hesistate to contact us immediately.

Sincerely yours,

Cuba Wadlington, Jr.
Director, Regulatory Affairs
Northwest Alaskan Pipeline Company

CW/paw

cc: Restricted Service List, Docket No. CP80-435

NORTHWEST ALASKAN PIPELINE COMPANY

1120 20th Street, N.W.
Suite S-700
Washington, D.C. 20036
(202) 872-0280

REA-80-1091

December 15, 1980

Mr. John B. Adger, Jr.
Alaskan Delegate to the
Federal Energy Regulatory Commission

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

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

Gentlemen:

On October 7, 1980, at Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest") technical conference, the Office of the Federal Inspector ("OFI") presented two documents addressed to John Adger, Alaskan Delegate, wherein the subject matter was the Outstanding Design Issues Related to Alaskan Leg. The two documents reflected a total of twenty-five (25) issues.

The OFI stated in the documents as well as orally that the design issues were the type of issues which Alaskan Northwest should consider during the detailed final design process.

Enclosed, pursuant to your request, is a copy of the Alaskan Northwest response to the detailed final design issues raised for consideration by the OFI.

If you have any questions regarding the enclosed material, please contact me.

Very truly yours,

NORTHWEST ALASKAN PIPELINE COMPANY

Cuba Wadlington, Jr.

Cuba Wadlington, Jr.
Director, Regulatory Affairs

Enclosure
cc: Restricted Service List Docket No. CP80-435
RDM Index

RESPONSES TO OFI SUMMARY REPORT ON MAJOR OUTSTANDING DESIGN ISSUES OCTOBER 1980

1. Design Criteria

We agree that definitive criteria for design of the gas pipeline are required wherever the alignment is adjacent to existing facilities. Criteria for the preliminary design are contained in the FERC filing and have been used as the starting point for the development of definitive criteria, which is now underway. These definitive criteria are required for all portions of the route.

2. 1980 Field Program

Field Programs, detailed procedures and concepts are developed primarily to support the design effort. They are important to the resolution of technical issues, particularly the frost heave testing, and the results will be applied to final design. The 1980 programs are almost completed as of this writing and the results are being utilized in design. The 1981 Field Programs are in the planning stage and the schedule for output from these tasks are being blended with the design schedule to make certain that the data acquisition is timely for final design.

3. Frost Heave Design

The criteria used to classify the existence and degree of frost heave potential and reported in the FERC filing documents, were on a preliminary basis. Work is continuing in this area - in the lab, in the field and in the office. The criteria are being confirmed so that a high degree of confidence can be placed in the definition of the extent of frost heave potential.

4. Steady-state Thermohydraulic Simulation

The steady-state thermohydraulic simulation program has been upgraded by coupling it with a geothermal program so that heat transfer in the soil can be calculated on a broader base. Also the input is improved as new data is received. As changes are made, the cost implications are evaluated and will be incorporated into the final design estimate.

5. Ditch Design and Stability

We agree that the number of miles of each ditch design type may conceivably change. Detail design is underway at the

present time. One purpose of this detail design effort is to "fine tune" the location of the different ditch types and assess the impacts on materials quantities and costs. Both plus and minus differences are anticipated with minimal net effect on the final cost.

6. Pipe Selection Criteria

The mainline pipe materials were discussed in the FERC Conferences and are recorded in Transcript Volume from October 23, 1980 pages 18 to 26.

7. Workpad Design

The separation distance of 200 feet between the gas pipeline and TAPS has been incorporated into the Reroute Filing submitted to the Alaskan Delegate in October 1980. The impact on the design of the pad and the changes in the quantities of materials are in this same filing. A thermal workpad is more costly than a structural workpad ($437,000 per mile vs. $150,000 per mile) and therefore the structural pad was selected for design. The criteria for the workpad, both north and south of the Brooks Range will be reviewed during the detail design phase.

8. Major River Crossings

We agree that major rivers require special designs. The field programs to collect data on these streams is 90 percent completed, and data is already being used by the design engineers. The design of the crossings and the protective structures is underway and will be completed during final design.

9. Minor Stream Crossings

Minor stream crossings are being analyzed in the detail design phase to assess the probabilities for the formation of frost bulbs around the pipe. If a set of conditions is found that would result in the blockage of a stream, design alternatives will be utilized to avoid this situation. These alternatives include deeper burial and overhead structures

10. Thaw Settlement

Criteria for limiting thaw settlement during the dormant period have been developed and ditch configurations have been designed to control the thaw during this period. Type II A ditch will utilize a layer of insulation 1-1/2 to 3-1/2 inches thick in the ditch to control thaw. It also is a

shallow ditch with a berm over the top of the pipe. It will be used on the North Slope to minimize disturbance of permafrost. Type II B ditch will utilize a 5-inch layer of insulation in the ditch in permafrost areas south of the Brooks Range where the active layer is deeper than on the North Slope.

11. Special Construction Sites

Designs for special sites are being developed in the detail design phase. The Atigun Tunnel is under study. Two boreholes have been completed along the trace of the primary site for this tunnel and several additional boreholes are scheduled to be drilled in 1981. The present design contemplates installing the pipeline over Atigun Pass. The estimated cost of a section of the system is $43.7 million dollars in 1980 dollars. It is considered feasible to continue with this plan and meet necessary safety requirements. However, the tunnel will be thoroughly studied as a possible alternative to provide additional reliability at an acceptable cost.

The Yukon River Bridge is designed to accommodate at least one more pipeline. Negotiations are currently in progress with Aleyska and the State to utilize this bridge for the natural gas pipeline. Considerations which will be balanced are design, security, cost, and any potential delay arising from possible litigation. The alternative is a separate bridge.

12. Temporary Facilities

The renovation or replacement of the existing sewage treatment plants at the TAPS camps is under study in detail.

13. Winter Construction

The utilization of snow and ice materials for workpads and access roads has been analyzed and was discussed at the FERC Conferences (Transcript Volume from November 18, 1980.)

14. Compressor Stations

All aspects of the compressor station design are being given further considerations in the detail design phase including pressure relief, emergency blow downs, foundations, and valving. The cost effectiveness of the design will be analyzed during this phase also.

15. Communication System

The possible utilization of portions of existing communications systems is being considered in the detail design phase.

16. Proximity to the TAPS

The filing of a reroute with the Alaskan Delegate in October, 1980 implemented the 200-foot separation from TAPS. There are about 5 miles (in total) of the route that require a variance from this 200-foot requirement because the gas pipeline crosses TAPS or the terrain restricts the space available for the gas pipeline. These areas do require special attention and they have been discussed with TAPS. The detail design will reflect design to resolve any concerns.

17. Proximity to the Fuel Gas Line

The workpad has been designed to protect the fuel gas line from damage during construction. Blasting criteria have been discussed with TAPS and that issue has been resolved.

18. Location of Metering/Compressor Station

Combining the metering station at the Yukon border with the compressor station in that area raises the following problems:

a. This is the custody transfer meter from NWA to Foothills and should take place as near the border as possible in order to properly establish responsibility for any lost or unaccounted for gas volumes. While it may not be possible to locate it exactly on the border because of soils conditions and access problems, the further west this station is moved, the more difficult it is to establish proper volumeter control and responsibility.

b. Seven compressor stations are scheduled to be constructed initially. Compressor Station No. 15 (MP 685) will be the closest to the Yukon border initially. When Compressor Station No. 16 is constructed at MP 731 in the future, the meter station must be moved if it is initially located at No. 15.

Costs will not necessarily be reduced by locating the meter station at a compressor station. Site work must be studied in detail before the cost impact can be determined and the cost of one set of pig traps would be more than offset by the moving of the station from No. 15 to No. 16 in the future.

19. Cross Flow of Groundwater

The pipeline is designed to accommodate the passage of water across it. Surface water will be controlled by drainage structures. The passage of sub-surface water is being analyzed on a site specific basis to assess the probabilities for the formation of aufeis or ice dams. Where the indications are that the consequences will adversely impact adjacent structures or the environment, mitigative designs will be utilized such as deeper burial, sub-surface drainage structures or overhead structures for pipeline crossings of smaller streams.

20. Impact of Conditioning Plant Design on the Entire System

The processing and conditioning plant design is being coordinated with the pipeline system design. The most critical variables are pressure, temperature, gas quality and equipment reliability. The pressure and temperature are defined. Studies are in progress to assure that the plant and compression equipment on the pipeline are properly matched to provide appropriate reliability to meet service contractual requirements.

The gas quality is resolved with the exception of the permissible carbon dioxide content. The highest acceptable limit is approximately 3 percent without incurring undue corrosion risks and economic penalties. The lowest reasonable design level is about 1 percent. Therefore, studies are evaluating the optimum level between 1 and 3 percent.

21. Valve Spacing

Valve spacing cannot be increased because of the requirements of the Federal Code (49 CFR 182).

22. Additional Compressor Station Design Issues

The utilization of exhaust heat has been studied and maximized. In order to utilize the energy in the exhaust heat, an intermediate process would be necessary to convert it to a driving force for the refrigeration system. This would not be cost effective.

The use of the larger, more fuel efficient turbines create problems such as foundation requirements that make it more cost effective to use the lighter aircraft derivative drivers.

ORGANIZATIONAL AND SCHEDULE RELATED ISSUES

1. Construction Management

During construction, multiple levels of the PMC organization with NWA oversight at these levels are necessary in order to have timely response to construction problems. Decision making about problems will be placed as close to the actual work as possible. This involves both PMC and NWA personnel. If a certain problem cannot be solved at a given level because of its size or complexity, and requires action at the next higher level, both PMC and NWA need representation there also so that time is not lost passing the problem through the entire organization.

2. Construction Schedules

The schedule for construction in ice rich soils has been planned for shoulder months and is shown on the March Charts along with the scheduling for the other construction. The limited time window for this activity has been taken into account. The construction across fish streams has also been scheduled in similar detail.

3. QA/QC Authorities

The QA/QC organization does not establish or modify specifications. They review specifications prepared by technical experts in each discipline, assess the quality requirements and recommend changes to the originator to clarify or simplify inspection requirements.

ARCO Oil and Gas Company
Legal Division
Post Office Box 2819
Dallas, Texas 75221
Telephone 214 651 4868

Edward J. Kremer
Counsel - Natural Gas

December 29, 1980

Mr. John P. Roddy
Commission Staff Counsel
Federal Energy Regulatory Commission
825 North Capitol St., N.E.
Washington, D.C. 20426

In Re: Alaskan Northwest Natural Gas
Transportation Company
Docket No. CP80-435

Dear Sir:

Written Interrogatories propounded by the Commission Staff were received by ARCO Oil and Gas Company, a Division of Atlantic Richfield Company, on December 9, 1980. Although not so specified, it is assumed that these Interrogatories relate to the informal off-the-record remarks of Mr. Charles Rogers, ARCO's Director of Operations Research, made on November 18, 1980 at the Technical Conference being held in the above captioned matter. Mr. Rogers, in response to a request of the Alaskan Delegate and not in support of or on behalf of the applicant, Alaska Northwest, gave an explanation of the general methodology followed by ARCO in developing project cost estimates. Following Mr. Rogers remarks, he responded freely to questions by the Alaskan Delegate and representatives of the Office of Federal Inspector, the Commission Staff and other parties. Mr. Rogers' remarks, together with his responses to questions, were summarized by the Alaskan Delegate for the record.

Under these circumstances, the issuance of written Interrogatories by the Staff as a vehicle for asking additional questions is deemed inappropriate by ARCO. However, in order to assist the Staff's understanding of ARCO's procedures in estimating project costs, the Interrogatories were discussed with Mr. Rogers and his responses are as follows:

1. The estimated contingency utilized by ARCO in determining expected value of major projects applies to the total project and is not broken down by categories such as normal contingency, abnormal events, central bias adjustment or possible design and scope changes.

2. Contingencies are developed at various stages from early concept through final design.

3. ARCO does not calibrate. Overall revisions of expected values are made when deemed appropriate as a matter of judgment and often have the effect of increasing the contingency.

4. ARCO does not have a special analysis for unknown-unknowns. The risk of such events is deemed to be covered, where applicable, by the overall estimate of contingency.

Edward J. Kremer

Edward J. Kremer
Attorney for
ARCO Oil and Gas Company,
Division of Atlantic
Richfield Company

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official restricted service list compiled by the Secretary in Docket No. CP80-435, in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated at Dallas, Texas this 29th day of December, 1980.

Edward J. Kremer

Edward J. Kremer
Attorney for
ARCO Oil and Gas Company,
Division of Atlantic
Richfield Company

FEDERAL ENERGY REGULATORY COMMISSION

Delegation of Authority by the Federal Energy Regulatory Commission to the Office of the Federal Inspector

AGENCY : Federal Energy Regulatory Commission

ACTION : Delegation

SUMMARY: Notice is hereby given of a delegation, by the Federal Energy Regulatory Commission to the Office of the Federal Inspector (OFI), of the Commission's authority under Sections 4, 5, 7, and 8 of the Natural Gas Act (15 U.S.C. Sections 717c, d, f, and g) and related regulations to review and approve costs and related accounts of the Alaska Natural Gas Transportation System (the ANGTS) for inclusion in the ANGTS sponsors' rate base.

DATE : The Delegation Order is effective upon publication in the Federal Register.

FOR FURTHER INFORMATION CONTACT:

Barry Smoler
Office of the General Counsel
Room 8600B
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D. C. 20426
(202) 357-8433

or

Ned Hengerer
General Counsel
Office of the Federal Inspector
Room 2413, Post Office Building
1200 Pennsylvania Avenue, N. W.
Washington, D. C. 20044
(202) 275-1144

SUPPLEMENTARY INFORMATION:

I. Background

Control of capital costs during construction is perhaps the most complex regulatory issue facing the ANGTS. Two Federal agencies, the Commission and the Office of the Federal Inspector (OFI), have cost control authority, sometimes mutual and sometimes discrete. Cost control has two primary purposes: protection of the U.S. gas consumer from excessive transportation rates; and assistance to private financing of the ANGTS.

The Commission's cost control responsibilities come from two sources. First, under Section 7 of the Natural Gas Act (15 U.S.C. Section 717f), the Commission must, pursuant to certification, assure that credible capital cost estimates (and a financing plan) for a proposed pipeline project are "in the public convenience and necessity." Once the pipeline is in operation, the Commission must act pursuant to Sections 4 and/or 5 of the Natural Gas Act (15 U.S.C. Sections 717c and 717d) to assure that rates to be charged are "just and reasonable", which indirectly entails approval of capital costs for rate base. Second, the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System (Decision) imposes similar requirements, which are specifically tailored to the ANGTS. The Commission must develop the Incentive Rate of Return (IROR); it must approve rate base inclusions on a timely basis; and it must assure that the certification cost estimate does not "materially and unreasonably exceed" the March 1977 cost estimate, upon which the Decision was based.

The OFI's cost control responsibilities come from three sources. (1) Under Section 7(a)(5)(C) of the Alaska Natural Gas Transportation Act (ANGTA), 15 U.S.C. Section 719e, the OFI must monitor, among other things, actions taken to assure cost control. (2) Under Section 5 of the President's Decision the OFI must enforce a number of construction cost and schedule conditions, as well as, under

Section 7 of the Decision, review procurement for general competitiveness. (3) Reorganization Plan No. 1 of 1979 transferred to the OFI responsibility to enforce the requirements imposed on the ANGTS by the Commission pursuant to the Natural Gas Act.

The cost control responsibilities of the Commission and the OFI are more or less split between the certification and construction phases, respectively. This is in keeping with the Reorganization Plan. The only aspect of cost control oversight which requires further delineation concerns rate base audit and approval. Both agencies agree that, due to the OFI's ongoing cost control responsibilities, the continued process of project rate base audit and approval during pre-construction and construction should rest there. In this manner, once the ANGTS has been completed and commences operations, the Commission will include the initial, OFI-approved project rate base in the project cost-of-service tariff for each ANGTS leg, and then commence its ongoing rate regulation of ANGTS, in accordance with Sections 4 and 5 of the Natural Gas Act. Whether or not an explicit delegation is now required to achieve this result, caution dictates such an interagency action at this time.

The OFI finds adequate authority for its rate base audit and approval actions in the Reorganization Plan. While subsection 102(d) of the Reorganization Plan explicitly transferred enforcement of the ANGTS certificates of public convenience and necessity (issued under Section 7 of the Natural Gas Act), Section 102 begins by expanding the transfer of the specifically cited statutory authority, as "including but not limited to the specific sections of the statute cited." Moreover, Section 102(h)(3) transfers enforcement of the terms and conditions established in Section 5 of the President's Decision (at page 37); the second finance term and condition found therein mandates that the "applicant shall, however, submit to the FPC for approval on a timely basis all components of construction work in

progress." In light of the expansive scope of the Reorganization Plan -- transferring to the OFI "exclusive responsibility for enforcement of all Federal statutes relevant in any manner to pre-construction, construction, and initial operation" of ANGTS -- the OFI regards such a transfer as encompassing the rate base process.

The Commission believes that this particular function is extremely important, that it should be performed by a single agency, and that all uncertainty as to responsibility for its performance should be eliminated. Because Section 202(b) affords both agencies the ability to assure that this function will be centralized in the OFI until construction is completed, it will be utilized to authorize the present delegation. Section 202(b) specifically provides that:

> Upon agreement between the Federal Inspector and the head of any agency, that agency may delegate to the Federal Inspector any statutory function vested in such agency related to the functions of the Federal Inspector.

This delegation provision has already been employed by the Commission to delegate to the OFI certain certificate conditioning authority. 45 Fed. Reg. 24224 (April 9, 1980).

II. Delegation Order

Paragraph (a) of the attached Delegation Order delegates to the Federal Inspector the Commission's authority to review and approve ANGTS construction work in progress (for inclusion in rate base) pursuant to Sections 4, 5, and 7 of the Natural Gas Act.

Paragraph (b) of the Delegation Order delegates to the Federal Inspector the Commission's authority to review and approve the ANGTS sponsors' accounts, records, and other papers, pursuant to Section 8 of the Natural Gas Act and to the Commission's Uniform System of Accounts, 18 CFR Part 201, and to monitor compliance with procurement policy and practices, 18 CFR Part 160.

The determinations of the Federal Inspector with respect to the prudence of costs incurred, and approval of their inclusion in rate base, shall be final and shall not be subject to review or revision by the Commission.

III. Effective Date

Pursuant to Paragraph (e) of the Delegation Order, the delegation becomes effective upon publication in the Federal Register, and shall include all project costs incurred on or after January 1, 1980.

Department of Energy Organization Act, 42 U.S.C. Section 7101, et seq.; Natural Gas Act, 15 U.S.C. Section 717, et seq.; Alaska Natural Gas Transportation Act, 15 U.S.C. Section 719, et. seq.; Reorganization Plan No. 1 of 1979, 44 Fed. Reg. 33663.

By the Commission.

(S E A L)

/Kenneth F. Plumb

Kenneth F. Plumb,
Secretary.

FEDERAL ENERGY REGULATORY COMMISSION

DELEGATION ORDER NO. ANGTS-2 TO THE

OFFICE OF THE FEDERAL INSPECTOR

Pursuant to the authority vested in the Federal Energy Regulatory Commission ("the Commission") and in the Office of the Federal Inspector ("the Federal Inspector") by Section 202(b) of Reorganization Plan No. 1 of 1979 --

(a) The Commission hereby delegates to the Federal Inspector the Commission's authority under Sections 4, 5 and 7 of the Natural Gas Act (15 U.S.C. Section 717 et. seq.) to the extent necessary to enable the Federal Inspector to review and approve the construction costs for the Alaskan Natural Gas Transportation System ("the ANGTS"), for inclusion in the respective rate bases of Alaska Northwest Natural Gas Transportation Company, Northern Border Pipeline Company, and Pacific Gas Transmission Company. The Federal Inspector shall perform this function consistent with the Commission's Uniform System of Accounts, 18 C.F.R. Part 201, and Order Nos. 31 and 31-B issued in Docket No. RM78-12 on June 8 and September 6, 1979, including any amendments adopted by the Commission subsequent to the date of issuance of this order.

(b) The Commission hereby delegates to the Federal Inspector the Commission's authority under Section 8 of the Natural Gas Act and the Commission's Uniform System of Accounts, 18 C.F.R. Part 201, to the extent necessary to enable the Federal Inspector to review and approve the ANGTS project sponsors' accounts, records and other papers pertinent to the construction of the ANGTS, including the monitoring of compliance with procurement policy and practices pursuant to 18 CFR Part 160.

(c) The Federal Inspector shall perform the above delegated functions pursuant to whatever procedures he shall determine to be consistent with applicable provisions of law, including, but not limited to, the U.S. Constitution, the U.S. Code, and the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System (September 1977)("the President's Decision").

(d) Nothing in this order shall be construed to delegate any of the Commission's authority to issue or condition certificates of public convenience and necessity pursuant to Section 7 of the Natural Gas Act, to determine the respective certification cost estimates for the Alaska and Northern Border segments of the ANGTS, to approve or modify any tariffs, or to perform any functions allocated to the Commission by the President's Decision (except for the functions allocated in the last sentence in Finance Condition No. 2 on page 37 of the Decision).

(e) The Federal Inspector hereby accepts the authority delegated by this order, and agrees to perform all of the functions delegated herein.

(f) This order shall become effective upon publication in the Federal Register, and shall include all project costs (as defined above) incurred on or after January 1, 1980.

Issued in Washington, D. C. on December 19, 1980.

Georgiana Sheldon
Acting Chairman
Federal Energy Regulatory Commission
(By agreement of the Commission)

John T. Rhett
Federal Inspector

UNITED STATES OF AMERICA
Before The
FEDERAL ENERGY REGULATORY COMMISSION

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY	)	DOCKET NO. CP80-435

REPORT OF ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY ON ITS UNDERSTANDING OF AGREEMENTS REACHED WITH THE COMMISSION STAFF REGARDING THE CERTIFICATION COST AND SCHEDULE ESTIMATE

To: John B. Adger, Jr.
Alaskan Delegate to the Commission

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

Pursuant to the request of the Alaskan Delegate and the Division Director in the above-referenced docket, the Commission Staff filed comments on November 7, 1980 setting forth its tentative position on various matters addressed in the technical conferences held pursuant to the Commission's August 1, 1980 order. On December 8, 1980, the Commission Staff and representatives of Alaskan Northwest met to determine whether agreements could be reached on any of the tentative Staff positions. 1/ The following reflects Alaskan Northwest's understanding of the discussions at this conference with respect to each of the 22 tentative Staff positions set forth in Staff's November 7, 1980 comments:

1. Project Directorate Estimate Issues

The Commission Staff and Alaskan Northwest agree that $75.2 million of the $278.6 million estimated for third party monitoring costs, which represents that amount required by Federal and Alaska

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1/ Also in attendance at this conference were representatives from the State of Alaska and Foothills Pipe Lines (Yukon) Ltd.

statutes, should remain in the base CCE for approval by the Commission. However, in accordance with Alaskan Northwest's request in its July 1, 1980 filing the CCE will be adjusted to reflect actual third party monitoring costs be for purposes of establishing the cost performance ratio, provided that any such costs directly caused by Alaskan Northwest would have to be reviewed and approved by the OFI.

Alaskan Northwest proposes that the remaining $203.4 million in socio-economic costs estimated to be reimburseable to the State of Alaska, and currently included in the CCE, remain in the CCE until the Commission decides on their allowability. Again, the cost performance ratio will be adjusted to reflect actual State of Alaska costs incurred. The Commission Staff does not agree with this position and will request that these amounts be removed from the CCE until the Commission rules that such costs are allowable.

Finally, the Commission Staff and Alaskan Northwest disagree on the proper treatment for costs yet to be determined for required minority training programs and an EEO compliance program. Alaskan Northwest's position is that since the OFI has not yet approved Alaskan Northwest's EEO program and Alaskan Northwest has not yet established the training programs required by the December 1, 1980 ROW grant such costs cannot be realistically ascertained at this point in time. Alaskan Northwest submits that the proper approach is for the submission of the costs of such programs to the Office of the Federal Inspector for approval as a design change in accordance with the procedures of Condition 9 of Orders Nos. 31 and 31-B.

2. DOI Reroute

The Commission Staff does not now question the reroute itself or the costs associated therewith. 2/

3. Embankment Construction Mode

The Commission Staff does not now question the cost estimate for the embankment mode set forth in Alaskan Northwest's November 11, 1980 Embankment and Snow Road/Pad Report.

2/ Staff's environmental questions concerning the reroute are dealt with in Item No. 22.

4. Snowpad - Snow Route Construction

The Commission Staff agrees with Alaskan Northwest's position in its November 11, 1980 Embankment and Snow Road/Pad Report that snowpad and snowroad construction should not be utilized. The Commission Staff further agrees with Alaskan Northwest's cost assessment for this construction mode.

5. Atigun Pass Tunnel

The Commission Staff and Alaskan Northwest agree that in the event Alaskan Northwest is required to utilize a tunnel alternative the costs currently in the CCE for traversing Atigun Pass will be replaced by those costs approved by the OFI for tunneling Atigun Pass.

6. Thermal Workpad

Alaskan Northwest recognizes that some use of thermal workpads may be required by the State and the owners of Alyeska and that any such use will increase costs above those in the current filing. The amount of thermal workpad required will depend upon negotiations with the State and the owners of Alyeska. Alaskan Northwest is currently analyzing Staff's estimated cost increase of $73 million for the use of thermal workpads for Sections 1 through 4. Any costs associated with the required use of thermal workpads are costs appropriately included in the CCE.

7. Aerial Crossing of Yukon River

Both the Commission Staff and Alaskan Northwest consider the costs associated with an aerial crossing to be de minimus. Therefore this matter is now moot with respect to the establishment of a CCE for Commission approval.

8. Reduction or Elimination of Workpad in Spreads 5 and 6

Both the Commission Staff and Alaskan Northwest disagree on this issue and will set forth their respective positions in comments to be filed with the Delegate and Division Director on December 15 and 22, 1980.

9. Ambient Temperature Pipeline in Spreads 5 and 6

See response to Item 8.

10. Less Conservative Frost Heave Mitigation

See response to Item 8.

11. An Increase Of One Year In Construction Schedule

The Commission Staff and Alaskan Northwest agree this is no longer an issue.

12. Communications System Design

The Commission Staff and Alaskan Northwest agree that those costs currently in the CCE for the communications design should be replaced with the costs required by the final design to be approved by the OFI.

13. New Construction Camps

See response to Item 8.

14. Pipeline Lay Rate

See response to Item 8.

15. Pipeline Construction and Contingency for Weather and Delay

See response to Item 8.

16. Ditch Gravel Quantity Error

Staff will file comments on December 15, 1980 modifying its position with respect to this issue.

17. Line Pipe Specifications and Price

The Commission Staff has no problem with the random placement of the higher toughness level of pipe.

Alaskan Northwest agrees with the Commission Staff that if a crack arrestor approach is ultimately chosen the CCE will be adjusted to reflect the costs associated therewith.

The Commission Staff and Alaskan Northwest disagree with respect to the method of estimating pipe costs and will set forth their respective positions in comments to be filed on December 15, and 22, 1980.

18. Miscellaneous Unspecified Materials

Staff will readdress this matter in its December 15, 1980 filing.

19. Compressor and Metering Station Estimate Concerns

The Commission Staff and Alaskan Northwest agree that this is no longer an issue.

20. Temporary Facilities and Service Estimate Concerns

See response to Item 8.

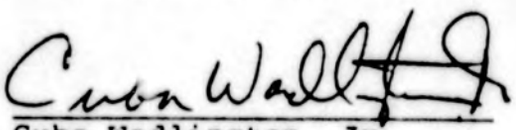
21. The Communications and Supervisory System Estimate

See response to Item 12.

22. Environmental Concerns

See response to Item 8.

Respectfully submitted,



Cuba Wadlington, Jr.
Director, Regulatory Affairs
Northwest Alaskan Pipeline Company
1120 20th Street, N.W.
Suite S-700
Washington, D.C. 20036

cc: Restricted Service List
Docket No. CP80-435

224 South 108th Avenue
P. O. Box 3330
Omaha, Nebraska 68103
Telephone (402) 691-2100

Northern Border Pipeline Company
New Natural Gas for America

September 18, 1981

Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

Attention: Mr. Kenneth F. Plumb, Secretary

Re: Alaskan Northwest Gas Transportation Company, Docket No. CP80-435

Dear Mr. Plumb:

Attached for filing in the above docket are an original and fourteen (14) copies of Initial Comments of Northern Border Pipeline Company on the Final Report of the Alaskan Delegate and Director, Audit and Cost Analysis, Office of the Federal Inspector.

As indicated by the Certificate of Service, service will be made on all parties.

Very truly yours,

Daniel B. O'Brien, Jr.
General Counsel

DBO:acm
Enclosures

cc: Parties of Record

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

Initial Comments of Northern Border Pipeline Company on the Final Report of the Alaskan Delegate and Director, Audit and Cost Analysis, Office of the Federal Inspector

I.

Pursuant to the Commission's August 21, 1981 order, Northern Border Pipeline Company (Northern Border) submits these initial comments in response to the Final Report to the Commission by the Alaskan Delegate and the Division Director, Audit and Cost Analysis, Office of the Federal Inspector (OFI) dated August 14, 1981 concerning the Certification Cost and Schedule Estimate (CCE) and Center Point requests of Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest).

Alaskan Northwest's proposed CCE and Center Point were considered in a series of technical conferences conducted by the Alaskan Delegate and the OFI Director in the Fall of 1980. Also participating in this review were the OFI's consultants, Williams Brothers Engineering Company (WBEC), the Commission Staff and its consultants, Pervin & Gertz, and the State of Alaska. A Draft Report was issued in March of 1981 by the Delegate and the Director which contained tentative recommendations based primarily on an appended draft audit prepared by WBEC. Two further conferences preceded the final Report together with the filing of additional comments on the issues addressed, one conference in March which considered the issues disputed in the draft Report and a second brief conference in May on a limited issue.

II.

Northern Border is filing these comments to refute the conclusions reached in the Report concerning the issue of pipeline lay rate. Based on the contention by WBEC that a higher lay rate can be achieved than that estimated by Alaskan Northwest, the Report concludes that the Alaskan Northwest CCE should be reduced by $172.2 million.

In its CCE, Alaskan Northwest estimated that an average lay rate of 40 joints per day for 80-foot double jointed noninsulated pipe and 35 joints per day for insulated pipe could be achieved. This rate was collectively arrived at by the execution contractors (EC) who assisted Alaskan Northwest and Fluor in the preparation of the CCE and is based upon their prior arctic experience, including TAPS where each of these EC's achieved a much lower lay rate, generally 25-30 joints per day. Their justification for a 30 to 40 percent higher lay rate for this project vis-a-vis TAPS is that, unlike TAPS, the Alaskan Northwest EC's will exercise total control over the spread under fixed price contracts, including all labor relations matters. WBEC contends, however, that the lay rate should be higher. Based on what WBEC refers to as a "time and motion study," WBEC concludes that a lay rate of 48 joints per day can be achieved. As will be hereinafter shown, Northern Border's actual experience completely refutes the contentions of WBEC as adopted in the Report.

III.

Northern Border is presently in the process of installing 42-inch, X-70, 80 foot double jointed non-insulated pipe with a wall thickness of .598 inches. Northern Border has analyzed the lay rate achieved on 387 miles of installed pipe. The results of this analysis were then adjusted to take into account the difference in pipe size, the number of welders utilized in preparing Alaskan

Northwest's CCE and to account for winter-summer construction.[1/] The results of this analysis are set forth in Exhibit 1.

Line 3 of the first three columns of Exhibit 1 sets forth the actual weighted average number of joints per day experienced by Northern Border in installing 387 miles of pipe. The first column shows that it took .83 welders to weld one joint per day. Column 2 shows that an average of 62.5 welders were employed per contractor and column 3 shows that an average lay rate of 76.6 joints was achieved per day per contractor, ranging from a high of 100 joints per day by one contractor to a low of 49 joints per day by another contractor.[2/]

Columns 4, 5 and 6 show the adjustments that must be made to the Northern Border experience to reflect the use of 48-inch pipe by Alaskan Northwest and to reflect the number of welders included in the Alaskan Northwest CCE. With more inches to weld, the 48-inch pipe will take more welder hours to complete one joint per day. Column 4 shows the adjustment to the Northern Border experience to accommodate to this difference in pipe diameter. No adjustment is required to account for wall thickness since the wall thickness is the same for both the 42-inch and the 48-inch pipe.

1/ In an apparent effort to shore up the lay rates estimated by WBEC, the Report refers to lay rates typically reaching "70-80 Joints per day on the Western Delivery System." Such a comparison on its face is neither accurate nor reliable because it fails to account for the variables that exist between the two projects. For example, the pipe size on the Western Delivery System ranges from 24 inch to 30 inch.

2/ A pipeline spread laying more joints per day by employing more welders is not necessarily accomplishing the work at the lowest cost per mile. It should also be noted that this weighted average was computed using the miles of pipe completed. Since the more efficient contractors have more miles completed, the weighted average shown will be less at the end of construction when the less efficient contractor's miles are included.

Column 5 reflects the fact that Alaskan Northwest proposes to employ 46 welders per spread. To arrive at a 48-inch lay rate in joints per day equivalent to the Northern Border experience, column 5 is divided by column 4 (i.e. 46 ÷ 0.94) which results in an estimated average summertime lay rate of 49 joints per day.

In arriving at its conclusion as to lay rate, WBEC first computed an "ideal rate" of 68 joints per day. Because the Alaskan construction will be carried on in both winter and summer, WBEC provided winter and summer efficiency factors to be applied to the "ideal rate." These efficiency factors are shown on page 1 of Exhibit 2. Utilizing the data on page 1 of Exhibit 2, Northern Border has computed on page 2 of Exhibit 2 the average efficiency for the winter (57.5%), summer (87.0%) and the winter-summer average (70.9%). By applying these efficiency factors to WBEC's number of joints per day (68), the number of joints per day can be determined for each of the seasons and for the winter-summer average. As shown on page 2 of Exhibit 2, these equate to 39 joints per day for the winter season, 59 joints per day for the summer season and 48 joints per day for the combined winter-summer season.[3/] Since Northern Border's average lay rate of 49 joints per day was experienced during the summer months, the most appropriate comparison is that shown on column 6 of Exhibit 1. This shows that the average lay rate for the summer months computed from WBEC data is 59 joints per day compared to the Northern Border experience of 49 joints per day.

To complete the comparison, the Northern Border experience average lay rate was adjusted to a combined winter-summer rate. Accepting WBEC's seasonal lay rate relationship as correct, this adjustment results in an estimated average lay rate of 40 joints per

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3/ The 48 joint per day lay rate is the lay rate that WBEC contends can be achieved as an overall average for the Alaskan segment.

day[4/]. Column 7 of Exhibit 1 compares this average lay rate with that estimated by Northwest Alaskan and that estimated by WBEC. As can be seen, the estimated average lay rate based on the actual experience of Northern Border substantiates the lay rate estimated by Alaskan Northwest and refutes the lay rate estimated by WBEC.

But even here caution must be exercised in assuming that the average lay rate of 40 joints per day will be achieved by Alaskan Northwest. Northern Border's average work day was 10.6 hours for welders whereas the Alaskan Northwest CCE and the WBEC report reflect a 10 hour day for welders. Further, many other intangible factors will also affect productivity, such as weather, competition for labor, skill of contractor's management, working conditions, reliability of equipment and severity of x-ray interpretation. It is far from certain that these other factors can be maintained in Alaska at a level comparable with that experienced by Northern Border so as to permit Alaskan Northwest to achieve the same level of productivity as that actually experienced by Northern Border.

For all of the above reasons, Northern Border submits that the conclusions contained in the Report as to the lay rate to be achieved shoud not be adopted.

Respectfully Submitted,

NORTHERN BORDER PIPELINE COMPANY

By _____
Its Attorney

Dated: September 18, 1981

4/ From Exhibit 1: $\frac{\text{Line 3 Column 6 X Line 2 Column 7}}{\text{Line 2 Column 6}}$ or $\frac{49 \text{ X } 48}{59}$

EXHIBIT I

NORTHERN BORDER ACTUAL LAY RATE
APPLIED TO ALASKAN NORTHWEST CCE PARAMETERS

	1	2	3	4	5	6	7
	42"			48"			
	Welders/ Jt/Day	No. Welders	Jt/Day	Welders/ Jt/Day	No. Welders	Jt/Day Summer Average	Jt/Day Winter/Summer Average
1. Alaskan Northwest CCE	-	-	-	-	46	-	40
2. Adger/Berman/WBEC Recommendation	-	-	-	-	-	59 2/	48
3. NBPL Experience 3/	0.83	62.5	76.6	0.94	46	49 1/	40

1/ Assumes same weld productivity in Alaska as Lower 48

2/ Exhibit II (Taken from WBEC, Vol. 1, page 1-46)

3/ 387 miles installed, weighted average

0509-1A/db

WILLIAMS BROTHERS ENGINEERING COMPANY

A Resource Sciences Company

a) Efficiency Factor for Sections 1, 2, and 3 (excluding Atigun Pass):

February, March, April, October, November, December	55%
May, June, July, August, September	85%
Average Efficiency Factor	68.6%

68.6% of 68 = 47 joints per day, which is equivalent to 3,760 feet per day.

b) Efficiency Factor for Section 4:

February, March, April, October, November, December	60%
May, June, July, August, September	87%
Average Efficiency Factor	72.3%

72.3% of 68 = 49 joints per day, which is equivalent to 3,920 feet per day.

c) Efficiency Factor for Sections 5 and 6:

February, March, April, October, November, December	60%
May, June, July, August, September	90%
Average Efficiency Factor	73.6%

73.6% of 68 = 50 joints per day, which is equivalent to 4,000 feet per day.

Summary (Average of a, b and c from Page 1):	Efficiency	Joints/Day
Winter: February through April and October through December	57.5%	39
Summer: May through September	87.0%	59
Winter/Summer Average	70.9%	48

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon each person designated on the official service list compiled by the Secretary in Docket No. CP80-435, in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated at Omaha, Nebraska, this 18th day of September, 1981.

Daniel B. O'Brien, Jr.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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ANGTS
Importation Authorization

Before Commissioners: Georgiana Sheldon, Acting Chairman;
J. David Hughes and A. G. Sousa.

Northwest Canadian Gas Sales Company	)	Docket Nos. CP81-388-000, CP81-388-001, and CP81-388-002
Northwest Alaskan Pipeline Company	)	Docket No. CP78-123, et al.

FINDINGS AND ORDER AFTER STATUTORY HEARING,
AUTHORIZING THE IMPORTATION OF NATURAL GAS,
ACCEPTING TARIFF AND RATE SCHEDULE,
AND GRANTING PETITIONS TO INTERVENE

(Issued October 1, 1981)

On June 19, 1981, Northwest Canadian Gas Sales Company (Northwest Canadian) filed in Docket No. CP81-388-000 an application pursuant to the Alaska Natural Gas Transportation Act of 1976 (ANGTA) and Sections 3 and 7(c) of the Natural Gas Act for an import authorization and for a certificate of public convenience and necessity authorizing Northwest Canadian to import and sell Canadian natural gas in lieu of Northwest Alaskan Pipeline Company (Northwest Alaskan).

Northwest Canadian is a subsidiary of Northwest Energy Company formed for the purpose of purchasing and selling Canadian natural gas as part of the first phase of construction of the Alaska Natural Gas Transportation System (ANGTS). Northwest Alaskan, also a subsidiary of Northwest Energy Company and the contracting party for the Canadian gas, would assign those contracts to Northwest Canadian.

By an order issued on January 11, 1980, as modified by an order on rehearing issued on June 13, 1980, in Docket No. CP78-123, et al., Northwest Alaskan was authorized to import from Pan Alberta Gas, Ltd. (Pan-Alberta) up to 300,000 Mcf of gas per day for resale to Pacific Interstate Transmission Company (Pac-Interstate). 1/

1/ Findings and Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas, issued January 11, 1980 (11 FERC ¶61,032), and Supplemental Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Imporation of Natural Gas, and Order on Rehearing, issued June 13, 1980 (11 FERC ¶61,279), both in Docket No. CP78-123, et al.

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By an order issued on April 28, 1980, as modified by an order on rehearing issued June 20, 1980, in Docket No. CP78-123, et al., Northwest Alaskan was authorized to import up to 800,000 Mcf of gas per day for resale to Northern Natural Gas Company, a Division of InterNorth, Inc. (Northern), Panhandle Eastern Pipe Line Company (Panhandle), and United Gas Pipe Line Company (United). 2/

Northwest Canadian states in its application that Northwest Alaskan has entered into contracts with Pan-Alberta, Pac-Interstate, Northern, Panhandle and United pursuant to which Northwest Alaskan may assign or transfer its contractual rights and obligations to an affiliate. Upon execution of the assignment of contracts between Northwest Alaskan and Northwest Canadian, Northwest Alaskan would have assigned its rights as buyer under contracts dated March 9, 1978, as amended, for the purchase of 1,040,000 Mcf of natural gas per day from Pan-Alberta to Northwest Canadian, and would have assigned its rights as seller of the imported gas to Northwest Canadian under the following contracts:

(1) with Pac-Interstate, dated March 9, 1978, as amended, for the resale of up to 240,000 Mcf of gas per day; 3/

(2) with Northern, dated March 24, 1978, as amended, for the resale of up to 200,000 Mcf of gas per day;

(3) with Panhandle dated April 14, 1978, as amended, for the resale of up to 150,000 Mcf of gas per day; and

(4) with United dated March 9, 1978, as amended, for the resale of up to 450,000 Mcf of gas per day.

Notice of Northwest Canadian's application was issued on July 14, 1981, and was published in the Federal Register on July 16, 1981 (46 F.R. 36924).

2/ Findings and Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas, issued on April 28, 1980 (11 FERC ¶61,088), and Order Granting Applications for Reheating in Part, issued June 20, 1980 (11 FERC ¶61,302), both in Docket No. CP78-123, et al.

3/ The March 9, 1978 contract for the resale of the gas, as well as the March 9, 1978 contract for the importation of the gas, both provide for purchase and sale of gas in excess of 240,000 Mcf per day on a best efforts basis.

On August 31, 1981, Northwest Canadian filed in Docket No. CP388-001 a "petition to amend a prior order authorizing the importation of natural gas." The petition requests the Commission to amend its above referenced orders of January 11, April 28, and June 13 and June 20, 1980, so as to authorize Northwest Alaskan to import Canadian natural gas through the Western Delivery System of the ANGTS at the increased border price of $4.94 (U.S.) "per Mcf" 4/ approved by the National Energy Board of Canada (NEB) for exports of gas from Canada. Citing the above described application of June 19, 1981, the petition concludes by requesting authorization for Northwest Canadian to import natural gas from Canada, at a price of $4.94 "per Mcf", at a point on the international boundary near Kingsgate, British Columbia, for transportation through the prebuilt Western Delivery System of the ANGTS, in the volumes previously authorized to be imported by Northwest Alaskan, with the import authorization to be effective October 1, 1981.

Notice of the petition was issued on September 10, 1981, and was published in the Federal Register on September 21, 1981 (46 F.R. 46622).

In response to the notices, timely petitions to intervene were filed by Southern California Gas Company and Pacific Lighting Gas Supply Company, Pacific Interstate Transmission Company, TransCanada Pipelines Limited, and Northern Natural Gas Company, (all on August 4, 1981) and by Mountain Fuel Supply Company (September 21, 1981). No protest or request for hearing was received.

4/ The presently effective Canadian border price is $4.94 per MMBtu, not per Mcf. We will construe the Northwest Canadian petition as seeking authority to import the gas in question at the $4.94 per MMBtu border price, rather than at the $4.94 per Mcf price stated in the petition.

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In supplemental information filed on September 25, 1981, Northwest Canadian states that the "principal purpose" of the proposed transfer of certificate and import authority "is to ensure that the sole business of Northwest Alaskan is to act as operator for the Alaskan Northwest partnership under its partnership agreement." Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest) is the partnership holding a conditional certificate to construct and operate the Alaska segment of the ANGTS. Northwest Alaskan is, in effect, the managing partner of the Alaskan Northwest partnership.

Northwest Canadian states that section 8.6 of the Alaskan Northwest partnership agreement restricts Northwest Alaskan's "sole business" to management of the design, construction, and operation of the Alaska segment, liason with governmental agencies and applications for governmental permits necessary to the construction and operation of the Alaska segment, and supervision of the project management contractor and all other independent contractors involved in the project. Northwest Canadian states that the partnership consented to Northwest Alaskan negotiating and entering into contracts with Pan-Alberta for the purchase of Canadian gas to support the ANGTS prebuild project, and consented to Northwest Alaskan's applications to the Commission for certificate and import authority to implement the prebuild project. The filing states that "Northwest Alaskan became the importer for the prebuild volumes, because of their nexus to the construction of the entire ANGTS and the importance of acting in an expeditious fashion to secure these imports." Northwest Canadian would now assume the prebuild import and resale functions and "could also potentially seek to purchase and import additional volumes of Canadian gas" . . . "in order to allow Northwest Alaskan to devote itself more completely to the design and construction of the Alaska segment, as required by the partnership agreement." As a secondary purpose, Northwest Canadian states that the transfer to Northwest Canadian of Northwest Alaskan's responsibility for the imports would simplify Northwest Alaskan's accounting.

The Commission has previously determined that Northwest Alaskan's importation of Canadian gas in connection with the prebuild of the ANGTS, and the sale of that gas for resale in interstate commerce, are related to the construction and operation of the ANGTS within the meaning of Section 9 of ANGTA. 5/ As noted in prior Commission orders on this subject, the Secretary of Energy, in Delega-

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5/ Order issued January 11, 1980, at pages 23 and 43, and Order issued April 28, 1980, at pages 7 and 138, both in Docket No. CP78-123, et al. See also Midwestern Gas Transmission Co. v. F.E.R.C., 589 F.2d 603, 614-616 (D.C. Cir. 1978).

tion Order No. 0204-8 (42 F.R. 61491), has delegated to the Commission the authority under Section 3 of the Natural Gas Act to approve the importation of gas in connection with the construction and operation of the ANGTS, including importation of Canadian natural gas in support of the prebuild phase of the project. 6/

The Commission is not prepared at this time to act on Northwest Canadian's application for certificate and importation authority. Further information is required with respect to the need for separate certificate and importation authority for Northwest Canadian in lieu of the authority previously granted to Northwest Alaskan. In particular, the September 25 filing does not provide adequate explanation of why Northwest Alaskan signed the gas purchase contract with Pan-Alberta, and why Northwest Alaskan filed applications for authority to import and resell the gas, and accepted such certificate and importation authority, in its own name, if the terms and conditions of its partnership agreement precluded it from exercising such authority. Alternatively, if Northwest Alaskan's partnership agreement does not in fact preclude Northwest Alaskan from exercising that authority, then the September 25 filing does not provide adequate explanation of why the public convenience and necessity requires issuance of a certificate to Northwest Canadian in lieu of Northwest Alaskan. The September 25 filing also provides insufficient explanation as to how issuance of a certificate to Northwest Canadian would simplify Northwest Alaskan's accounting, and why Northwest Alaskan cannot perform that accounting as easily by itself without creating another corporate entity.

Accordingly, the Commission will defer consideration of the Northwest Canadian application of June 19, 1981 to afford Northwest Canadian an opportunity to provide additional information as to the purpose of its application and the need for the authority requested.

The Commission does, however, recognize the national importance of the ANGTS as determined by the President and the Congress, and wishes to avoid if at all possible any delay in the inauguration of service through the Western Delivery System. Accordingly, the Commission will proceed with consideration of the August 31, 1981 petition with respect to the Canadian border price, on the premise that

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6/ Order issued January 11, 1980, at page 2, n. 2, and Order issued April 28, 1980, at page 2, n. 1, both in Docket No. CP78-123, et al. See also Midwestern Gas Transmission Co. v. F.E.R.C., supra, 589 F.2d at 617.

Northwest Alaskan could adopt Northwest Canadian's application so as to amend Northwest Alaskan's own importation authorization to reflect the present border price.

In its orders of April 28 and June 13, 1980, the Commission approved importation of the Canadian gas at issue at the then prevailing border price of $4.47 per MMBtu. Since that time, the Canadian Government has increased the border price for exports of gas from Canada to $4.94 per MMBtu. With respect to the natural gas to be imported at Kingsgate, British Columbia, for transportation through the Western Delivery System of the ANGTS, Northwest Canadian, in its petition of August 31, 1981, requests authority to import that gas, effective October 1, 1981, at the current border price, $4.94 per MMBtu. 7/ It is our understanding that the applicant is prepared to commence importation through Kingsgate on or about October 1, 1981.

In an order issued on April 24, 1981, the Commission authorized a group of four companies (the "ProGas Purchasers") to import certain volumes of Canadian natural gas for transportation through Northern Border, at the present border price of $4.94 per MMBtu. 8/ In so doing, the Commission adopted the findings of the Department of Energy's Economic Regulatory Administration (ERA), in its order issued March 22, 1981, approving the continued imporation into the U.S. of the Canadian natural gas imports subject to ERA's jurisdiction at the new (effective April 1, 1981) border price of $4.94 per MMBtu. That order was based on ERA's determination that ". . . the new border price remains within the competitive range of alternative fuel prices in the United States and is, therefore, reasonable."

7/ Northwest Canadian's application does not seek comparable authority with respect to the price of the Canadian natural gas to be imported at a point on the border near Monchy, Saskatchewan, for transportation through Northern Border. Accordingly, this order does not address that issue. The Commission stands ready to address it at such time as an application requesting such authority is filed.

8/ Order Authorizing the Importation of Natural Gas, Issuing Certificates of Public Convenience and Necessity Upon Statutory Hearing, and Granting Interventions, issued April 24, 1981, Docket No. CP79-332-001 (15 FERC ¶61,073). The four companies authorized therein to import that gas were Natural Gas Pipeline Company of America, Michigan Wisconsin Pipe Line Company, Tennessee Gas Pipeline Company and Texas Eastern Transmission Corporation.

(DOE Opinion and Order No. 29, "Opinion and Order Authorizing Payrent of an Increased Border Price for Natural Gas Imported from Canada," ERA Docket No. 81-09-NG, et al., at page 5.) The same reasoning would be equally applicable to importation through the Western Delivery System.

In this regard, on September 30, 1981 Northwest Alaskan filed a letter in "Docket No. CP81-388" requesting the Commission "to find that the import is authorized at the increased border price of $4.94 per Mcf," and "to effectuate its orders authorizing Northwest Alaskan to import the subject gas." For the reasons discussed earlier (see footnote 4, supra), we will construe the Northwest Alaskan letter as seeking authority to import the gas at $4.94 per MMBtu, and will approve that amendment to Northwest Alaskan's importation authorization for the Western Delivery System so as to authorize importation of that gas at the present Canadian border price of $4.94 per MMBtu.

In addition to its petition of August 31, Northwest Canadian filed on the same date, in Docket No. CP81-388-002, Northwest Canadian's FERC Gas Tariff, Original Volume No. 2, and its Rate Schedule X-4, which is a part of that same tariff. 9/ Northwest Canadian requested that its Tariff and Rate Schedule X-4 be made effective October 1, 1981. In the above described letter of September 30, 1981, Northwest Alaskan filed another copy of the Northwest Canadian tariff and rate schedule, requesting that the Commission "accept and place into effect the tariff filed by Northwest Canadian by substituting the name Northwest Alaskan for Northwest Canadian." In order to avoid delay in the in-service date for the Western Delivery System, the Commission will waive its regulations to the extent necessary to accept the tariff and rate schedule tendered by Northwest Alaskan in its own name pursuant to its own certificate authority, to be made effective October 1, 1981, subject to the minor modifications discussed below.

Under the provisions of the tendered tariff and rate schedule, Northwest Alaskan will flow through concurrently on a monthly basis to Pac-Interstate the purchased gas costs Northwest Alaskan is required to pay Pan-Alberta. In addition to flowing through purchased gas costs, Northwest Alaskan also proposes to flow through administrative costs previously incurred by it in arranging for the

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9/ Rate Schedule X-4 is applicable to Pac-Interstate. Rate Schedules X-1, X-2, and X-3 are to be filed at a later date and are applicable to Eastern leg prebuild volumes to be purchased by Northern, Panhandle and United.

prebuild volumes and administrative costs to be incurred. Northwest Alaskan's proposed charges to Pac-Interstate commencing October 1, 1981 would thus be $4.9400 per MMBtu for purchased gas costs plus 0.463¢ per Mcf for administrative costs. The 0.463¢ per Mcf charge reflects amortization over a one-year period of 23.1 percent 10/ of the $1,480,678 administrative costs attributed to Northwest Alaskan (0.390¢ per Mcf), plus 23.1 percent of the $275,000 projected annual administrative costs (0.073¢ per Mcf). Acceptance of the administrative cost component of Northwest Alaskan's charges to Pac-Interstate is conditioned to any reduction that may be required pursuant to the auditing of the "pre-certification" expenditures (Docket No. CP78-123, et al.), or subsequent auditing of the subject claimed costs.

Northwest Alaskan proposes also to adjust the administrative cost component of its rates on a semi-annual basis. The company also proposes to provide for deferred accounting of actual administrative costs incurred and the recovery of such costs through its rates and to compute carrying charges on any over or under recovery at interest costs computed in accordance with Section 154.67(d) of the Commission's regulations. The Commission approves this methodology for computing carrying costs and semi-annual rate adjustments, subject to Northwest Alaskan computing carrying charges and adopting the principles of interperiod income tax allocation in a manner similar to that prescribed in Section 154.33(d)(4)(iv) of the Commission's Regulations.

Northwest Alaskan states it also applied the same above described methodology to compute carrying charges on certain administrative costs previously incurred by it relative to the prebuild import arrangements. However, review of the data filed by the applicant indicates that the claimed carrying costs were computed at higher interest rates 11/ than permitted by the Commission's Regulations. Accordingly, Northwest Alaskan shall be required to recompute carrying costs in accordance with the procedures set forth in the Commission's Regulations.

The tariff filed by Northwest Alaskan provides a description of and provisions for implementing the take-or-pay "cap" required by previous Commission orders dealing with the prebuild project. However, that description does not reflect fully the Commission's determination on take-or-pay obligations attached to the prebuild volumes. Specifically, Northwest Alaskan's tendered tariff fails

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10/ The 23.1 percent factor reflects the relationship between prebuild volumes assigned to the Western Leg (240,000 Mcf per day) and the Eastern Leg (800,000 Mcf per day).

11/ The interest rates actually used are referenced to the prime rate as determined by the Bank of America, plus one (1) percent.

to incorporate the escalation adjustment factor 12/ for general inflation established by the Commission's order dated June 20, 1980, in Docket No. CP78-123, et al. (pages 8-10). Northwest Alaskan therefore shall be required to file revised tariff sheets 13/ to properly and clearly define the take-or-pay "cap" in accordance with the mechanics described in the Commission's orders related to the prebuild project. 14/

At a hearing held on October 1, 1981, the Commission on its own motion received and made a part of the record in this proceeding all evidence, including the application and exhibits thereto, submitted in support of the authorization sought herein, and upon consideration of the record,

The Commission finds:

(1) The petition of Northwest Canadian Gas Sales Company in Docket No CP81-388-001, as adopted by Northwest Alaskan Pipeline Company in its letter of September 30, 1981, and the tariff and rate schedule tendered by Northwest Alaskan Pipeline Company on September 30, 1981, are related to the overall construction and operation of the Alaska Natural Gas Transportation System within the meaning of Section 9 of the Alaska Natural Gas Transportation Act.

(2) The importation of natural gas from Canada at a point on the international border near Kingsgate, British Columbia, for transportation through the Western Delivery System of the Alaskan Natural Gas Transportation System, at a border price of $4.94 per MMBtu, will not be inconsistent with the public interest under Section 3 of the Natural Gas Act.

(3) Northwest Alaskan Pipeline Company's FERC Gas Tariff, Original Volume No. 2, and Rate Schedule X-4, should be accepted for filing to become effective October 1, 1981, conditioned upon the filing of the revisions required by this order.

12/ Application of this factor has the effect of increasing the "dollar cap." The quotient obtained by dividing the take-or-pay dollar cap by the Canadian export price defines the minimum import volume obligation of Northwest Alaskan.

13/ Special attention should be directed to Tariff Sheet Nos. 406, 419, 420, 456, 479 and 480.

14/ If the intent of the exporter and the importer is to establish a take-or-pay "cap" at a lesser level than previously prescribed by the Commission, that intent is not clear from the proposed tariff provisions, but the Commission would view such a proposal favorably if it were the agreement of the affected parties.

(4) Participation in this proceeding by the petitioners to intervene may be in the public interest.

The Commission orders:

(A) Northwest Alaskan Pipeline Company is authorized to import natural gas from Canada, at a point on the international border near Kingsgate, British Columbia, for transportation through the Western Delivery System of the Alaska Natural Gas Transportation System, at a border price of $4.94 per MMBtu, subject to all of the conditions set forth in the Commission's above referenced orders of January 11, April 28, and June 13 and 20, 1980 in Docket No. CP78-123, et al.

(B) Northwest Alaskan Pipeline Company FERC Gas Tariff, Original Volume No. 2 and Rate Schedule X-4 are accepted for filing and made effective October 1, 1981, conditioned upon Northwest Alaskan Pipeline Company filing, within 30 days from the date of issuance of this order, revised tariff sheets to reflect the modifications discussed in the text of this order.

(C) Parties to the above-captioned dockets may file applications for rehearing of this order within 30 days of the date of issuance of this order. The applications for rehearing shall be submitted pursuant to the procedures set forth in Section 1.34 of the Commission's Rules of Practice and Procedure.

(D) The petitioners to intervene listed above are permitted to intervene in this proceeding subject to the Rules and Regulations of the Commission; Provided, however, that the participation of such intervenors shall be limited to matters affecting asserted rights and interests as specifically set forth in their petitions to intervene; and, Provided, further, that the admission of said intervenors shall not be construed as recognition by the Commission that they may be aggrieved because of any order of the Commission entered in this proceeding.

By the Commission.

(S E A L)

Lois D. Cashell,
Acting Secretary.

December 19, 1980

John B. Adger, Jr.
Alaskan Delegate
Federal Energy Regulatory Commission
Richard Berman, Director
Office of Audit and Cost Analysis
Office of the Federal Inspector

Re: Trial Staff's Understanding of Areas of Agreement with Applicant; Docket No. CP80-435

On December 15, 1980, Alaskan Northwest Natural Gas Transportation Company (Applicant) filed its Report of Alaskan Northwest Natural Gas Transportation Company on Its Understanding of Agreements Reached with Commission Staff Regarding the Certification Cost and Schedule Estimate. Please be advised that the staff believes that certain clarifications of our position are required.

First, as to the staff's general offer of settlement on outstanding design issues, the offer is described in the staff's filing of December 15, 1980: (Mimeo at 31)

> "The offer was that for those design issues or alternatives identified but for which cost figures are unavailable, the cost analysis need not be done at this juncture. Provided, however, that NWA agree that if such alternatives were ordered and adopted and resulted in next savings over the cost figures in the CCE that the CCE would be reduced to reflect such savings." [Emphasis supplied]

Should such alternatives increase costs over the CCE, the determination of the upward cost adjustment made to the CCE is the responsibility of the Office of the Federal Inspector. The staff recommends that the OFI should determine if the particular design change is covered by the estimate contingency before allowing upward adjustment. (See Staff Comments of December 15, 1980, at 10 and 31-32).

The staff's statement of December 15, 1980, should supercede all other descriptions of the staff's offer should any difference exist between the filings as to exactly what was offered and accepted.

On those areas where agreement was reached, the staff believes some additional comment is necessary. Due to the lack of time to prepare the staff's comments and to review this document, all our concerns could not be addressed or corrected. Specifically, the staff's concerns are:

Item 1. Project Directorate Estimate Issues

The staff's understanding of the agreement on the treatment of overruns in the $75.2 million Third Party Monitoring Costs is explained in the Commission Staff Comments of December 15, 1980. (Mimeo at 32).

Item 9. Ambient Temperature Pipeline in Spreads 5 and 6

Technical respresentatives of Foothills Pipeline Co., Ltd., have contacted the staff to voice concerns over increased costs for an ambient temperature pipeline for the first 64 kilometers of the Canadian segment. Rough cost estimates would indicate $80 to 100 million in additional costs for thaw settlement mitigation. Although the staff cannot analyze the technical basis of the claimed mitigation costs, we still note a cost savings overall (Alaskan & Canadian segments) for the ambient temperature approach. Therefore, the staff recommendation for treatment of this potential design change remains the same as put forth in the Commission Staff Comments of December 15, 1980. (Mimeo at 33).

Item 10. Less Conservative Frost Heave Mitigation

The staff expects NWA to show that a reduction of insulation requirements would be a net benefit to the consumer under the IROR. Absent such a showing, the CCE should be reduced to reflect such savings.

Item 11. An Increase of One Year in Construction Schedule

The staff believes that this issue relating to completion of the gas processing plant and initiation of gas flow and the consequent tracking of costs is more properly addressed in the Shipper Tariff phase of this Docket. The Commission Order of April 28, 1980 in Docket No. CP78-123, et al., certificating the Northern Border pre-build segment instructs the Alaskan Delegate to prepare a report for use in a future proceeding on the issue of shipper tracking of Alaskan and Canadian transportation charges.

Item 19. Compressor and Metering Station Estimate Concerns

The staff continue to have serious concerns about refrigeration capacity requirements and equipment testing as stated in the Commission Staff Comments of December 15, 1980. (Mimeo at 16, 35-36). NWA submitted a workpaper on December 9, 1980, showing the following agreement with the staff calculations on refrigeration capacity requirement:

Compressor Station	Milepost	Chiller Load-Tons	
		NWA	Staff
No. 15	684.92	7970	7706
No. 13	579.69	7197	5740
No. 11	494.15	7809	6760
No. 9	380.93	7708	6970
No. 7	273.93	7942	7834
No. 4	141.32	3717	3283
No. 2	80.06	4013	3778

The tabulated NWA results were generated using site specific design parameters in a new, recently implemented and more rigorous

heat transfer model and computational procedure superceding that used for the July, 1980, NWA application.

Based on this relative agreement, the staff recommends two 4000 ton refrigeration units, for Compressor Station 7 through 15, and one 4000 ton refrigeration unit for Compressor Stations Nos. 2 and 4, rather than two 4500 ton refrigeration units for each station as proposed by NWA.

Respectfully,

John P. Roddy
David L. Huard
Thomas J. Burgess
Commission Staff Counsel

cc: All Parties

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PROPOSED TRANSCRIPT CORRECTIONS
TECHNICAL CONFERENCE CP80-435
VOLUMES SEVEN THROUGH EIGHTEEN

These proposed corrections are not intended to be exhaustive but are intended to adhere as much as is possible to the sense of what transpired.

OCTOBER 21

Corrections

Page	Line	
3	19	Should read "Trounson, James E. FERC Staff".
20	21	Change "pack" to "packet".
29	12	Should read "MR. BURGESS: Not to beat a dead horse, but some of the".

OCTOBER 22

3	19	Should read "Trounson, James E. FERC STAFF".
13	13	Change "Certaint" to "certain".

OCTOBER 23, 1980

3	19	Should read "Trounson, James E. FERC STAFF".
13	25	Change "request" to "quest".
23	5	Change "the sections" to "a section".
23	7	Should read "that is the efficiency in terms of preventing initiation of the crack or preventing the".
27	16	Change "is" to "are"
32	11	Change "a related" to "as related".

Page	Line	Corrections
36	11	Should read "to could we get a set of this stuff in Washington, and one sent".
40	10	Change "as" to "and is".
40	14	Delete "or".
		NOVEMBER 10
22	4	Change "begun" to "began".
		NOVEMBER 11
12	13	Delete "point".
13	1	Should read "MR HUARD: I believe the point we are making is we've asked".
34	14	Change "84-35" to "80-435".
		NOVEMBER 12
39	4	Change "ever" to "every".
41	1	Change "80" to "90".
"	16-17	Change "20th to 70" to "720".
58	15	Change "and" to "to the"
65	11	Change "so" to "from".
66	6	Change "is" to "as".
		NOVEMBER 13
10	14	Delete first "you".
"	21	Change "proceeded" to "proceed".
13	18	Change "files" to "filings".
15	6	Chaange "is" to "are".
29	23	Change "by" to "of".
40	25	Change "continuance" to "contingency".
		NOVEMBER 14
3	16	Change to "trial staff."

3	21	Change to "trial staff".
28	13	Change to "I'm willing ...".
30	9	Delete "but".
32	22	Delete "been".
42	20	Change first "the" to "not".
59	9	Add "to" after "way".

NOVEMBER 17

3	16	Change to "trial staff".
3	21	Change to "trial staff".
17	25	Change to "... was no site-specific ..."
21	16	Change to "... Hammond and the Koyukuk."
30	23	Change to "... going to be real hard ..."
36	10	Change "my" to "may"
"	12	Change "Sotrk" to "Sotak"
49	22	Change "comparitive" to "comparable".
55	2	Change "counsel" to "countries".
58	9	Change "put on" to "put it in".
61	11	Change "a" to "of".
73	24	Change "found" to "find".
76	24	Change to "permafrost ...".

NOVEMBER 18

3	16	Change to "... trial staff".
3	21	Change to "...trial staff".
9	9	Change to "unk-unks, unknown-unknowns..."
17	1	Change "acknowledged" to "knowledgeable".
28	9	Delete "that".
29	4	Delete "not".
47	18	Change "whish" to "which".
48	2	Change "possible" to "impossible".
54	21	Change "always" to "also".
64	19	Delete "an".

NOVEMBER 19

3	16	Change to "... trial staff."
3	21	Change to "... trial staff."

NOVEMBER 20

3	16	Change to "...trial staff".
3	20	Change to "...trial staff".
9	21	Change "phrase" to "phase".

John P. Roddy
Commission Staff Counsel

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon each person designated on the official restricted service list compiled by the Secretary in Docket No. CP80-435, in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C. this 19th day of December, 1980.

John P. Roddy
Commission Staff Counsel

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

REQUEST TO AMEND MOTION
TO COMPEL DISCOVERY

On December 17, 1980, trial staff in this docket filed with the Commission a motion to compel discovery. Staff thereby requested the Commission to divert Alaskan Northwest Gas Transportation Company to respond to Interrogatories propounded by Staff on October 21, 1980, and November 6, 1980, respectively.

Staff noted at the time of filing its motion that a third set of Interrogatories had been propounded to the Applicant on December 5, 1980, but that sufficient time for response had not elapsed. (See footnote 1 of attachment).

Sufficient time has now elapsed for Applicant to respond to the December 5, 1980, Interrogatories and no such response has been received. 1/

Staff, therefore, requests that its motion of December 17, 1980 be amended to include December 5, 1980 Interrogatories, and that the Commission compel production of proper answers to them for the reasons stated in the original motion.

Respectfully submitted,

John P. Roddy
David L. Huard
Thomas J. Burgess
Commission Staff Counsel

1/ Answer of Northwest Alaskan Pipeline Company to Commission Staff Motion to Compel, was filed, apparently unsigned and unverified, on December 29, 1980.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing documents upon each person designated on the official restricted service list compiled by the Secretary in Docket No. CP80-435, in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C. this 6th day of January, 1980.

John P. Roddy
Commission Staff Counsel

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of:	)	
	)	Docket No. CP80-435
Alaskan Northwest Natural	)	
Gas Transportation Company	)	

ANSWER OF NORTHWEST ALASKAN PIPELINE
COMPANY TO COMMISSION STAFF MOTION TO COMPEL

Pursuant to Section 1.12(c) of the Commission's Regulations, Northwest Alaskan Pipeline Company herewith files its answer to the motion of the Commission staff seeking to compel a reply, in writing, to staff interrogatories directed to Northwest Alaskan on October 21, 1980 and November 6, 1980. Staff asserts that Northwest Alaskan has not responded to the interrogatories.

Staff is in error. The questions posed in the interrogatories relevant to the matters before the Commission for decision -- resolution of the outstanding IROR matters, including approval of a CCE and center point -- have been answered either in writing or at the technical conferences authorized by the Commission's August 1, 1980 order in Docket No. CP80-435. 1/

The August 1, 1980 order established a special procedure to address the issues presented by the July 1st filing. The focus of this procedure was a series of technical conferences, and the process agreed on was to hold informational discussions off-the-record with a summary of these exchanges provided for the record by the presiding officer. The questions posed by the October 21, 1980 set of interrogatories were asked by the staff during the technical conferences and answered by Northwest Alaskan at that time. An examination by staff of its notes on the informal discussions and a review of the conference transcripts will provide staff with the information it seeks.

1/ Staff states in footnote 1 of its motion that it has served an additional set of interrogatories (December 5, 1980) and that the "time for response has not yet elapsed." Upon review of these particular interrogatories, Northwest Alaskan notes that these interrogatories as well were discussed at the technical conferences which the Alaskan Delegate commenced on September 3 and concluded on November 20, 1980.

The remaining questions posed by staff in the two sets of interrogatories go beyond the "limited purview of the subproceeding" as staff itself recognizes. Staff Motion at 1. As noted in its July 1, 1980 filing, Alaskan Northwest has not yet filed its financing plan and related economic materials. In its August 1, 1980 order the Commission "defer[red] such matters to a final certification proceeding which will be initiated upon submission of the financing plan." August 1 Order at 4-5 (footnote omitted). Since staff's unanswered questions relate to these types of concerns, Northwest Alaskan is unable to reply to questions that pertain to matters that are not part of the filed application. Northwest Alaskan will respond to the remaining questions at such time as it is able and when the questions posed correspond to the issues before the Commission.

Staff has filed a motion to compel replies to questions that Northwest Alaskan has already answered. Staff has received the information relevant to the certificate matters now pending before the Commission for decision. Therefore, since the relevant interrogatories have been answered, and the remaining questions are not ripe for Commission determination, the staff motion to compel should be denied.

Respectfully submitted,

William J. Grealis

Akin, Gump, Hauer & Feld
1333 New Hampshire Avenue, N.W.
Suite 400
Washington, D.C. 20036

Attorney for Northwest Alaskan
Pipeline Company

VERIFICATION

DISTRICT OF COLUMBIA) ss.

WILLIAM J. GREALIS being duly sworn, on oath, says that he is an attorney for Northwest Alaskan Pipeline Company; that he has read the foregoing Answer of Northwest Alaskan Pipeline Company to Commission Staff Motion to Compel and he is familiar with the contents theroef; that as an attorney, he has executed the same for and on behalf of said Company with full power and authority to do so; and that the matters set forth therein are true to the best of his information, knowledge and belief.

William J. Grealis

SUBSCRIBED AND SWORN TO before me this 29th day of December, 1980.

Sheila Lowenstein
Notary Public

My Commission Expires:

My Commission Expires April 30, 84

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in Docket No. CP80-435 in accordance with the requirements of §1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C. this 29th day of December, 1980.

William J. Grealis

BEFORE THE
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

To: John G. McMillian
Chairman of the Board of Partners
Alaskan Northwest Natural Gas
Transportation Company

c/o William J. Grealis, Esq.
Akin, Gump, Hauer, & Feld
1333 New Hampshire Avenue, N.W.
Suite 400
Washington, D.C. 20036

INTERROGATORIES PROPOUNDED BY THE COMMISSION STAFF

The following are propounded by the Commission Staff by reason of its lack of success in obtaining information by less formal means.

In responding to these Interrogatories, please follow these instructions:

(A) As used in the following requests, references to facts or documents include all facts or documents known to, prepared or reviewed by Alaskan Northwest, its affiliated companies, officers, representatives, employees, agents, or consultants.

(B) Unless agreed to in advance by the staff, all answers herein requested shall be submitted within 30 days of the date of receipt of these Interrogatories.

(C) These Interrogatories are to be deemed continuing in nature so as to require updated responses at a later time if the answer requested is pertinent to facts not now in the custody or possession of Alaskan Northwest.

(D) A response to any Interrogatory herein to the effect that the information sought has been, in whole or part, previously submitted by any party in this or any other proceeding before the Commission is insufficient.

(E) Unless otherwise specified, the Interrogatories herein are not intended to elicit the submission of voluminous material, computer printouts, or run data.

(F) In the event that any question or objection arises concerning these Interrogatories, such questions or objections should be communicated in writing, specificially detailing the nature of such concerns.

(G) If for any reason a requested document cannot be produced, the reason for its nonproduction must be stated. If such a

document is no longer in the possession, custody, or control of Alaskan Northwest, please set forth the control of said document and the identity of the person who currently is in possession, custody, or control such document.

(H) As to each Interrogatory, please identify the person answering by name, position, and employer, as well as the identity and degree other sources were relied upon to provide response.

1. Please state the general policy reasons why the 1977 design is considered to be substantially different from that submitted in 1980. (Please refer to the question posed by Mr. Essley to Mr. Hauser on September 30, 1980).

2. a. Please provide the specific instructions given by applicant to the panel of Execution Contractors in preparation of their report to NWA.

   b. If these instructions were given orally, please reduce them to writing and indicate which individual or individuals gave the oral instructions. Identify the instructing individuals by name, position, and relationship to the Applicant.

3. a. Please provide a list of all technical reports given to the members of Execution Contractor's panel.

   b. If technical information were provided to the Execution Contractors orally, please provice a narrative description of the topic areas and a summary of the conversation(s).

4. Please identify by name, position, and relationship to the applicant those individuals who provided basic estimate data that was used by Dr. Spetzler in conducting his computer simulation to develop ranges and distribution of cost impacts.

5. Please provide the instructions given to those individuals whose identity is requested in question numbered #4, above.

   Where oral instruction was given, please summarize that instruction in writing and identify each individual who gave said instruction.

6. When does Applicant intend to enter into a project labor agreement?

7. a. What number of welds per day was premised in NWA's 1977 estimate?

   b. What, if any, cost contingency was included in the 1977 estimate?

8. a. What, if any, agreement has been reached between NWA and Alyeska regarding NWA's use of the Yukon River Bridge? Please provide a copy of any such agreement(s).

   b. What discussion have taken place between NWA and Alyeska regarding NWA use of the Yukon River Bridge. Give the date of any such discussions.

9. Please provide a copy of NWA's Equal Employment Opportunity Plan for construction of the Alaskan Leg of ANGTS.

10. What specific programs has NWA initiated and/or planned for the training native Americans to participate in construction of the Alaskan Leg of ANGTS?

11. a. Please provide a list of the individuals comprising the Board of Directors of Wilbros Energy Co.

b. Please indicate what if any relationship each of the members of the Wilbros Energy Co. Board of Directors has with NWA or Fluor Corporation.

12. Please provide a detailed estimate (1980 dollars) of the cost to Alyeska to dismantle existing Alyeska work camps and restore the camp sites. Please provide the figure estimated for NWA to dispose of them and restore the sites after construction.

13. Please specify the exact location and expected date of completion for all proposed frost heave test sites.

14. What steps does NWA plan to take to prevent theft of spare parts or the cannibalizing of equipment?

15. Please provide a detailed schedule showing how NWA developed its cost estimate and financing information.

16. If final certification were delayed 3 months, (6/81) what would the impact be on each specific schedule milepost? Show the same information assuming a six month delay (9/81) in certification.

17. If Fluor's piping manhour standard charts are in Gulf Coast hours, how is the efficiency factor for Alaska arrived at?

18. a. Please provide a breakdown describing Fluor's overhead structure on jobs where Fluor was bidding competitively.

b. The multiplier factor for base pay is 3.33. Has the factor been that high on any competitive bids?

19. When insulated pipe is to be bent in the field, what percentage of the insulation was assumed to become damaged, and what basis was used for estimating repair charges?

20. Please identify by name and experience the most likely appointments to NWA's Cost and Schedule Control Staff.

21. What impact will employing a seven-day week for headquarters have on the cost estimate?

22. What procedures exist or have been approved for radiographic document retrieval, transportation, and/or retention?

23. Please provide a detailed schedule for development of financing and cost of service information.

24. What information does NWA have on the correlation of Alyeska's borehole tests to the actual conditions encountered by Alyeska during construction. Please explain if information not detailed.

25. Please identify as accurately as possible the share of gas upon completion of the Alaskan segment of the partners.

26. On what basis was 4% of the labor cost selected to represent tools and consumables in the estimate?

27. How much diesel fuel, gasoline, and lubricating oil is required for this project? Where will it come from and what effect will shortages have on the costs?

28. What is included in the 70% overhead? Please provide a breakdown of this amount.

John P. Roddy
David L. Huard
Thomas J. Burgess

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official restricted service list compiled by the Secretary in Docket No. CP80-435, in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C. this 21st day of October, 1980.

John P. Roddy
Commission Staff Counsel

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

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Alaskan Northwest Natural Gas Transportation Company	))	Docket Nos. CP78-123, et al. and CP80-435

COMMENTS OF THE COMMISSION STAFF TO FINAL REPORT TO THE COMMISSION BY THE ALASKAN DELEGATE AND THE DIRECTOR, AUDIT AND COST ANALYSIS, OFFICE OF THE FEDERAL INSPECTOR

Richard W. Foley
Commission Staff

John P. Roddy
Thomas J. Burgess
William J. Froehlich
Commission Staff Counsel

Washington, D.C.
September 18, 1981

TABLE OF CONTENTS

Executive Summary

On August 21, 1981, the Federal Energy Regulatory Commission (FERC or Commission), issued an Order Inviting Comments and Granting Intervention in Docket Nos. CP80-435 and CP78-123, et al. (Order).

Therein, the Commission sought the views of the parties to the aforementioned dockets regarding the Memorandum to the Commission From the Alaskan Delegate and the Director, Audit and Cost Analysis, Office of the Federal Inspector and the accompanying Report to the Commission on Certification Cost Estimate and Related Incentive Rate of Return Issues for the Alaskan Segment of the Alaskan Natural Gas Transportation System, dated July, 1981 (Adger/Berman Report or Report).

1. Staff Agreement With the Report

The Order sets out accurately and in great detail the chronology of the Commission's review of the application for a final certification of public convenience and necessity filed by Alaskan Northwest Natural Gas Transportation Company (Applicant or Alaskan Northwest) on July 1, 1981, as amended November 17, 1980. Trial staff, therefore, will forgo a repetitious presentation of that history. Staff notes, however, that the record will demonstrate that the Commission has gone to great lengths and expended much of its resources to process in a careful yet expedited fashion the vast amount of material submitted by the Applicant in support of its proposal.

The Adger/Berman Report calls for the setting at this time of a Certification Cost Estimate (CCE) at a level substantially below that requested by Alaskan Northwest in its July 1, 1980, filing as amended November 17, 1980. Where certain elements of the CCE lacked sufficient cost analysis data, the Report recommended a deferral in setting necessary CCE values for those elements. 1/ In addition, the Report recommends values for normal contingency and Center Point as required by the mechanics established in Order Nos. 31 & 31B for the Incentive Rate of Return (IROR) governing the proposed project.

Subject to our statements below, the Commission trial staff is in general agreement with and supports, the conclusions of

---

1/ In effect the Commission is being asked at this time to establish a partial CCE. Approximately 10% of the total base estimate of the Project is comprised of those elements which the Report targets for some form of deferred treatment.

the Report and the proposed values for CCE and Center Point. Staff acquiesces to the normal contingency contained therein. The staff strongly recommends a rapid adoption by the Commission of nearly all CCE values now proposed by the Report. In light of the ANGTA mandate for expedition, the Applicant's repeated request for same, and the exhaustive examination of the data provided thus far, Staff urges that no additional material be considered prior to a Commission decision on all proposed CCE matters set out in this Report. This recommendation need not apply to those elements recommended by the Report or Staff for deferred treatment.

Williams Brothers Engineering Company (WBEC or Williams Brothers) was chosen by the Office of Federal Inspector (OFI) to evaluate the Alaskan Northwest estimate. The Adger/Berman Report then adopted the Williams Brothers report with minor exceptions. The exceptions were items which are recommended to be deferred until a more definite cost can be determined. The bottom line values recommended by the Adger/Berman Report appear very close to the value recommended by the trial staff in its December 15, 1980, Comments. The following tabulation shows the deferrals recommended by staff and the deferrals recommended to the Commission by the Adger/Berman Report:

Millions of 1980 $

	Adger/Berman Report	Commission Trial Staff
Total (Excluding Finance Charge)	9,140	9,140
Deferrals	*(807)	**(1,390)
Related Contingency	(80)	(136)
Center Point Reduction	(177)	(305)
Recommended for Approval	8,076	7,309

*/

Management Plan	485
Communication	97
Socio-Economic Costs	225
	807

**/

Management Plan	485
Communications	97
Pre-Certification Cost	130
FERC Fees	20
Construction Camps	379
Third Party Monitoring	279
	1,390

While trial staff may differ with some of the avenues the Adger/Berman Report uses to reach its overall cost, we can support these values as being reasonable for approval by the Commission. That support is subject to the clarifications and the proposed procedural safeguards outlined below. Staff believes these safeguards should be set in place by the Commission. The safeguards would ensure that the proposed values set out in the Report, and ultimately a just and reasonable rate of return, are not eroded either by the ill-defined residual procedures necessary for final project certification by the Commission or the administration by OFI of the design change procedures.

2. Staff Recommendation for Treatment of Deferred Items

The Adger/Berman Report isolates three major CCE base elements for deferred treatment. 2/ These items could exceed $887 million. The recommendation for deferral results from Applicant's continued inability or unwillingness to provide cost estimate or reliable background data for the items in question. This is despite the passage of over 14 months since the filing of the partial Application in July, 1980. 3/ Staff notes that despite Applicant's assertion that the design data was frozen as of March, 1981, Applicant has filed two revisions.

There is no question that the items recommended for deferral, except for the socio-economic costs claimed by the State of Alaska, are CCE elements. They are, therefore, within incentive rate of return rubric. The establishment of any value for these items is clearly the responsibility of the FERC. Applicant's delay in providing the necessary information to set appropriate values should not allow these important elements to escape the level of Commission scrutiny brought to bear on the rest of

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2/ The list of elements includes Communication Systems, Socio-economic and Monitoring costs, and certain costs under the heading of Project Directorate.

3/ The Commission has in its Notice and Procedural Order of August 1, 1980, noted major deficiencies in the Application as filed.

the project estimate. At this time there is no valid basis for abdicating the responsibilities for setting values on these items to OFI. Staff believes that the OFI is less expert at resolving these rate base related issues. Indeed, considerable work on this project still awaits Commission consideration before any final certificate can be issued. 4/ In short, trial staff recommends that the Commission order the Applicant to perfect its application as to items recommended for deferral as quickly as possible so that a complete and reliable CCE can be fixed.

If the Commission determines, contrary to staff recommendation, to delegate the setting of values for any items in question to the OFI, staff urges procedures be established to allow a vigorous participation by the trial staff in the OFI decision-making process on these matters.

4/ Staff notes that no financing plan, a major prerequisite to certification, has been filed as yet. In addition, the threshold question remains before the Commission as to whether the present estimate "materially and unreasonably exceeds" the 1977 Estimate. That estimate was the premise of the President's Decision and excessive costs may render the project no longer in the public interest. At present, certain waivers are being advanced by the Applicant to Congress which could curtail or change the normal scope of Commission review. As a result of these waivers a processing plant (approximate cost 6 billion dollars) may be brought within the scope of the project and the Commission jurisdiction for certificate review.

Staff Comments

I. Staff's Support for the Certification Cost Estimate

As stated previously, the Commission trial staff generally supports the Adger/Berman Report and its analysis of the CCE. From the Report it is clear that Williams Brothers evaluated the Alaskan Northwest estimate, and did not prepare a new estimate of their own. The Commission trial staff, assisted by the engineering consulting firm of Purvin & Gertz, did likewise. The fact that their figures were wholly corroborative of WBEC, irrespective of acceptable differences in methodology, lends further credence to the validity of the Report. It is trial staff's observation that the Williams Brothers' analysis, as embodied in the Report, effectively extracts the excess contingencies from the CCE as directed by Order Nos. 31 and 31-B. The WBEC evaluation of the CCE recommends a 7% reduction in the filed CCE, as adjusted for the $.9 billion recommended to be deferred. The Report is quite accurate in describing this reduction as not overly significant in terms of the range of estimated costs, but quite significant as regards a cost-performance target for the IROR and the goal of risk-neutrality. Staff further agrees with the Report's reasoning, at II-6, II-7, for reduction of the overstated Alaskan Northwest CCE construction costs past the point of equilibrium of risk-neutrality. The analysis in the Report, as corroborated by staff and its consultants, is subject to no perverse incentives nor self interest. The Report's analysis of the CCE should be approved by the Commission as reasonable.

The CCE figure, adjusted by the Center Point allowance as recommended by the Report, is virtually identical to the result reached independently by staff and its consultants. 5/ For a project of such magnitude, the limited differences merit only brief mention below.

II. Areas of Disagreement or Qualified Support

A. Productivity & Lay Rate

With respect to pipeline adjustments, WBEC correctly assails the productivity rates and material quantities estimated by

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5/ Accord: Staff comments of December 15, 1981.

Applicant. Further, WBEC examined the projected lay rate and found it in need of adjustment. Recent construction on the Western Leg and the Foothills (Canadian) portions of ANGTS indicates that the WBEC productivity and lay rate evaluation was low, if anything. 6/ Staff believes the WBEC lay rate to be reasonable for Commission approval. Similarly, the analysis in the Report of trench excavation and backfill quantities comports with staff estimates as does treatment of some of the temporary facilities, compressor and metering stations, and operations and maintenance facilities.

B. Crack Propagation Resistance

The uncertainty in conceptual design this late in the design finalization process was not envisioned in the CCE or Final Design Estimate as described in Order No. 31. Some of these uncertainties have the potential for major impacts on other IROR parameters. For instance, the high liquifiables content proposed for the gas requires more stringent pipe toughness (crack propogation resistance) specifications than would be the case if the gas were free of liquifiables. It is quite probable that the liquifiables will be removed at the processing plant at the line's point of origin for use as petrochemical feedstocks. This probability, plus the demonstrated successful development of crack arrestors by Northern Border on the Eastern pre-build segment, make a relaxation of pipe toughness specifications and use of crack arrestors just as probable in final design of the Alaskan segment. However, the decision to remove liquifiables may not be finalized until after construction is completed. The costs for extreme crack propogation resistance required by liquifiables would not be allocated to the cost of transporting these liquifiables to the end user by the general tariff approved in Order No. 31; thus, the gas consumer would be forced to pay a disproportionate share of these costs. For these reasons, deferral is not a feasible resolution if only the estimated costs were to be considered; rather the Commission should seriously reconsider the tariff to allocate the transportation costs more properly.

C. Construction Camps

With respect to the best reasonable estimate for construction camps, the Report aptly notes that the figures included in the filed CCE are conceded by Alaskan Northwest to be void at this time. The figures are predicated on existing camps

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6/ Attachment "G" to the Final Report; Report at II-11.

owned by Alyeska, which is no longer negotiating to sell them. Notwithstanding the Report's explanation sanctioning their use, 7/ the unusable figures should be replaced expeditiously with the relevant costs for new camps. The value of those camps to Alyeska is a minus unless they can sell them to their only possible buyer, Alaskan Northwest. Alaskan Northwest is in the incongruous position of having alleged that they have applied for a final certificate without knowing who will be recruited to construct the project, nor where they will stay while doing so. Analysis of these costs should also be deferred to a subsequent proceeding before this Commission.

D. Design Change Mechanism

As described in the Report, there are two significant points relating to cost estimate approval. Of primary interest is the CCE to be considered by this Commission; the second is the Final Design Estimate. Of great concern to staff and the authors of the Report is a formula for categorizing CCE items which may change the design or cost from the time the CCE is set to the formulation of the Final Design Estimate. These items are variable because either the Applicant has not chosen among outstanding alternatives; has not established sufficient detailed data to constitute a design worth consideration at this juncture; or has not eliminated the possibility that further alternatives may be necessary as a result of additional testing or experimentation. If these variables were to have major cost implications, then the intent of the IROR could well be subverted, absent a formula for control. To the extent possible, these matters should be resolved by this Commission, which is the agency most capable. Indeed the Commission mandated the resolution of these concerns prior to certification. 8/

This concern leads staff to recommend that the Commission ensure to the fullest extent possible the adoption of and adherence to the proposed guidelines to OFI relative to design changes, as contained in Attachment "E" to the Report. Indeed, staff's general support of the Report is premised upon the adoption of procedural safeguards against abuses of the intent of the IROR. These guidelines provide such safeguards. It had been staff's contention that, due to its relative inability to penetrate the CCE items to any great extent, a normal contingency level of 7.3% was sufficient. This was demonstrated at some length

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7/ Report II-15; footnote 44; IV-10.

8/ Commission Notice and Order issued August 1, 1980.

in staff's December 15, 1980, comments. 9/ The staff is willing to accede to the WBEC recommended level of 12% in view of the much more detailed examination of the CCE items WBEC was able to achieve. It is staff's position that such a level is indeed reasonable if the guidelines in Attachment "E" are followed. If the contrary were true, however, a much lower level of normal contingency would be in order. 10/

E. TAPS Experience

The Report quite properly draws on the TAPS experience and the subsequent report of the General Accounting Office (GAO). The GAO report has analyzed the TAPS overruns leading to the development of the IROR. Staff would draw a single analogy between the ANGTS case and TAPS: TAPS had a base budget control estimate of $6.4 billion developed in 1975, and a final design estimate of $7.9 billion in 1977 after project completion. This base budget control estimate did not allow for contingency. If one were to allow 12% for normal contingency the adjusted estimate would have been $7.2 billion. If the final costs are diluted by an index in common use, the adjusted actual costs would be $7.3 billion. 11/ A $.1 billion overrun or a cost performance ratio of 1.01 would have been realized by TAPS under an IROR framework. Thus, if TAPS were operating under a Center Point of even 1.05, it would have been completed under budget. Likewise, if TAPS had had the 1.2 Center Point advocated by the Report, it would have had an incentive rate of return of 19 . A fortiori, to allow them 1.20 for a Center Point would more than "truly generous". Staff believes it quite reasonable for the Commission to adopt a Center Point at a level less than 1.2. 12/

III. Design Change Agreements

Staff advocates the use of its agreement with Alaskan Northwest to control the design change process. Minor design issues

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9/ See Commission Staff Comments, December 15, 1980, pp. 3-14.

10/ See the Commission's Order issued in Docket No. CP78-123, et al., on April 28, 1980, at 97. Commission Staff Comments of December 15, 1980, pp. 4-14.

11/ Hardy Whitman Index and FERC oil pipeline index would permit 5% for 1975 & 1976, and 2% for 1976-1977.

12/ Order No. 31 at p. 54; see also Report III-8, footnote 22, and III-14.

raised in Section IV of the Report might seem fit for handling by such a process, but their value should not be automatically altered. By rough count the design items most susceptible to change might represent up to a $1.5 billion increase in the final CCE. 13/

The Adger/Berman Report makes several references to proposed stipulations and agreements advanced by staff and Alaskan Northwest for the establishment of CCE values for those items where underlying data was unavailable or unreliable. 14/ The Report errs in its representation of staff's position as to these stipulations.

The Report suggests that staff had agreed to the substitution of actual costs for estimated costs for certain items. The source of this misunderstanding is an undated document titled, Report of Alaskan Northwest Natural Gas Transportation Company on its Understanding of Agreements Reached With Commission Staff Regarding the Certification Cost Schedule Estimate. That document was filed unilaterally by the Applicant and did not accurately reflect staff position at that time. 15/

Staff position regarding stipulations was correctly set out in its filing of December 15, 1980. Staff reiterated its position on December 19, 1980, in a memorandum (Staff memo, attached as Appendix I) to the authors of the Report and thereby repudiated Alaskan Northwest's interpretation of the proposed stipulations. The Report (see I-12, especially footnote 46) failed to credit staff with this repudiation, and yet made reference to the Staff memo at I-15, especially footnote 56.

Staff is hard pressed to understand the continued difficulty of the authors of the Report to grasp the staff position on this issue. Staff called this error to the attention of the authors

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13/ Yukon River Crossing, Workpad, Borrow Quantities, Refrigeration Level, Pipe Insulation, Full Load Testing, Ambient Operation, Communications, Management Plan, Atigun Pass, Temporary Facilities, Frost Heave Mitigation, Snow Pads, and Pipe Metallurgy.

14/ The initial reference to these proposed agreements is at I-11 of the Report, especially footnote 40.

15/ Though undated, the document was received at the Commission on December 15, 1980.

at the Tulsa conference where the preliminary version of the Report was reviewed. 16/

Staff has always contended that its offer was to substitute actual costs into the CCE only where they were lower than estimated costs. If actual costs were higher, no upward adjustment would be allowed unless approved by the OFI and then only after a determination that the cause for the increase was not otherwise allowed for in the normal contingency or Center Point. Any other interpretation of staff's offer is incorrect and would be untenable from the point of view of consumer protection.

The passage of time and availability of additional information calls for an individual re-examination of staff's position regarding each of those issues which was targeted for treatment by stipulation.

IV. Items Proposed By Report For Deferral

The Adger/Berman Report cites three issues for which it maintains the construction plan and pipeline design does not offer a basis for CCE approval. The Report finds the sponsors' plan has not crystallized sufficiently to allow preparation of a reliable estimate. These three items are: the Communications System, the Affirmative Action Training Plan, and the Management Plan. The Report recommends that the Commission defer selecting values for these three components of the CCE until sponsors make an adequate filing. In the alternative, the Report suggests that Alaskan Northwest provide adequately based estimates to the Federal Inspector for his approval. 17/ By footnote to the alternative, the Report suggests that because the OFI has design approval functions, it should be in a good position to review these costs.

The Commission trial staff urges the Commission to qualify the recommendation and reject the alternative recommendation which would delegate items to OFI. The proper forum to decide these issues is the FERC, and the proper time to finalize

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16/ At the Tulsa Conference in March, 1981, Staff pointed out orally and in writing where the preliminary report had misconstrued its position on stipulations.

17/ See Report IV-1 through IV-6.

these components of the CCE is now. The rationale advanced to defer to some future unspecified date or in the alternative to defer to the OFI, is not well taken. Approval of the Report's recommendation or the alternative recommendation would amount to abdication of the Commission's responsibility to establish the CCE. 18/

Addressed seriatim, staff urges the following approach to the subject three items:

A. The Management Plan

The President's Decision requires that "prior to the issuance of [a] certificate [of Public Convenience and Necessity], the successful applicant shall provide a detailed overall management plan, to be approved by the Federal Inspector, for the preconstruction and construction phases of the transportation system project." 19/ Alaskan Northwest estimates total project management costs (including PMC and outside service contracts) at $485.1 million. However, as the Adger/Berman Report correctly notes, a detailed overall management plan, as required by the Decision, was not submitted with the CCE. 20/ Staff would note that Northern Border submitted its management plan in seven volumes prior to the setting of its CCE.

Williams Brothers' evaluated project management cost estimate is $446.8 million, a reduction from the filed CCE by $38.3 million. The Report recommends that the Commission defer consideration of this portion of the CCE until a detailed management plan has been submitted to and approved by the Federal Inspector. 21/ Applicant has been on notice since the issuance of the

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18/ See President's Decision as qualified by Order Nos. 31 and 31-B. By failing to adhere to the guidelines provided in Attachment "E", the Federal Inspector will endanger the fragile interdependent balance stuck between the CCE and the Center Point.

19/ President's Decision, at page 27, Condition I.1.

20/ A "basic management philosophy" was presented in the filing to support the estimate.

21/ The exact figure is unclear in that there is a discrepancy between the chart on page 7 of the Executive Summary and the text on page IV-7.

President's Decision to prepare a detailed management plan. Since March, 1981, at the Alaskan Delegate's request, Alaskan Northwest has submitted additional voluminous material which they assert is all that is possible to demonstrate the Williams Brothers' reductions are not justified. 22/ After careful analysis of these materials, the Report concludes, "While these submissions have convinced Williams Brothers to recommend a lesser reduction of $38 million, 23/ neither we nor Williams Brothers are satisfied with the material provided thus far." Trial staff believes the sponsors have had ample time and opportunity to submit the material required by the Decision. No basis exists for rewarding Applicant for its lack of diligence in this expedited proceeding. The material heretofore filed should not be the basis for setting the CCE component for the management plan. The Commission should order immediate submission of a detailed management plan and withhold any CCE value until that time. Deferral of this component to OFI would serve no useful purpose.

B. Affirmative Action Training Programs

On May 8, 1980, the Commission adopted rules implementing Section 17 of the ANGTA, 24/ which requires agencies to take affirmative action to prevent discrimination based on race, creed, color, national origin, or sex in the construction and operation of ANGTS. These rules, inter alia, require the Applicant, most contractors, and subcontractors, to develop affirmative action plans. Except for certain costs associated with project management, Alaskan Northwest has not included in its filed estimate any costs attributable to affirmative action training. Alaskan Northwest, reasoned that until the plan was approved by OFI, no cost consequences of its elements could be estimated for CCE purposes. The Adger/Berman Report, issued August 21, 1981, concludes that because the OFI has not yet approved Alaskan Northwest's affirmative action training programs, these costs can not be included in the CCE at this time. The Report states, "in light of our uncertainties as the content of the approved plan, (sic) we recommend not setting a time period for filing the cost estimate until all facts are known." 25/

22/ See, e.g., Alaskan Northwest Response, vol. III, sec. 7.

23/ Initially Williams Brothers recommended reduction of sponsor management costs by $87 million.

24/ P.L. 94-586, October 22, 1976, 90 Stat. 2903.

25/ Report page IV-5.

The Report's recommendation is based upon the assumption that an affirmative action training program had not beer approved by the OFI. Events seem to have overtaken the Report, which was issued August 21, 1981. Prior to that, on August 13, 1981, the Federal Inspector approved the affirmative action plan submitted by Alaskan Northwest, thereby voiding the major basis for deferral of cost analysis of this item. Costs associated with the hiring, training, and staffing of the labor and management force should be in place at the earliest stages of this project. For that reason, if this matter can be resolved at this juncture, it should be done. The Report compounds its oversight by reciting an agreement reached between Alaskan Northwest and the staff and then cancelling its effect. The Report notes that staff urged in its December 15, 1980, Comments that Alaskan Northwest "be required to file (with the Commission) the costs of the training programs for inclusion in the CCE within 30 days of OFI approval of the affirmative action plan". Alaskan Northwest accepted the staff position but requested 60 days to file. 26/ The staff urges the Commission to enforce the agreement voluntarily entered into by Alaskan Northwest and the staff, and to require the costs be filed with the Commission by October 12, 1981. The recommendation of the Report should be modified to reflect the understanding and agreement of the parties. In this regard, the Report accepted the staff proposal but delayed its implementation because of "uncertainties as to the content of the approved plan." 27/ Reason dictates that it is cost beneficial to identify and train the work force at the earliest phase. Failure to do so was painfully evident in the TAPS experience. Resolution of the cost consequences of this item affects other elements of the CCE. Staff traces the effect of this program to at least Center Point item 23, the Competition in the Domestic Market for Craft Labor. Staff finds that the $107.2 million in protection from the consequence of competition for the same trained craft labor was requested in the CCE. The need to provide protection from this threat would certainly be reduced significantly if Alaska had its own indiginous craft labor force as a result of a vigorous

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26/ If the agreement between staff and Alaskan Northwest is given effect, the affirmative action training costs would be filed with the Commission on October 12, 1981 (Date of approval by the OFI, August 13, 1981, plus 60 days).

27/ Report at IV-5, V-6.

affirmative action plan. The Report would seem to agree. 28/ Since this cost can be resolved at this time there is no need to delay its consideration.

C. Communications System

The Alaskan Northwest filing contains no specific design for a communications system. The Report therefore recommends the Commission defer consideration of this portion of the CCE until a valid basis for approval is submitted. By footnote the Report states, "the appropriate cost estimate value could probably be settled by stipulation among the various parties, then submitted to the Commission or OFI for approval." 29/

Staff believes this item may be deferred, but the value of this item, as with all items comprising the CCE, should be set by this Commission rather than OFI. Staff's belief, in this regard, is premised upon the philosophy that the FERC has the primary responsibility to establish the CCE and Center Point. This is because these items directly affect the ultimate rates consumers will pay.

D. CCE Elements Requiring Actual Costs

Three items are, in the opinion of staff, clearly distinguishable for the purpose of CCE. For these three items no values are appropriate for inclusion at this time. Only actual costs should be used, if and when incurred. These items are: Pre-Certification Costs, Fees paid to FERC, and Fees paid to DOI/OFI.

28/ Report III-A-17; footnote 58, which reads:

> We note here that one of the items we must recommend for deferral is any allowance in the CCE for training costs. The reason for deferral is the absence of an approved plan for training programs. It seems illogical for Alaskan Northwest to argue for a significant allowance for inability to obtain the services of skilled labor prior to having completed an evaluation of the possibility of obtaining additional skilled labor through training.

29/ Report at IV-4, See footnote 14.

1. Pre-Certification Costs

The accurate setting of total allowable pre-certification costs resides with the Commission. It should be determined exactly and all parties expect, promptly. 30/

There is no reason to accept an estimate from the Applicant when an exact figure, beyond the control of Applicant, is imminent. Applicant had agreed to accept actual costs for this item.

2. Fees Paid to FERC

Applicant has requested that $20,261,500 be included in the CCE for incremental fees paid to the FERC. The Adger/Berman Report surprisingly makes no attempt to remove these costs. Staff strongly recommends that no amount be placed in the CCE under this category at this time since Applicant has to date refused to pay. Applicant has challenged the Commission's authority to assess such fees under existing regulations. 31/ Only upon a determination by the Commission of the exact fee owed and prompt payment thereof, can an exact figure as to total fees paid to the Commission be placed in the CCE. Any other course of action has the potential for rewarding a recalcitrant Applicant with a windfall benefit under the IROR should the Commission elect to apply a less stringent standard for fee collection to this Applicant.

3. Fees Paid to DOI/OFI

Similarly, staff notes that Alaskan Northwest refusal to pay the DOI reimbursable monitoring costs of $398,582 for the 1st

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30/ Applicant has requested a Commission determination of those pre-certification costs. This matter is pending.

31/ Under the Commission's Regulations (18 CFR 159.2), an initial incremental fee of $5,315,505 is now due an owing. The Commission requested and received on June 26, 1981, briefs from concerned parties on issues relating to the collection or adjustment of the incremental fees in Docket No. CP80-435. This matter is pending.

quarter of 1981. 32/ The overall figure is estimated in Section V of the Report is $53.6 million. Again, such an entry can hardly be counted as an expense under these circumstances until such time as the sum is actually remitted. That figure should be the only one used, and then, only after actually paid.

V. Other IROR Issues

Beyond the three items discussed above, the Report recommends deferral of certain other items. Under the heading "V. Other IROR Issues" the Report addresses Third Party Monitoring and Socio-Economic Costs. 33/ Portions of these items are also recommended for deferral. The Federal right of way monitoring figures are addressed, supra.

Alaskan Northwest's filing contains an allowance of $278.6 million for reimbursable costs to be incurred by Federal and state agencies.

On February 13, 1981, the State of Alaska submitted a revised estimate of monitoring and socio-economic costs. The Adger/Berman report addresses these figures and makes recommendations. The chart below compares these figures:

(See Page 16a)

32/ See Attachment H to the Report.

33/ Report at V-4.

	NWA ESTIMATE	State of Alaska Estimate	Report's Recommended Values
1. Federal right of way monitoring/OFI/DOI	$53.6 million		$53.6 million
2. State of Alaska monitoring	$21.6 million	$51.3 million	deferred to further proceeding
3. Socio-economic payments to State of Alaska	$203.4 million	$19.8 million	deferred to further proceeding

Staff recommends the following disposition of these items:

With regard to the OFI/DOI monitoring costs, the staff previously stated its belief that only the actual costs incurred should be included, and then, only when they are incurred.

State of Alaska Monitoring (originally submitted as $21.6 million) has mushroomed to a figure of $51.3 million for "surveillance" costs; more than double the original estimate. Staff concurs with the Adger/Berman Report's observation that some of these increased "surveillance" costs appear to be more properly classified as socio-economic expenditures. Staff recommends a Commission proceeding be instituted to classify and quantify monitoring costs properly. Staff believes it is impossible at the present time to decide the proper cost figure to be included in the CCE for State of Alaska monitoring costs. At the present time neither figure submitted by Alaska should be included in the CCE.

Staff reiterates its opposition to the inclusion of any figure attributable to socio-economic payments to the State of Alaska. The Report recommends further Commission proceedings to develop fully the factual and legal basis for the socio-economic costs filed by Alaska in the subproceeding. Staff urges the Commission reject this recommendation of the Report and include a value of $0 in the CCE for socio-economic payments to the State of Alaska. If the Commission, however, is not disposed to rule on the lack of merit of this line item, staff urges that this be deferred to a future proceeding before this Commission.

Conclusion

The Adger/Berman Report has recommended, after extensive analysis, values for most elements comprising the base CCE, normal contingency, and Center Point. It has recommended deferred treatment for several elements.

Trial Staff recommends prompt acceptance by the Commission of nearly all of those values set out in the report and the establishment of a partial CCE at this time subject to staff's exceptions.

Staff takes exception to the recommendations of the Report regarding treatment of some deferred items. Where residual review is required, staff recommends that such review remain with the Commission.

As to those items targeted for deferral and as to other minor differences the staff recommends the following:

Crack Propagation Resistence

To avoid the potential for excessive burdens on the consumer, the Commission should reconsider the tariff to allocate the transportation costs should removal of the liquefiables cause a reduction in pipe specifications and costs.

Management Plan

The Commission should order immediate submission by the Applicant of a detailed management plan to the OFI. An in-depth cost analysis of the plan should be ordered submitted to the Commission immediately so that the Commission can set an appropriate CCE value for this element.

Affirmative Action Training Program

Because the OFI has already approved the Applicant's affirmative action plan, the Commission should order Applicant to submit by October 12, 1981, a detailed cost estimate of that plan for Commission evaluation and inclusion in the CCE.

Communication System & Construction Camps

Staff agrees that sufficient cost data has not as yet been submitted to set CCE values for these elements and agrees that deferral for these items is appropriate. However, the setting of those values should not be delegated to OFI.

Pre-Certification Costs Fees Paid to FERC and Reimbursable Costs Paid to DOI/OFI

For the reasons stated above, staff recommends that CCE values for these elements reflect only actual expenses incurred.

State of Alaska Monitoring Costs

The cost element is sufficiently confused at this time to warrant staff's recommendation for a future Commission proceeding before setting a CCE value.

State of Alaska Socio-Economic Costs

Staff recommends no value be placed in the CCE for this element.

Finally, the staff recommends the Commission ensure adoption of the Design Change Guideline (Report Attachment E) to prevent undue escalation of project costs and detriment to the consumer.

Respectfully submitted,

John P. Roddy
Commission Staff Counsel

Thomas J. Burgess
Commission Staff Counsel

William J. Froehlich
Commission Staff Counsel

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these proceedings in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C. this 18th day of September, 1981.

John P. Roddy
Commission Staff Counsel

ATTACHMENT I

December 19, 1980

John B. Adger, Jr.
Alaskan Delegate
Federal Energy Regulatory Commission
Richard Berman, Director
Office of Audit and Cost Analysis
Office of the Federal Inspector

Re: Trial Staff's Understanding of Areas of Agreement with Applicant; Docket No. CP80-435

On December 15, 1980, Alaskan Northwest Natural Gas Transportation Company (Applicant) filed its Report of Alaskan Northwest Natural Gas Transportation Company on Its Understanding of Agreements Reached with Commission Staff Regarding the Certification Cost and Schedule Estimate. Please be advised that the staff believes that certain clarifications of our position are required.

First, as to the staff's general offer of settlement on outstanding design issues, the offer is described in the staff's filing of December 15, 1980: (Mimeo at 31)

> "The offer was that for those design issues or alternatives identified but for which cost figures are unavailable, the cost analysis need not be done at this juncture. Provided, however, that NWA agree that if such alternatives were ordered and adopted and resulted in next savings over the cost figures in the CCE that the CCE would be reduced to reflect such savings." [Emphasis supplied]

Should such alternatives increase costs over the CCE, the determination of the upward cost adjustment made to the CCE is the responsibility of the Office of the Federal Inspector. The staff recommends that the OFI should determine if the particular design change is covered by the estimate contingency before allowing upward adjustment. (See Staff Comments of December 15, 1980, at 10 and 31-32).

The staff's statement of December 15, 1980, should supercede all other descriptions of the staff's offer should any difference exist between the filings as to exactly what was offered and accepted.

On those areas where agreement was reached, the staff believes some additional comment is necessary. Due to the lack of time to prepare the staff's comments and to review this document, all our concerns could not be addressed or corrected. Specifically, the staff's concerns are:

Item 1. Project Directorate Estimate Issues

The staff's understanding of the agreement on the treatment of overruns in the $75.2 million Third Party Monitoring Costs is explained in the Commission Staff Comments of December 15, 1980. (Mimeo at 32).

Item 9. Ambient Temperature Pipeline in Spreads 5 and 6

Technical respresentatives of Foothills Pipeline Co., Ltd., have contacted the staff to voice concerns over increased costs for an ambient temperature pipeline for the first 64 kilometers of the Canadian segment. Rough cost estimates would indicate $80 to 100 million in additional costs for thaw settlement mitigation. Although the staff cannot analyze the technical basis of the claimed mitigation costs, we still note a cost savings overall (Alaskan & Canadian segments) for the ambient temperature approach. Therefore, the staff recommendation for treatment of this potential design change remains the same as put forth in the Commission Staff Comments of December 15, 1980. (Mimeo at 33).

Item 10. Less Conservative Frost Heave Mitigation

The staff expects NWA to show that a reduction of insulation requirements would be a net benefit to the consumer under the IROR. Absent such a showing, the CCE should be reduced to reflect such savings.

Item 11. An Increase of One Year in Construction Schedule

The staff believes that this issue relating to completion of the gas processing plant and initiation of gas flow and the consequent tracking of costs is more properly addressed in the Shipper Tariff phase of this Docket. The Commission Order of April 28, 1980 in Docket No. CP78-123, et al., certificating the Northern Border pre-build segment instructs the Alaskan Delegate to prepare a report for use in a future proceeding on the issue of shipper tracking of Alaskan and Canadian transportation charges.

Item 19. Compressor and Metering Station Estimate Concerns

The staff continue to have serious concerns about refrigeration capacity requirements and equipment testing as stated in the Commission Staff Comments of December 15, 1980. (Mimeo at 16, 35-36). NWA submitted a workpaper on December 9, 1980, showing the following agreement with the staff calculations on refrigeration capacity requirement:

Compressor Station	Milepost	Chiller Load-Tons	
		NWA	Staff
No. 15	684.92	7970	7706
No. 13	579.69	7197	5740
No. 11	494.15	7809	6760
No. 9	380.93	7708	6970
No. 7	273.93	7942	7834
No. 4	141.32	3717	3283
No. 2	80.06	4013	3778

The tabulated NWA results were generated using site specific design parameters in a new, recently implemented and more rigorous

heat transfer model and computational procedure superceding that used for the July, 1980, NWA application.

Based on this relative agreement, the staff recommends two 4000 ton refrigeration units, for Compressor Station 7 through 15, and one 4000 ton refrigeration unit for Compressor Stations Nos. 2 and 4, rather than two 4500 ton refrigeration units for each station as proposed by NWA.

Respectfully,

John P. Roddy
David L. Huard
Thomas J. Burgess
Commission Staff Counsel

cc: All Parties

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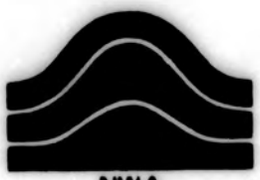
PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY } DOCKET NO. CP80-435

INITIAL COMMENTS OF ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY ON THE FINAL REPORT OF THE ALASKAN DELEGATE AND DIRECTOR, AUDIT AND COST ANALYSIS, OFFICE OF THE FEDERAL INSPECTOR



NWA
For
ANNGTC

SEPTEMBER 18, 1981 WASHINGTON, D. C.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL COMMENTS OF ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY ON THE FINAL REPORT OF THE ALASKAN DELEGATE AND DIRECTOR, AUDIT AND COST ANALYSIS, OFFICE OF THE FEDERAL INSPECTOR

Pursuant to the Commission's August 21, 1981 order, Alaskan Northwest Natural Gas Transportation Company submits these initial comments on the Final Report to the Commission by the Alaskan Delegate and the Division Director, Audit and Cost Analysis, Office of the Federal Inspector (OFI) dated August 14, 1981 concerning the Certification Cost and Schedule Estimate (CCE) and Center Point requests of Alaskan Northwest. Alaskan Northwest's supplemental application for a final certificate of public convenience and necessity for the Alaskan pipeline segment of the ANGTS included a requested CCE of $8.18 billion, excluding financing charges, and a Center Point of 1.28.[1]

Alaskan Northwest's proposed CCE and Center Point were considered in a series of technical conferences conducted by the Alaskan Delegate and the OFI Director in the Fall of 1980. Also participating in this review were the OFI's consultants, Williams Brothers Engineering Company (WBEC), the Commission Staff and its consultants, Pervin & Gertz, and the State of Alaska. A Draft Report was issued in March 1981 by the Delegate and Director which contained tentative recommendations based primarily on an appended draft audit prepared by WBEC. Two further conferences preceded the Final Report which were followed by the filing of written comments on the issues addressed, one conference in March which considered the issues disputed in the Draft Report and a second brief conference in May on a limited issue.

I. STATEMENT OF POSITION

The Final Report (Report) recommends reduction of Alaskan Northwest's reconciled $8.13 billion CCE by $1.09 billion and deferral of any decision on certain

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[1] The CCE was revised to $8.13 billion in the Comments of Alaskan Northwest Natural Gas Transportation Company on the Draft Report of the Alaskan Delegate and the OFI Division Director (filed April 13, 1981).

specified CCE items totalling an additional $620 million.[1] The Report also recommends that Alaskan Northwest's Center Point request of 1.28, representing an allowance of $2.28 billion, be reduced to 1.20, or by $448 million, and that an additional $311 million be transferred from the Center Point value to the contingency portion of the CCE. The result is a recommended CCE of $6.73 billion, or $1.40 billion less than that requested by Alaskan Northwest, and a Center Point allowance of $448 million less than that requested by Alaskan Northwest.

If adopted, the collective recommendations of the Report would eliminate any reasonable opportunity for Alaskan Northwest to earn the Commission approved center rate of return. This opportunity must be retained if the Alaskan Northwest partnership is to provide the equity necessary to complete this essential project.

Financing discussions are now in progress with major bank lenders who have been called upon to provide significant amounts of debt for the project and who must also assist in attracting other debt on a worldwide basis. The lenders are requesting the Alaskan Northwest partners to assume even greater financial risks during construction than envisioned at the time the Commission issued Orders 31 and 31-B. The willingness of the partners to consider assuming greater risks will be affected by many considerations, including the rate of return that can reasonably be expected to be earned on the risk capital. Additionally, the Alaskan Northwest partnership has been advised by the major bank lenders that its ability to attract debt from other countries will be significantly affected by foreign lenders' perceptions of whether the U.S. government continues to support completion of this project.

It is, therefore, obvious that in establishing a CCE and Center Point this Commission will play a principal role in determining the attractiveness of the investment necessary to raise the required equity and debt and thus the future course of the project. If the Commission endorses the Report's recommendations, thereby eliminating any reasonable chance for equity investors to earn the risk premiums which the Commission previously found necessary to attract capital, the likelihood of obtaining the necessary equity commitments will be greatly diminished. Furthermore, such action by the Commission may be perceived by foreign investors and others as an official downgrading of the national interest status of the project.

The Report's potentially crippling recommendations are based upon the authors' contention that the Incentive Rate of Return mechanism established in

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[1] The Report recommends total adoption of WBEC's recommended reductions of $1.09 billion to the CCE. WBEC's recommended reductions include a $203 million reduction for State of Alaska socioeconomic and third party monitoring costs and a $38 million reduction for project management costs with a $26 million associated normal contingency for a total reduction of $267 million. The Report recommends that this $267 million be deferred, plus an additional $620 million comprised of estimated costs for communications and supervisory systems ($97 million), project management ($447 million), Alaska Pipeline Coordinator ($22 million), and an associated $54 million contingency, for a total deferral of $887 million.

Orders 31 and 31-B lends itself to submission of CCE and Center Point requests that are not risk neutral -- that is, the authors assert there is a greater than 50 percent chance that the project will cost less than the filed CCE, as adjusted for the Center Point request. The authors attempt to lend credence to their belief by alleging that: 1) the Alaskan Northwest estimators could not follow the Commission's IROR cost estimate definitions with precision and, therefore, could not have prepared a risk neutral estimate; and, 2) a comparison of this project with TAPS, the Alaskan oil pipeline project, indicates that Alaskan Northwest's actual cost growth will be much less than the expected costs projected in its filings. This reasoning then forms the foundation for the Report's recommended reductions to the CCE, which consist of the Report authors' arbitrary adoption of all of the numerous subjectively derived reductions to the CCE recommended in the WBEC audit, together with an even lower Center Point than was recommended in that audit.

The authors' contention is in fundamental error. First, in preparing the CCE and Center Point the estimators strictly adhered to the Commission's mandate in Orders 31 and 31-B that the CCE reflect only normal expected costs and that the Center Point cover cost impacts from abnormal events not be includable in the Change of Scope events. This task, which has the only record support in this proceding, was not unusual or overly difficult, because the required cost segregation was not significantly different from standard estimating techniques for large projects. Additionally, a valid factual comparison of this project with TAPS or any other project will not support the Report's conclusions that the expected cost growth on this project will be less than that projected in the filing. If anything, such a comparison further supports the reasonableness of the CCE and Center Point requests. In essence, the authors' assertions amount to nothing more than a collateral attack on the cost categories established in Orders 31 and 31-B and the manner in which the Commission required such costs to be submitted to it for review.

In the final analysis the Report must stand or fall on the authors' ability to justify why the results of the WBEC audit, rather than the Alaskan Northwest estimate, more closely reflect the realistic estimate the Commission required be submitted for approval. Neither the controlling facts nor the Report provide such justification. The WBEC audit as admitted by the authors was "...performed with only a fraction of the resources required to develop an independent estimate."[1] Yet, the Report relies totally on and without variation from the WBEC audit for its recommended reductions to the CCE despite the authors' acknowledgement that the Alaskan Northwest CCE and the WBEC audit "...are close enough to corroborate each other..." and are within "...a range of estimated costs within which the Alaska Segment of the ANGTS can be expected to be built."[2] The credible opinions and persuasive explanations of those who prepared the Alaskan Northwest estimate, including the Project Management Contractor (PMC) and the execution contractors who participated in the construction of TAPS and many other multi-billion dollar construction projects are ignored, even where the WBEC audit has been demonstrated to be factually incorrect or premised upon faulty assumptions.

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1 Report at II-2.

2 Id. at 6 and II-5.

The following table illustrates the dollar value differences between our CCE and Center Point and the Report and WBEC audit recommendations.

TABLE I

COMPARISON OF CERTIFICATION COST ESTIMATE

WITH WBEC's EVALUATED ESTIMATES

Cost Element	Filed CCE [1]	Reconciled CCE [2]	WBEC Evaluated Estimate [3]	Adjustments to WBEC's Estimate	CCE As Adjusted	CCE Amounts To Be Deferred [4]	CCE Requested To Be Approved	Reduction From Reconciled CCE
Compressor & Metering Stations [5]	$ 693,073	$ 667,739	$ 642,141	$ 15,922	$ 658,063	$ --	$ 658,063	$ 9,676
O & M Facilities	53,428	53,428	50,891	2,537	53,428	--	53,428	--
Temporary Facilities	926,881	909,148	867,538	32,841	900,379	--	900,379	8,769
Communications & Supervisory	98,622	98,622	98,622	--	98,622	(98,622)	--	98,622
Pipeline [6]	4,285,077	4,273,787	3,663,670	557,406	4,220,076	--	4,220,076	53,711
Project Directorate	1,246,481	1,261,095	964,981	283,556	1,248,537	--	1,248,537	12,558
Subtotal	7,301,542	7,261,819	6,284,843	892,262	7,177,105	(98,622)	7,080,483	181,336
Contingency [6]	876,158	871,381	1,064,857	(203,562)	861,295	(11,578)	849,717	21,664
TOTAL Certification Cost Estimate	8,177,700	8,133,200	7,349,700	688,700	8,038,400	(108,200)	7,930,200	203,000
Center Point Allowance	2,304,000	2,278,900	1,514,500	764,400	2,278,900	--	2,278,900	--
TOTAL (Excluding Finance Charge)	10,481,700	10,412,100	8,864,200	1,453,100	10,317,300	(108,200)	10,209,100	203,000
Finance Charge	926,200	921,200	832,700	77,700	910,400	(12,200)	898,200	23,000
TOTAL (Including Finance Charge)	$11,407,900	$11,333,300	$9,696,900	$1,530,800	$11,227,700	$(120,400)	$11,107,300	226,000
CENTER POINT RATIO [7]	1.282	1.280	1.206		1.284		1.287	

1 CCE filed on July 1, 1980 as revised October 27, 1980 for the DOI reroute.

2 CCE as revised on April 13, 1981 pursuant to comments on the Draft Report.

3 WBEC Final Report issued by the Alaskan Delegate and OFI Director on August 14, 1981.

4 CCE amounts which Alaskan Northwest agrees are appropriate to be deferred.

5 Special studies have been restored to the appropriate WBS element.

6 Assigned contingency has been restored to the Center Point Allowance.

7 Center Point Ratio is derived by dividing the Center Point Allowance by the total CCE.

As shown in the preceding table and for the reasons set forth in these comments, Alaskan Northwest agrees with only $95 million of the $1.09 billion of the WBEC recommended reductions in the CCE and totally disagrees with any reduction in the requested Center Point value. Finally, Alaskan Northwest agrees with deferral of only $108 million of the $887 million for which the Report authors would defer CCE approval. For the reasons set forth more fully hereinafter, Alaskan Northwest respectfully requests Commission approval of a $7.93 billion CCE and a 1.287 Center Point, subject to the revisions to the CCE resulting from the forthcoming filing on the referenced deferred items.

The major areas of disagreement between Alaskan Northwest's requests and the Report's recommendations can be summarized as follows:[1]

A. CCE

1. Pipeline

A major contention of the Report and WBEC audit is that Alaskan Northwest failed to optimize resources when putting together the CCE.[2] More particularly, WBEC contends that a higher productivity than that estimated by Alaskan Northwest for laying the pipe can be achieved, that crews and equipment have not been optimized in the Alaskan Northwest estimate, that execution contractors and subcontractors will accept a reduced overhead and profit allowance, and that Alaskan Northwest's civil quantity estimates are overstated. Based on these erroneous contentions WBEC recommends reductions totalling $612 million in the pipeline portion of the CCE.

First, WBEC premises its pipe lay rate productivity estimate on a study which, as Alaskan Northwest demonstrated in its April 13 comments on the Draft Report, totally ignores two work functions and underestimates another work function critical to avoidance of costly weld repairs. When the WBEC estimate is corrected to include factors which WBEC itself has ignored, its resulting lay rate estimate approximates that of Alaskan Northwest. Additionally, WBEC's lay rate estimate for this project is significantly higher than that projected by WBEC for essentially the same route five years ago in the very proceeding that led to the selection of Alaskan Northwest to construct and operate the Alaskan segment of the ANGTS. WBEC's estimate is also significantly higher than its recent estimate to Sohio for construction of flow lines at Prudhoe Bay over the next three years. The Report ignores these inconsistencies and deficiencies in adopting the WBEC lay rate reduction of $172 million. Therefore, this arbitrary and unsupported reduction should be rejected.

Second, WBEC's other recommended reductions of $195 million primarily in crew and equipment are based solely on an unsupported contention that certain

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1 This summary is solely for the purpose of identifying the major areas of disagreement among the many issues raised in this subproceeding. It is not intended to convey acquiescence in recommended reductions not summarized here. Alaskan Northwest's positions on such other reductions are explained in detail in the body of these comments and its April 13, 1981 Comments on the Draft Report, which incorporated by reference herein where noted.

2 Report at III-15.

operations have been duplicated. No such duplication exists. In preparing its CCE Alaskan Northwest optimized crews and equipment for each of the six pipeline spreads. WBEC does not, and cannot, dispute this fact. Nor can WBEC demonstrate how crew and equipment reductions will permit accomplishment of the same amount of work in a shorter time frame. For these reasons WBEC's recommended $195 million reduction should be rejected.

Third, in its draft audit released in March of this year WBEC recommended a reduction in the execution contractors' overhead and profit allowance from 18 percent to 15 percent, or $105 million, and a reduction in certain subcontractors, overhead and profit for an additional $15 million reduction. In its April 13 comments, Alaskan Northwest rebutted each reason advanced by WBEC in support of its recommended reduction in the execution contractors' overhead and profit allowance. In its final audit WBEC retracted two of the three reasons previously advanced in support of its position and relies now on only the assertion that the salvage value of the execution contractors' equipment, after adjustments for inflation, will be in excess of the Alaskan Northwest estimate. As the Commission is well aware, Orders 31 and 31-B prohibit the inflationary escalation of any costs in establishing a CCE.

With respect to the subcontractor overhead and profit allowance contained in the CCE, Alaskan Northwest noted in its April 13 comments that these amounts were obtained from subcontractors as the amount they currently realize for existing work. WBEC did not dispute this fact. Accordingly, its $15 million recommended reduction should be rejected.

Finally, Alaskan Northwest's civil quantity estimates reflect what realistically can be expected to occur in the field. These estimates were prepared by contractors involved in the civil construction of TAPS and reflect their actual experience. WBEC's new "design" and resulting recommended reduction of $125 million do not reflect actual arctic construction experience.

2. Project Directorate

The major areas of dispute in the area of project directorate are the Report's recommended deferral of CCE approval of a value for project management costs and the appropriate treatment of third party monitoring and socio-economic costs (government-related costs).

We requested approval of a CCE value of $485 million for the estimated project management costs of the Project Management Contractor and Northwest Alaskan, as operator for the Alaskan Northwest partnership. The Report adopts the WBEC audited estimate for project management costs of $446.8 million, but recommends that CCE approval of this amount be deferred until a detailed management plan has been submitted to and approved by the Federal Inspector. CCE approval of project management costs should not be deferred. There is no basis in either the President's Decision or the Commission's IROR orders for deferring approval of a CCE value for such costs. An overall management plan was submitted to the Federal Inspector on June 2, 1980 and has been approved in principle by OFI. Furthermore, as more fully explained hereinafter, there is no basis for $33 million of the $38 million WBEC recommended reduction in our project management costs.

Alaskan Northwest strongly objects to the Report's recommendation that it be required to estimate and be held accountable for government-related costs. As the Report itself concedes, Alaskan Northwest has no control over the preparation by various governmental agencies of estimates for monitoring and socioeconomic costs. Furthermore, it has no effective means for preventing governmental agencies from overrunning their estimates. Therefore, the Cost Performance Ratio should be adjusted to reflect actual governmental costs or, alternatively, such costs should be excluded altogether in calculating the IROR. Otherwise, Alaskan Northwest will be unfairly penalized for cost overruns by governmental agencies.

Finally, there is no basis for the recommended reductions of $25 million and $28 million in, respectively, the tax and insurance portions of our project directorate estimate.

B. Center Point

In Orders 31 and 31-B the Commission instructed Alaskan Northwest to prepare and submit an exhibit assessing the likelihood of abnormal events which could increase project costs and the resulting cost impacts, which exhibit would then be used to establish a Center Point.[1] The Report acknowledges that the Center Point exhibit filed by Alaskan Northwest conforms to this Commission mandate. However, the Report disagrees with the result reached and recommends a lower Center Point based upon extraneous considerations such as the ANGTS cost growth experienced to date, a comparison with TAPS, and the opportunities available to limit overruns.

These extraneous considerations do not support the Report's recommendation. Ironically, they instead buttress the reasonableness of Alaskan Northwest's Center Point request. For example, the Report's allegations that further cost growth will be accounted for in the design or scope change process ignore the fact that the cost increases may not qualify for such treatment, even assuming the Commission does not abolish the design change process as recommended by the Report. Moreover, the Report's attempts to compare this project at a 5 to 10 percent design stage with TAPS immediately prior to construction demonstrates the Report authors' willingness to go to extremes to justify arbitrary and unsupportable reductions. Finally, the Report's allegations that Alaskan Northwest can draw upon the TAPS owners and contractors with arctic construction experience to limit overruns is true. In fact, Alaskan Northwest drew upon this experience in preparing realistic CCE and Center Point requests, only to have the Report authors arbitrarily reject the views and opinions of this highly experienced group in each and every instance.

Alaskan Northwest submits that if the Center Point is to be reduced it can be done only on the basis of defects in the analysis submitted for Commission review. The Report can find no evidence of any such defects. In fact, the Report's largest single recommended reduction to the Center Point request -- an amount for unknown-unknown events -- is contradicted by WBEC's acceptance in principle that such events can and will occur and by the Report authors'

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[1] Orders 31-B at 8.

statements that other experts could identify events which were not analyzed by Alaskan Northwest but which will increase project costs.

C. Design Change Policy

The President's Decision and Commission's IROR orders recognize that there will be two distinct cost estimate approvals at two different stages of design. In order to encourage the refinement in design that would take place between approval of the CCE and approval of the final design, the Commission in Condition 9 of Orders 31 and 31-B provided for a liberal design change policy prior to approval of the final design. The Report, however, attempts to restrict severely possible upward adjustments in the CCE for approved design changes. Contrary to the intent of the President's Decision and IROR orders, the effect of the Report's recommendations is to make the approved CCE, which is based on a 5 to 10 percent design, the final cost estimate, which was to be based on at least a 70 percent design. Basing the target costs on such an incomplete design will substantially increase the risk that the sponsors will not be able to earn the IROR. Therefore, the liberal design change policy prior to final design must be reaffirmed.

D. Other

With respect to other issues raised in the Report, we do not oppose deferral of establishment of a CCE value for communications and supervisory systems and affirmative action training programs. We also propose herein a labor inflation index for use in the IROR inflation adjustment mechanism. Finally, we will be submitting an estimate for the possible costs of damages to State of Alaska highways. We propose, however, that any such highway costs be treated similarly to our proposed treatment of other government-related costs.

E. Summary

For the reasons stated in these comments, Alaskan Northwest strongly opposes most of the Report's recommendations. The Report does not reflect a fair and even-handed evaluation of differing opinions, the reasons behind these opinions, and the relative experience of those rendering the opinions. We trust the Commission will make a thorough and balanced review of all the evidence concerning the matters in dispute and reach a realistic and reasonable decision resolving all of the remaining issues in a manner which will permit private sector financing and expeditious completion of the ANGTS.

II. BACKGROUND

A. Orders 31 and 31-B

In recognition of the potential for cost overruns on a project of the magnitude of the ANGTS, the President's 1977 Decision and Report[1] required the use

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[1] Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaska Natural Gas Transportation System (September 1977) (hereinafter referenced as President's Decision).

of a variable rate of return mechanism to reward the sponsors for cost underruns and penalize them for cost overruns.[1] This mechanism was implemented by the Commission in its Orders 31 and 31-B where the Commission recognized at the outset that:

> The final or ultimate cost of this project is now unknown; the best that can be done is to specify a probability distribution of possible final cost outcomes. The range of possible costs...for the Alaska segment, with its inherent uncertainties regarding system design and logistics of construction, is likely to be much broader.
>
> Cost estimates for most large projects tend to increase as more is known about the detailed design of the system.[2] (Emphasis added).

Accordingly, the Commission established a four stage process for ascertaining the projected or target costs against which actual costs are to be measured in determining the incentive rate of return:

(1) Commission review and approval of a "Certification Estimate...based on the normal or likely conditions and parameter values that the sponsors expect to experience during construction (for example, weather conditions, field or soil conditions, prices, wage rates, and labor and equipment productivity)."[3] This CCE is to consist of a base estimate and a normal contingency to reflect the normal uncertainty in assembling such estimate.[4]

(2) Commission review and approval of a Center Point, based upon the expected value of "...abnormal events that could increase costs which are not covered under the Change in Scope mechanism...."[5]

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1 The President offered the following guidance to the Commission in establishing an IROR mechanism:

> Within certain maximum and minimum levels, return on equity would increase were the project to come in at or under budget but decrease were costs to exceed budget. Were the project under budget, consumers would pay a lower price for gas and sponsors would receive a higher return on equity. Were the project over budget, the higher total invested capital would be partially offset by a lower allowed rate of return on that capital, so that equity investors would assume part of the cost overrun.

President's Decision at 123.

2 Order 31 at 15

3 Order 31-B at 7-8.

4 See the Commission's April 28, 1980 "Findings and Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas," Northwest Alaskan Pipeline Company, et. al., Docket Nos. CP78-123, et. al., at 95.

5 Order 31-B at 8.

(3) OFI Review and approval of the cost of design changes which occur between the time the CCE is approved and OFI approval of final design, pursuant to "...a liberal design change policy...."[1]

(4) OFI review and approval of the cost of certain scope changes which occur after construction commences and which are beyond the control of the sponsors.[2]

The final target costs against which Alaskan Northwest's return will be measured will equal the CCE, as adjusted for the cost of design and scope changes, multiplied by the Center Point.

B. Alaskan Northwest's CCE and Center Point Requests

Alaskan Northwest has assembled a team of over 400 highly experienced cost estimators, cost engineers, design and pipeline engineers, and other experts representing every discipline necessary for estimating, designing, engineering, constructing, and controlling the cost of a project of the magnitude of the ANGTS. The companies working with Alaskan Northwest in this effort, and who assisted in the preparation of the CCE and Center Point values, include Fluor Engineers and Constructors,the Project Management Contractor, Gulf Interstate Engineering, Michael Baker, Jr., Inc., Northern Technical Services, Inc., and R&M Consultants, Inc. Also assisting in the preparation of the CCE were execution contractors who participated in the construction of TAPS, as well as many other multi-billion dollar construction projects in Alaska and Canada, including Morrison-Knudsen, Reading and Bates Construction Company, Peter Kiewit and Sons, Curran Houston Inc., a subsidiary of Sedco, and Green Construction Company. Collectively, Alaskan Northwest, Fluor, and these consultants spent over one year and more than 1,000,000 manhours preparing the CCE and Center Point analyses.

The approach utilized to prepare the CCE and Center Point has been referred to as the "four basket" approach. That is, costs have been assigned to the following categories, as required by Orders 31 and 31-B: 1) the base engineering estimate; 2) normal contingency; 3) abnormal events for the Center Point value; and, 4) design and scope changes.

The approach includes a risk analysis which quantified the "probability distribution of possible cost outcomes." The results of this risk analysis are shown

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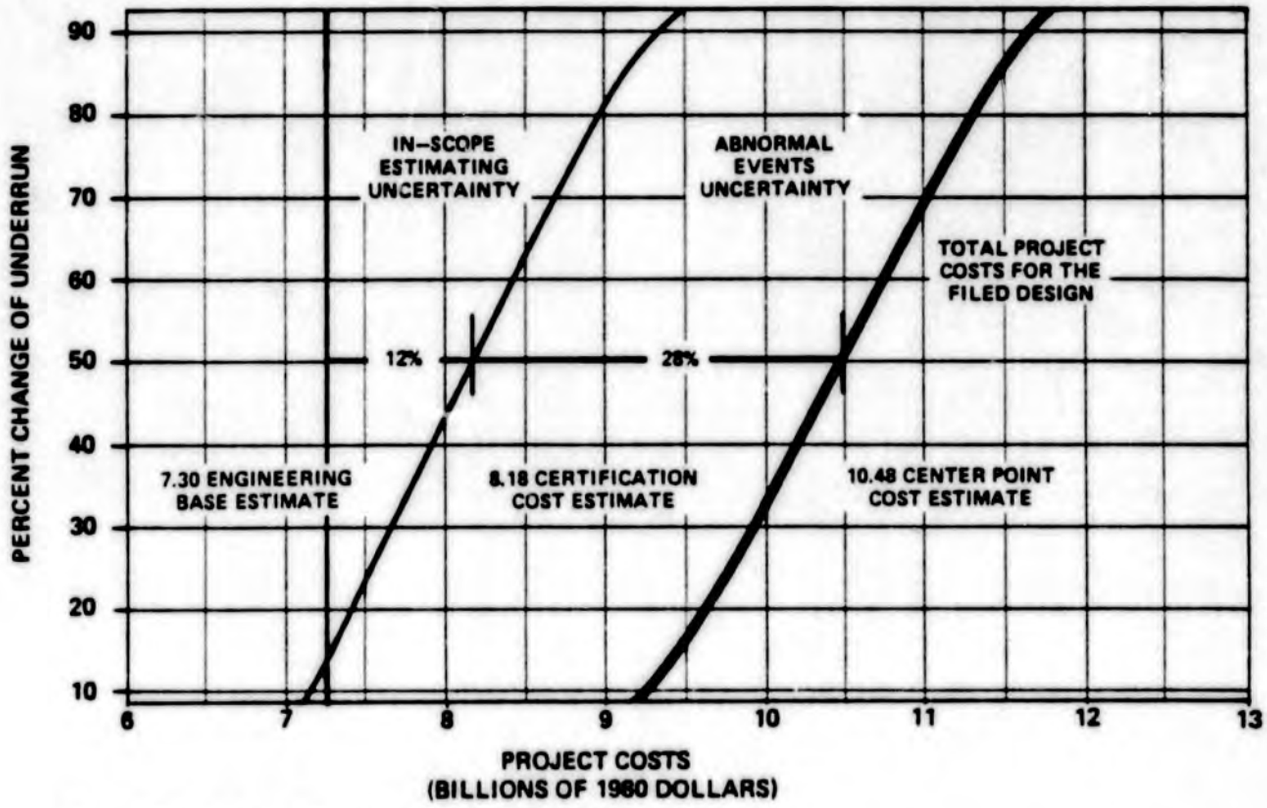
1 Order 31 at 17. The Commission adopted this policy in recognition that the CCE would be approved at a time when project design was far from complete. Accordingly, the Commission concluded that the IROR mechanism must "...accommodate changes in cost estimates attributable to increasing knowledge of design requirements...." Id.

2 Order 31-B at 73-75.

in the figure below. As the figure shows, the filed Center Point target cost of $10.48 billion has an even chance of underrun or overrun, i.e. it is the risk neutral target cost.



1. The Base Engineering Estimate

In preparing the base engineering estimate, Alaskan Northwest obtained written bids from various suppliers of major materials and equipment such as the pipe itself, valves, compressors, turbines, power generation units, and refrigeration equipment. Quotes were obtained for corrosion coating, insulation, and major construction equipment. To ascertain the optimum levels of crew and equipment necessary to meet the project schedule, Alaskan Northwest, Fluor, and the execution contractors established the optimum level of crew and equipment productivity that must be maintained over the three year construction schedule. Alaskan Northwest and Fluor then proceeded to cost out these crews based upon existing craft labor rates in Alaska. Construction equipment costs were based upon new equipment prices depreciated in a traditional fashion. The resulting base estimate equaled $7,302 million, broken down between work components as follows: 1) $4,285 million for pipeline; 2) $693 million for compressor and metering stations; 3) $53 million for operation and maintenance facilities; 4) $97 million for communications and supervisory systems; 5) $927 million for temporary facilities and services; and, 6) $1,247 million for project directorate, which includes project management costs such as salaries and related expenses, third party monitoring costs, insurance, and taxes.[1]

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[1] These were the CCE values requested in the July 1980 filing. The CCE values for which Alaskan Northwest is here requesting Commission approval are set forth in the table on page 4 of these comments.

2. Normal Contingency

A normal contingency was added to this base estimate to reflect the normal uncertainties in putting together such an estimate. In order to avoid any double counting between the base estimate, contingency, design and scope changes, and abnormal events, the contingency was carefully defined prior to establishing the base estimate to represent in-scope estimating uncertainty resulting from the following: accuracy of material quantity estimates; accuracy of material price estimates; human productivity assumptions; equipment reliability assumptions; engineering/design development; accuracy of scheduled durations; and, accuracy of bid specifications based on current project definitions. Utilizing a probabilistic analysis where both potential increases and decreases are weighed, the appropriate contingency was then determined to be $876 million, or 12 percent of the base estimate.

3. Center Point

In Order 31-B the Commission requested Alaskan Northwest to prepare an exhibit assessing "...the likelihood of abnormal events that could increase costs..." which exhibit would then"...be used to set a Center Point...."[1] Accordingly, Alaskan Northwest identified 35 specific abnormal events that could increase project costs, plus an additional category of cost impacts recognized in major projects as "unknown-unknown" events, and prepared an analysis of the risks of cost overruns from these abnormal events.

Because the Commission wanted "...a clear separation and distinction between the basic cost estimate itself and allowances for abnormal or unexpected events that may or may not occur..."[2] the list of abnormal events was carefully screened to ensure that: 1) events could be quantified separately and, thus, there would be no double counting between events; 2) no event could be considered a design or scope change, since the CCE will be adjusted to reflect the cost consequences of design or scope changes approved by the Federal Inspector; and, 3) no similar event had been included in contingency, because Orders 31 and 31-B require that the Center Point cover only the cost impacts of abnormal events.

In the detailed risk analysis, each event was assigned a probability of occurrence and a range of cost impacts by experts of Alaskan Northwest and Fluor experienced in preparation of risk analyses. A probabilistic analysis was then performed to derive the expected value of each abnormal event. The expected values of the abnormal events were added to arrive at the total dollar impact of potential cost overruns from the CCE. The CCE of $8.18 billion (base estimate plus normal contingency) plus the allowance of $2.30 billion for abnormal events divided by the CCE yielded a Center Point Ratio of 1.28.[3]

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1 Order 31-B at 8.

2 Order 31-B at 7.

3 Alternatively, the Center Point can be calculated with the formula:

$$\text{Center Point} = 1.0 + \frac{\text{expected value of abnormal events}}{\text{CCE}}$$

III. DISCUSSION

A. Alaskan Northwest's Methodology for Preparing the CCE and Center Point Values was Valid

A common theme throughout the Report is that the "four basket" approach "conflicts with the intent and/or letter of the IROR Orders," that the approach "...is not a familiar one to estimators," and that "its implementation by anyone would be difficult before the project is actually constructed."[1] From this, the Report presumes that certain costs have been overstated because estimators could not have possibly categorized costs properly between the "four baskets" to arrive at a risk neutral estimate and because "[n]either contractors nor engineering/design firms typically prepare risk-neutral bids or estimates."[2] Accordingly, the Report recommends adoption of certain reductions in the CCE itself based upon WBEC's belief that a higher productivity could be achieved with less labor and equipment and that civil materials are overstated.

The Report also recommends a reduction in the Center Point value, again because of an intuitive feeling that the values are overstated due to the estimators' inability to estimate costs under a "four basket" approach, because certain abnormal events allegedly were compensated for in the IROR Risk Premium, and because of a belief that cost overruns on other projects at a similar design stage were not as great as the Center Point request.

The Report's conclusory statements on the "four basket" approach and risk neutrality are not supported by Orders 31 and 31-B, traditional cost estimating procedures, the methodology utilized in preparation of the CCE and Center Point values, or a valid, factual comparison of this project with others at various design stages. Yet, the Report uses these statements as justification for recommending adoption of the WBEC audit and rejection of the filed CCE in each instance where the WBEC audit is lower. The Report also places great reliance on these statements in arriving at its Center Point recommendation. Because these statements are demonsteably invalid, the Report's recommendations must be judged by weighing the opinions of WBEC, based upon its construction and construction management experience, the facts and input available to WBEC in preparation of its audit, and the detailed support behind that audit, against the opinions of the Alaskan Northwest estimating team based upon their construction and construction management experience, the facts and input available to them in preparation of the CCE and Center Point values, and the detailed support behind the Alaskan Northwest filing.

1. The "Four Basket" Approach

Contrary to the Report's allegations, Orders 31 and 31-B required utilization of the "four basket" approach. Those orders required submission of a CCE, consisting of a base estimate and separate contingency allowance, and the separate submission of an exhibit dealing with abnormal or unexpected events which would be utilized to establish a Center Point value. Those orders also adopted design and scope change mechanisms which require that such changes be examined

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[1] Report at II-8 and III-18

[2] Id. at II-6.

separately from the CCE and Center Point. Finally, the Commission in those orders did not find that the cost segregation requirement would be either difficult or impossible, or that the requirement would inherently result in cost duplication. The Report's allegations are nothing more than a collateral attack on the IROR process itself established in Orders 31 and 31-B.

Additionally, the allegation that the "four basket" approach is not familiar to estimators and cannot be implemented ignores normal estimating practices. Historically, major engineering and construction firms utilize a segregated estimating approach, albeit not in the regulatory context, for providing clients with the expected cost of a project. For example, contractors do not include in an estimate the cost of potential design changes because: 1) there normally is no basis for estimating such costs since there can be no scope of work on design changes until such changes are defined; and 2) inclusion of costs for possible design changes not yet known would render the estimate or bid uncompetitive. Contractors historically seek and receive compensation for all work performed outside of a very rigid and precise scope of work definition, a definition which excludes all potential design changes. Abnormal events are also segregated because such events are outside the control of the contractor, but instead represent a risk to the project owner for which the contractor will be reimbursed. The contractor is protected against these risks by various contractual provisions including force majeure clauses. While contractors exclude these costs from bids, they represent real costs to the project owners.

Finally, it is inexplicable for the Report to conclude that the Alaskan Northwest estimating team could not have properly categorized costs between the "four baskets" to arrive at a risk neutral estimate, but that the authors and their consultants could properly perform this task, even to the extent of creating a "fifth" basket entitled "assigned contingency."[1] The Report's conclusions are even more disturbing given WBEC's admitted unfamiliarity with the IROR mechanism and the limited time available to them to conduct their audit.

2. Risk Neutrality

The Delegate and Division Director's apparently intuitive, but unsupported belief that the CCE and Center Point values are too high is particularly evident in such statements as:

> ...ANNGTC's base estimate plus "contingency" reflects a degree of assurance well above the target envisioned by the IROR. While it is impossible to assess exactly how much the ANNGTC CCE is above the roughly 50% assurance level, we suspect it is somewhere in the mentioned 70-80% range.[2]

and

> ...one would expect a risk-neutral estimate to be below what would be estimated in a commercial setting. We have concluded that Alaskan Northwest's proposed CCE overstates risk-neutral construction costs."[3]

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1 See, e.g., Report at III-19.

2 Draft Report at II-9 (emphasis added).

3 Report at II-6.

The authors' intuitive beliefs are contrary to the overwhelming historical evidence and experience that commercial cost estimates which underestimate actual costs are the rule rather than the exception.[1] The Commission itself recognized this in Order 31 at page 43 stating:

> Common observation as well as historical and statistical studies of many different types of large projects have revealed a tendency for the estimates of total cost-to-completion to increase as a project moves over time from initial conception to completion. In the early stages of a project this growth often reflects the study required to turn an idea into a detailed set of plans and specifications. In the process of research, evaluation, planning, and budgeting, natural initial optimism is tempered by more realistic appraisals; and in the usual case, unperceived complexities are discovered and the difficulty of the required tasks becomes better understood. (footnote omitted).

Ignoring this historical evidence the Report attempts to bootstrap its risk neutral assertions by comparing TAPS at its April 1975 stage to this project, where the CCE and Center Point were prepared at a 5 to 10 percent design frozen as of the First Quarter 1980 in order to prepare the CCE filing, and concludes that further cost overruns for completion of the Alaskan segment should not be any more than the 23 percent experienced by TAPS from 1975 to completion. This conclusion has no basis in fact. The TAPS April 1975 estimate was made two years before project completion, when design engineering was 90 percent complete, the haul road was completed, all mainline pipe was purchased and delivered, all other major equipment and vessels were on order, construction camps were in place and in operation, the project labor agreement had been executed, labor rates had been established, mobilization was nearly complete, execution contractor manning schedules were established, field construction work for the pipeline, stations, and terminal had started, and major support contracts had been awarded and executed. Based on the above, it is beyond question that a comparison of where TAPS was in April 1975 with where this project was at the time the CCE was prepared is not valid. We would note that the TAPS 1973 estimate of $4.09 billion, excluding contingency, was prepared when TAPS was at a comparable stage with Alaskan Northwest, and the final cost of TAPS was approximately $8 billion,[2] or 95 percent over this 1973 estimate.

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1 The Rand Corporation, "A Review of Cost Estimation in New Technologies: Its Implications for Energy Process Plants," Report No. R-2481-DOE (July 1979); Walter J. Mead, et al., "Transporting Natural Gas from the Arctic, the Alternative Systems," American Enterprise Institute for Public Policy Research (AEI Studies 171), Washington, D.C. (1977); Department of Energy, United Kingdom of Great Britian and Northern Ireland, "North Sea Costs Evaluation Study," Energy Paper No. 7 (December 31, 1975); and United States General Accounting Office, "Report to Congress of the United States, Lessons Learned from Constructing the TransAlaska Oil Pipeline," Report No. EMD-78-52 (June 15, 1978).

2 The difference between the 1973 TAPS estimate, which was computed in "as spent" dollars, and the final TAPS cost is substantial even when the 1973 estimate is adjusted for any inflation.

The Report attempts to dismiss the differences between TAPS in 1975 and this project at its January 1980 stage by asserting that reduced uncertainties about labor and equipment productivity should offset any increased risk of cost growth and that Alaskan Northwest is free to submit design changes to OFI. Thus, the Report concludes that Alaskan Northwest should be able to live with the risks associated with a lesser design.[1] Alaskan Northwest is at a loss to understand how these bald assertions create a meaningful comparison. First, what has suddenly caused this reduced uncertainty about labor and equipment productivity? It certainly is not the Report itself, which ignores the crew and equipment productivity estimates of EC's working in Alaska and recommends substituting WBEC's more optimistic views. Second, even if the design change process is not modified or restricted as the Report recommends, that process alone is not the panacea for the cost overruns that can and do increase initial estimated costs by as much as 50 to 100 percent through completion. Thus, a comparison of this project with the Report authors' unsupported conceptions of TAPS provides no justification for their view that the CCE and Center Point are not risk neutral.

Finally, we note that underlying biases, whether consciously or unconsciously motivated or simply due to ignorance, can have a considerable influence on an estimate. The sources cited by the Report itself, such as the GAO Report, confirm this point. In fact "estimating philosophy" (the intention of the estimators) is generally recognized as one of the major factors contributing to estimator error. Therefore, it is incumbent on the Commission to evaluate the predisposition of the Report and WBEC.

The Report and WBEC clearly reflect an underlying bias -- namely, that Alaskan Northwest and its contractors must have tried to inflate their estimates. The whole tone of the WBEC audit reflects a predisposition to search for overestimation. Furthermore, audits are by nature specifically suited for finding errors in stated costs rather than identifying missing cost elements. The WBEC process is, therefore, clearly biased downward.

The assumption that Alaskan Northwest had a bias toward an inflated cost estimate fails to recognize the actual balance of pressures on Alaskan Northwest. The countervailing pressure being that a higher target cost makes the project more difficult to finance and adversely affects marketability projections. As a result, the filed estimate was built under constant exhortation to realism. It is not inflated and represents the best and most realistic judgment of the Alaskan Northwest estimating team.

B. The Recommended Reductions to the CCE are Arbitrary and Unsupportable

The Report finds the CCE is within "... a range of estimated costs within which the Alaska Segment of the ANGTS can be expected to be built," and that the CCE and independent WBEC audit "are close enough to corroborate each other...."[2] The Report further finds that:

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1 Report at III-28.

2 Report at II-5 and 6.

> A cost estimate, by definition, cannot be exact. It is a "best judgment" based on a variety of factors. These factors include past experience, the complexity of the estimate, the design and its degree of development when the estimate is prepared, the instructions given the estimators, the assumptions underlying the estimate, and the amount of information available to the estimator. Thus, individual estimators may disagree, not only on the selection of a "best" figure, but also on the odds they would assign to completion of a project within a given cost range.[1]

Alaskan Northwest agrees that cost estimation is not an exact science and that estimators will disagree. Yet, the Report accepts and urges adoption of all the reductions to the CCE recommended in the WBEC audit and continues to ignore the experienced judgments of Alaskan Northwest, Fluor, and their consultants on areas of disagreement, even where Alaskan Northwest demonstrated in its April 13, 1981 comments on the Draft Report[2] that the WBEC audit was factually incorrect or premised upon erroneous assumptions or information. Reasoned decision-making requires more. Accordingly, Alaskan Northwest must again address each of these disputes and indicate why the WBEC audit should not be adopted. For brevity, we will incorporate by reference whereever possible our prior comments.

1. Pipeline

The Report recommends a $612 million reduction to the pipeline component of the CCE based exclusively on the WBEC audit conclusions that: a) a higher rate of productivity can be achieved in laying the pipe; b) the project schedule can be met with a reduction in certain other crews and equipment; c) overhead and profit for both execution contractors and certain subcontractors can be reduced; and, d) civil quantity materials can be reduced based upon new design drawings prepared by WBEC itself. We address these conclusions separately.

a. Pipeline Lay Rate

The crews and equipment involved in laying the pipe were estimated based on achievement of an average lay rate of 40 joints per day for 80-foot, double jointed, non-insulated pipe and 35 joints per day for insulated pipe.[3] This rate was collectively arrived at by the execution contractors who assisted Alaskan Northwest and Fluor in the preparation of the CCE and is based upon their prior arctic experience, including TAPS where each of these execution contractors achieved a much lower average lay rate, generally 25-30 joints per day. Their justification for a 30 to 40 percent higher lay rate for this project vis-a-vis TAPS is that, unlike TAPS, the Alaskan Northwest execution contractors will exercise total control over their pipeline spread under fixed price contracts, including all labor relation matters.

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1 Id. at II-6.

2 Comments of Alaskan Northwest Natural Gas Transportation Company on the Draft Report of the Alaskan Delegate and the OFI Division Director (filed April 13, 1981) (hereinafter cited as April 13, 1981 Comments).

3 An average lay rate of 40 joints per day means that on some days a higher lay rate will be achieved, on other days a lower rate will be achieved.

1) WBEC's "Time and Motion Estimate"

WBEC justifies a $172 million reduction to the CCE by utilizing a higher lay rate than that contained in the CCE. WBEC's lay rate is based on what WBEC refers to as a "time and motion estimate," which is actually only a subjective WBEC time estimate of a portion of one crew in the pipe laying process. In our April 13, 1981 comments on the Draft Report,[1] we noted that in preparing this "time and motion estimate" WBEC had clearly underestimated the time required for certain lay rate operations and completely ignored other necessary operations.[2] For example, WBEC recommends a welding speed of 14 inches per minute. Our experience is that this speed will produce an unacceptable percentage of defective welds, and this is corroborated by the Alaskan Welding Center and Exxon Production Research Company, who both claim the optimum welding rate for high grade 48-inch, X-70 grade pipe is 8 to 12 inches per minute. WBEC's response is that the Alaskan Welding Center materials did not describe the tests they performed and that since EPR admits that pipeline welders can work at higher speeds than 12 inches per minute, albeit with a higher weld rejection rate, the EPR recommended optimum speed should be rejected.[3] Suffice it to say that six execution contractors and two highly regarded welding experts recommend a speed lower than WBEC's speed for one obvious reason: the higher speed increases the risk of defects and costly weld repairs.

The integrity of the pipeline is paramount and high quality first time welding is more conducive to this integrity than excessive repairs regardless of the repair quality. Alaskan Northwest would note that "optimization" of a higher weld rate by acceptance of more repairs is not common construction practice for pipelines. Moreover, there could be special problems in Alaska if such an "optimization" were performed and high reject rates were encountered. For example, the time to radiograph, analyze, locate, and repair defective welds would require the ditch to be open for longer periods of time. This could be a serious problem in permafrost where thawing and degradation occur. The alternative to leaving the ditch open would be to make repairs in bellholes after the pipe is buried, an uneconomic procedure. Furthermore, defects which involve cracks in root beads require that the entire weld be cut out and a "pup" joint inserted and rewelded. In this case, two complete girth welds are required. It is difficult to imagine that numerous repairs of this nature could be economic,

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1 See April 13, 1981 Comments Vol. 1 at S-1 to S-4; Vol. II at 1-1 to -13.

2 The Report's statement that we did not challenge WBEC's lay rate estimate is false. Report at II-10. WBEC's estimate was presented in the October 22, 1980 conference as a "working paper" "circulated...for purposes of discussion" which did not represent the official position of the Delegate or Division Director. October 22, 1980 Tr. at 21. Mr. Grassman of WBEC stated that "[i]t's strictly a work paper." Id. at 22. After an opportunity to review this work paper over the luncheon recess, we expressed our initial concerns with it. Id. at 23-35. Later when the discussion paper surfaced as the official position of the Delegate and Director, we performed a more thorough analysis of its shortcomings and made these known in our April 13, 1981 Comments. The Report, however, has chosen to ignore these comments.

3 WBEC Vol. I at 1-49.

and yet a higher welding speed will result in more "cutouts". The acceptance of a higher than normal defect rate would mean that in the event of an audit of radiographs, a proportionately higher number of possible defects would be identified. Under these circumstances, repairs would be made after the pipe had been buried, and the resulting cost increases would more than offset any savings from a faster weld rate. In summary, the "optimization" of weld rate and defect repair is not a common practice. The purported savings have not been demonstrated, and the prudence of this practice is questionable. Therefore, the assumption of such "optimization" is not appropriate for any cost estimate.

In addition to underestimating certain cycle times in preparing its time and motion estimate, WBEC also ignored certain critical work elements. More specifically, in its draft audit WBEC listed certain operations that take place in pipelaying and then assessed a time for each element. These cycle times were added to achieve WBEC's projected ideal lay rate. This ideal lay rate was then multiplied by efficiency factors to achieve WBEC's estimated lay rate. Both at the Tulsa technical conference and in our April 13, comments we questioned why WBEC neither listed nor estimated any cycle time for two critical operations: the sequences of striking multiple arcs and changing welding rods. WBEC admitted in its final audit that these cycle times were in fact not estimated, but claimed they were accounted for in the efficiency factors applied to their so-called ideal lay rate to obtain their estimated lay rate.[1] This answer is spurious at best. How can WBEC prepare a study which attempts to estimate the specific times allegedly necessary for each and every operation and then claim that those not included are accounted for in efficiency factors which WBEC had precisely defined to include only the impact of weather, terrain, and human and equipment productivity?

In its April 13 comments Alaskan Northwest noted that while a "time and motion estimate" is invalid because it will yield any result the preparer desires, the WBEC study would yield an average rate of only 39 joints per day rather than 47 to 50 joints per day if it is properly adjusted for those changes necessary to account for the operations ignored by WBEC and the weld speed rate reduction needed to avoid costly weld defects.[2]

WBEC admits that a "time and motion estimate" is not used by execution contractors to develop their lay rate estimates for final bids, that the time and motion estimate was created for this proceeding alone, and that its estimate "...was not intended to represent an EC type estimate, but rather was intended to represent an estimate (based on experience) that the EC's should be able to lay 45 to 50 joints per day."[3] Alaskan Northwest questions why WBEC would perform a study it admits is not prepared by execution contractors in submitting bids and why it should be relied upon?

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1 WBEC Vol. I at 1-44.

2 In arriving at 39 joints per day, no other changes were made to the inputs underlying the WBEC "time and motion estimate", including the efficiency factors which Alaskan Northwest agreed to originally with the understanding that they were premised, not on forgotten cycle time operations, but in weather, terrain etc.

3 WBEC Vol. I at 1-41, 1-50.

2) Other WBEC Lay Rate Estimates

Alaskan Northwest also must question why WBEC did not address the questions raised in Alaskan Northwest's April 13, 1981 comments (Vol. I at S-3) regarding WBEC's 30 percent increase in its current lay rate estimate over the estimate that it submitted in the competitive proceedings that led to the selection of Alaskan Northwest?[1] In that proceeding Mr. Franks of WBEC, who prepared the WBEC "time and motion estimate" for this proceeding, testified that an average year-round lay rate of approximately 2,640 feet per day, or 33 joints per day, was reasonable for a proposed 800 mile, 42 inch pipeline which would have paralleled the majority of the Alaskan Northwest route. Mr. Franks now estimates a rate of 3,760 to 4,000 feet per day, or 47 to 50 joints per day, over essentially the same route even though larger diameter pipe will be utilized thereby increasing the amount of weld time.

Additionally, Mr. Franks has recently supplied Sohio with WBEC's estimated pipe lay rate for new flow lines to be constructed between 1982 and 1985 at Sohio's Prudhoe Bay facilities.[2] Those average rates for smaller pipe between 20 and 36 inches in diameter are significantly less than Mr. Frank's prior two estimates for an Alaskan gas pipeline. For example, WBEC's estimated lay rate for Sohio's 36 inch pipe ranges from a low of 936 feet per day during winter construction to a high of 1,560 feet per day for summer construction. This compares to their 1975 lay rate in the El Paso Alaska comparative hearings of 2,640 feet per day for 42 inch pipe and their current "time and motion estimate" of 3,760 to 4,000 feet per day for 48 inch pipe. We question how WBEC can now significantly increase its 1975 estimate presented to the Federal Power Commission from 33 joints to 47 to 50 joints per day for the Alaska Segment and why WBEC then estimates a much lower lay rate for Sohio's Prudhoe Bay work?

3) Comparison with Alyeska

WBEC alleges that Alaskan Northwest should obtain a higher lay rate than Alyeska. We do not disagree. In fact our estimate is significantly higher than that actually obtained on TAPS on a joints per day basis. In addition, Sohio Gas Pipeline Company has compared the actual weld productivity for Alyeska with that estimated by Alaskan Northwest on an average manhour basis, which comparison demonstrates that Alaskan Northwest's estimated productivity is optimistic compared to the actual TAPS experience.[3]

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1 See Tr. 35017, El Paso Alaska Co., et. al., FPC Docket No. CP75-96 et. al.

2 See Appendix A, letter of Arlie M. Skov, Sohio Gas Pipeline Company to Cuba Wadlington, Jr., Northwest Alaskan Pipeline Company, dated September 15, 1981. WBEC supplied these estimates to Sohio Construction Company in September 1981.

3 See Appendix B, letter of V. A. Breitenbach, Sohio Gas Pipeline Company to Cuba Wadlington, Jr., Northwest Alaskan Pipeline Company, dated September 15, 1981.

4) Actual Lay Rate Experience

The Report cites the reported lay rates of 70 to 80 joints per day achieved by spreads on the Western Leg and Western Delivery System in support of its adoption of the WBEC's lay rate estimate as superior to Alaskan Northwest's.[1] This is a misuse of the data, because terrain, weather, and soil conditions are much more favorable to construction of the Western Leg and Western Delivery System and smaller diameter pipe is being utilized. Thus, this lay rate experience is not indicative of what can be obtained in Alaska. Also, as previously discussed, these spreads experienced high rates of defective welds. This practice would not be cost effective in Alaska and would require leaving the ditch open an excessive length of time. Melting and ditch cave-ins would occur in permafrost areas.

5) Lay Rate Productivity Summary

In addition to the obvious errors in WBEC's "time and motion estimate" and the unexplained inconsistency between the three WBEC pipeline lay rate estimates for arctic construction, Alaskan Northwest questions how much reliance can be put on the judgment of WBEC, given that the individuals at WBEC who argue that 45 to 50 joints per day can be achieved have had no recent experience in the management and construction of major arctic projects.[2] The Report places total reliance on the WBEC lay rate estimate, with no weight given to the execution contractors assisting Alaskan Northwest who have far more arctic construction experience than WBEC. Alaskan Northwest recognizes that any estimate contains certain subjective judgments. Yet, objectivity in decision-making requires weighing and evaluating the judgments of all who have experience in a given field. To do otherwise taints the credibility of the conclusions reached. Alaskan Northwest submits that the evidence does not support WBEC's recommended lay rate reduction of $172 million and that such recommendation must therefore be rejected.

b. Reductions of Crew and Equipment

1) WBEC's Reduction in Crews to Achieve its Estimated Lay Rate

Once an estimated lay rate was determined, Alaskan Northwest, Fluor, and the execution contractors established the crews and equipment required to meet that lay rate. WBEC would not only impose a higher lay rate, but also reduce

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1 Report at II-11.

2 WBEC is involved in the business of designing and engineering projects, but does not participate in actual construction of such projects. Although prior to 1975 WBEC was a division of the Williams Companies, which had a separate construction division, the individuals of WBEC who performed the audit either did not work for the construction division, and therefore have no actual construction experience, or have little recent major arctic construction experience and little, if any, experience on TAPS construction management. See Appendix C, letter of Larry J. Bump, Chairman and President, Williams International Group, Inc., to R. N. Hauser, Vice President, Northwest Alaskan Pipeline Company, dated September 14, 1981.

all of the crews and equipment to be utilized.[1] As explained in our April 13, 1981 comments, even assuming a higher lay rate might be obtained, and assuming crews and equipment could be reduced, any such reductions must be limited only to the duration of those crews directly involved in pipe laying operations -- stringing, welding, firing line, coating, and insulation. The other crews were established independent of the lay rate estimate, a point WBEC seemingly does not now dispute stating that "...most pipeline lay operations require specific crews and equipment regardless of the progress rate."[2] The maximum cost reduction, assuming both a higher lay rate and a reduction in the above-referenced crews, is only $16.87 million. Yet, WBEC still recommends reducing all pipe laying crews and equipment for its resulting $172 million recommended cost reduction. Given WBEC's admissions its $172 million recommended reduction must be rejected.

2) Optimization of Other Crews and Equipment

In its audit WBEC assumed that Alaskan Northwest did not optimize crews and equipment and recommends a $195 million reduction to the pipeline portion of the CCE. WBEC's assumption is untrue. In constructing the CCE, crews were built to perform various work assignments, based on certain quantities of total production required, i.e. footage of pipe, cubic yards of gravel, clearing and grading, ditch excavation. Productivity rates for each crew were then established. An hourly rate was applied against these numbers of men and equipment, resulting in a cost for utilization of equipment during that specific period of time. These rates are based on recapturing 70 percent of the purchase price of a piece of equipment during its useful life on the project, not on its used life.

This method of computation within each spread of the pipeline system is a common practice in the construction industry and automatically optimizes the total equipment required for the project. Thus, when one operation is completed, another utilizing the same equipment begins and the equipment is automatically moved to that site and utilized there, thereby providing a leveling effect on equipment usage.

The construction work on various segments of the system will be performed concurrently by separate independent contractors. Since this work will be performed under fixed price contracts, equipment interchange between sections cannot be dictated by Alaskan Northwest. Moreover, it would be impractical to move equipment from Northway to Prudhoe for 3 or 4 days work in order to achieve an academic or theoretical leveling effect. In the real world, the concept of computation of crews on usage time only results in an automatic optimization within each segment.

As with the lay rate, the Report recommends total adoption of WBEC's recommendations on crew and equipment reductions and completely ignores the collective judgment of those execution contractors who assisted Alaskan Northwest and Fluor in establishing crew and equipment sizes. Again, the lack of objectivity

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1 WBEC recommends the crew size reductions even though it admits that such reductions may be directly contrary to the terms of current labor agreements.

2 WBEC Vol. I at 1-50.

in the Report is apparent by the absence of any discussion of why the collective judgment of the Alaskan Northwest estimating team is wrong. Nor is there any discussion in the Report as to how crew and equipment reductions will permit accomplishment of the same work in a shorter time frame. The obvious answer is that it cannot. Accordingly, the recommended $195 million reduction must be rejected.

c. Overhead and Profit

1) Execution Contractors

WBEC recommends that overhead and profit for the execution contractors be reduced from 18 percent to 15 percent, or $105 million. In its March 1981 draft report WBEC attempted to justify this recommended reduction by alleging that: 1) "all of the risk (to the EC's) has been removed by low production rates;" and, 2) there is profit embeded in the CCE's equipment rental rate assumption that the execution contractors will recover 30 percent of the cost of new equipment through salvage value; that in fact the execution contractors will recover "60 percent" of the new value of their equipment due to escalation.

In its April 13, 1981 comments, Alaskan Northwest noted that: 1) WBEC's first justification was inconsistent with WBEC's prior assertions that productivity can be increased by reducing crews and equipment for many operations; 2) its second justification demonstrates a lack of understanding of Orders 31 and 31-B, which requires preparation of an estimate in base year dollars and prohibits any cost escalation therefrom; and, 3) it is inconceivable that an execution contractor would accept a 15 percent rate for overhead and profit given the requirement of the President's Decision that fixed price, not cost plus, contracts be utilized, and the fact that an execution contractor will have to commit all, or a substantial portion, of its management resources to this project alone.[1]

In its final audit, WBEC does not now challenge Alaskan Northwest's first and third assertions. Instead, it bases its recommendation solely on the assumption that the execution contractors will recover 60 percent of the new value of equipment through escalation. Again, it is contrary to Orders 31 and 31-B to substitute inflated dollars for base year 1980 dollars. WBEC's argument demonstrates its lack of understanding of those orders and the IROR mechanism. Second, WBEC's conclusions are premised upon the fact that the salvage value of 2½ year-old equipment "in top condition" utilized in the lower 48 states will equal 60 percent of the original purchase price. It is without question that salvage values for equipment utilized in Alaska are less than those utilized in the lower 48 states, given the harsh arctic climate and terrain. WBEC responds to this point by stating that "...it will be mandatory that EC's maintain this equipment rigorously."[2] Alaskan Northwest agrees. Execution contractors in the lower 48 states also maintain their equipment "rigorously." The fact still remains that the wear and tear on equipment used 2½ years in the lower 48 states is far less than in Alaska, even where both are maintained "rigorously." TAPS and other recent arctic experience bears this out.

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1 April 13, 1981 Comments Vol. I at S-23 to S-24.

2 WBEC Vol. III at 6-64.

WBEC responds to Alaskan Northwest's third assertion by gratuitiously expressing its preference for an alternative bonus/penalty fee concept, but then states that this concept did not enter into its recommended reduction. We presume WBEC now agrees that the fixed price contract requirement will enter into the execution contractors' evaluation of the appropriate overhead and profit allowance.

Given WBEC's apparent agreement with two of the three prior points raised by Alaskan Northwest in its April 13 comments on the Draft Report and the illegality and factual incorrectness of WBEC's only remaining justification, the recommended $105 million reduction must be rejected.

2) Subcontractors

WBEC also recommends reducing the subcontractors' overhead and profit for double jointing, thin film epoxy coating, and pipe insulation. Originally it based its recommendation on a belief that Alaskan Northwest made an error that was not corrected prior to filing, that the subcontractors' overhead and profit was intended to be identical to the execution contractors' overhead and profit allowance of 18 percent. WBEC was informed both at the Tulsa technical conference and in the April 13, 1981 comments that the correct figure was 25 percent not 18 percent, and that the 25 percent figure was obtained from subcontractors as their markup on current work. Nonetheless, WBEC refuses to withdraw its recommendation, but presents no new justification in support thereof. With no factual or historical basis that subcontractors would accept a reduction in overhead and profit for work on this project, vis-a-vis others, the $15 million recommended reduction must be rejected.

d. Civil Quantities

WBEC alleges Alaskan Northwest's estimated civil quantities are excessive and recommends a $124.8 million reduction in the CCE based principally on its own trench excavation and backfill analysis. WBEC bases its recommendations on the subjective judgmental differences between it and Alaskan Northwest on the amount of over-excavation that will be experienced relative to the neat design trench cross section, on measurement of yards of material to be mined, hauled and placed in bedding and backfilling, and on estimated hauling losses.

In its April 13, 1981 comments, as supplemented on June 2, 1981 following further technical conferences on this matter, Alaskan Northwest explained the purpose of the detailed design drawings prepared by the engineers and what those drawings represent, as compared to the cost estimates prepared from such drawings. The Alaskan Northwest and Fluor estimating team, including Morrison-Knudsen, Peter Kiewit, and Green Construction, all world leaders in civil construction, determined that the cost estimator must consider such factors as "the over-excavation necessary due to sloughing, bellholes at tie-ins, sidebends, water crossings, overbreak in the shot ditch, valve sites, and road crossings" which are not taken into account by the design engineers.[1]

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1 June 2, 1981 Response of Alaskan Northwest Natural Gas Transportation Company to Materials Filed by State of Alaska Pipeline Coordinator and to Data Request of Williams Brothers Engineering Company at 3.

WBEC now "...agrees that quantities in excess of the design drawings will be necessary to construct a pipeline."[1] However, WBEC proceeds to prepare its own ditch design drawings, compares them to those of Alaskan Northwest, and concludes that the latter contain excess allowances vis-a-vis the WBEC drawings. The Alaskan Northwest estimating team has examined the WBEC design drawings and believe those drawings are not realistic -- they do not provide sufficient allowances that will be necessary during actual construction, allowances which were necessary for the TAPS civil construction. Accordingly, its recommended $125 million reduction must be rejected.

2. Compressor and Metering Stations

The Report recommends a total reduction of $25.6 million in the $668 million contained in the filed CCE, as adjusted after the March 1981 technical conference, for the Compressor and Metering Station area. The Report's recommended reductions are based solely on the WBEC audit of the Compressor and Metering Station estimate. WBEC first audited the Compressor and Metering Station estimate as filed by Alaskan Northwest and recommend reductions of $14.7 million. WBEC then recommended additional reductions of $10.8 million based on special evaluations of alternative designs of certain items within the Compressor and Metering Station area. With the exception of a $9.7 million reduction for reduced refrigeration capacity, WBEC's recommended reductions are unjustified, and the Report's adoption of those recommendations is an arbitrary substitution of WBEC's judgment for ours.

a. Reductions in Compressor and Metering Station Area

WBEC recommends a reduction of $14.7 million in the Compressor and Metering Station area, as filed in the CCE. The vast majority of WBEC's recommended reductions, $8.3 million, is based on differences in judgment between Alaskan Northwest and WBEC on how much vendor shop inspection is necessary and the staffing levels for the technical engineering staff in the field and for quality control at the compressor and metering station construction sites. The remainder is principally accounted for by WBEC's erroneous conclusion that $4.9 million for testing of pipe welds had been provided for elsewhere in the compressor station estimate.

The recommended reductions in vendor shop inspection, quality control, and technical engineering staff are completely arbitrary and evidence a failure to grasp the complexity of this project. The levels provided for in the base estimate are necessary to ensure an adequate level of quality (as required by Federal Stipulations), effective management of construction, and cost control.

WBEC based the $4.9 million reduction on its casual observation that "[t]he Outside Services estimate of $4,927,000 for NDE inspectors appears to be a duplication of work contained in the piping estimate."[2] In fact, there was no duplication here. The alleged duplication is a continuing misunderstanding by WBEC of the Compressor and Metering Stations estimate.

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1 WBEC Vol. I at 1-72.

2 WBEC Vol. II at 2-20.

The $4.9 million covers non-destructive engineering tests (NDE) that will be performed, for the most part, on the high pressure gas piping in the compressor and metering stations. These tests, which include x-ray, magnetic particle, and dye penitrant tests, are necessary to assure the integrity of the welding. This testing is specialized and will be performed by an outside contractor. Of the $4.9 million, $2.3 million covers labor and $2.6 million covers material, such as x-ray film, cameras, trucks on which to mount equipment, and trailers to develop film.

The NDE costs included in the piping portion of the compressor and metering station estimate do no duplicate the above testing. These NDE costs cover support services that the x-ray contractor will require, such as scaffolding for access to welds and utilities required by the contractor, including water and electricity.

Furthermore, the recommended reductions are inconsistent with recommendations made elsewhere in the Report and in the WBEC audit. For example, as a justification for reducing our Center Point allowance, the Report alleges Alaskan Northwest failed to incorporate opportunities for effective management to limit cost overruns in the filed CCE.[1] Yet, at the same time the Report uses this justification to reduce the Center Point, it takes away the tools essential for effective management contained in the CCE by arbitrarily reducing the number of vendor shop inspectors, quality control personnel, and supervisory engineers necessary to control costs on a project of this magnitude.

Given the proximity of WBEC's evaluation to our estimate, we believe the WBEC evaluation confirms the reasonableness of our estimate, particularly when the difference is attributable chiefly to differences in judgment. Moreover, the substitution of WBEC's judgment for that of Alaskan Northwest, whose estimators are much more familiar with the project, is arbitrary and totally unsupported. As the Commission recognized in its April 28 order approving Northern Border's CCE, items such as the level of construction supervision are for management judgment.[2] Therefore, the Report's recommended reductions of $14.7 million should be rejected.

b. Special Studies Reductions

Although we concur in the recommended reduction of $9.6 million in the CCE based on reduced refrigeration capacity, we disagree with the recommended elimination of $3.1 million for refrigeration testing and recommended reductions of $800,000 for full load, full pressure testing of compressors and $445,000 requiring a change in metallurgy for flare stacks.[3]

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1 Report at III-15.

2 April 28 Order at 102.

3 However, although we agree generally with reduced refrigeration capacity, we are not in complete agreement with the Staff on the necessary refrigeration capacity at each station.

1) Compressor Testing

The filed CCE includes $1.1 million for full load, full pressure tests for each mainline compressor unit to be installed at the compressor stations. These units will be new systems including some new designs. As explained in our April 13, 1981 comments on the Draft Report,[1] such testing is necessary, in addition to component testing, to ensure the reliable operation of the units prior to shipment to Alaska. Full load, full pressure tests in the manufacturer's shop will allow as much debugging as possible to take place in the factory, where costs, such as labor rates, will be significantly less than in Alaska.

While WBEC concedes that the full load, full pressure testing we propose to have performed is prudent and the average cost of $160,000 per unit we estimate for such tests is reasonable, WBEC arbitrarily decides that such tests are only required for two units. Consequently, WBEC recommends only $320,000 for full load, full pressure tests for two mainline compressors. However, prudent management dictates that all seven units be thoroughly tested prior to shipment to Alaska. Because two units have been debugged provides no guarantee there will be no problems with the others. While later units may not require as thorough testing as early units, all units will require testing beyond component testing to assure that all of the subsystems within each unit operate properly. Our plan to test all seven units is a reasonable cost and quality control decision and our estimate of the costs for such testing is reasonable. In addition, the reduction recommended here is arbitrary and inconsistent given its obvious conflict with the Report's allegation that we failed to take advantage of opportunities to limit overruns. Therefore, the full amount of $1.12 million should be approved.

2) Refrigeration Testing

Alaskan Northwest reduced its original estimate of $28 million to $3.1 million concurring with WBEC's recommendation to eliminate full load testing.[2] The Report recommends elimination of this $3.1 million on the ground that WBEC found that the testing covered by the $3.1 million had already been included in the base estimate for refrigeration equipment.[3] The Report's recommendation, however, shows a complete misunderstanding of this issue. The Report's discussion on Page IV-19 confuses full load, full presure testing for mainline compressors, which the Report and WBEC concede is appropriate, with such testing for the refrigeration systems (which also contain compressors). Actually, the basis for WBEC's recommendation was that the testing it covered was unnecessary, not that such testing had already been costed in the equipment estimate.[4] Furthermore, WBEC's recommendation to eliminate the $3.1 million is unjustifiable and would result in inadequate testing of refrigeration equipment.

WBEC's conclusion that component testing for the refrigeration systems is adequate and that the additional testing is unnecessary is unwarranted and

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1 April 13, 1981 Comments Vol. I at S-7.

2 Id. at S-9 and Vol. II at 1-30 to -31.

3 Report at IV-19.

4 WBEC Vol. II at 2-27.

inconsistent with its recognition that full load, full pressure testing of the mainline compressor units is appropriate and its criticism that we have failed to optimize resources.[1] The sub-system testing we propose is the most prudent approach to ensure that all equipment works in accordance with specifications and to minimize the possibility of cost overruns resulting from installation of a novel refrigeration system in a remote location. As much debugging as possible must be done in the shop in order to avoid the significantly higher cost of remedial work in Alaska. These refrigeration systems cannot be purchased "off-the-shelf". Unlike most refrigeration systems, these must be able to operate in two modes: refrigeration and free cooling. During the refrigeration mode the system operates similar to a conventional system, except that, instead of delivering a constant amount of refrigeration, it must be able to vary the amount of refrigeration produced depending on how much cooling capacity is required on a given day. In the free cooling mode, the system takes advantage of low ambient air temperatures in Alaska to conserve energy by turning off the compressors and circulates the refrigerant through the system by means of a pump.

Because the testing covered by the $3.1 million is reasonable and cost effective, the $3.1 million for refrigeration testing should be approved.

3) Flare Stack Metallurgy

The WBEC evaluation recommends that nickel alloy steel instead of stainless steel be used in the flare stacks at the compressor stations, except for the tips of the stacks, which would remain stainless steel. According to WBEC, this change in metallurgy will result in a total cost saving of $455,000.[2] Alaskan Northwest used stainless steel in the design for the flare stacks because, at the time of the CCE filing, Alaskan Northwest was confident this design would work. WBEC has not demonstrated the feasibility of its alternative design or that it would result in savings. Alaskan Northwest still believes its design to be technically feasible and cost effective.

In summary, the appropriate base estimate value for Compressor and Metering Stations is $658 million.[3]

3. Operations and Maintenance Facilities

The Report adopts WBEC's recommended reductions of $2.5 million in the base estimate of $53 million for Operations and Maintenance Facilities, because it found the WBEC reductions reasonable.[4] But, the Report also found that Alaskan Northwest's estimate of project costs was reasonable. The blind substitution of WBEC's evaluations for Alaskan Northwest's estimate is arbitrary and

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1 See, e.g., Report at III-15.

2 WBEC Vol. I at 1-100.

3 This value is our reconciled value of $668 million including $3.1 million for the refrigeration testing described above, less WBEC's figure of $9.7 million for reduced refrigeration capacity and miscellaneous reductions of $30,000.

4 Report at II-16.

evidences a single-minded determination to reduce the base estimate even though the estimate is admittedly reasonable and WBEC's recommendations are unsupportable.

For example, one of the largest of WBEC's recommended reductions in the O&M area is a $1.5 million reduction in pre-commissioning costs. This is based on WBEC's estimate of 480 man-months. However, WBEC also states that the real basis of its estimate is 13 crews of 12 men each for a four-month duration.[1] A simple calculation (13 X 12 X 4) shows that the WBEC evaluation is 624 man-months (not 480). As clearly stated in the filed CCE the workweek at a construction site is 70 hours long; however, WBEC used 52 hours per week. These two WBEC oversights change their evaluated manhours from 108,144 to 189,000 (624 man-months X 303 manhours per man-month). This exceeds the filed CCE value of 162,240 manhours. This simple analysis of WBEC's evaluation clearly shows this determination to reduce the estimate when there is no objective basis therefore and even when their backup indicates an increase.

Consequently, Alaska Northwest recommends that the Commission approve the filed base estimate of $53 million for O&M.

4. Communications and Supervisory Systems

WBEC agrees with the base estimate CCE for the communications and supervisory systems area.[2] However, the Report recommends that approval of a CCE value for communications be deferred until Alaskan Northwest submits a more detailed design and cost estimate for this item. We agree with this procedural recommendation and are in the process of developing a detailed communications cost estimate, which will be submitted for CCE approval in the near future.

5. Temporary Facilities and Services

Alaskan Northwest is requesting a CCE value of $900 million for Temporary Facilities and Services, including $439 million for camps.

The Temporary Facilities and Services base estimate includes costs for the purchase, renovation, and, where necessary, relocation of Alyeska camps for use by all personnel in the field during construction of the pipeline and compressor and metering stations. The CCE does not, however, contain any estimated costs for construction of either new camps or new campsites. Although the CCE filing is based on purchasing the Alyeska camps, purchase negotiations between Alaskan Northwest and Alyeska have terminated. Alaskan Northwest is therefore continuing to seek government permits to use existing campsites and is preparing a revised camp estimate based on the estimated costs of new camps. Also, although Alaskan Northwest submitted permit applications in the Fall of 1978 for 10 campsites on Federal lands, and substantial additional information relating to these applications was submitted to the government in May 1981, the permits still have not been issued. The Bureau of Land Management of DOI advised Alaskan Northwest by letter dated September 11, 1981 that several of the campsites are

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1 WBEC Vol. II at 3-8.

2 WBEC Vol. I at ES-5.

not approved for future use pending further consideration of other options.[1] Notwithstanding these developments, Alaskan Northwest is, in partial agreement with the Report's recommendation that the Temporary Facilities and Services portion of the CCE not be delayed by the breakdown in negotiations and delay in permits. The Commission can go forward with consideration of the CCE value for Temporary Facilities and Services based on Alaskan Northwest's filing.

If there are no further developments in the camp purchase negotiations, Alaskan Northwest will submit a revised estimate for new camps at the appropriate time. If this submission occurs prior to Commission approval of the CCE, it should be treated as an amendment to the CCE filing analogous to our October 1980 amendment reflecting the 200 foot separation from TAPS required by the DOI Right-of-Way Grant. If submission is after approval of the CCE, the submission will be to the Federal Inspector, and the revised estimate should be eligible for treatment as a design change, contrary to the Report's recommendation that a change to new camps not qualify as a design change, because any cost difference between existing and new camps "...would be considered to be a change in price and, as such, would not be eligible for a CCE adjustment pursuant to Condition 9...."[2] As more fully explained in the section of these comments concerning the design change mechanism, the Report's recommendation is without any basis in fact or the Commission's IROR orders. A change from existing camps to new camps, possibly at new locations, is obviously a change in design, techniques, and quantities and not merely a change in price.

Turning then to the Report's treatment of Alaskan Northwest's reconciled CCE estimate of $909 million for Temporary Facilities and Services, the Report recommends reductions of $41 million based upon WBEC's audit.[3] Alaskan Northwest agrees with only $8.2 million of the recommended reductions. As explained below, however, $32.8 million of the recommended reductions are without any basis.

a. Craft Labor Productivity

The principal basis of WBEC's reductions to Alaskan Northwest's estimate for camps was higher labor productivity assumptions.[4] No one, including WBEC, questions the fact that a significant decline in labor productivity in the heavy

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1 Letter from Curtis McVee, Alaska Director, BLM, to Harold W. Moles, Vice President, Northwest Alaskan Pipeline Company, dated September 11, 1981. See Appendix D.

2 Report at IV-10. Alaskan Northwest is also in disagreement with the Report's statement that the CCE for camps can be set at this time "...because the filed estimate includes a substantial amount of contingency related to the costs of providing camps...." Report at 11-15 n. 44. This statement is factually incorrect. The contingency for Temporary Facilities and Services was designed to cover uncertainties in estimating the costs of renovating existing camps, not the costs of designing and building new camps. In addition this contingency covers uncertainties in estimating the other components of Temporary Facilities and Services, including, for example, transportation and revegetation.

3 Id. at II-15.

4 WBEC Vol. I at 1-16.

construction industry has occurred from 1961-63 to date. Yet WBEC contends that the craft labor productivity contained within the 1961-63 U.S. Gulf Coast manpower estimates should be adopted as the productivity in Alaska during the temperate months in 1982-83. Accordingly, WBEC recommends an $18.9 million dollar reduction.[1] Alaskan Northwest believes WBEC may have meant to correct its final audit and withdraw this recommended reduction, because WBEC accepted a similar adjustment for labor productivity in the Compressor Stations estimate. Furthermore, the labor productivity used for the camps was increased over the value used for Compressor Stations in order to account for camp work being done during more temperate months and under less congested working conditions. Thus, Alaskan Northwest's labor productivity assumptions used in preparation of its camps estimate are consistent with productivity assumptions underlying the Compressor and Metering Station area and both are correct and should be affirmed. Conversely, the recommended reduction of $18.9 million should be rejected.

b. Cost of Borrow Material/Haul

WBEC reduced the estimated unit cost for gravel used in camp construction from $17 per cubic yard to $15 per cubic yard, which is the unit cost we estimated for gravel in the pipeline area of the CCE. WBEC's justification was that the increase from $15, which value WBEC accepts, to $17 was unexplained.[4] We, however, did explain that gravel used in constructing the camps will have to be hauled longer distances on average than borrow material used in pipeline construction.[5] Borrow material for the camps will have longer average haul distances because camp construction will begin prior to pipeline construction and fewer gravel pits will be available at the time of camp construction.

The difference in transportation costs for gravel between camps and other areas of the CCE justifies the higher unit cost of $17 per cubic yard for gravel used in building the camps. Thus, the Commission should reject WBEC's erroneous recommended reduction of $2.8 million in borrow costs.[6]

c. Foundation Cribbing Manhour Rates

The crew manhour rates for cribbing, which is the construction of timber foundations for the temporary buildings to be used in the camps, was derived from Means, a standard estimating handbook. Because there is no rate in Means for timber cribbing, we utilized the Means rate for a similar construction task,

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1 WBEC's reductions in craft labor total $18.9 million. See WBEC Vol. II at 4-40 ($5.5 million), 4-44 ($8.2 million), 4-47 ($690,000), and 4-52 ($4.5 million).

2 April 13, 1981 Comments Vol. III at 6-2.

3 WBEC Vol. III at 6-16.

4 Id. at 4-29.

5 April 13, 1981 Comments Vol. III at 4-39.

6 WBEC Vol. II at 4-30 ($475,800), 4-42 ($1.2 million), and 4-49 ($1.14 million).

concrete forming. To this rate we applied the productivity factor of 1.53, which is the productivity factor indicated by Means for this activity in Anchorage, Alaska.[1] WBEC claims that the use of this factor was inapproriate because it is a wage and material adjustment factor, not a productivity factor.[2] The simple answer is that WBEC has misread Means. Means shows separate factors for labor productivity (installation) and materials for concrete form work in Alaska.[3] The labor productivity factor listed therein is 1.532. That this is a productivity, rather than a wage and material factor, is also shown in the explanatory text of Means.[4] Thus, there is no basis for WBEC's rejection of Alaskan Northwest's labor productivity factor for cribbing, and the Commission should reject the WBEC's erroneous recommended reduction of $1.7 million.[5]

d. Other

Of the remaining $16.5 million in WBEC recommended reductions, Alaskan Northwest agrees with $8.2 million which principally results from the deletion of costs for freight and handling for revegetation materials.[6] Alaskan Northwest does not agree with $8.3 million of WBEC's reductions, which are less than 2 percent of our estimate. Because of the valid basis for our estimate and deficiencies in certain of WBEC's audit as described below, these reductions should also be rejected.

The contested balance of the recommended reduction of $8.3 million includes a $7.1 million reduction in the PMC expenses in Alaska for reprographics, communications, and expendables. Alaskan Northwest has provided additional backup for these cost items, including actual costs incurred to date by the PMC. The WBEC recommendation totally ignores this material. Our estimate for these items for Alaska is one-half our estimate of the same items for Irvine. Even though the PMC's actual expenses to date are exceeding the estimated expenses, WBEC recommends reducing the estimate. It simply does not make any sense to reduce an estimate when actual cost experience shows the estimate is already too low. This again demonstrates how arbitrary the recommendations are.[7]

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1 April 13, 1981 Comments Vol. III at 4-41.

2 WBEC Vol. II at 4-34 to -35.

3 Means (1981 ed.) at 290.

4 Means (1981 ed.) at 299.

5 WBEC Vol. II at 4-35 ($593,000), 4-46 ($27,460), and 4-51 ($1.07 million).

6 The $8.2 million actually results from several WBEC upward and downward adjustments to the CCE with which Alaskan Northwest agrees as follows: downward adjustments of $8.59 million for freight and handling of revegetation materials (Id. at 4-9) and $50,000 in EDP equipment (Id. at 4-21); upward adjustments of $12,000 in Intermediate Pipe Storage Yards (Id. at 4-25), $455,000 in Land and Land Rights (Id. at 4-26), and $193,000 in other Alaska Offices (Id. 4-57 and -58).

7 It also shows the bias to reduce the estimate. While WBEC elsewhere relies on events subsequent to the CCE filing to reduce the estimate, it refuses to consider such information where it could mean leaving the estimate as is or increasing it. See infra at page 36.

6. Project Directorate

The proposed CCE value for Project Directorate, as adjusted after the March 1981 technical conference, was $1.26 billion. Of this amount, the Report recommends that $225 million, representing the monitoring and socioeconomic costs submitted by the State of Alaska, be deferred for further subproceedings.[1] Of the remaining $1.0 billion audited by WBEC, the Report recommends that WBEC's reductions totalling $92.7 million be adopted. Most of these reductions are in project management ($38 million), taxes ($25 million), and insurance ($28 million). As explained below, there is no basis for the recommended reductions, and the appropriate base estimate value for Project Directorate, is $1.25 billion.

a. Project Management

The project directorate costs for Northwest Alaskan and the PMC are estimated to be $485 million. The Report recommends deferral of this item because OFI has not finally approved the management plan and, therefore, deferral is required because of the authors' view "...the management plan cost estimate, absent other events, should not be subject to alteration once approved in the CCE...."[2]

There is no basis in the President's Decision or the IROR orders for deferring approval of a CCE value for management costs. The President's Decision requires that "[p]rior to the issuance of the certificate, the successful applicant shall provide a detailed overall management plan, to be approved by the Federal Inspector, for the preconstruction and the construction phases of the transportation system project."[3] After numerous conferences between Alaskan Northwest and OFI personnel, Alaskan Northwest on June 2, 1980 transmitted the final draft of its Management Plan (dated May 30, 1980) to OFI. On June 6, 1980, OFI transmitted a letter to Northwest Alaskan stating "[t]he overall management framework and principles established in the May 30 draft are acceptable and approved."[4]

Additionally, WBEC's audit of the CCE corroborates Alaskan Northwest's management cost estimate. WBEC found that the CCE filing presented a comprehensive management philosophy.

There is no requirement that all detailed aspects of the management plan be approved prior to approving project management costs. The management plan is a "living document" which reflects the stage of the project. Thus, it would be unreasonable to expect that a complete and detailed overall managment plan be ready at the stage of the design at which the CCE filing was prepared. Further, the Federal Inspector's approval in principle of our overall management plan and

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1 Report at II-13 and n. 39. The Report recommends deferral of $203 million of socioeconomic costs and $22 million of monitoring costs.

2 Id. at IV-7.

3 President's Decision at 27.

4 See Appendix E, letter from John T. Rhett, Federal Inspector, signed by Peter L. Cook, to Darrell B. MacKay, Northwest Alaskan Pipeline Company, dated June 6, 1980.

WBEC's audit confirms the reasonableness of our estimate and provides a sufficient basis for approving a CCE value for the project management costs now.

Finally, the Report asserts that changes to the management plan cannot qualify as design changes. Management costs can be impacted where there is a design change and any such cost impact should be reflected in an adjustment to the CCE pursuant to Condition 9 of Order 31 along with the adjustment for the design change itself and that the management cost estimate is now ripe for approval.

In WBEC's audit of Project Directorate, WBEC recommends that the base estimate for project management be reduced by approximately $38 million, $9.7 million in the PMC's estimated costs and $28.6 million in Northwest Alaskan's estimated costs.

1) PMC

Of the $9.7 million recommended reduction for PMC costs, $4.0 million in reductions in home office expenses, benefits and burdens, and PMC's finance staff is unwarranted. For example, WBEC recommends reductions of $0.9 million in the PMC's Irvine office expenses, such as expendables and overhead and fee, on the basis the the Northwest Alaskan/PMC contract specifies a lower rate for these items than those contained in the CCE filing. The CCE estimates for these items, however, were based on the interim contract between Northwest Alaskan and the PMC, which was the only basis for establishing an estimate at the time of preparation of the CCE. For WBEC to now substitute the rates specified in the final NWA/PMC contract entered into subsequent to the CCE is like substituting actual for estimated costs, which is inconsistent with the Report's position that the CCE be based on estimated costs.[1] The $0.3 million deduction in finance staff and expenses[2] and the $2.8 million deduction for methodological difference in Irvine manhour extensions and recovery for days off[3] must not be made.

The PMC maintains that the PMC manhours included in the CCE were developed based on job requirements, organization charts, and job durations, and the man-hours required to accomplish specific tasks (such as drawings, specifications, flow sheets, and calculations). These manhours were calendarized for manpower planning (office space, hiring requirements, cash flows) by equating the manhours to equivalent people using a division of 36 hours per week. Since paid time off is frequently offset by additional overtime, for estimating purposes there is no methodological difference.

2) Northwest Alaskan

None of WBEC's recommended $28.6 million reduction in NWA's project management costs is justified. WBEC fails to grasp the magnitude of NWA's role as operator for the Alaskan Northwest partnership and the complexity of the project.

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1 Alaskan Northwest agrees with this position except where it has no control over costs such as government-related costs.

2 WBEC Vol. IV at 7-15 to -20.

3 Id. at 7-5 to -7 and 7-15.

A principal assumption underlying WBEC's conclusion that NWA's staffing levels are too high is that NWA is merely going to oversee and monitor the performance of the PMC. This is not the case. In addition to supervising the PMC, NWA's management responsibilities include financing, obtaining all necessary government permits, licenses, and certificates, acquiring rights-of-way, accounting, auditing quality assurance and quality control, public relations, and government liaison. Moreover, because of the unique nature of this project, there will be an unprecedented amount of government oversight, and NWA is responsible for responding to the needs and requirements of government agencies monitoring the project.[1] NWA must also respond to and coordinate the views of the ten-member partnership and the Design and Engineering Board. WBEC fails to comprehend the full scope of these responsibilities, which are far greater than those normally undertaken by the operator on a regulated utility project.

Furthermore, where WBEC's reductions are based on its subjective judgments and rule of thumb allowances, NWA's estimated costs are based on its actual historical experience. Our estimate is justified by our CCE filing and our April 13, 1981 comments,[2] which WBEC's audit fails to address and which the Report ignores.

For example, WBEC recommends the duties of the Records and Data Management staff in the Salt Lake City office be combined with and performed by the receptionist, courier, and administrative assistant. This naive suggestion demonstrates a complete lack of understanding of the complex and extensive records management. program required for this project, a program fully endorsed by the Federal Inspector.

WBEC reduces the Alaskan Northwest financial staff on the basis that their functions will be performed by the PMC supplemented by computer software to convert cost data for accounting requirements. This argument again reflects a lack of comprehension of the complexity of the financial affairs of NWA. WBEC ignores the demands on the owner's financial department created by a multi-billion dollar project.[3] To reduce this staff is unrealistic in the face of what will be the most costly pipeline project ever built.

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1 See, e.g., the various terms and conditions of the President's Decision imposed on the Alaskan Northwest partnership and its operator, Northwest Alaskan.

2 April 13, 1981 Comments Vol. III at 7-120 to -133.

3 For example, these demands flow from the following:

1) The fiduciary role of Northwest Alaskan as operator for a complex, multi-company, multi-billion dollar partnership requires continuous contact with the members of the partnership;

2) Requirements will be placed on the Operator by various institutions in the financial community to maintain a continuous reporting and communication network on the budget and financial position of the project;

3) The audit interface between government, owner, and public entities will surpass anything yet experienced by any project of this magnitude.

WBEC recommends reductions in three other areas -- General Services, Management Information Systems and Permit Acquisition -- on the basis that the PMC will provide these services. This recommendation ignores the complexity of the Management Information Systems necessary to support a project of this magnitude. A MIS from construction phase to operation phase must be performed by Owner/Operator personnel. While the PMC supports Northwest Alaskan's responsibility for all permit acquisitions, the final preparation, submittal, and interface with permitting agencies is the responsibility of Northwest Alaskan, not the PMC.

WBEC argues that operator camp staff should not be maintained during the winter months on the basis that a high turnover will occur each fall and that Northwest will hire and train new staff each spring. Alaskan Northwest will be exposed to costs whether the staff remains on during the winter or if turnover occurs since maintenance work is required during the winter. Additionally, WBEC's recommendation actually requires more costs for recruitment and training not included by Alaskan Northwest in its filed CCE. Thus, the costs to the sponsors will be similar whether staff remains in camp over the winter or NWA recruits and trains a new staff.

b. Taxes

WBEC suggests an overall reduction to the tax estimate based on the ratio of the total WBEC evaluated estimate to the CCE. At the outset we would note that WBEC's recommended reductions to the overall tax estimate must be rejected to the extent the Commission determines that the requested CCE values, not the values recommended in the WBEC audit, should be approved.

WBEC recommends that the CCE be reduced for the effects of a change in Alaska tax law which transpired subsequent to the date of the CCE filing. While it is true that the law was changed, the premise in Orders 31 and 31-B that the CCE be based on law existing at January 1, 1980 must be maintained. Alaskan Northwest finds it difficult to reconcile how the Report can accept this "tax law change" and reduce the CCE , but then recommend that changes in tax laws not be given design change treatment.

It is essential to recognize that taxes are non-controllable costs. As witnessed during the period since the CCE was filed, legislative bodies can and do change tax laws. Administrative bodies interpret, administer, and enforce tax laws and ordinances in an ever-changing manner. The Commission should not, as the Report recommends, penalize the project for any such changes. Alaskan Northwest asserts that legislative, interpretive, and administrative changes to tax laws must be treated as design or scope changes.

c. Insurance

WBEC recommends reducing insurance costs in the CCE by some $28 million, but provides no support for the rates it proposes. The rates utilized by Alaskan Northwest in preparation of the CCE were determined by contacts with the actual markets which will provide insurance. However, WBEC fails to indicate whether brokers can and will underwrite at its lower rates. Therefore, its unsubstantied opinions should not be adopted.

1) Excess Umbrella Liability Insurance

WBEC attempts to estimate by rule of thumb the appropriate Excess Umbrella Liability premium estimate. This is an invalid approach because: a) estimating excess liability premiums as a function of primary liability premiums on this particular project is not appropriate since we utilized a primary general liability factor approximately 700 percent lower than the rates that would have been produced had manual rating been used; b) excess Umbrella Liability underwriters on this project are dealing with known catastrophic exposures which could produce a policy limits loss; and, c) the Excess Liability Insurance must conform to the Mutual Indemnification Agreement which imposes many areas of strict liability and provides stringent requirements with respect to pollution coverage. Underwriters' acknowledgement and adherence to the Northwest Alaskan/TAPS Mutual Indemnification Agreement requires much broader coverage than that which would be required under a normal excess umbrella program.

2) Aircraft Liability

WBEC's estimated rate of $3,000 per aircraft year is not substantiated by a London desk quote. The $5,000 figure used in the CCE is substantiated by such a quote.

3) Ocean Marine Shipments

WBEC attacks the rate of 1 percent and advocates use of .7 percent, but offers no underwriting source for that rate. This is a rather small percentage difference, but when applied to a $2.5 billion base, the effect is quite profound. In addition to the rates quoted by Reed Stenhouse, the 1 percent rate was also advocated by Fluor's insurance broker, Johnson & Higgins, for marine shipments between West Coast ports and southern Alaska ports. While the 1 percent rate is endorsed by two major insurance brokers, the WBEC rate is unsubstantiated by any knowledgable insurance sources.

4) Inland Marine Shipments

WBEC again does not have any underwriting source that will write the insurance at its recommended lower premium rate.

5) Aircraft Hull Insurance

WBEC recommends utilization of a .5 percent of value rate as opposed to the .7 percent utilized for the CCE. Alaskan Northwest is not able to write lower 48 aircraft hull insurance for a .5 percent of value rate, let alone Alaskan based aircraft. WBEC again does not reveal the underwriting source for insurance at the premium rates quoted. Alaskan Northwest would note that Northwest Energy's current fleet hull rates are .73 percent to 1.50 percent for aircraft based in Utah.

6) Physical Damage Construction Camps

The CCE utilizes a .35 percent rate applied against the base value of the camps. This rate was obtained by contact with the American Insurance Group, a potential insurance underwriter. WBEC's recommended rate is not supported by any potential market. These properties have little or no fire detection or

supression equipment, and firefighting is of little effect. Underwriters would regard these as unprotected properties and would certainly surcharge base rates because of their status.

7) Builder's Risk

Alaskan Northwest utilized a .6 percent estimate rate for the CCE applied to actual values at risk. WBEC proposes a .322 percent estimate based on a rule of thumb method of 55 percent of completed value. Since the CCE estimate was a result of contacts with prospective markets and was applied against actual values, the method is much more reliable than WBEC's unfounded estimate.

C. Normal Contingency

As previously explained Alaskan Northwest followed a very precise definition for normal contingency evaluation. Through a probabilistic analysis a value of 12 percent was determined as appropriate after evaluating the possibility of cost increases or decreases from the base estimate. Williams Brothers by a process which it does not fully define arrived at approximately the same value, 12 percent, for its estimate.

However it is essential to point out that were Alaskan Northwest to assess a contingency for the WBEC evaluated estimate using the same precise definition of contingency as the CCE, it would arrive at a value considerably above 12 percent. A 12 percent contingency is not realistic considering the overly optimistic production rates in WBEC's evaluated estimate. Human productivity assumptions are a significant aspect of the precise definition of our contingency category. The combination of reduced crew and equipment size coupled with higher productivity would dramatically increase our contingency because the likelihood of sustaining production would be jeopardized. WBEC's evaluation resulted in transferring expected values from Center Point to contingency thereby in effect increasing its 12 percent contingency and reducing the Center Point. Alaskan Northwest disagrees with this assigned contingency concept as explained in the following section. However, it must be recognized that the abnormal events involved in this assignment by WBEC do not offset the optimistic productivity assumptions of WBEC.

D. Center Point

Alaskan Northwest's Center Point request of 1.28 was based on an analysis prepared in accordance with Orders 31 and 31-B and the following instructions from the Commission:

> The exhibit dealing with the Center Point should assess the likelihood of abnormal events that could increase costs which are not covered under the Change in Scope mechanism and the impact on costs that these events would have. This information will be used to set a Center Point that compensates for the possibility of abnormal events increasing costs.[1]

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[1] Order 31-B at 8.

The Report essentially concedes that the Center Point analysis is in accordance with Orders 31 and 31-B.[1] However, it disagrees with the result reached and, therefore, recommends a Center Point of 1.20, based on other considerations such as the cost growth experienced to date, a comparison with TAPS, and the opportunity to limit overruns.[2] These extraneous considerations do not support the Report's recommendations. If anything they support the Center Point request. Moreover, the Report's criticism of the Center Point analysis prepared by Alaskan Northwest is without merit.

1. Other Considerations Do Not Provide a Basis for Reducing the Center Point

The Report supports its conclusion that our Center Point request is not risk neutral by resorting to arguments that 1) most of the cost growth that can be expected has already occurred; 2) experience with other projects suggests that we will not experience significant additional cost growth beyond that projected in our filings; and, 3) effective management can limit such overruns as they occur. None of these contentions are valid or provide support for the Report's recommended reduction in Alaskan Northwest's Center Point.

a. Cost Growth to Date and Experience with Other Projects

The Report contends that significant growth has already occurred since the March 1977 estimate and further cost growth may qualify as a design or scope change. Therefore, the likelihood of cost overruns in excess of a CCE adjusted to reflect such design and scope changes has been reduced. However, as experience with other large projects shows, significant cost growth can, and does, occur after final design. The Report's contention that the design and scope change mechanisms can be used to adjust the target costs for the project to reflect any such cost growth is fallacious, because under the Report's interpretation of the design change mechanism, there are not likely to be many, if any, upward adjustments in the CCE to reflect approved design changes; and, as previously discussed, design refinements are extremely unlikely to qualify as scope changes.

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1 Report at III-1.

2 In recommending a Center Point of 1.2 the Report inexplicably concludes that

> ...expected further cost growth [will] be considerably less than that anticipted at the time of the President's Decision and thus, that the Center Point be considerably less than 1.3. Report at 9.

This statement appears to form the foundation for the Report's entire Center Point analysis. Alaskan Northwest fails to see any relationship between the 30 percent figure used in the President's Decision and the Commission's mandate in Order 31-B that the Center Point be based not upon the 30 percent figure, but on the expected value of abnormal events which could increase project costs. In that order the Commission did not state that the ceiling for the expected value of abnormal events was 30 percent.

The Report cites experience with cost growth on other major projects as a basis for reducing our Center Point request.[1] The Report, however, does not actually attempt to compare these projects and their history of cost growth with the Alaska segment. In fact, the Report does not even identify, let alone discuss, the other projects, with the sole exception of TAPS.

Even assuming that TAPS is comparable to the Alaska segment for the purpose of establishing the Center Point, the Report's attempts to compare TAPS immediately prior to construction with this project at a 5 to 10 percent design stage is indefensible.

b. Opportunities to Limit Overruns

The Report contends the availability of management opportunities to limit cost overruns is a basis for reducing our requested Center Point.[2] The Report cites the body of Alaska construction experience, including contractors with arctic experience and the TAPS owners, which experience we can draw on to limit overruns, and suggests that we failed to take advantage of that experience with its statement that "...Alaskan Northwest's apparent failure to incorporate certain opportunities to reduce costs in preparing the CCE Filing is one of the major weak spots in the Filing."[3] The Report is essentially saying that our Center Point can safely be reduced because our base estimate is too high. The Report ignores the fact that under Orders 31 and 31-B the opportunity to limit overruns is not relevant to setting the Center Point, because the Center Point is designed to compensate for the cost impacts of abnormal events beyond the sponsors' control.

The irony of the Report's "lost opportunities" argument is that we in fact utilized the best of the very arctic experience cited by the Report in preparing our base estimate, and the Report repudiated that experience, substituting the authors' or WBEC's own subjective judgment instead. Both the Project Management Contractor, Fluor, and the operator for Alaskan Northwest, Northwest Alaskan, have people in virtually every organizational discipline with arctic experience. In addition, consultants hired by both the PMC and Northwest Alaskan have been involved in construction or engineering in Alaska since the beginning of TAPS. To design the project and assemble the CCE filing we drew upon the experience of personnel who worked with the execution contractors that constructed all spreads of TAPS and who have since constructed most of the other energy-related projects on the North Slope of Alaska. We also purchased an extensive amount of data from Alyeska to aid in the design of the gas pipeline system. Furthermore, the producer members of the Design and Engineering Board are TAPS owners and experienced North Slope operators and have approved the completeness and reliability of the CCE and Center Point as a measure of the expected costs of the Alaska segment. Thus, contrary to the Report's assertions, we have already applied reasonable resource optimization in preparing the CCE, which has been shown to be both realistic and reasonable.

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1 Report at III-8.

2 Id. at III-15.

3 Report at III-15.

2. Alaskan Northwest's Center Point Analysis is a Sufficent Basis to Establish the Center Point

The above factors relied upon by the Report obviously do not provide any support for setting a Center Point lower than that requested by us. Therefore, if our Center Point is to be reduced, it must be on the basis of defects in our analysis of abnormal events, prepared in accordance with Orders 31 and 31-B. The Report attempts to show our analysis is too subjective for establishing the Center Point, but does not particularize its claims other than to argue that we have misclassified as abnormal events certain items that should be in contingency; certain of our abnormal events cover unanticipated increases in inflation already compensated for by the IROR inflation adjustment mechanism; and, our allowance for cost impacts from unknown events should be eliminated. None of these contentions are warranted.

a. Elimination of Unknown-Unknowns is Arbitrary

The inclusion of an allowance of $490 million for potential costs attributable to unknown impacts, referred to as "unknown-unknowns," was reasonable, because of the unique size, complexity, and location of the Alaska segment. We know that we cannot anticipate every abnormal event that could cause cost overruns beyond our control. The risk of cost uncertainty from such unknown-unknowns is covered by Event No. 36 in our Center Point analysis.[1]

Unknown-unknown events can and do occur even in traditional projects as well as first generation or higher technology projects. Unknown-unknown events as a likely source of potential cost overrun for this project was first identified for the Commission by Mr. James D. McCullough of the Institute for Defense Analysis.[2] There are many examples of unknown-unknowns occurring in traditional projects, e.g., the recent incident of a drilling rig under contract to Texaco drilled into a salt mine in Louisiana draining a small lake; the creation of earthquake swarms near the Rocky Flats Arsenal in Colorado due to the subsurface injection of radioactive wastes; the discovery of the snail darter fish which delayed the Telico Dam Project; and the failure of the frames of new Grumman Flxible Buses. Furthermore, a report by the Rand Corporation on project cost growth shows that the filed value for unknown-unknown events is reasonable.[3] This report states that exogenous (abnormal) events and scope changes (which are very narrowly defined under the IROR orders) are primary contributors to cost growth. Further, this study compares the ratios of actual to estimated costs for over 200 traditional and non-traditional projects. In this analysis, even

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1 CCE Vol. V at 4-38.

2 "On the Treatment of Risk and Uncertainty in Determining Change in Scope Allowability and Center Point Establishment in the Alaska Gas Pipeline IROR Mechanism, " James D. McCullough (Institute for Defense Analyses Paper P. 1413), March, 1979.

3 See Rand Corporation, "A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants" (July 1979).

highway projects, which should have very low uncertainty, have an average ratio of 1.26 times the estimated cost.[1]

The Report does not deny the existence of unknown-unknowns or that they can impact this project, but recommends no allowance for unknown-unknowns because they cannot be quantified with any certainty.[2] This recommendation is inconsistent with the Report's general concern that our 36 Center Point events, including unknown-unknowns, do not account for all possible sources of cost overruns.[3] The Report's statement that elimination of an allowance for unknown-unknowns will give "...a better assessment of the range of identifiable cost uncertainty facing the project at this stage of design and construction planning"[4] cannot be reconciled with its concern that "...any number of unanticipated or inadequately anticipated events could cause a cost overrun allowed for by approving a Center Point in excess of 1.0."[5]

Merely because an event is difficult to estimate is not a reason for ignoring the admittedly potential cost consequences of that event. While WBEC agrees that it is impossible to estimate unknown-unknowns with certainty, it "...accepts the philosophy that unk-unks do pose a risk to large, unique projects such as the NWA pipeline...,"[6] and recommends an allowance of $239 million for unknown-unknowns.[7]

WBEC's reduction of our value for unknown-unknowns is based on the ground that some unknown-unknowns will be presented as design or scope changes.[8] However, as previously explained,[9] potential design and scope changes were excluded from consideration when determining the Center Point

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1 Alaskan Northwest first estimated that unknown-unknowns based upon historical evidence would be at least 25 percent of the CCE at the 5 to 10 percent design stage. Alaskan Northwest recognized that most experience is based on cost-plus projects without the IROR mechanism and, therefore, with less incentive to attempt to anticipate events. Alaskan Northwest, because of the significant effort employed to anticipate "abnormal events" made a conservative estimate, determine that it could be conservative in its estimate of unk-unks and, therefore, cut the unk-unks in half to 12.5 percent. Alaskan Northwest then considered 12.5 percent to be the extreme of the range for unk-unks with a mid-range value of 6.25 percent. This value has to be considered as lower than average past experience and should not be reduced. Thus, the $490 million for unk-unks should be approved.

2 Report at III-A-24.

3 Id. at III-4.

4 Id. at III-A-24.

5 Id. at III-4.

6 WBEC Vol. IV at 9-53

7 Id. at 9-53 and 9-61.

8 WBEC Vol. IV at 9-53.

9 See comments, supra, at 7-8.

events. Also, unknown-unknowns are most likely to occur after we commence construction and, therefore, after the design change mechanism has ceased to operate. In addition, the Report would so narrowly restrict the operation of the design change mechanism that it is very unlikely that the CCE would be adjusted to reflect unknown-unknowns in the event any were discovered prior to final design. After final design, there are only a limited number of events that can qualify under the Change in Scope mechanism. The Design and Scope Change mechanisms are not meant to cover abnormal events. It was the intent of the IROR orders that abnormal events be covered by the Center Point.

b. Assigned Contingency

The Report agrees with WBEC's reclassification of all of the cost impacts of five abnormal events to an "assigned contingency" and partial reclassification of the cost impacts of five other abnormal events to "assigned contingency,"[1] because we assigned these events a 100 percent chance of occurrence. Our classification of these abnormal events was consistent with the intent and purpose of the IROR orders.

Contrary to the Report's erroneous assertion,[2] the Center Point basket was not considered a catch-all basket by the sponsors. As explained in the Technical Conferences, the list of Center Point events was made prior to development of the base estimate or contingency. Abnormal events were listed first in order to be sure their impacts would not be included in the establishment of the base estimate or contingency. However, probabilities and cost impacts could not be assessed for the Center Point events until after the base estimate had been set. While some abnormal events were assigned a 100 percent likelihood of occurrence, they do not fit our established criteria for normal contingency or the intent of the IROR orders that the CCE, which includes a contingency for normal estimating uncertainty, not contain an allowance for abnormal events. Allowances for the abnormal events identified in our analysis would not normally be included in a contractor's or vendor's contingency. These events would be covered by a force majeure clause, change orders, or some other contractual modification. Furthermore, the fact that an event was assigned a 100 percent likelihood of occurrence does not mean that the event is really normal. The very concept of a Center Point allowance recognizes there is a 100 percent chance that project costs will be impacted by abnormal events. However, the logical conclusion of the Report's position is that the entire Center Point allowance should be shifted to contingency. This is clearly not what the Commission's IROR orders intended. For these reasons, abnormal events with 100 percent probability were properly classified as Center Point events.

The reclassification of these abnormal events to a fifth basket -- "assigned contingency" -- creates confusion and interjects cost impacts of abnormal events into the CCE. Therefore, these events should remain in the Center Point and not be transferred to assigned contingency.

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1 Report at III-19.

2 Id. at III-19 n. 46.

c. Center Point Event Nos. 19 Through 23 are not Allowances for Unanticipated Inflation

The Report claims that the cost impacts of Center Point Event Nos. 19 through 23 are really allowances for unanticipated inflation and should be eliminated from the Center Point, because the IROR inflation adjustment mechanism is intended to remove the effects of inflation from the calculation of the Cost Performance Ratio and because the IROR risk premium is intended to protect Alaskan Northwest against inaccuracies in the application of that mechanism.[1]

Center Point Event Nos. 19 through 23 are not designed to cover unanticipated increases in inflation. These events cover the risks of cost increases due to unexpected competition for construction materials,[2] transportation services,[3] construction equipment,[4] qualified contractors,[5] and craft labor and foremen.[6]

It is also important to note that WBEC and the Report agree that these events reflect real risks of overruns for which we should be protected, and there is no allegation that these costs have already been provided for elsewhere in the CCE or Center Point.

The project faces the very real risk that, at the time it goes to the market to acquire materials, equipment, transportation services, construction services, and labor, it will have to compete for these items with other large construction projects, under construction during the same time frame as the Alaska segment, both worldwide and domestic. Such competition could result in demand far outstripping supply, causing sharp increases in the real costs of these items independent of inflationary increases.

Both the staff and WBEC recognize that these are legitimate Center Point events and would include an allowance for them. Notwithstanding its assertions referenced above that these are not true Center Point events, the Report itself recommends that one-fourth of their cost consequences, as estimated by Alaskan Northwest, be retained in the Center Point, effectively conceding that they are in fact true Center Point events.[7] The three-quarter reduction, however, is completely arbitrary.

The Report's recommendations on these Center Point events are internally inconsistent and conflict with both the staff and its own consultant and should be rejected. Our value for these events, $321 million, has been fully justified in our CCE filing and April 13, 1981 comments on the Draft Report and should be retained in the Center Point.

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1 Report at III-20.

2 Event No. 19, See, generally, CCE Vol. V at 4-20 to -24.

3 Event No. 20.

4 Event No. 21.

5 Event No. 22.

6 Event No. 23.

7 Report at III-20 n. 51.

E. The Liberal Design Change Process Should be Reaffirmed

The July 1, 1980 CCE filing submitted for approval by the Commission was based upon an approximately 5 to 10 percent design. The Report finds that this is an adequate design basis for approving most of the filed CCE at this time.[1] Since the July 1 submittal, Alaskan Northwest has continued to detail this design as we move toward the final design, which must be submitted to OFI for approval prior to the start of construction. It was the manifest intent of the President's Decision and the Commission's IROR orders that the most complete design and cost estimate possible be finalized prior to commencement of construction. Every effort was to be employed by the sponsors in consort with OFI to determine the projected cost of the project prior to construction commencing. The requirements of a final design prior to construction was the outgrowth of the cost overruns on the TAPS oil line, which were partially attributable to lack of a complete design prior to construction.

In order to foster the refinement in design that would take place between approval of the CCE and the final design, the Commission, in Order 31, provided for a liberal design change policy prior to final design, stating as follows:

> The Commission's approach has been to structure the IROR mechanism to accommodate changes in cost estimates attributable to increasing knowledge of design requirements, through adoption of a liberal design change policy prior to the commencement of construction. However, the Commission insists that realistic cost estimates be provided to the government prior to the commencement of construction. This result is achieved by severely constraining the circumstances in which scope changes will be considered once construction has commenced.[2]

The purpose of the liberal design change policy is twofold. First, the design is to be as complete as possible before construction commences in order to lessen the chance of cost overruns. Second, the sponsors are provided an incentive to incorporate cost saving design changes which benefit the consumer by reducing the total costs of the project. In this regard, the Commission further stated in Order 31 as follows:

> Changes that occur prior to approval of the Final Design are governed by Condition No. 9. Such changes, for instance, could include design changes generated by new technology or further study by the project sponsors.
>
> Condition No. 9 provides a strong incentive, and wide latitude, for the project sponsors to consider seriously and study intensively all of the problems and risks that they will confront, and to evaluate, propose and justify any design

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1 Report at 17.

2 Order 31 at 17 (emphasis added).

changes that they deem necessary and appropriate, including all of the cost consequences of such proposed changes. If properly justified as desirable changes in design that cause real changes in cost, those cost changes will then be reflected in revisions to the Certification Cost Estimate and the Projected Capital Costs (but not in the Center Point).[1]

In Order 31-B, the Commission clarified that design changes resulting in reduced capital costs would not require a reduction in the CCE.[2] The only limitation on the design change mechanism is that the CCE will be reduced where it can be shown that the sponsors put a more costly design in the CCE in order to improve their expected Cost Performance Ratio and, thus, their return.[3] However, the Commission did not repudiate its intention that, absent evidence of such abuse, the sponsors benefit from cost saving design changes.[4]

Although the Report recognizes that the President's Decision provides for two distinct cost estimate approvals at two different stages of design[5] and pays lip service to the liberal design change policy,[6] the entire thrust of the Report is to restrict severely upward adjustments in the CCE for design changes and to prevent the sponsors from benefiting from cost saving design changes. The cumulative effect of the Report's recommendations and guidelines is to read Condition 9 out of Order 31 and for all practical purposes make the approved CCE the Final Cost Estimate, contrary to the intent of the President's Decision and the IROR orders.

In addition to showing a general disregard for Condition 9, the Report's recommendations are deficient in three particular respects.

1. The Federal Inspector Does not Have Absolute Discretion to Make Adjustments in CCE for Design Changes

The Report interprets Condition 9 to confer absolute discretion on the Federal Inspector to determine whether the CCE should be adjusted upwards or downwards to reflect the cost consequences of approved design changes, including the discretion to offset increases in the CCE with decreases resulting from other design changes or amounts contained elsewhere in the approved CCE.[7] Condition 9 does not authorize the Federal Inspector to offset reductions in the CCE resulting from cost saving design changes against increases in the CCE from design changes with increased costs. The only authority vested in the Federal Inspector to deny the sponsors the benefits of cost saving design changes is

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1 Order 31 at 122.

2 Order 31-B at 41-42.

3 April 28 Order at 100-101 n. 121.

4 Id.

5 Report at I-3.

6 Id. at III-7 n. 19

7 See, e.g., Report at IV-14,-18,-20, and Attachment E at 6-7.

where some abuse has been shown. Otherwise, Order 31 is quite explicit that the CCE must be adjusted to reflect the cost increases of approved design changes.

It would also not be appropriate to consider the base estimate, contingency, or Center Point when determining whether to adjust the CCE for design changes, because, as we have previously stated, the CCE and Center Point exclude any allowance for design or scope changes.[1] Moreover, offsetting design changes with amounts in the Center Point or assigned contingency would be doubly erroneous because they compensate for the risks of cost impacts occurring after final design and after construction has commenced. Conversely, the design change process is designed to cover the cost impacts of changes occurring between approval of the CCE and final design.

Thus, the Federal Inspector's discretion is not absolute. While he has discretion to determine whether proposed changes are "...changes in quantities or types of materials, labor, and services, and changes in project development or construction schedule and construction techniques, resulting from changes in design or schedule...", approve or disapprove the inclusion of the cost consequences of such changes in the CCE, and determine whether the CCE should be reduced to reflect the cost impacts of a cost saving design because of an abuse by the sponsors, he does not have discretion to net cost increases and decreases.[2]

2. The Report's Recommendations on Particular Design Changes Are Inconsistent with a Liberal Design Change Policy

The Report's particular recommendations on whether a change would qualify as a design change under Condition 9 are inconsistent with Order 31's liberal design change policy. The Report states that a change from refurbishing Alyeska's construction camps to building new camps would not be a design change, because "...the basic component -- camps -- would not have changed and any differences between the estimate and actual camp costs should be considered, in essence, price changes."[3] This argument would wipe out entirely the design change mechanism.

While the Report argues that in order for a change to qualify as a design change under Condition 9, the change must be a change in a basic component of the pipeline. The Report has already recognized that the basic components of the pipeline project should not change.[4] Thus, the requirement that a change be a change in a basic component before it could qualify as a design change would make it virtually impossible to qualify, contrary to the intent of Condition 9. Nothing in Condition 9 supports the Report's limitation of the design change process to changes in basic components.

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1 Id. at IV-12.

2 Order 31-B at 72.

3 Report, Attachment F at 7.

4 See Report at I-7, I-18.

Furthermore, a change from existing camps to new camps is obviously a change in design, techniques, and quantities and not merely a change in price. Different quantities of different materials are necessary to construct new camps instead of renovating existing camps.

The Report's recommendation on camps is also internally inconsistent with other recommendations it makes. For example, the Report states that additional testing of refrigeration, if required by the Federal Inspector, would be a design change.[1] However, the basic component -- refrigeration testing -- will not have changed; rather, the amount of such testing will have been increased. The Report also states that a change in design from using the Yukon River bridge to building a new bridge to cross the Yukon River, should we be unable to obtain the necessary approval of the State of Alaska and the TAPS owners to use the existing bridge, would not qualify as a design change "...if the choice between alternatives is made solely on the basis of price."[2] Ironically, this is the one potential change referenced by the Report that could qualify as a design change under the Report's "basic component" argument, because the original basic component -- Yukon River bridge -- would not be utilized.

3. The Report's Recommendations Usurp the Authority of OFI

As demonstrated above the Report's recommendations on design changes are often inconsistent with the Commission's IROR orders and self-contradictory. The Commission should disavow the particular recommendations of the Report on whether a particular change would or would not qualify as a design change for which an adjustment to the CCE should be made. Such recommendations invade the province of the Federal Inspector and are inconsistent with the Report's own observations that design changes should be determined on a case-by-case basis after consideration of all the circumstances.[3] The resolution of whether something is a design change should await a concrete presentation by the sponsors. If guidelines are to be developed, they should be developed by the Federal Inspector, not the Commission.[4]

4. The Commission Must Reaffirm a Liberal Design Change Policy

Most importantly, the Commission must reaffirm the liberal design change policy established by Order 31. This policy was relied upon by Alaskan Northwest in preparing the CCE and Center Point. If the Commission is now going to abandon this policy in favor of a restrictive policy as recommended in the Report, Alaskan Northwest will have to consider recommending appropriate adjustments in contingency and the center rate of return to cover the increased risks to the project from the cost impacts of design changes prior to final design.

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1 Id. at IV-19.

2 Id. at IV-12.

3 Id., Attachment E at 3.

4 See also Condition 9, which requires the Federal Inspector to adopt guidelines. Order 31-B at 73.

F. Other IROR Issues

1. Labor Cost Adjustment Index

Because the Commission believed the sponsors should not be penalized for cost increases resulting from general inflation, the Commission provided in Order 31 that the actual capital costs for the project should be adjusted to eliminate the effect of general inflation prior to calculating the Cost Performance Ratio and the IROR.[1] For this purpose, the Commission provided for an inflation adjustment mechanism to deflate actual construction costs (excluding interest during construction) to base year prices for comparison with the CCE, which is also in base year prices. In essence, the inflation adjustment mechanism is a composite of indices for categories of costs of building the project, such as labor, line pipe, etc.

In Order 31-B, the Commission invited the sponsors to propose specifications for the labor component of the composite index.[2] Pursuant to this invitation, Alaskan Northwest proposed in its July 1, 1980 CCE filing that the labor component of the composite index be the index or indices defined in the Project Labor Agreement(s) negotiated for the project.[3] The basis for this proposal was two-fold. First, if the labor inflation index is established prior to negotiation and execution of the PLAs, it is no longer available to Alaskan Northwest as a bargaining chip in negotiating the PLAs. Any lessening of flexibility in negotiating the most overall favorable PLAs could likely result in higher labor costs. Second, a national labor index will not reflect the historically higher inflationary increases prevalent in Alaska labor rates.

The Report recommends rejection of Alaskan Northwest's proposal.[4] Instead, the Report recommends use of the National Pipeline Agreements and Richardson Construction Cost Trend Reporter, which were approved for the Eastern Leg pre-build, unless Alaskan Northwest develops a better, broadly based index in the course of its comments on the Report. The Report's proposed rejection of Alaskan Northwest's proposal appears to rest on the following position:

> Thus, acceptance of Alaskan Northwest's proposal would be inconsistent with the Commission's express desire to use "published, objective price and cost data that are not substantially affected by the actions of project sponsors."[5]

The fallacy in the Report's reasoning is that significant differences in inflation already exist between Alaska and lower 48 wage rates. This difference will be inherited by Alaskan Northwest, not created by it. A national index which is not adjusted to reflect this historical difference will fail to protect the sponsors from the effects of inflation.

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1 Order 31 at 111.

2 Order 31-B at 30.

3 CCE Vol. I at 13-14.

4 Report at V-4.

5 Id. at V-3.

It is no answer, as suggested by the Report, that the IROR Risk Premium will compensate the sponsors for such inaccuracy.[1] While the IROR Risk Premium is partially designed to compensate Alaskan Northwest for the risk that the inflation adjustment mechanism will not exactly track inflation experienced by the project, this is no excuse for adopting an index known to be flawed from the outset, particularly when labor costs will be such an important component of project costs. Furthermore, the IROR Risk Premium is to compensate for risks associated with the entire IROR mechanism, not just the vagaries of one element (labor) of one component (inflation adjustment) of that mechanism. The failure of a national labor index, as proposed by the Report, to track the historically higher Alaska labor inflation could, however, use up most of the Risk Premium so that risks from failure of the other 24 major components of the inflation adjustment mechanism to reflect actual inflation and risks from the operation of the IROR mechanism generally would not adequately be covered.

If the Commission should decide to utilize a national labor index for the labor component of the composite inflation index, Alaskan Northwest proposes that the labor inflation index be based on the Means skilled average labor rates as adjusted by the Means weighted average labor index for Anchorage. Means' skilled average rate is based on the average labor rates in the 30 largest cities and 35 construction trades. The proposed labor index is based on an objective, broad based source, Means, and an objective adjustment, also from Means, that reflects the historical difference in inflation in labor rates between Alaska and the lower 48.[2]

Finally, the Report states that:

> In fulfilling his IROR enforcement duties under the Northern Border certificate, the Federal Inspector had to substitute certain indices for similar indices no longer published. We recommend incorporation of the substituted indices chosen by the Federal Inspector in Alaskan Northwest's certificate.[3]

The Commission should not automatically and unilaterally incorporate into Alaskan Northwest's certificate indices substituted by the Federal Inspector for similar indices contained in Northern Border's certificate that are no longer published. Instead, Alaskan Northwest recommends that the Federal Inspector, based upon the facts and circumstances peculiar to Alaskan Northwest and after consultation with Alaskan Northwest, determine the appropriate substitutes for indices no longer published.

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1 Report at V-3.

2 In this regard we would note that the 1981 Means city index for labor in Anchorage is 145.0 while such indices for the lower 48 cities with the traditionally highest labor rates are 127.6 for San Francisco and 111.8 for New York City. See Means (1981 ed.) at 290 and 295.

3 Report at V-4 n. 11.

2. The Sponsors Should Not Be Held Accountable for Third Party Monitoring, Socioeconomic and Other Government Related Costs

In preparing the CCE, Alaskan Northwest requested and received an estimate of reimbursable costs that would be incurred by various federal and state agencies.[1] We did not make an independent evaluation of the validity of these estimates. For purposes of submitting a complete filing, they were included in the CCE. However, we proposed in our July 1 filing that the CCE be adjusted to equal the actual capital costs for third party monitoring and other government-related costs for the determination of the Cost Performance Ratio.[2] Alaskan Northwest proposed use of actual costs for government-related costs because Alaskan Northwest has no control over the preparation of the estimate for or the incurrence of such costs.

Although the Report concedes that "...the Federal and State governments completely control their own estimates,"[3] it nonetheless insists that Alaskan Northwest estimate government related costs and include such estimates in the CCE.[4] The use of estimated costs which Alaskan Northwest has 1) no hand in preparing; 2) no way to verify; and, 3) no way to control effectively clearly penalizes Alaskan Northwest and is directly contrary to the purpose of the IROR mechanism.

The single purpose of the IROR mechanism is to provide an incentive to the sponsors to control costs during construction.[5] This purpose, however, can have no meaning where Alaskan Northwest is without control over the preparation of the estimate or the incurrence of costs.[6] The Report's recommendation that Alaskan Northwest be required to estimate government costs cannot be reconciled with its own admission that Alaskan Northwest has no control over the governmental agencies' estimates. The Report attempts to dodge this problem by stating that Alaskan Northwest should resolve disagreements over such estimates through negotiation with the agencies or "appropriately justified" adjustments to the estimates.[7] The Report, however, does not discuss how Alaskan Northwest might justify changes to an estimate submitted by an agency. How can Alaskan Northwest say how many manhours of work the governmental agencies should be expected to take in overseeing construction of the pipeline or how many trips various agency personnel should or will make to Alaska and other company office locations. If an agency's estimate provides for 75 trips per year,

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1 Estimates were submitted by the Office of the Federal Inspector, Department of Interor, and the State of Alaska.

2 CCE Vol. I at 14.

3 Report at V-5.

4 Id. at V-8.

5 See, e.g., Order 31 at 21-23.

6 Alaskan Northwest would note that the IROR mechanism provides that the sponsors should not be penalized in those instances where they have no control over costs, such as inflation and change in scope events.

7 Report at V-5.

how can the project sponsors be expected to determine whether 75 per year is too many, not enough, or just right, and how can Alaskan Northwest "justify" a change? Although there are historical bases for estimating the costs of labor and materials for constructing a pipeline, there are none for governmental monitoring. For example, Alaskan Northwest utilized standard sources for estimating labor productivities for construction work in Alaska in putting together the CCE. Alaskan Northwest has a good idea of how many manhours it can be expected to take to construct a compressor station or lay pipe. Alaskan Northwest does not have any similar bases for estimating the costs of governmental monitoring. Alaskan Northwest cannot check or verify the validity of the labor productivity assumptions that went into the agency estimates. Records of the labor productivity of government agencies in monitoring construction projects, if available at all, are not available to the sponsors. Furthermore, Alaskan Northwest cannot check the validity of monitoring cost estimates by resort to requests for bids or quotes as in the case of other areas of the CCE, because there is obviously only one "vendor" for required government approvals or services. Thus, Alaskan Northwest is not in a position to justify the estimates submitted by the agencies, let alone adjustments to those estimates. Moreover, for the sponsors to estimate the cost of government monitoring of their own project raises troublesome conflict of interest problems.

The Report recommends that the OFI estimate be approved because it "has not been questioned or challenged by Alaskan Northwest or any other party...."[1] Who would question it? The FERC staff? WBEC? On what basis?

Alaskan Northwest similarly has no control over the incurrence of costs by governmental agencies once construction commences. With non-governmental items we have leverage to try and force a contractor or vendor to meet schedules and stay within budget. For example, we can go out for competitive bids. We can station quality assurance personnel in a vendor's shop or at an execution contractor's work site. We write the specifications for material and equipment. The bottom line is that if a vendor or contractor fails to control costs, we can replace him.

But, other than moral suasion and litigation, Alaskan Northwest has no such leverage to control government costs. We cannot have our quality assurance personnel and auditors monitor the government monitors to make sure they are within budget. We cannot go out for competitive bids for governmental agencies or threaten to replace a governmental agency that overruns its estimate. The sponsors could theorectically withhold funds when overruns occur; however, history has made clear than an agency can halt required services and/or withhold necessary approvals thereby creating delay and increasing the costs of the project.[2] Finally, although government-related costs may significantly impact the project, such costs are reimbursed on a cost-incurred rather than a fixed price basis.

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1 Report at V-8.

2 Alaskan Northwest would note that when it objected to the Commission's filing fees, the Secretary suspended processing of its application. Alaskan Northwest would also note that the DOI Right-of-Way Grant and certain OFI regulations provides for issuance of stop work orders.

The Report's recommended cost control technique is that we sue the particular agency if we believe monitoring costs are unreasonable.[1] We find this recommendation at odds with the Report's rationale for opposing the use of actual costs: "[a]cceptance of the Alaskan Northwest staff proposal would...put parties who should be striving to cooperate with each other in an adversarial position at a critical time in project construction."[2] In fact, the Alaskan Northwest proposal does just the opposite by eliminating the conflicts. Furthermore, the fact that certain governmental costs are reimbursable as a matter of law does not mean that they are reasonable from a cost control standpoint.

Alaskan Northwest faces substantial risks from increases in government-related costs. Holding us responsible for actual governmental costs in excess of the estimated costs, when we have no control over them, unfairly penalizes us by increasing the Cost Performance Ratio and lowering our return. The reasonable resolution of this issue is to adopt our proposal. Alternatively, government-related costs could be excluded altogether from the CCE and Actual Costs and not be considered in determining the Cost Performance Ratio.

Because Alaskan Northwest proposed utilization of actual government-related costs for purposes of calculating the Cost Performance Ratio, Alaskan Northwest did not include a normal contingency on such costs. Nor did Alaskan Northwest include in its Center Point allowances for governmental failure to perform. If the Commission decides that government-related costs must be treated on a basis other than that proposed in our agreement with Staff, Alaskan Northwest will have to attempt to evaluate the estimates submitted by the government agencies and consider increasing the contingency and Center Point accordingly.[3]

Alaskan Northwest will be submitting a revised estimate for third party monitoring and government-related costs. Such costs will again be based on the revised estimates provided to Alaskan Northwest by the various governmental agencies which will charge this project based upon the agencies' estimation of the useful service they will render to the project.

As shown above, there is no basis whatsoever to support the Report's recommendation. Whatever estimate for government-related costs is ultimately approved, the project should not be penalized for changes to such estimate beyond its control. Instead, the Commission should state that actual costs are to be used in calculating the Cost Performance Ratio or that government-related costs are to be excluded altogether from such calculation.

3. State of Alaska Highway Costs

The Report states that "[s]hould Alaskan Northwest desire to include the costs of repairing highway damage in the CCE, they should file an estimate of

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1 Report at V-8 n. 30.

2 Report at V-8.

3 In this regard, Alaskan Northwest would note the Report's position that most increases in government-related costs could not qualify as a design change. See Report at V-9.

such costs for Commission Review in the above-mentioned proceeding."[1] Alaskan Northwest will submit an appropriate estimate of any such costs for Commission review and approval as part of the additional data and information necessary for the Commission to issue a final certificate.

Even though Alaskan Northwest will submit a filing addressing any possible State of Alaska highway costs, Alaskan Northwest believes it is necessary to address at this time the following two points raised in the Report:

> Whatever the result of such a proceeding, two points are important to mention here. First, the Commission could, for all practical purposes, be determining the prudence of costs in addition to the propriety of their inclusion in the CCE (footnote omitted). Second, as is the case with all "non-design" costs, once a CCE amount for these costs, if any, is determined, there should not be any CCE alterations available to the sponsor prior to the approval of Final Design unless the alteration is caused by a schedule change or unanticipated requirements in a major government authorization issued subsequent to CCE approval.[2]

As to the first point, the Report implies that there is a question as to whether it is prudent to include this type of cost in rate base. If the Commission believes it necessary to make a policy determination on this matter, such determination should be made expeditiously to provide the sponsors with some guidance on the matter.

As to the second point, the Report proposes pre-determination of action which may or may not occur subsequent to the Commission approval of the CCE. As previously discussed the Report tampers with the jurisdiction of OFI. More fundamentally, acceptance of the Report would preclude adjustments to the CCE for changes in an estimate of costs that could be affected by the stipulations in the State Right-of-Way lease yet to be received. Those stipulations will have been agreed to subsequent to CCE approval, but prior to submission of the final design cost estimate to OFI. If this is the true position of the Report, it is arbitrary and unreasonable.

4. Affirmative Action Training Programs

In the July 1, 1980 filing, Alaskan Northwest included in the CCE certain costs associated with administrating an Affirmative Action Plan. At that time two important government actions remained to be taken as follows: 1) approval of Alaskan Northwest's AAP by the OFI, which occurred August 13, 1981, and 2) issuance of a right-of-way accross Federal lands to Alaska, which occurred on December 1, 1980, and which imposed a new requirement for the recruitment,

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1 Report at V-9.

2 Id. at V-9.

testing, training, placement, employment, and job counseling of Alaska Natives. Alaskan Northwest will submit as part of the additional data and information necessary for the Commission to issue a final certificate an estimate of the costs of implementing the approved plan and training program required by the DOI Grant. If it becomes necessary to modify programs to comply with changes in interpretation, changes in law, and government directives, the discretion of whether any cost adjustment should be made to the CCE should rest with the Federal Inspector.

G. Deferred Items

The Report recommends deferring the setting of a CCE value for the communications and supervisory systems, the affirmative action training programs, State of Alaska monitoring and socioeconomic costs, and the management plan, because the sponsors' plans for those items had not crystallized sufficiently at the time of the CCE filing to allow preparation of a reliable estimate.

While Alaskan Northwest agrees with deferral of consideration of the communications and supervisory systems and affirmative action training programs, the CCE value for the management plan must be set now as previously explained in these comments.

Further proceedings to consider these deferred issues should be before the Commission and should utilize informal notice and comment proceedings, with the settlement of issues by stipulation encouraged. Alaskan Northwest believes the deferred issues should be resolved by the Commission, because a structure is already in place for approval of CCE related matters.

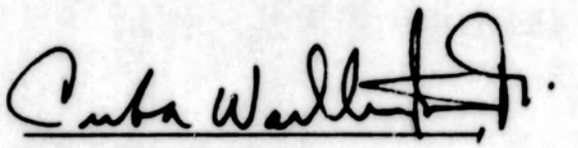
CONCLUSION

The CCE and Center Point requests are in full accord with the letter and intent of the President's Decision and the Commission's IROR orders. The assumptions and contentions of the Report's authors which form the basis for the Report's various recommendations are demonstrably misleading or in error. The weight of the evidence does not support the subjective conclusions of the audit and the Report's total reliance thereon is arbitrary and capricious. The Report's attempts to ignore the Center Point exhibit and rely instead on extraneous factors must fail for such factors do not support the Report's conclusions. The Report's attempts to deviate from Orders 31 and 31-B are an admission that this exhibit demontrates the validity of the Center Point request. The Report's recommendations on restricting the design change process should not be countenanced. Lenders and equity investors are reluctant to place significant sums at risk in a project where the government exhibits a tendency to change the ground rules upon which investor decisions have been based.

For the foregoing reasons, Alaskan Northwest requests the Commission to approve a CCE of $7.93 billion and a Center Point of 1.287, subject to the revisions to the filed CCE resulting from Alaskan Northwest's forthcoming filing on the deferred items referenced herein.

Respectfully submitted,

ALASKAN NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY

By: 

Cuba Wadlington, Jr.
Director, Regulatory Affairs
Northwest Alaskan Pipeline Company
1120 20th St., N.W.
Suite S-700
Washington, D.C. 20036

September 18, 1981

APPENDIX A

SOHIO GAS PIPELINE COMPANY

3333 MICHELSON DRIVE, IRVINE, CA 92730

September 15, 1981

Mr. Cuba Wadlington, Jr.
Northwest Alaskan Pipeline Company
c/o Fluor Engineers and Constructors, Inc.
3333 Michelson Drive
Irvine, California 92730

Dear Cuba:

The following information on pipe lay rates are provided to you for your use in commenting on the Alaska Delegate and OFI Director Final Report on the Certification Cost Estimate and Center Point Request.

The current estimated pipe lay rate developed by WBEC for SOHIO's Prudhoe Bay Facilities at Prudhoe Bay, Alaska are as follows:

	WBEC Estimated Lay Rate per day		
Pipe Size	Summer May to Oct.	Fall/Winter Oct. to Jan.	Winter Jan. to May
36"ø	1560 Ft.	1320 Ft.	936 Ft.
34"ø	1560 Ft.	1320 Ft.	936 Ft.
28"ø	2112 Ft.	1760 Ft.	1267 Ft.
24"ø	2160 Ft.	1760 Ft.	1267 Ft.
20"ø	2980 Ft.	2376 Ft.	1788 Ft.

The lay rates are based on double-jointed pipe and are part of WBEC's "Pipeline Optimization Plan" prepared for SOHIO Construction Company in September 1981.

Sincerely yours,

Arlie M. Skov

Arlie M. Skov

MKHC

AMS:MKHC:trg

APPENDIX B

SOHIO GAS PIPELINE COMPANY

3333 MICHELSON DRIVE IRVINE CA 92730

September 15, 1981

Mr. Cuba Wadlington, Jr.
Northwest Alaskan Pipeline Company
c/o Fluor Engineers and Constructors, Inc.
3333 Michelson Drive
Irvine, California 92730

Dear Cuba:

Pipeline Lay Rate

With regard to pipeline lay rate assumptions in the Final Report to the Commission by the Alaskan Delegate and the Division Director, Audit and Cost Analysis, Office of the Federal Inspector, SOHIO offers the following comments:

The Williams Brothers Engineering Co. (WBEC) argument on their pipeline productivity or lay rate relies on a time and motion estimate performed by Mr. H. W. Franks, who is recently employed by WBEC. Northwest Alaskan (NWA) pointed out in their response of May, 1981 that while Mr. Franks argued for a lay rate of 3,864 feet per day, he had previously testified to the FPC (as quoted by the Commission in their report of May 1, 1977), (Page VIII-10) that a rate of 1/3 mile per day (1,742 feet per day) was reasonable for a proposed 800 mile, 42" line[1] paralleling the majority of the NWA route.

Mr. Adger was notified during the Fall, 1980 hearings that a reasonable pipeline work rate had been espoused by Mr. Franks when a member of a prior study group that estimated the cost of

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(1) 48" pipe would involve a lower productivity in feet per day.

laying 48" pipe in Alaska[2][3] and there was a need to show what had changed to justify a new estimate near 4,000 feet per day.

The FERC should reject out of hand the current lay rate opinion by this witness for WBEC and the Alaskan Delegate as he (they) has failed to show why the rate given in previous testimony and studies for near identical pipelines should suddenly be doubled.

In fact, while the cost of the pipeline is greatly affected by lay rate, the cost of that activity and crews controlled by it, are highly dependent on crew sizes. The only true measure of labor costs for laying pipe is the total manhours consumed by each activity per quantity installed, in this case, line-up and weld in manhours per foot of pipe. Comparison of NWA to the only data for laying large diameter pipe, Alyeska's, shows that, in fact, NWA may be overly optimistic in estimating labor costs for laying pipe rather than having overestimated costs as alleged.

Alyeska data on manhours required to line up and weld a foot of pipe embraces the total manhours for the line-up, stringer bead and hot pass crews (repair labor hours resulting from the well-publicized x-ray problem are not included)

NWA estimated manhours for activities 606, 607 and 608 have been combined to compare with TAPS data. The comparison clearly indicates that more manhours will be required than estimated based on the collective memories and judgment of the NWA consultants. The Alyeska "Actual" data was obtained from a 2nd quarter 1977 manhour summary and may not correspond precisely to final Alyeska records.

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(2) Letter of November 5, 1980 to Cuba Wadlington, Jr. from V. A. Breitenbach placed in the hearing record.

(3) D. D. Grassman, of WBEC stated that this letter and remarks by Mr. Breitenbach on Mr. Franks' inconsistencies were interpreted by him as an endorsement of Mr. Franks as an estimator. This is an obvious gross misinterpretation.

Comparison of Weld Productivity

Alaska 48" Pipe

Line-Up and Weld Manhours Per Foot

Section No.*		Alyeska Actual		
Alyeska	NWA	Above Ground	Below Ground	NWA Estimate
1**	6**	0.69	0.94	0.70
2	5	0.86	0.77	0.66
3	4	0.67	0.59	0.67
4	3	0.75	0.74	0.65
	2			0.51***
5	1	0.90	1.13	0.64
System Average		0.79	0.87	0.64

Above Ground and Below Ground Average 0.82

Excluding Section 1 and Total Section 5 0.73

*Not directly comparable on section by section basis for NWA versus TAPS.

**Alyeska Section 1 and NWA Section 6 completely different.

***Does not include Atigun Pass.

It should be noted that data on Sections 2, 3 and 4 indicate no essential change in line-up and weld labor manhours between above ground and below ground pipe. Sections 1 and 5 do not enter into this comparison because of distortions in below ground activity because of Atigun Pass, Thompson Pass, and Keystone Canyon. The most meaningful overall comparison between TAPS actual and the NWA estimated manhours per foot results by excluding these problem areas in Sections 1 and 5 below ground modes and Section 5 above ground (due to extensive use of 60 ft. joints), resulting in a comparison

of 0.7 average manhours per foot for TAPS versus 0.64 manhours per foot in the NWA estimate. This shows that NWA's estimate in this area is 12% too low, rather than requiring correction to a lower labor cost, and forcefully argues against any cost reduction due to lay rate, as recommended by the Alaskan Delegate.

In support of their position, WBEC has argued that NWA should obtain a higher lay rate than Alyeska. Their arguments lack merit as indicated below:

1. WBEC argued that Alyeska built the first major Alaskan pipeline, men and equipment were unprepared for the harsh environment, hence a later pipeline would do better.

   For this argument to have validity, Alyeska's second year experience should have demonstrated a higher lay rate. No improvement in lay rate was experienced although Alyeska did improve equipment and methods wherever possible.

2. WBEC states that frequent mode changes between the above and below ground pipe interrupted and slowed the work.

   The pipe gang, as the pacing activity, welded pipe above ground whether dealing with elevated or buried pipe modes. The "Lower In" or "Elevate" crews following are non-pacing activities. Usually there was no need to interrupt pipe gang work because of mode change. Experience proved lay rates to be about the same for above ground and below ground pipe. NWA will encounter similar interruptions in changing from regular burial to insulated pipe for frost heave areas.

3. WBEC argues unexpected soil condition changes forced frequent Alyeska slowdowns with EC's waiting on Alyeska decisions before proceeding with the same or a new mode. The same potential for delay will exist for NWA. The problem will be changed in that the ditching process will discover unexpected frost heave susceptibility rather than high ice content permafrost. As with TAPS, delays for NWA will be in obtaining a Notice to Proceed to cover the problem.

4. The Southern section of Alyeska construction (excluding Thompson Pass and Keystone Canyon areas) crossed extremely

rough terrain. WBEC infers that this terrain is so rough that it drastically affected the average Alyeska lay rate. This is not true. While some effect was noted, actual experience showed that lay rates in all Alyeska sections were generally equal and approximated the lay rates assumed in the Arctic study prepared in part by Mr. Franks--about 2,000 feet per day. (See tabular lay rate comparison.)

5. Alyeska lay rates are claimed to be low because work was done under reimbursable contracts. This is a horrible indictment of the industry for which WBEC claims expertise. There is, in fact, no data indicating that improved Alaskan lay rate performance will result from fixed unit rate contracts--or that fixed unit rate contracts can be contained without inclusion of excessive allowances for contingencies.

WBEC states that NWA and Alyeska lay rate cannot be realistically compared. This statement brands the analysis as incorrect as Alyeska experience is the only lay rate experience that has any semblance of comparability.

WBEC "experience and judgment" is quoted as the basis for their lay rate "efficiency assessment"--they attempt to validate this by stating that a footnote in NWA's Response of May, 1981 set forth an efficiency factor essentially identical to theirs; and, therefore, endorsed their own efficiency percentage. This is a gross misuse of NWA's statement. The two "efficiencies" apply to different bases. If "base" standard rate is 38 joints per day and actual is 26, efficiency (NWA) is 69%--if "base" were 68 and actual 48, a 71% efficiency would be calculated as used by WBEC. It is improper to apply an efficiency percentage drawn from one base to a different base. Any efficiency percentage is only valid when used in conjunction with the same standards on which it was derived in the first place.

It should be noted that the Alaskan Delegate in his report to the Commission misspeaks when he says on Page II-10, that WBEC lay rate was not challenged by anyone, except in a minor way by one EC contractor. A major objection was raised by the undersigned in pointing out that both NWA and (more so) WBEC lay rates were too high. These comments have been ignored.

In his final report, the Alaskan Delegate quotes the reported 70-80 joints per day routinely achieved by spreads on the Western

Leg, to support his adopting the WBEC lay rate forecast as superior to NWA's. This is a misuse of the data as terrain, weather, and soil conditions are much more favorable to construction of the Western Leg, so that together with the smaller diameter of that line, that lay rate experience is not indicative of what can be obtained in Alaska.

The Alaskan Delegate argues that NWA will experience higher lay rates as they will find it to their advantage to maintain highest practicable weld speed, trading off savings with lower cost of repairing defective welds. He notes that one spread on the Western Leg has achieved 100 joints per day by this means. While such a procedure is possible in the Western Leg, this would require leaving the ditch in Alaska open an excessive length of time. Melting and ditch cave-ins would occur in permafrost areas. Thus this option is not realistically open to NWA for their work as permafrost areas comprise over 2/3's of their route.

Sincerely yours,

Arlie M. Skov for V. A. Breitenbach

V. A. Breitenbach

VAB:trg

APPENDIX C

WILLIAMS INTERNATIONAL GROUP, INC.
- U. S. A. MAILING ADDRESS -
c/o WILLBROS ENERGY SERVICES COMPANY
2530 EAST 71ST STREET
TULSA, OKLAHOMA 74136

LARRY J. BUMP
CHAIRMAN & PRESIDENT

September 14, 1981

Mr. R. N. Hauser
Vice President Construction/Logistics
Northwest Alaska Pipeline Company
3333 Michaelson Drive
Irvine, California 92730

Dear Bob:

During a recent conversation, you asked my opinion of the construction cost estimate submitted by your Company in respect to the Alaska segment of the proposed Alaska Natural Gas Transportation System.

I am generally familiar with the Northwest Alaska cost estimate because a vice-president of our U.S. pipeline construction subsidiary, Mr. C. M. Hoffman, participated in the preparation of the estimate. Mr. Hoffman was previously employed in a management position with Morrison-Knudsen and acted in a high-level supervisory capacity in Alaska during the construction of the Alyeska pipeline project. In addition, we have several employees who were active in the management and execution of the Arctic Constructors' section of the crude oil line as well as a former executive of H. C. Price Co. who was involved in the management of section 3 of Alyeska and is now a vice-president of our U.S. construction subsidiary. Quite naturally the high degree of participation by our personnel in the construction of the crude oil pipeline led to a keen interest in the cost estimate submitted by Northwest Alaska to assure its validity in the light of Arctic construction costs and avoidance of cost overruns, particularly in the purview of the fixed price contracting concept currently anticipated by Northwest Alaska.

Generally, I support the cost estimate submitted by Northwest Alaska and am of the opinion that the major assumptions underlying the estimate are realistic, particularly the rates of progress, productivity and daily operating costs.

One major item in the cost estimate that may be unrealistic and low is the overhead and profit margin allowed the execution contractors. Whether or not the profit margin set out in the estimate is adequate will primarily depend upon the ability of Northwest Alaska to adequately define the scope of the work and the contractors' assessment of the financial risk inherent in such a project due to delays and work stoppages that are beyond the control of the contractor, particularly those caused by third parties. A proper balancing of risk and

potential reward is a basic axiom of the pipeline construction industry; therefore, if contractors determine that their risk is great, in my opinion the estimated margin for overhead and profit will be inadequate.

I realize that some controversy exists as to the daily lay rate established by Northwest Alaska and the production rate put forth by consultants employed by the FERC/OFI.

I support the estimated daily pipe lay rates established by Northwest Alaska simply because I believe it to be realistic based upon my own experience and my knowledge that the estimating group utilized by Northwest Alaska included several individuals who were directly involved in the construction of the Alyeska crude oil pipeline system in senior management and supervisory capacities. I know their on-site experience acquired during the building of the crude oil pipeline has been heavily drawn upon by Northwest Alaska. I think everyone concerned will agree that experience in constructing pipelines under Arctic conditions is essential in costing, planning and executing work on a project of the magnitude and complexity of the proposed gas pipeline system. I believe that such equivalent experience would also be useful and necessary to a consultant in any "review and critique task" such as that assigned Williams Brothers Engineering Company ("WBEC") by FERC/OFI.

Perhaps it would be helpful if I explained to you how my Company and WBEC had, at one time, a common parent and pointed out to you the distinction that exists today between the two companies. Williams Brothers has for many years been a prominent name in the pipeline industry, having started as a small contracting company in 1907 and ultimately becoming a large, diversified company known today as The Williams Companies. Neither my company, Williams International Group, Inc. ("WIGI"), or WBEC is today a member of The Williams Companies. WBEC was sold in 1972 and is today a subsidiary of Ashland Oil Company. WIGI was sold in 1975 to a group of management employees and operates in the U.S. and several foreign countries and is privately owned. There is now no relationship whatsoever between WIGI and WBEC. Whereas WIGI continues to be active in pipeline construction, WBEC has traditionally performed technical assignments for its clients, both prior and subsequent to its separation from The Williams Companies. To my knowledge, WBEC is still performing technical assignments and has not worked as an execution contractor on any pipeline project. The WBEC personnel are therefore experienced and competent in design and engineering functions, but not necessarily in actual execution of pipeline construction.

I am hopeful that I have satisfactorily answered the question that you addressed to me. If not, please let me know.

Yours very truly,

Larry J. Bump

LJB:wn

APPENDIX D

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
ALASKA STATE OFFICE
OFFICE OF SPECIAL PROJECTS
701 C Street, Box 30
Anchorage, Alaska 99513

IN REPLY REFER TO
A-0001313

Case C (914)
AIAO.0202
.0101

SEP. 1 1 1981

Mr. Harold W. Moles
Vice President, Operations
Northwest Alaskan Pipeline Company
701 Douglas Avenue
Fairbanks, Alaska 99701

Dear Mr. Moles:

In response to your letter of May 28, 1981, and in accordance with agreement reached at the August 21, 1981 ECC meeting, I am forwarding a revised copy of the Enclosure A, Utility Corridor Construction Campsite and Airstrip Decision for your use in FERC filing cost estimates. These decisions state which campsites will be available for future use when existing permit arrangements have been adjudicated.

These decisions are based upon existing information as submitted by Northwest Alaskan Pipeline Company (NWA). I understand that, as suggested at the ECC meeting, further data may become available from your company showing the interrelationships between construction camps which might lead to a better understanding of the need for all camps requested.

Please note that several sites on the enclosures are not approved for future use. This is not to say that campsites will not be approved in the general areas. Rather, the decisions are strictly based upon existing locations and existing applications. Reuse of the camp near Galbraith Lake is opposed by the North Slope Borough. There may be other alternatives such as eliminating this camp and using Toolik, or establishing a construction campsite at compressor station 4. Again, your analysis of options could be useful in arriving at a final decision. At Prospect, the part of the existing campsite that is out of the 100-year floodplain will be considered for reuse although we prefer to see the campsite moved to the airstrip area.

Although the enclosure includes airstrips, we will require individual applications to be submitted for their use.

With respect to the applications of 1978, the State's and BLM's requests for additional information in 1978, and NWA's response to that request in 1981, we fully concur with the analysis the Federal Inspector's office completed of the 1.6.1 Plans (essentially the same as application data). In addition to

the Federal Inspector's findings of inadequacy, it should be made clear that regardless of total area applied for, any further use on existing campsites will be limited to the areas presently disturbed unless clear justification is shown for additional space. In the case of Dietrich Camp, please note that Enclosure B - General Reuse Criteria requires some adjustment in the existing campsite facility locations relative to the Dietrich River.

To assist you in perfecting your applications, I am enclosing a highlighted copy of BLM's Utility Corridor Management Decision Criteria which was just finalized. Incidentally, I am taking this opportunity to convey my appreciation for the comments your office provided during the development of this document. Any permits issued will, of course, have terms and conditions which are consonant with that document and the other attached enclosures.

Sincerely yours,

Curtis V. Hyde

State Director

Enclosures (3)

APPENDIX E

THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
ROOM 2413 POST OFFICE BUILDING
1200 PENNSYLVANIA AVENUE
WASHINGTON, D.C. 20044

JUN 6 1980

Mr. Darrell S. MacKay
Northwest Alaskan Pipeline Co.
1801 K Street, NW
Suite 901
Washington, DC 20006

Dear Mr. MacKay:

As requested in your letter of June 2, I reviewed the final draft of Northwest Alaskan's Management Plan (dated May 30, 1980). The overall management framework and principles established in the May 30 draft are acceptable and approved. This approval is conditional, however, upon Northwest providing additional details for my review and approval at a later date. I believe this conditional approval is in conformance with our policies of maintaining an interactive relationship with Northwest and providing input in the early stages of all phases of project development.

I recognize that, in some cases, Northwest has not yet fully developed details for the management approach to be used and that, in others, the details will not be ready for release until the FERC Certificate filing date. I also recognize that, as the project evolves, certain revisions to the management approach may become necessary. Such details and changes should be submitted for my review as they are implemented.

Our May 23 letter identifies those areas for which additional details must be provided. Some of these areas are especially critical to project success. Consequently, a detailed description of the duties, responsibilities, and delegations of authority must be provided in the appropriate supplemental documents enumerated in the management plan. The most critical areas are: (1) the responsibilities of the Chairman and Chief Executive Officer, the Vice Chairman and the President; (2) the level of delegation of authority to the NWA field teams; and (3) the relationship between NWA, the Project Management Contractor and the Execution Contractors. While the May 30 draft gives some additional information on items 1 and 3, further details must be provided. Additional details on item 2 are necessary for me to establish a compatible field organization.

Finally, while formal establishment of the specific points of technical staff interface between NWA, PMC, and OFI staff can be worked out at a later date, I believe such a formal identification of the appropriate interface points is essential to a smooth, coordinated working relationship.

Sincerely yours,

Peter T. Cook for

John T. Rhett
Federal Inspector

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official restricted service list compiled by the Secretary in Docket No. CP80-435, in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C. this 18th day of September, 1981.

Cuba Wadlington, Jr.

Cuba Wadlington, Jr.
Director, Regulatory Affairs
Northwest Alaskan Pipeline Company
1120 20th Street, Suite S-700
Washington, D.C. 20036

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Alaskan Northwest Natural Gas Transportation Company	))	Docket No. CP78-123, et al.

MOTION FOR CLARIFICATION OR MODIFICATION OF ORDER TO SHOW CAUSE

The Public Service Commission of the State of New York (New York), an intervenor in these proceedings, herewith moves that the Commission clarify or modify its Order to Show Cause, issued December 15, 1980, to make clear that interested persons or parties believing that the recommendations of the Office of the Chief Accountant in the audit reports which are the subject of the Show Cause order should be adopted by the Commission will have a reasonable period, not less than 30 days after service of the last of the responses to the Show Cause order, to reply thereto.

The audit reports inter alia recommend that the Commission find that none of the $38,366,833 expended by four of the partners of the Alaskan Northwest Natural Gas Transportation Corporation (ANNGTC) as their share of the $154,849,500 expended by Canadian Arctic Gas Study Limited (CAGSL) in support of an unsuccessful certificate application to provide the service for the Alaska Natural Gas Transportation System (ANGTS) had been shown to be of future value to the ANGTS, or otherwise of a nature to qualify for inclusion in the ANGTS rate base. ($134,089,813 of the total was found to be of "no future value," $20,759,657 to be of "possible future value or usefulness," not yet demonstrated). With the recent admission into the ANNGTC partnership of four more of the CAGSL members, an additional $32,082,132 is at stake.1/

By the December 15, 1980 Show Cause order "interested persons" disagreeing with the data and opinions of the Office of the Chief Accountant were given 60 days to respond. But no

---

1/ See e.g., Opinion No. 101, Columbia Gas Transmission Corp., denying Columbia's request to include CAGSL costs in rate base without prejudice to its seeking recovery of such costs if it or an affiliate become a partner in ANNGTC.

provision was made for answering pleadings by parties like New York concurring in the Office of the Chief Accountant's recommendations. Accordingly, New York requests the Commission to clarify or modify its December 15, 1980 Order to Show Cause to provide a period, to be no less than 30 days after service of the last response to the Show Cause order, for responsive pleadings by all "interested persons" and parties, including the Commission staff, who might wish to support the Chief Accountant's recommendations.

Respectfully submitted,

THE PUBLIC SERVICE COMMISSION OF
THE STATE OF NEW YORK

Peter H. Schiff
General Counsel
Empire State Plaza
Albany, New York 12223

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Wilner & Scheiner
1200 New Hampshire Avenue, N.W.
Suite 300
Washington, D.C. 20036
(202) 861-7800

Its Attorneys

December 23, 1980

CERTIFICATE OF SERVICE

I, Richard A. Solomon, do hereby certify that I have this day served a copy of the foregoing "Motion for Clarification or Modification of Order to Show Cause," by first class mail, postage prepaid, upon all interested parties in this proceeding.

Richard A. Solomon

December 23, 1980

OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
IRVINE FIELD OFFICE
2222 Martin Drive, Suite #155
Irvine, California 92715

October 2, 1980

MEMORANDUM

TO: John Adger, Alaska Delegate

FROM: Amos Mathews, Director, Alaska Field Office
Earle Ausman for

SUBJECT: Major Outstanding Design Issues Related to Alaskan Leg

The FERC, in it's August 1, 1980, "Notice of Application and Order Establishing Procedures," requested the OFI to prepare for circulation, at the earliest possible time, a brief report identifying the major outstanding design issues. Attached in response to this request, is a report prepared by our contractor, Unified Industries Inc. Supplemental comments from the OFI staff may be provided during the next conference on Tuesday, October 7, 1980.

The design on which the NWA Certification Cost Estimate and these reports are based was frozen in March 1980. Significant progress is currently being made in the finalization of that design. The intent of these reports is to identify areas containing design options that should be considered as the design is finalized.

These areas are under continuing review by the OFI and the reports do not necessarily represent the final views of the Office. They are intended for purposes of discussion at the conference scheduled to begin on October 7.

SUMMARY REPORT ON MAJOR OUTSTANDING DESIGN ISSUES

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

09-TR-0006-3

WBS 1.01.22.02

CONTRACT NUMBER

OFI 80-0001

October 1980

for Ashraf M. Mirza
Engineering Manager

Richard K. Shogren
Project Manager

UNIFIED INDUSTRIES, INCORPORATED
2222 Martin Drive
Irvine, California 92715

TABLE OF CONTENTS

1.0 INTRODUCTION

The Northwest Alaskan Pipeline Company's (NWA) certification cost estimate submitted to the Federal Energy Regulatory Commission (FERC) for the cons ɔn of the Alaskan segment of the Alaska Natural Gas Transpor. ;ystem (ANGTS) contains a substantial amount of information regard..g the following topics:

- Overall Planning and Design Procedures
- Environmental Engineering Programs
- Current and Projected Field Programs
- Identified Problems and Proposed Solutions
- Assumptions for Design Bases

The Federal Inspector's Office (OFI) has requested its Technical Support Contractor, UII/SDC, to identify and provide a report on outstanding major design issues related to the cost filing. This report is provided in accordance with that request.

These issues have been grouped into the following categories:

- Technical and Environmental Issues (Section 2.0)
- Organizational and Schedule Issues (Section 3.0)

These issues do not include other elements of the cost filing, such as EEO requirements, etc. Upon completion of the ongoing technical review, a more definitive list of outstanding design issues can be developed. Nonetheless, it is our judgement that contained within the issues identified in this report is the potential no matter how slight, for major cost changes, both up and down.

2.0 TECHNICAL AND ENVIRONMENTAL ISSUES

This section identifies those major technical and environmental issues that are considered important to design development for the ANGTS. These issues require resolution early in the development of system designs to minimize large cost changes later in the program.

(1) Design Criteria

Definitive criteria or bases for design of the gas pipeline are required wherever the alignment is adjacent to existing facilities (TAPS, Haul Road, etc.). These criteria must be supplemented with specific construction procedures for installation of the gas line to ensure the integrity and safety of these existing facilities. These criteria are needed also to avoid realignment or a redesign at a later date, and to judge the adequacy of the field data gathering programs.

(2) 1980 Field Program

The 1980 field programs appear to be generally directed toward resolving the major technical issues. However, the adequacy of these programs can not be evaluated because detailed procedures and concepts are not currently available. These programs, which provide the basic data for design confirmations, will not be completed until late 1980 or early 1981.

(3) Frost Heave Design

Frost heave associated with the burial of a chilled gas pipeline in discontinuous permafrost is the most significant design issue affecting

the project. The criteria adopted by NWA to classify the existence and degree of frost heave potential have yet to be validated. These criteria have been applied in estimating the total length of the pipeline which will require special measures to counteract differential frost heave. NWA is not yet ready to demonstrate that select granular material and insulation can control differential heave to the extent necessary to maintain stress concentrations within acceptable limits. At present the magnitude and extent (bounds) of differential heave are difficult to define.

(4) Steady-state Thermohydraulic Simulation

Simulating accurately the thermal behavior of the chilled flowing gas resulting from interaction of gas properties and soil temperatures and conductivities encountered in the Arctic environment is an important requirement of the steady-state thermohydraulic program used for flow calculations. The calculated flowing gas temperatures impact the flow rates, and compressor station equipment design. Further review is necessary to evaluate the cost implications of the thermohydraulic model.

(5) Ditch Design and Stability

Detailed geotechnical data is being acquired but is not yet complete. Therefore, the number of miles required for each ditch design type may conceivably undergo change. Material quantity requirements are affected by changes in ditch design.

NWA has addressed ditch stability by proposing the use of insulation to prevent rapid thaw of the ditch walls, and to limit construction in unstable locations to the shoulder and winter months. However, productivity targets indicate that there will be great incentive to continue pipeline operations through summer months, which could require changes in ditch design.

(6) Pipe Selection Criteria

The mainline pipe material requirements indicated in the FERC Filing may be more restrictive in terms of carbon limitation and Charpy impact values than is necessary for the service anticipated.

(7) Work Pad Design

The decision to increase the minimum separation distance between the gas pipeline and the TAPS oil pipeline from 80 to 200 feet may have an impact on the design of the pad and hence, the quantity of materials required for construction. Likewise, extensive use of a thermal workpad instead of a structural workpad may be necessary north of the Brooks Range to prevent excessive thermal degradation. In addition, the criteria governing the selection of workpad type south of the Brooks Range require further examination.

(8) Major River Crossings

Crossings of major rivers require special designs to account for site specific hydrologic, geotechnical, and thermal conditions. Since the

field programs to collect design data have not been completed, it presently cannot be determined to what extent protective structures or other design treatments will be required.

(9) Minor Stream Crossings

The frost bulb surrounding the chilled gas pipeline could act as a barrier to water flow resulting in erosion damage due to channel diversion caused by massive ice formations. This condition could also directly impact fishery resources. Development of measures used to avoid this condition, such as deep burial or change of mode, may well be in progress, but were not presented in the Filing.

(10) Thaw Settlement

Design criteria limiting thaw settlement beneath the pipe during the dormant period have not yet been presented; thus it is not known if allowance has been made for the application of treatments to control such problems as loss of pipe support and erosion of backfill.

(11) Special Construction Sites

Designs for special sites such as the Atigun Pass and the Yukon River Bridge are still being developed. Options may involve rerouting or the development of special designs, (e.g., tunneling) to accommodate the locations.

(12) Temporary Facilities

NWA plans to utilize existing sewage treatment plants at TAPS construction camps. Extensive renovation or replacement of these existing facilities may be required.

(13) Winter Construction

NWA does not currently intend to adopt winter construction techniques that involve utilization of snow and ice material for workpad and access roads. However, the Right-of-Way Grant requires a revaluation of this policy, which could result in either limited or extensive use of winter months for constructing the pipeline. If this occurs, winter construction should be considered as a major design issue which will require resolution.

(14) Compressor Stations

Certain aspects of compressor station design may be made more cost effective by giving further consideration to the pressure relief/emergency blowdown system, foundation details, and valving for such subsystems as scrubber isolation and refrigeration units.

(15) Communication System

Preliminary design documents give the impression that a new microwave system for communications will be installed. Clarification is required regarding the possible utilization of portions of the existing RCA system.

(16) Proximity to the TAPS

Location of the gas alignment in close proximity to the TAPS has raised a number of design and construction issues. Many of these concerns can be resolved by the Right-of-Way Grant requirement which stipulates a 200-foot minimum separation from the TAPS pipeline except that the two lines are expected to be closer than 200 feet at some locations. Special designs and protective measures may be required at these points.

(17) Proximity to the Fuel Gas Line

TAPS owners have expressed a concern about the integrity of its fuel gas line wherever construction activities are coincident. Special workpad design may be required to protect this facility.

3.0 ORGANIZATIONAL AND SCHEDULE RELATED ISSUES

This section identifies those issues in the management organization and schedules which could affect schedules and costs during the design and construction of the project.

(1) Construction Management

The construction management organization presented in the filing documents permits NWA direction of the project management contractor at multiple levels of the latter's organization. Such an arrangement should be reviewed in light of the need for timely response to construction problems.

(2) Construction Schedules

The schedule for ditching, pipelaying and backfill in ice-rich soils where potential ditch stability problems exist is an issue. These activities are planned for the shoulder months which provide a limited timing window for performing a very difficult construction activity. Schedules for fish stream crossings may possibly be impacted by similar constraints.

(3) QA/QC Authorities

The present QA/QC organization has the authority to establish or modify construction specifications as they relate to quality requirements. The qualifications of the QA/QC group to establish or modify technical or construction related specifications thus becomes an issue.

OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
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1200 PENNSYLVANIA AVENUE
WASHINGTON. D C 20044

OCT 7 1980

MEMORANDUM

TO: John Adger
Alaska Delegate

FROM: Earle Ausman for
Amos Mathews
Director of Alaska Field Office

SUBJECT: Major Outstanding Design Issues Related to Alaskan Leg

The attached numbered design issues should be added to those included with my October 2, 1980, memorandum on this subject.

Attachment

(18) Location of Metering/Compressor station

Combining the metering station currently located at the Yukon border with the compressor station in that area can reduce costs as less site work would be required and operation and maintenance would be simplified. Further, one set of pig traps could be eliminated.

(19) Cross Flow of Ground Water

The passage of water across the chilled gas line is an important problem because of environmental consequence, cost, and fears of inducing aufeis (surface icing) and ice damming which can affect the gas line and adjacent structure. The solution to the problem of providing water passage in an economical way can affect the choice of modes.

(20) Impact of Conditioning Plant Design on Total System

Pipeline gas quality specifications call for a one percent limitation in carbon dioxide. This specification is currently being reevaluated and, if changed (e.g. to two percent) could reduce both initial and life cycle costs.

(21) Valve Spacing

Increasing valve spacing coupled with automatic valve operation could reduce costs and improve response to emergency conditions.

(22) Additional Compressor Station Design Issues

Turbine exhaust heat could be utilized in driving the refrigeration system.

- Adsorption cycle powered from exhaust heat could be considered;

- The use of more fuel efficient turbines, such as those using regenerative or combine cycles, may be more cost-effective than aircraft derivative drivers when life cycle cost are considered.

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

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October 27, 1980

Honorable Kenneth F. Plumb
Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

Re: Northwest Alaskan Pipeline Company - Docket No. CP78-123

Dear Mr. Plumb:

Northwest Alaskan Pipeline Company and Alaskan Northwest Natural Gas Transportation Company submit herewith, for filing, pursuant to the Alaska Natural Gas Transportation Act and the Natural Gas Act, an original and 19 copies of Notice of Amendment to Partnership Agreement notifying the Commission of an amendment to the Partnership Agreement for the purpose of admitting Columbia Alaskan Gas Transmission Corporation, Tetco Four, Inc., Texas Gas Alaska Corporation, and TransCanada Pipe-Line Alaska Ltd. to the Partnership. Together with said Notice, there is also submitted:

1. A copy of Amendment No. 3 (effective August 1, 1980) to the Alaskan Northwest Natural Gas Transportation Company Partnership Agreement.

2. A proposed Notice of Filing of Notice of Amendment to Partnership Agreement.

3. A certificate of service.

Copies are being served on parties designated by the Commission on the service list for Docket No. CP78-123.

Very truly yours,

Rush Moody, Jr.

Enclosures

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

In the Matter Of:	)	
	)	Docket No. CP78-123, et al.
Alaskan Northwest Natural Gas Transportation Company	)	

NOTICE OF
AMENDMENT TO PARTNERSHIP AGREEMENT

Comes now Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest), 1/ a partnership, having heretofore received a conditional certificate 2/ for the construction and operation of the Alaska Natural Gas Transportation System (ANGTS), and respectfully advises the Federal Energy Regulatory Commission (Commission) of the following:

I

Effective August 1, 1980, the Partnership Agreement of Alaskan Northwest was amended (Amendment No. 3) 3/ to admit

---

1/ A general partnership organized under the laws of the State of New York and comprised of Northern Arctic Gas Company, Northwest Alaskan Pipeline Company, Pan Alaskan Gas Company, Calaska Energy Company, Pacific Interstate Transmission Company (Arctic), United Alaska Fuels Corporation, and American Natural Alaskan Company.

2/ Alcan Pipeline Company, et al., Docket Nos. CP78-123, et al. (December 16, 1977). The certificate issued to Alcan was transferred to Alaskan Northwest by order of June 30, 1978.

3/ Amendment No. 1 pertained to the discount schedule set forth in Section 5.2 of the Partnership Agreement. The amendment was noted at mimeo p. 7, fn. 6 of the Commission order issued in the captioned docket on June 30, 1978. Amendment No. 2 was filed February 6, 1980 and was the subject of a notice and order requesting comments issued in the above-captioned docket on August 1, 1980. This Amendment No. 3 is the third amendment to the Partnership Agreement, and is attached hereto as Appendix A.

four additional partners: Columbia Alaskan Gas Transmission Corporation, an affiliate of Columbia Gas Transmission Corporation; Tetco Four, Inc., an affiliate of Texas Eastern Transmission Corporation and Transwestern Pipeline Company; Texas Gas Alaskan Corporation, an affiliate of Texas Gas Transmission Corporation; and TransCanada PipeLine Alaska Ltd., an affiliate of TransCanada PipeLines Limited. Affiliates of each of these new participants operates a major pipeline transportation network, the first three in the United States subject to regulation by the Commission, and the latter in Canada subject to regulation by the National Energy Board (NEB).

II

On January 31, 1978, the Alaskan Northwest Partners entered into a general partnership agreement for the purposes of constructing and operating the Alaskan segment of the ANGTS. The terms of this agreement were accepted by the Commission in an order issued June 30, 1978. Section 11 of the Partnership Agreement provides for the admission of additional partners after the formation of the Partnership upon terms and conditions of admission determined by the Partnership.

Pursuant to that section, effective Janaury 1, 1980, the Partnership and American Natural Alaskan Company (American Natural Alaskan) agreed that American Natural Alaskan would become a Partner according to the following terms and conditions:

1. American Natural Alaskan agrees to abide by all conditions and obligations of the Partnership Agreement, unless specifically waived.

2. American Natural Alaskan will make a cash contribution to the capital account of the Partnership in an amount equal to that contributed by any individual Partner for the period between the formation of the Partnership and January 7, 1980. This contribution will be paid-off in increments with each future cash call so that the total paid by American Natural Alaskan will be twice that of any other Partner until the full amount has been equalized.

3. American Natural Alaskan will have the right to submit to the Board of Partners for inclusion in the American Natural Alaskan Capital Account certain sums, called Qualified Expenditures, expended prior to admission that the Partners determine to be of value to the project.

4. American Natural Alaskan will be entitled to a representative on the following committees of the Partnership: Executive, Audit, and Compensation.

5. For purposes of the admission of American Natural Alaskan, the Partnership agrees that solely for purposes of Section 5 of the Partnership Agreement, American Natural Alaskan will be deemed to have been a Partner on or before March 17, 1978. This acts to waive the requirement of Section 5.2 that a Partner admitted after that date is subject to a special allocation of profits, losses and credits.

6. The admission of American Natural Alaskan is conditioned upon the approval by the Commission of the terms and conditions of admission.

These terms and conditions were incorporated into Amendment No. 2 to the Partnership Agreement, which was filed with the Commission on February 6, 1980. Accompanying this submittal was an expression by the Partnership of its willingness to offer the same terms and conditions of membership to any other eligible person for a period of thirty (30) days following the issuance by the Commission of the notice of Amendment No. 2.

The Commission notice was issued August 1, 1980 and included a request for comments and reply comments with respect to certain areas of concern. 4/ Although comments were requested on these specific points, the Commission stated that it was inclined to approve the admission of American Natural Alaskan as a partner, the waiver of the discount schedule for that purpose, the use of the thirty-day grace period for admittance of new partners without penalty, and the use of a discount schedule for new partners entering after the grace period.

The Partnership filed initial comments on August 22, 1980 and reply comments on September 5, 1980. In the initial comments, the Partnership explained further the reasoning in support of Amendment No. 2 and the offer of a grace period. By the time the reply comments were due, the Partnership was able to advise the Commission that four companies (Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska) had responded favorably to the Partnership offer and agreement had been reached on the terms and conditions of their admittance.

4/ The notice and order of the Commission issued August 1, 1980 invited comments on the following: (1) the waiver of the discount schedule (Section 5.2 of the Partnership Agreement) for the purpose of admitting American Natural Alaskan as a partner; (2) the acceptance of the thirty-day grace period for possible additional membership, (3) the appropriate level of discount to put into effect at the end of the grace period (assuming the grace period is approved), and (4) the appropriateness of using particular events to determine changes in the discount schedule.

The formal agreement expanding the Partnership Agreement to include the four new members is the attached Amendment No. 3 (Appendix A). In addition to the acceptance of the terms and conditions agreed on between the Partnership and American Natural Alaskan, as set forth previously, the Partnership, including American Natural Alaskan, and the four new Partners agreed to further condition membership on the following:

(1) Commission approval of the thirty-day grace period as tendered in the February 6, 1980 filing,

(2) Commission approval of Amendment No. 3,

(3) an understanding that Section 4.3.1 of the Partnership Agreement is not intended to require, and will not be construed to require, any Partner to assume a Partnership interest greater than that interest elected under Section 4.3.1.

The above matters are incorporated into Amendment No. 3.

The Commission will note that in the letter agreement between Columbia Alaskan and the Partnership whereby Columbia Alaskan agreed to become a Partner, which was filed with the Commission on September 5, 1980, a condition was added providing for a waiver of the last sentence of Section 3.6 and waiver of Section 11.1.4 of the Partnership Agreement, together with the receipt by Columbia Alaskan of an order or orders from the Securities and Exchange Commission (SEC) authorizing Columbia Alaskan's participation in the Partnership and the performance of its obligations thereunder. The cause of this condition is the Public Utility Holding Company Act of 1935, which is administered by the SEC, and which is applicable to Columbia Alaskan. Section 3.6 of the Partnership Agreement requires each Partner to represent that it is not subject to that Act, and Section 11.1.4 requires that the admission of any new Partner will not result in the Partnership becoming subject to the Act. As previously stated, the Partnership has agreed to the waiver of these requirements.

III

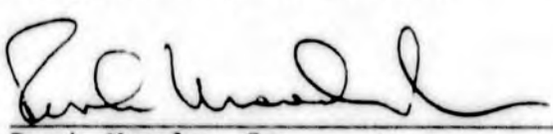
The instant filing serves to notify the Commission that four more companies have joined the Partnership. The Partnership is now comprised of the original six members, whose participation was approved by the order of June 30, 1978, and five new members (American Natural Alaskan, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska), whose joinder has not yet

received Commission acceptance. The Partnership does not believe the Commission 5/ or any interested person 6/ has or could have any objection to the proposed expansion of the Partnership.

The admission of new Partners is a positive step toward the successful completion of the ANGTS. Additional Partners will facilitate project financing by broadening the base of equity support, spreading the risk of the current investment, and committing greater resources to the Project. Although much of the regulatory risk has been or is about to be overcome, substantial risks remain after Commission certification. The willingness of the new Partners to commit considerable resources to the ANGTS demonstrates their faith in the viability of the Project, reinforces the determination and foresight of the original Partners, and justifies the Partnership's offer of a thirty-day grace period to attract new members. Under these circumstances, the Partnership strongly suggests that the public interest will best be served by Commission approval of both Amendment Nos. 2 and 3.

WHEREFORE, Alaskan Northwest respectfully advises the Commission of the amendment to its Partnership Agreement and petitions the Commission to review and accept the amendment, as offered, and the joinder of the new Partners in accordance therewith.

Respectfully submitted,



Rush Moody, Jr.
Attorney for Alaskan Northwest
Natural Gas Transportation
Company

Northwest Alaskan Pipeline Company

Of Counsel:

AKIN, GUMP, HAUER & FELD
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Washington, D.C. 20036

5/ In the August 1, 1980 notice and order, the Commission stated in footnote 7 at page 5 that it was inclined to find the admission to the Partnership of American Natural Alaskan was not inconsistent with the requirements of the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System.

6/ In response to the August 1, 1980 notice and order, no person filed a comment objecting to American Natural Alaskan becoming a Partner. The Partnership anticipates that the instant submittal will not engender any opposition.

APPENDIX A

AMENDMENT NO. 3
AGREEMENT DATED AS OF AUGUST 1, 1980
BETWEEN
ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
AND
COLUMBIA ALASKAN GAS TRANSMISSION CORPORATION,
TETCO FOUR, INC., TEXAS GAS ALASKA CORPORATION,
AND TRANSCANADA PIPELINE ALASKA LTD.

THIS AGREEMENT dated as of August 1, 1980 (Amendment No. 3) by and among ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY, a New York general partnership, ("Partnership") formed pursuant to the Alaskan Northwest Natural Gas Transportation Company General Partnership Agreement effective as of January 31, 1978 ("Partnership Agreement"), and Columbia Alaskan Gas Transmission Corporation, a Delaware corporation ("Columbia Alaska") and a wholly-owned subsidiary of Columbia Gas System, Inc., a Delaware corporation; Tetco Four, Inc., a Delaware corporation ("Tetco Four") the capital stock of which is owned fifty percent by Texas Eastern Transmission Corporation and fifty percent by Transwestern Pipeline Company, Delaware corporations; Texas Gas Alaska Corporation, a Delaware corporation ("Texas Gas Alaska") and a wholly owned subsidiary of Texas Gas Transmission Corporation, a Delaware corporation; and TransCanada PipeLine Alaska Ltd., a Nevada corporation ("TransCanada-Alaska") all of whose capital stock is owned indirectly by TransCanada PipeLines Limited, a Canadian corporation.

WITNESSETH THAT:

WHEREAS, on February 6, 1980 by a filing in Docket No. CP78-123, et al., the Partnership gave notice to the Federal Energy Regulatory Commission ("Commission") of Amendment No. 2 to the Partnership Agreement, which set forth the terms and conditions agreed to for the admission into the Partnership of American Natural Alaskan Company ("American Natural Alaskan"), and the Partnership further notified the Commission that for a period of thirty days ("grace period") following the issuance by the Commission of a notice of the filing of Amendment No. 2 that membership in the Partnership would be available to other eligible, interested persons on the same terms and conditions agreed to with American Natural Alaskan; and

WHEREAS, on August 1, 1980 the Commission issued its Notice Of The Filing Of A Notice Of Amendment To Partnership Agreement, And Order Inviting Comments setting forth the terms of Amendment No. 2 and the offer of a grace period for additional membership, and requesting comments; and

WHEREAS, in response to the Partnership offer of a grace period, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska have separately requested to be admitted as a Partner on the terms and conditions set forth in this Amendment No. 3, and the Partnership is willing to admit each one as a Partner on such terms and conditions; and

WHEREAS, the terms of the admission of Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska to the Partnership, as set forth in Amendment No. 3, require the amendment or waiver of certain terms, conditions, or provisions in the Partnership Agreement, and the Partnership is willing to agree to such amendments or waivers;

WHEREAS, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska are ready, willing and able to abide by and comply with all the terms, conditions, and provisions of the Partnership Agreement, as amended hereby; and

NOW, THEREFORE, the Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska, intending to be legally bound hereby, agree as follows:

I

In accordance with the provisions of this Amendment No. 3, and the Partnership Agreement as amended hereby, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska shall each become a Partner in the Partnership as of August 1, 1980 (hereinafter called the "Admission Date"). In consideration of becoming a Partner, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska shall each make capital contributions to the Partnership on the terms and subject to the conditions of Section 4 of the Partnership Agreement, as amended by Amendment No. 2, and as further amended by this Amendment No. 3.

II

Section 1 of the Partnership Agreement is amended, effective as of the Admission Date, to add new sections 1.8 through 1.11 to read as follows:

> "1.8 COLUMBIA ALASKAN GAS TRANSMISSION CORPORATION, (hereinafter called 'Columbia Alaskan'), a corporation organized under the laws of the State of Delaware, with its principal corporate offices at 20 Montchanin Road, Wilmington, Delaware 19807. Columbia Alaskan

represents that: (a) all of its capital stock is owned by Columbia Gas System, Inc., a Delaware corporation; and (b) Columbia Alaskan or an Affiliate intends to become a Shipper."

"1.9 TETCO FOUR, INC. (hereinafter called ('Tetco Four'), a corporation organized under the laws of the State of Delaware with its principal corporate offices at One Houston Center Houston, Texas 77002. Tetco Four represents that: (a) fifty percent of its capital stock is owned by Texas Eastern Transmission Corporation and fifty percent by Transwestern Pipeline Company, Delaware corporations; and (b) Tetco Four or its Affiliates intend to become Shippers."

"1.10 TEXAS GAS ALASKA CORPORATION, (hereinafter called 'Texas Gas Alaska'), a corporation organized under the laws of the State of Delaware, with its principal corporate offices at 3800 Frederica Street, Owensboro, Kentucky 42301. Texas Gas Alaska represents that: (a) all of its capital stock is owned by Texas Gas Transmission Corporation, a Delaware corporation; and (b) Texas Gas Alaska or an Affiliate intends to become a Shipper."

"1.11 TRANSCANADA PIPELINE ALASKA LTD., (hereinafter called 'TransCanada-Alaska'), a corporation organized under the laws of Nevada, with its principal corporate offices at 54 Commerce Court, Toronto, Ontario, Canada M5L 1C2. TransCanada-Alaska represents that: (a) all of its capital stock is owned indirectly by TransCanada PipeLines Limited, a Canadian corporation; and (b) TransCanada-Alaska or an Affiliate may become a Shipper."

III

Section 3.6 of the Partnership Agreement is amended, effective as of the Admission Date, to read as follows:

"3.6 Representations and Warranties Concerning Formation of Partnership: Each Partner represents and warrants that, subject to the receipt of all necessary regulatory approvals relating to this Agreement and the investment of the Partners in this Partnership, the execution and delivery of this Agreement, the formation of the Partnership and the performance hereof will not contravene

any provision of, or constitute a default under, any indenture, mortgage or other agreement of such Partner or any Affiliate of such Partner or any order of any court, commission or governmental agency having jurisdiction, and this Agreement is a valid and enforceable Agreement against such Partner except insofar as enforcement hereof may be limited by bankruptcy, insolvency or other similar laws related to or affecting the enforcement of creditors' rights. Each of the Parties to this Agreement, other than Columbia Alaskan, represents that it is not subject to or is exempt from the jurisdiction of the SEC as a public utility holding company within the meaning of the Public Utility Holding Company Act of 1935."

IV

Section 4.2 of the Partnership Agreement is amended by changing Section 4.2.5 and by including new sections 4.2.7 and 4.2.8, effective as of the Admission Date, to read as follows:

"4.2.5 On or before December 1, 1979, and on or before each succeeding December 1 in the event the Commitment Date is estimated to occur after such succeeding December 1, the Board of Partners shall determine, taking into account budgeted costs and contractual commitments which will accrue if the Project is suspended, the anticipated cash requirements of the Partnership for the period from January 1, 1980 (or from any succeeding January 1) through the date then estimated to be the Commitment Date. Immediate notice of each such determination shall be given to all Partners. Each Partner agrees, subject to the withdrawal rights specified in Section 4.4.3, to contribute to the Partnership, for the period commencing January 1, 1980 and ending with the Commitment Date, an amount equal to (i) the amount by which the anticipated cash requirements of the Partnership during such period exceeds the total of the amount contributed by American Natural Alaskan pursuant to Section 4.2.6, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to Section 4.2.7, and Columbia Alaskan pursuant to Section 4.2.8, divided by (ii) the number of Partners.

4.2.7 Tetco Four, Texas Gas Alaska, and TransCanada-Alaska severally agree, notwithstanding anything to the contrary in Section 4.4.3, which Section shall not be applicable to this Section 4.2.7, to contribute to the Partnership that amount which is equal to the amount contributed by any Partner named in Sections 1.1 through 1.6 pursuant to Section 4.2 from the Formation Date through August 12, 1980. Until Tetco Four, Texas Gas Alaska, and TransCanada-Alaska shall have each contributed to the Partnership the entire amount required to be contributed by it pursuant to this Section 4.2.7, each shall, notwithstanding anything to the contrary in Section 4.4, contribute to the Partnership pursuant to this Section 4.2.7, on each date on which a capital contribution pursuant to Section 4.2.5 shall become due and payable, an amount equal to the lesser of (i) the highest amount contributed by any Partner named in Sections 1.1 through 1.6 pursuant to Section 4.2.5 on such date or (ii) the balance remaining to be contributed separately by Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to this Section 4.2.7. The contributions made by Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to this Section 4.2.7 shall be in addition to the contributions of Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to Section 4.2.5.

4.2.8 Upon the receipt by Columbia Alaskan of authorization from the SEC to participate in the Partnership pursuant to the Public Utility Holding Company Act of 1935, which shall occur after the Admission Date and subsequent to one or more requests for cash contributions pursuant to Section 4.2.5, as of the next such request for a cash contribution, Columbia Alaskan shall contribute an amount equal to the sum of (i) the amount previously paid by a Partner subject to both Sections 4.2.5 and 4.2.7 plus (ii) the cash contribution then requested, computed as if Columbia Alaskan were subject to the provisions of Section 4.2.7. Thereafter, for the purposes of cash contributions under Section 4.2.5, the contribution of Columbia Alaskan shall be calculated according to the provisions of Section 4.2.7 as if Columbia Alaskan were included therein on an equal basis with Tetco Four, Texas Gas Alaska, and TransCanada-Alaska."

V

Notwithstanding anything in the Partnership Agreement, as amended, that may be to the contrary, the Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska agree that Section 4.3.1 of the Partnership Agreement is not intended to require, and will not be construed to require, any Partner to assume a Partnership interest greater than that interest which such Partner has elected pursuant to Section 4.3.1.

VI

Notwithstanding anything in the Partnership Agreement, as amended, to the contrary, each Partner agrees that solely for purposes of Section 5 of the Partnership Agreement, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska shall be treated as if they had executed the Partnership Agreement on or before March 17, 1978.

VII

Section 8.3.1 of the Partnership Agreement is amended, effective as of the Admission Date, to read as follows:

> "8.3.1 The Executive Committee shall consist of a Chairman and ten members. Each Partner named in Sections 1.1 through 1.11 (or any substitute Partner succeeding to its interest hereunder) shall designate a representative to serve on the Executive Committee, and the Chairman of the Board of Partners shall also be the Chairman of the Executive Committee. Any vacancy on the Executive Committee occasioned by the withdrawal of a Partner named in Sections 1.1 through 1.11 (or any substitute Partner succeeding to its interest hereunder) shall be filled by the Board of Partners."

VIII

Section 8.4.1 of the Partnership Agreement is amended, effective as of the Admission Date, to read as follows:

> "8.4.1 The Audit Committee shall consist of ten members. No member of the Audit Committee shall be affiliated in any manner with Northwest, and each Partner (other than Northwest) admitted

to the Partnership prior to September 1, 1980 shall have one representative on the Audit Committee. The Board of Partners shall designate one member of the Audit Committee to serve as Chairman of the Audit Committee. Decisions of the Audit Committee shall be by a majority vote of the members. The members shall serve on the Committee at the will of the Board of Partners."

IX

Section 8.5.1 of the Partnership Agreement is amended, effective as of the Admission Date, to read as follows:

"8.5.1 The Compensation Committee shall consist of ten members. No member of the Compensation Committee shall be affiliated in any manner with Northwest, and each Partner (other than Northwest) admitted to the Partnership prior to September 1, 1980 shall have one representative on the Compensation Committee. The Board of Partners shall designate one member to serve as Chairman of the Compensation Committee. Decisions of the Compensation Committee shall be by majority vote of the members. The members shall serve on the Committee at the will of the Board of Partners."

X

For the purposes of Section 11.1 of the Partnership Agreement, execution of this Amendment No. 3 shall (a) satisfy the requirement that a new Partner execute a counterpart of the Partnership Agreement, and (b) except for Columbia Alaskan with respect to Section 11.1.4, constitute a warranty and representation by Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska that each has satisfied the conditions for admission to the Partnership set forth in Sections 11.1.2 through 11.1.4, and (c) constitute satisfaction of the requirements of Section 11.1.1.

XI

This Amendment No. 3 shall be governed by and interpreted in accordance with the laws of New York. Terms used in this Amendment No. 3 which are defined in the Partnership Agreement are, unless the context otherwise requires, used herein as therein defined.

XII

This Amendment No. 3 may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

XIII

This Amendment No. 3 embodies the entire agreement and understanding between the Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska and supersedes all prior agreements and understandings relating to the terms and conditions of the admission of Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska as Partners and any other matters which are the subject of this Amendment No. 3.

XIV

This Amendment No. 3 and the obligations of the Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska hereunder are subject to all applicable laws, rules, orders and regulations of United States federal, state or local governmental authorities having jurisdiction and, in the event of conflict, such laws, rules, orders and regulations of governmental authorities having jurisdiction shall control.

The Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska agree that admission to the Partnership is subject to a condition subsequent of Commission approval of the thirty-day grace period as tendered in the February 6, 1980 Partnership filing and Commission approval of this Amendment No. 3.

IN WITNESS WHEREOF, the parties have executed this Amendment No. 3 as of the day and year first written.

ATTEST:

COLUMBIA ALASKAN GAS TRANSMISSION CORPORATION

Assistant Secretary

By: John H. Croom

President

ATTEST:

TETCO FOUR, INC.

By: _____

ATTEST:

TEXAS GAS ALASKA CORPORATION

_____

By: _____

ATTEST:

TRANSCANADA PIPELINE ALASKA LTD.

_____

By: _____

ALASKAN NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY

By each of its Partners:

ATTEST:

NORTHWEST ALASKAN PIPELINE COMPANY

_____

By: _____

ATTEST:

NORTHERN ARCTIC GAS COMPANY

_____

By: _____

ATTEST:

PAN ALASKAN GAS COMPANY

_____

By: _____

ATTEST:

CALASKA ENERGY COMPANY

_____

By: _____

ATTEST:

TETCO FOUR, INC.

_____

By: _____

ATTEST:

TEXAS GAS ALASKA CORPORATION

_____

By: _____

ATTEST:

TRANSCANADA PIPELINE ALASKA LTD.

_____

By: _____

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

By each of its Partners:

ATTEST:

NORTHWEST ALASKAN PIPELINE COMPANY

_____

By: _____

ATTEST:

NORTHERN ARCTIC GAS COMPANY

_____
Assistant Secretary

By: Gordon Severa
President

ATTEST:

PAN ALASKAN GAS COMPANY

_____

By: _____

ATTEST:

CALASKA ENERGY COMPANY

_____

By: _____

ATTEST:

TETCO FOUR, INC.

_____ By: _____

ATTEST:

TEXAS GAS ALASKA CORPORATION

_____ By: _____

ATTEST:

TRANSCANADA PIPELINE ALASKA LTD.

_____ By: _____

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

By each of its Partners:

ATTEST:

NORTHWEST ALASKAN PIPELINE COMPANY

_____ By: _____

ATTEST:

NORTHERN ARCTIC GAS COMPANY

_____ By: _____

ATTEST:

PAN ALASKAN GAS COMPANY

Robert W. Reed By: R E Kelin

ATTEST:

CALASKA ENERGY COMPANY

_____ By: _____

ATTEST:

_____

TETCO FOUR, INC.

By: _____

ATTEST:

_____

TEXAS GAS ALASKA CORPORATION

By: _____

ATTEST:

_____

TRANSCANADA PIPELINE ALASKA LTD.

By: _____

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

By each of its Partners:

ATTEST:

_____

NORTHWEST ALASKAN PIPELINE COMPANY

By: _____

ATTEST:

_____

NORTHERN ARCTIC GAS COMPANY

By: _____

ATTEST:

_____

PAN ALASKAN GAS COMPANY

By: _____

ATTEST:

_____
Secretary

CALASKA ENERGY COMPANY

By: John A. Sproul
Chairman of the ...

ATTEST:

PACIFIC INTERSTATE TRANSMISSION COMPANY (ARCTIC)

_____
Assistant Secretary

By: _____
President

ATTEST:

UNITED ALASKA FUELS CORPORATION

_____

By: _____

ATTEST:

AMERICAN NATURAL ALASKAN COMPANY

_____

By: _____

ATTEST:

PACIFIC INTERSTATE TRANSMISSION COMPANY (ARCTIC)

_____ By: _____

ATTEST:

UNITED ALASKA FUELS CORPORATION

_____ By: _____

ATTEST:

AMERICAN NATURAL ALASKAN COMPANY

_____ By: James J. Grubisott

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Northwest Alaskan Pipeline Company	)	Docket No. CP78-123

NOTICE OF FILING OF
NOTICE OF AMENDMENT TO
PARTNERSHIP AGREEMENT

Take notice that on October 27, 1980, Northwest Alaskan Pipeline Company and Alaskan Northwest Gas Transportation Company, a partnership formed under the laws of the State of New York (hereinafter referred to as the Partnership), filed a document entitled "Notice of Amendment to Partnership Agreement," in which the Commission was advised that Columbia Alaskan Gas Transmission Corporation, an affiliate of Columbia Gas Transmission Corporation; Tetco Four, Inc., an affiliate of Texas Eastern Transmission Corporation and Transwestern Pipeline Company; Texas Gas Alaskan Corporation, an affiliate of Texas Gas Transmission Corporation; and TransCanada PipeLine Alaska Ltd., an affiliate of TransCanada PipeLines Limited have been admitted to the Partnership as of August 1, 1980. A copy of the amendment to the Partnership Agreement (Amendment No. 3) was attached to the above noted filing.

The instant amendment admits Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to section 11 of the Partnership Agreement. The admissions are in response to an offer of the Partnership in a filing dated February 6, 1980. At that time the Partnership notified the Commission of the admission to the Partnership of American Natural Alaskan Company, effective January 1, 1980, and formalized through Amendment No. 2 to the Partnership Agreement. Also in that filing, the Partnership made an offer that for a thirty-day period following issuance of the Commission notice of Amendment No. 2, any eligible person could become a Partner on substantially the same terms and conditions as those agreed to with American Natural Alaskan Company. The Commission notice was issued August 1, 1980. Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska all reached agreement for membership with the Partnership within the thirty-day period. In addition to the terms and conditions that applied to American Natural Alaskan, the four new Partners and the Partnership further agreed that admission would be conditioned upon: (1) Commission approval of the thirty-day grace period as tendered in

the February 6, 1980 filing; (2) Commission approval of Amendment No. 3; and (3) an understanding that Section 4.3.1 of the Partnership Agreement is not intended to require, and will not be construed to require, any Partner to assume a Partnership interest greater than that interest elected under Section 4.3.1.

Any person desiring to be heard or to make any protest with reference to said application should on or before _____, 1980, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules.

Kenneth F. Plumb
Secretary

VERIFICATION

DISTRICT OF COLUMBIA) ss.

RUSH MOODY, JR., being duly sworn, on oath, says that he is an attorney for Northwest Alaskan Pipeline Company; that he has read the foregoing Notice of Amendment to Partnership Agreement of the Northwest Alaskan Pipeline Company and the Alaskan Northwest Natural Gas Transportation Company and that he is familiar with the contents thereof; that as attorney, he has executed the same for and on behalf of said Companies with full power and authority to do so; and that the matters set forth therein are true to the best of his information, knowledge and belief.

Rush Moody, Jr.
Attorney

SUBSCRIBED AND SWORN TO before me this 27th day of October, 1980.

Notary Public

My Commission Expires:

My Commission Expires April 30, 1984

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in Docket No. CP78-123 in accordance with the requirements of §1.17 of the Rules of Practice and Procedure.

Dated at Washington, D.C., this 27th day of October, 1980.

Rush Moody, Jr.

PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

DRAFT

INFO BOOK

Please Note:

It is expected that some of the information presented here is of such a nature that it will change and become inaccurate.

This publication will be revised on a regular basis. Please check for a current publication date.

Publication Date: August 1980

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OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM

JOHN T. RHETT
FEDERAL INSPECTOR
ALASKAN NATURAL GAS TRANSPORTATION SYSTEM

Mr. Rhett is a professional engineer and administrator with almost 35 years experience supervising major construction in both the civil works and military construction fields. He was with the U.S. Army Corps of Engineers from 1945 to 1973, retiring as a Colonel after serving at posts both here and abroad. In 1973 he joined the Environmental Protection Agency as Deputy Assistant Administrator for Water Program Operations. There he administered EPA's major operation programs in the water pollution control field, such as the multi-billion-dollar grant program for construction of municipal wastewater treatment facilities. He was born in Ft. Benning, Georgia, and received his B.S. from the U.S. Military Academy in West Point, N.Y. in 1945; a Masters in Engineering from the University of California in 1952; and a Masters in International Relations from George Washington University in 1965. He is married, with two children and one grandchild. He and his wife currently reside in Arlington, Virginia.

OFFICE OF THE FEDERAL INSPECTOR - ANGTS

900 W. Fifth Avenue Pouch 6619 Anchorage, Alaska 99502	FTS-271-3668 907-271-3668
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2222 Martin Drive, Suite 155 Irvine, California 92715	
11414 W. Center Road, Suite 350 Omaha, Nebraska 68144	
215 Market Street, Room 767 San Francisco, California 94105	FTS-454-7171 415-764-7171
P.O. Building, Room 2413 1200 Pennsylvania N.W. Washington, D.C. 20044	FTS 275-1100 202-275-1100

OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM

FACT SHEET

Functions of the Office of the Federal Inspector, Alaska Natural Gas Transportation System

Origins: The Office of the Federal Inspector is a small but unique, independent entity created by Congress and the President specifically to expedite and oversee construction of the Alaska Natural Gas Transportation System. Congress in its 1976 legislation clearing the way for the project included the requirement that a single individual, to be called the Federal Inspector, be appointed to be responsible for assuring that the project is built as timely as possible, without excessive cost overruns, and with minimal harm to the environment. It included that requirement because the undertaking is itself unique in size and in importance to the Nation's energy future, and in light of the delays and large cost overruns that have in the past plagued large construction projects, such as the Trans-Alaskan Oil Pipeline.

The Project: The Alaska Natural Gas Transportation System will be an overland pipeline of varying diameters designed to carry about 2.4 billion cubic feet of natural gas daily from Prudhoe Bay, Alaska, to homes and industries in the lower 48 states. At a cost of about $15 billion it will be the largest privately-financed construction project ever undertaken anywhere. It will supply about five percent of our Nation's gas needs for the 25-year life of the project, based on current use rates. The entire project stretches 4,800 miles from Prudhoe Bay, on the northern coast of Alaska, along the route of the Trans-Alaska Oil Pipeline to Delta Junction, south of Fairbanks. There the gas line turns southeast and continues south into Canada, generally following the Alaskan-Canadian highway. Just north of Calgary it splits into two legs--the West Leg going to Antioch, California and the East Leg almost to Chicago. Construction is scheduled to start in 1981 on the two lower Legs. The last portion to be built, the Alaskan segment, is now scheduled for completion in 1984.

Legislative History:

The U.S. Congress enacted the Alaska Natural Gas Transportation Act on October 22, 1976, setting out a series of innovative procedures to expedite the selection, approval and construction of a natural gas pipeline system to bring Alaskan gas to lower 48 markets. After receiving a recommendation from the U.S. Federal Power Commission (now the Federal Energy Regulatory Commission), the President in September 1977 selected a route and applicant. Congress in November of that year approved the President's selection. The exact duties of the Federal Inspector were not defined until Reorganization Plan No. 1 was signed by the President on June 11, 1979. The concepts of that Plan were set out in Executive Order No. 12142, signed by the President on June 21. These three Presidential documents combined to implement the intent of Congress embodied in the ANGTA of establishing the Office of the Federal Inspector, which officially came into being July 1, 1979.

Responsibilities:

The Federal Inspector is an independent entity within the executive branch, established to oversee all construction and initial operation of the U.S. portions of the pipeline. He will coordinate and schedule actions of the eight Federal agencies which must approve some aspect of the project; monitor construction; and enforce all certificates and conditions issued by the agencies. He will be the "one window" for receipt of all data and permit applications and for issuance of all permits. Specifically, the Federal Inspector will:

1. coordinate the scheduling and issuance of all Federal permits and related activities to assure timely and unified decisions;
2. monitor activities to assure that cost control, safety, and environmental protection objectives are fulfilled while still meeting the project completion schedule;
3. keep the President and Congress informed on project progress, including potential delays or problems;
4. establish a joint surveillance and monitoring agreement with the State of Alaska; and
5. enforce all Federal statutes which affect the project, assuring that the builders are complying with all conditions or stipulations attached to any Federal approval.

Although the Federal Departments of Transportation, Energy, Interior, Agriculture, Treasury, the Environmental Protection Agency, U.S. Army Corps of Engineers, and the Chairman of the Federal Energy Regulatory Commission retain their authority to issue necessary permits and certificates, the Federal Inspector must assure that the agencies make these authorizations in timely fashion.

Organization:

Since the establishment of the Office of the Federal Inspector on July 1, 1979, and swearing in of a Federal Inspector on July 13, a concentrated effort has been made to develop a quality organization capable of effectively carrying out the critical responsibilities given it by the Congress and the President. An organizational structure is in place and many of the key positions are filled.

Three other elements which are not part of the OFI but will play an important role are:

Executive Policy Board - Established by Executive Order No. 12142, the EPB is composed of high-level representatives of the Departments of Labor, Agriculture, Energy, Transportation, and Interior; the Corps of Engineers, the Federal Energy Regulatory Commission, and the Environmental Protection Agency. The EPB advises the Federal Inspector on overall management of the program or specific agency concerns or authorities. The EPB has met periodically since January 1978.

Agency Authorized Officers - Each Federal agency which must approve some aspect of the project has appointed an Agency Authorized Officer to represent that agency in the Federal Inspector's Office, as required by the President's Decision and the Reorganization Plan. During the permitting phase, the AAO's will be the primary officials responsible for expediting their agency's approvals. The AAO's will work closely with their agencies and be responsible to the Federal Inspector for assuring timely completion of all necessary actions during this phase.

Citizens' Advisory Council - The Federal Inspector is establishing a citizens' advisory council to provide an avenue for citizen input into certain major decision areas such as environmental matters.

OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
ROOM 2413, POST OFFICE BUILDING
1200 PENNSYLVANIA AVENUE
WASHINGTON, D.C. 20044

July 15, 1980

(202) 275-1100

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Secretary	Linda V. Williams
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Administrative Clerk	Leroy McDonald
Clerk Typist	Robyn Jones

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Secretary	Hazel M. Younger
Deputy General Counsel	Rhodell Fields (7/27)
Attorney	Marcia D. Connelly
Attorney	Peter Esposito
Clerk Typist	Bennie Mae Yeargin

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Information Clerk	Eunetta R. Taylor

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ontracts Specialist ..... C. Allen Olson

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orrespondence Control Clerk ..... Stephanie Michie

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Auditor ..... Gary B. Barber 275-1144

Management Information Systems

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Equal Employment Opportunity/Minority Business Enterprise

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EEO Specialist ..... Mary S. Settle

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Biologist ..... Deborah Kirk

Archaeologist ..... Stephen Chomko

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Secretary ..... Pat Marcopulos

Director of Permits ..... Bob Mosher
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Fish & Wildlife Biologist ..... Carole Hamilton

Director of Compliance ..... Larry Ouellette

General Engineer ..... Ken Freelain

Civil Engineer ..... John Morton

Compliance Specialist ..... Kristie Patterson

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Director ..... Richard Berman

Cost Accountant ..... Eugene Muldoon

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Secretary Barbara Freeman

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Secretary Rita Rainwater

Civil Engineer ..... Earl Ellis

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Fish & Wildlife Biologist ..... W. Lewis Pamplin

External Affairs Representative ..... Paul T. Steucke

Laborer ..... Roy Jamerson

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Secretary Evelyn Melavic

Special Assistant to the
Federal Inspector ..... Austin Ward

General Engineer ..... Julius Moor

Fish & Wildlife Biologist ..... Tony Booth (8/10)

Clerk ..... Roxie Miller

SAN FRANCISCO OFFICE (415) 764-7171

Supervisory General Engineer ..... Leo Bellarts
Secretary Carolyn Rees

General Engineer ..... Joseph Tolly

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714 836 2393

IRVINE OFFICE

Engineering and Cost Review

Director of Engineering ..... Bill Black (9/2)

Supervisory Civil Engineer ..... Earle Ausman

OMAHA

Dennis Schroeder - Eng.

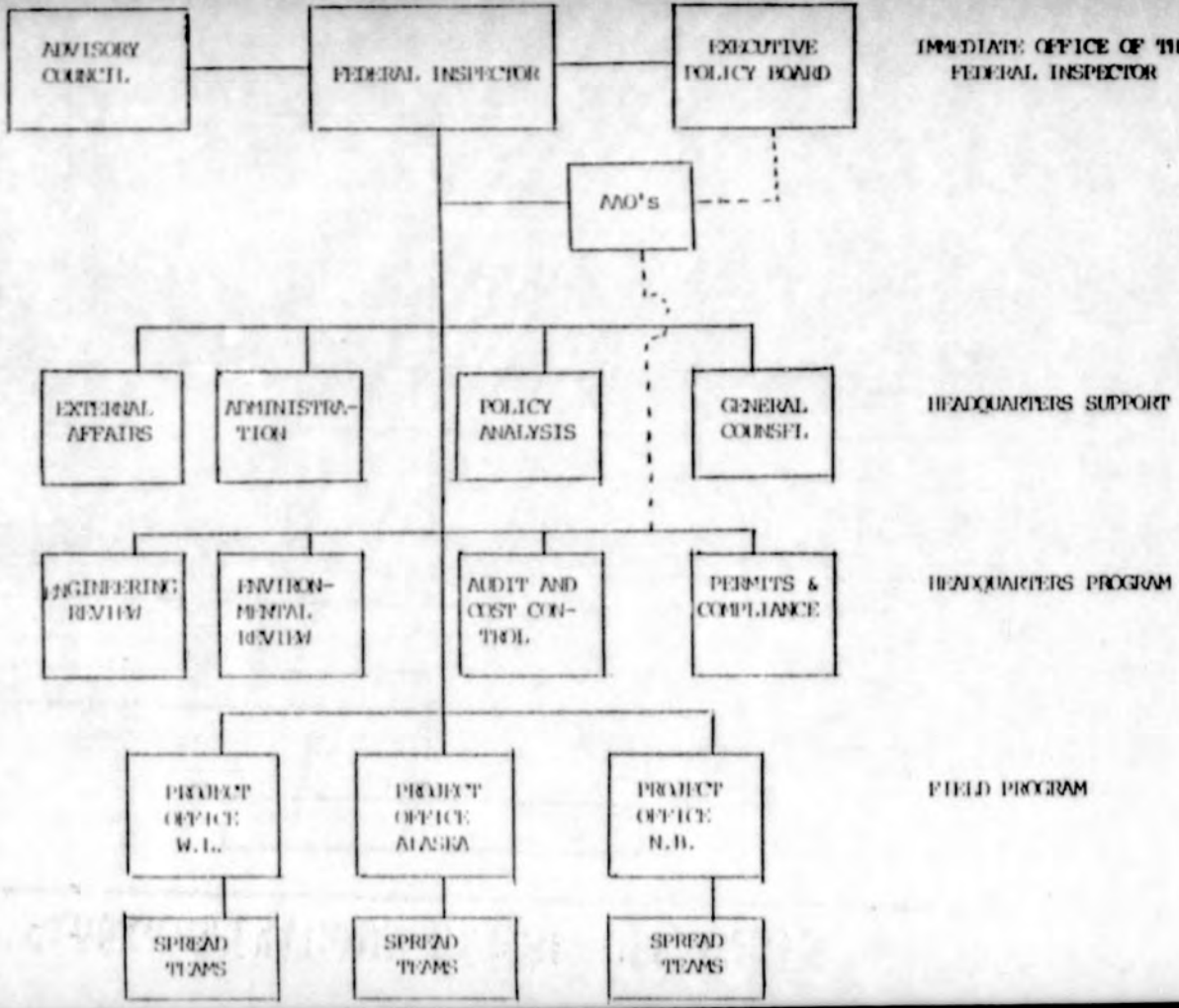
WASHINGTON, D.C. OFFICE

OFI ROSTER OF PERMANENT EMPLOYEES

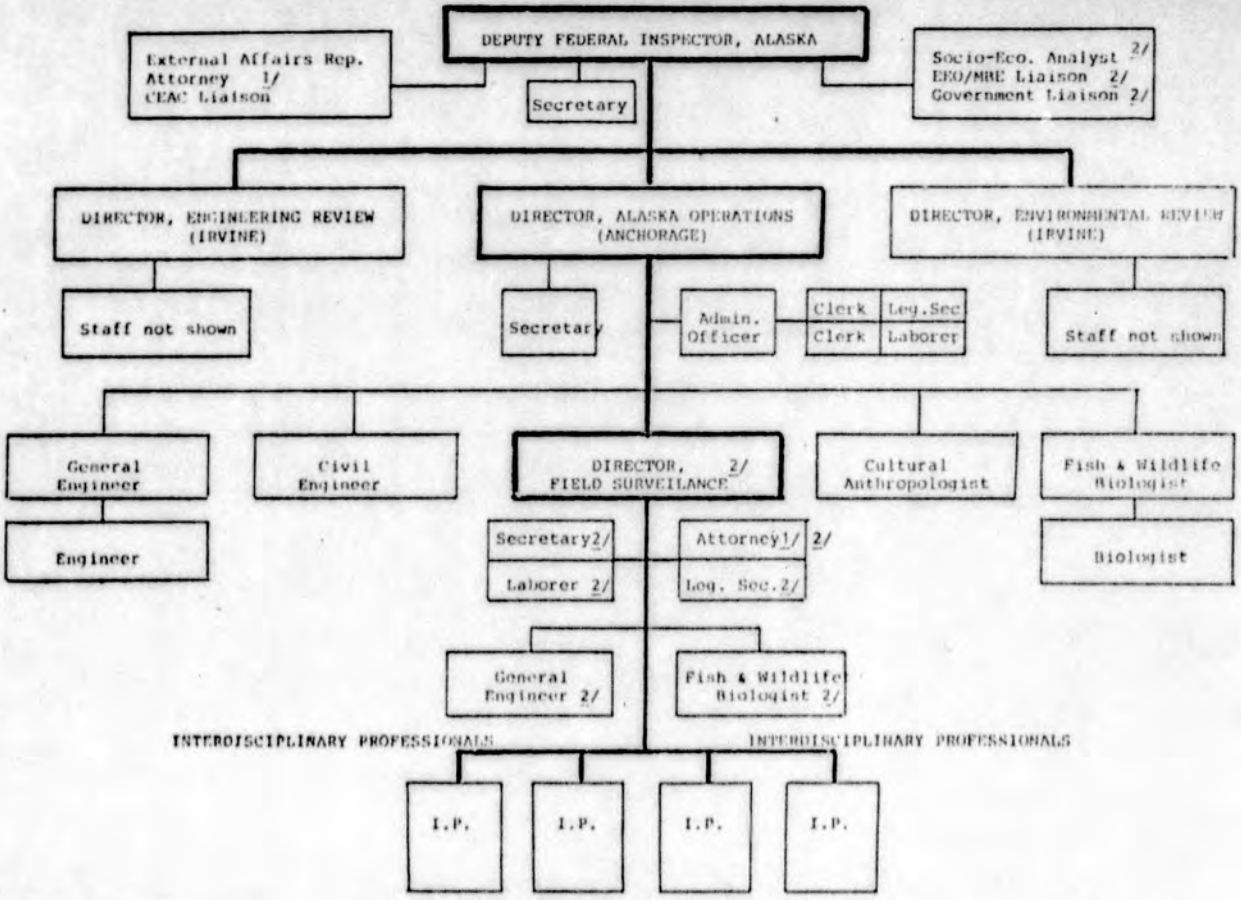
	EXT	ROOM	INTER	STA.
ADAMS, Linda	2751157	2426	A-5	5E
AUSMAN, Earle	" 51114	2407	B-0	2AA
BARBER, Gary	" 51144	2416	A-3	3C
BROWN, Dagmar	" 51162	2428	A-1	6B
CHERVENIC, Evelyn	" 51162	2428	A-0	6A
CONNELLY, Marcia	" 51144	2416	A-4	3D
COOK, Peter	" 51100	2408	A-6	1F
CRAGGS, Mara	51100	2432	A-20	1W
CRITCHFIELD, David	51153	2420	A-6	4F
CUMMINGS, Angela	51100	2432	A-21	1Z
DAVIS, Jean	51114	2412	B-6	2B
ELLETT, Nancy	51100	2406	A-1	1C
ESPOSITO, Peter				
FIGEL, Jack				
FRICKIE, Beverly	51167	2432	A-0	7A
GODBOUT, Tom	51162	2428	A-3	6C
GREENSTREET, WILLIS	51114	2409	B-3	2Y
.MAN, Margaret				
HENDRICKS, Susie	51114	2412	B-7	2C
HENGERER, Ned	51144	2411	A-0	3A
JONES, Robyn	51100	2432	A-9	1L
KIRK, Deb	51153	2420	A-5	4E
LAXTON, Bill	51157	2426	A-4	5D
LIVINGSTON, Nancy	51167	2432	A-4	7D
MARCOPULOS, Pat	51153	2420	A-4	4D
MCDONALD, Leroy	51100	2406	A-3	1D
MCKINNEY, Charlie	51144	2416	A-1	3B
MICHIE, Stephanie	51144	2416	A-7	3G
MORRISON, Joyce	51100	2405	A-7	1T
MORRISON, Renee	51157	2406	A-7	5G
MORTON, Audrey				
MORTON, John				
MOSHER, Robert				
MUELLER, Bruce	51162	2428	A-6	6G
OLSON, Allen	51162	2428	A-4	6D
OUCHI, Al	51162	2428	A-5	6F
OUELLETTE, Laurent				
POWELL, Sarah	51114	2412	B-5	2A
PROFATER, Stephanie	51157	2426	A-0	5A

RECTOR, David	51114	2415	B-4	2X
RHETT, Jack	51100	2402	A-0	1A
SETTLE, Mary	51157	2426	A-3	5C
SLEDGE, Janet	51157	2426	A-1	5B
SMITH, Adele	51167	2432	A-3	7C
SOORENKO, Hannah	51153	2413	A-0	4A
SOULEN, Russell	51153	2413	A-3	4C
TAYLOR, Eunetta	51100	2405	A-8	1S
TOSKEY, Bill	51153	2420	A-1	4B
TRENT, James	51167	2432	A-5	7E
VANCE, Jerry	51162	2430	A-7	6E
WILLIAMS, Linda	51100	2406	A-4	1E
WHITE, Ben	51157	2426	A-6	5F
WILKES, Carolyn				
YEARGIN, Bennie	51144	2412	A-6	3F
YOUNGER, Hazel	51144	2412	A-5	3E

ORGANIZATION CHART



ALASKA OPERATIONS~F.Y. 1981~OFI, ANGTS

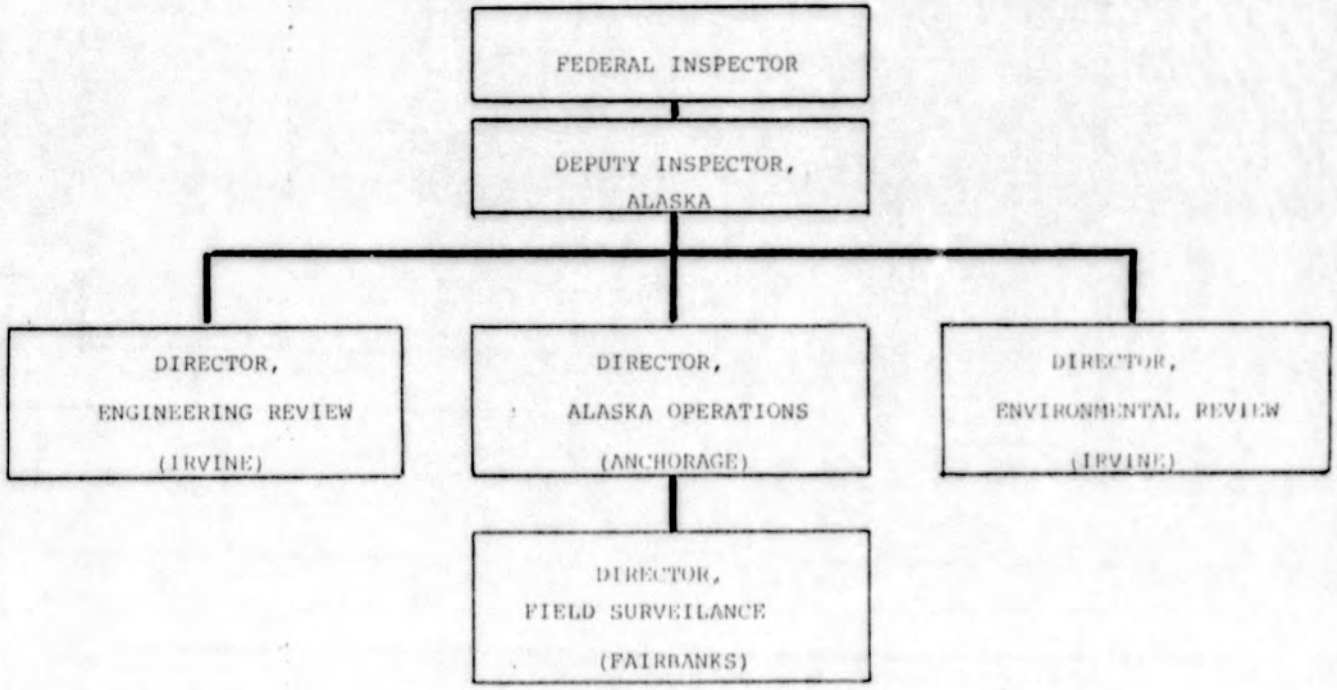


Office of General Counsel, (D.C.); 2/ Located in Fairbanks

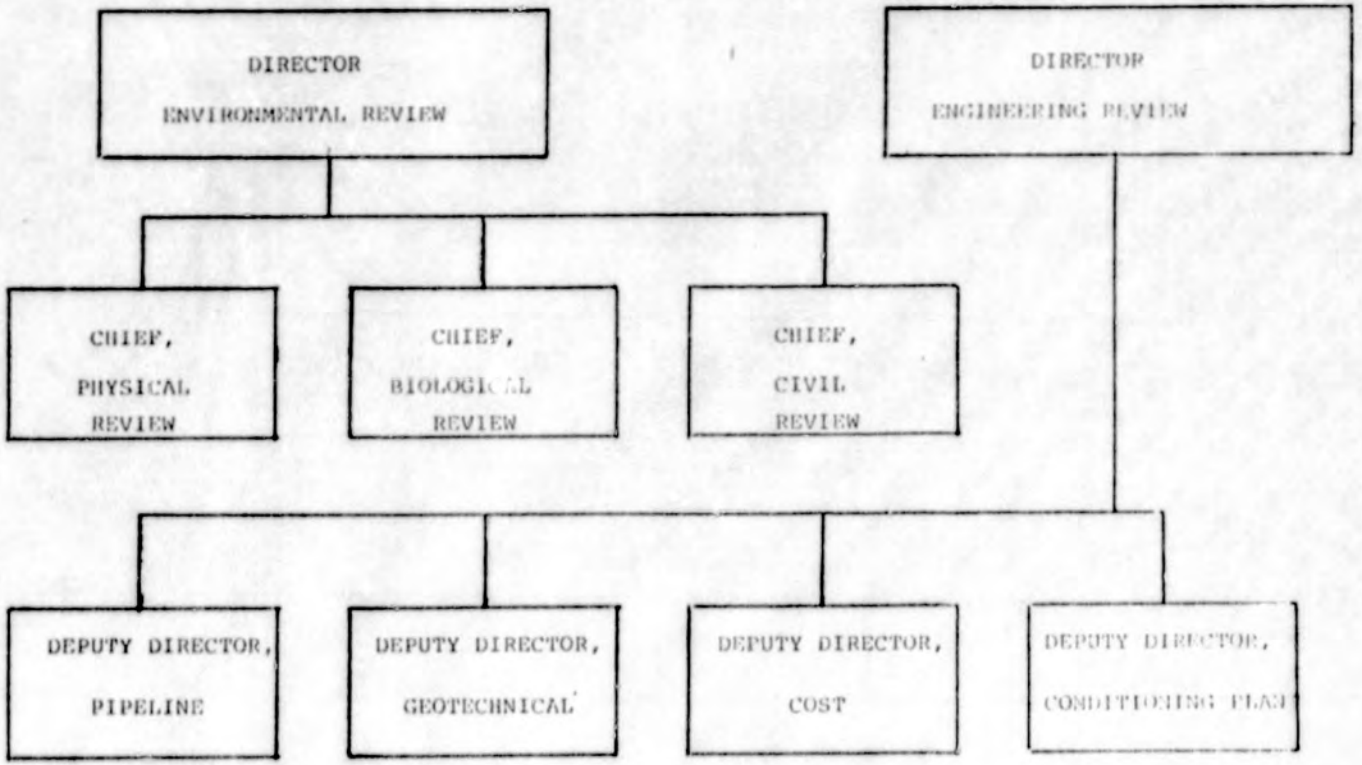
July 1980

DRAFT
7/31/80

ALASKA OPERATIONS ~ FY 1981 ~ OFI, ANGTS



ALASKA OPERATIONS ~ (IRVINE) ~ O.F.I., ANGTS



OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM

FACT SHEET

Technical Facts on the Alaska Natural Gas Transportation System

UTE

Alaska-Canada main trunk: Starting at Prudhoe Bay, Alaska, it parallels the Trans-Alaska Pipeline System corridor to Delta Junction, southeast of Fairbanks. There it turns southeast, generally paralleling the Alaska Highway, passing through the Yukon Territory, British Columbia, and Alberta. At James River, Alberta, it divides into two legs.

Western Leg: British Columbia, Idaho, Washington, Oregon, terminating at Antioch, California, near San Francisco.

Eastern Leg: Crosses Saskatchewan, Montana, North Dakota, South Dakota, Minnesota and Iowa, terminating near Chicago, Illinois.

The general route of the pipeline (shown on the reverse of this page) was selected by the President in September of 1977 after agreement with the Canadian Government was reached. Decision on final routing and alignment with the oil pipeline in Alaska is expected during

ENGTH

4,800 miles total.
Alaskan segment: 741 miles
Canadian segment: 2,028 miles, including those portions of the two legs that are in Canada.
Eastern Leg: 1,117 in U.S.
Western Leg: 911 miles of loop (loop is a common expansion technique in which a separate pipeline is built closely paralleling the existing line), with interconnections of existing compressor stations. Will include 1.6 million tons of pipe, 2.2 million tons of gross materials.

DIAMETER

Alaskan segment: 48 inch
Canadian segment: 56", 48" and 42" depending on segment
Eastern Leg: 42 inch
Western Leg: 42 inch

COMPRESSORS

Alaska: 7 compressors totaling 185,000 horsepower (hp).
Canada: 21 compressors totaling 763,000 hp.
Eastern Leg: 13 compressor stations totaling 416,00 hp.
Western Leg: upgrading of existing stations.

CAPACITY

Alaskan segment: 2-2.4 billion feet daily.
Canadian segment: About 2.5 billion cfd.
Eastern Leg: 2.1 to 2.2 billion cubic feet daily. (2/3 of gas to be transported through the system)

Western Leg: Looping to enable transport of Alaskan gas will increase capacity of existing line from 980 million cubic feet daily to 1,619, or an increase of about 659 million cfd.

SPONSORS

Alaskan segment: Alaskan Northwest Natural Gas Transportation Co. a consortium formed by:

Northwest Alaskan Pipeline Co.
(a subsidiary of Northwest Energy Co.)
315 E. 200th South
Salt Lake City, Utah 84111

Calaska Energy
(Pacific Gas & Electric)
77 Beale Street
San Francisco, California 94106

Pacific Interstate Transmission
(Pacific Lighting)
720 West 8th St.
Los Angeles, California 90017

Northern Arctic Gas Co.
(Northern Natural Gas Co.)
2223 Dodge St.
Omaha, Nebraska 68102

United Alaska Fuels Corporation
(United Gas Pipeline Co.)
P.O. Box 1478
Houston, Texas 77001

Pan Alaska Gas Co.
(Panhandle Eastern Pipeline Co.)
P.O. Box 1642
Houston, Texas 77001

American Natural Alaska Co.
(American Natural Resources Co.)
1 Woodward Avenue
Detroit, Michigan 48266

Canadian segment: Foothills Pipe Lines Ltd. (1600 Bow Valley Square II, 205 Fifth Avenue., S.W. Calgary, Alberta T2P2W4) Foothills is owned equally by Alberta Gas Trunk Line Co. Ltd. and West Transmissio Co. Ltd. The mainline system in Canada will be built in five segments by five subsidiaries, with a sixth for North Yukon if and when the Dempster Lateral, to bring MacKenzie Delta gas into the system, becomes feasible.

Eastern Leg: 811 miles of 42-inch line in Montana, North Dakota, South Dakota, Minnesota and Iowa.

Western Leg: Four segments of 42-inch loop totaling 160 miles in Idaho, Washington and Oregon.

Eastern Leg: Northern Border Pipeline Co., (20 Montchanin Road, Wilmington, Delaware 19801) is a consortium formed by:

Northern Plains Natural Gas Co.
(a subsidiary of Northern Natural Gas Co.)
2223 Dodge Street
Omaha, Nebraska 68102

Northwest Border Pipeline Co.
(Northwest Energy)
P.O. Box 1526
Salt Lake City, Utah 84110

Pan Border Gas Co.
(Panhandle Eastern Pipeline Co.)
P.O. Box 1642
Houston, Texas 77001

United Mid-Continent Pipeline Co.
P.O. Box 1478
Houston, Texas 77001

Trans-Canada Border Pipeline Ltd.
P.O. Box 54
Commerce Court West
Toronto, Ontario, Canada M5L1C2

Western Leg: Pacific Gas Transmission (245 Market Street, San Francisco, California 94105) and its parent, Pacific Gas and Electric Co. (77 Beale St., San Francisco, California 94106)

CONTRACTORS SUBCONTRACTORS

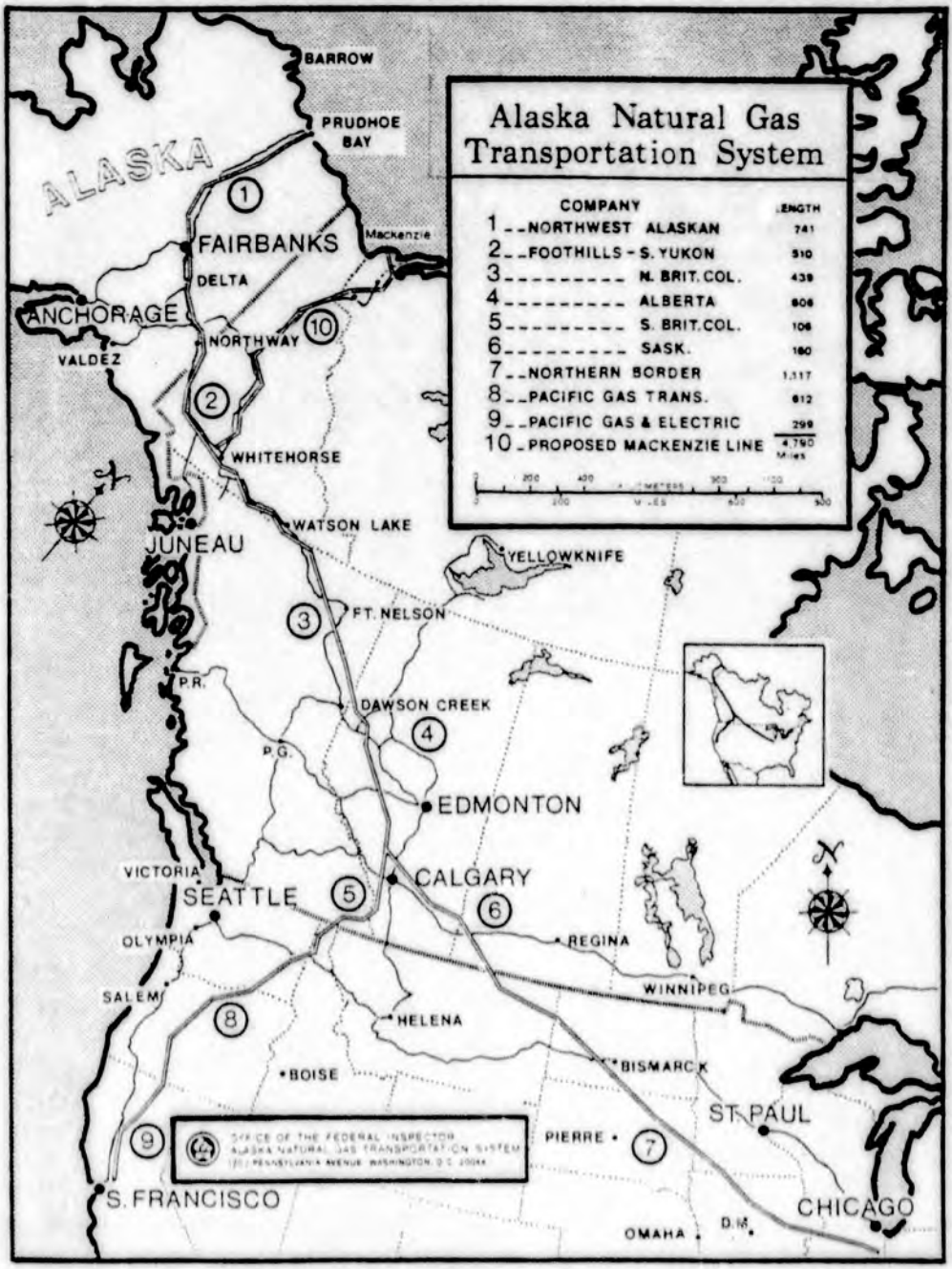
Alaskan Northwest has contracted with Fluor Corporation, of Irvine, California, to be its project manager for design and construction of the Alaskan portion. Fluor will be subcontracting much of the work. Major subcontractors at the end of April included:

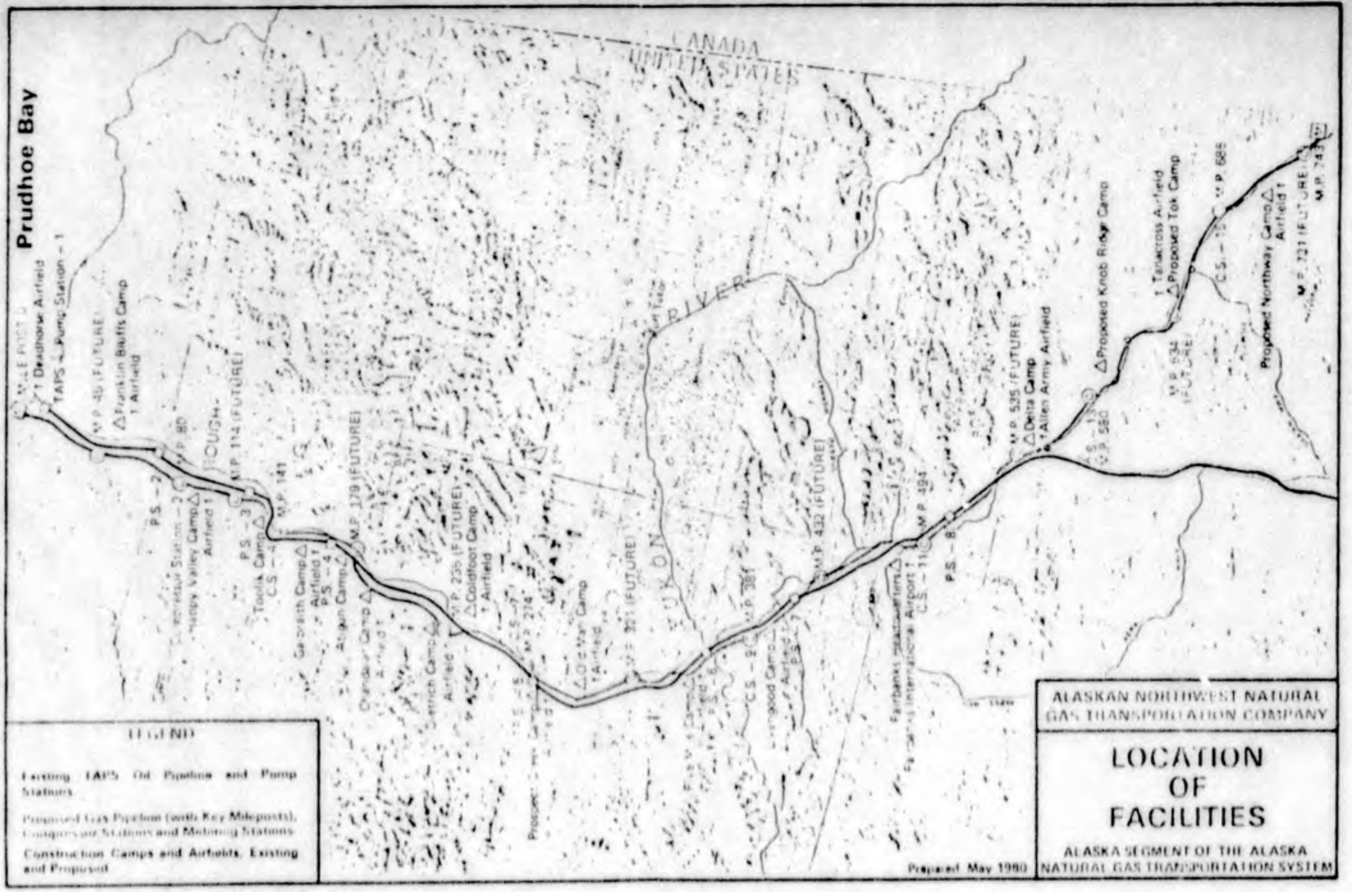
Michael Baker Inc., of Houston, Texas
Gulf Interstate Engineering Co., of Houston
Northern Technical Services, of Anchorage, Alas
R & M Consultants, of Anchorage, Alaska
Hardy Associates, of Edmonton, Alberta

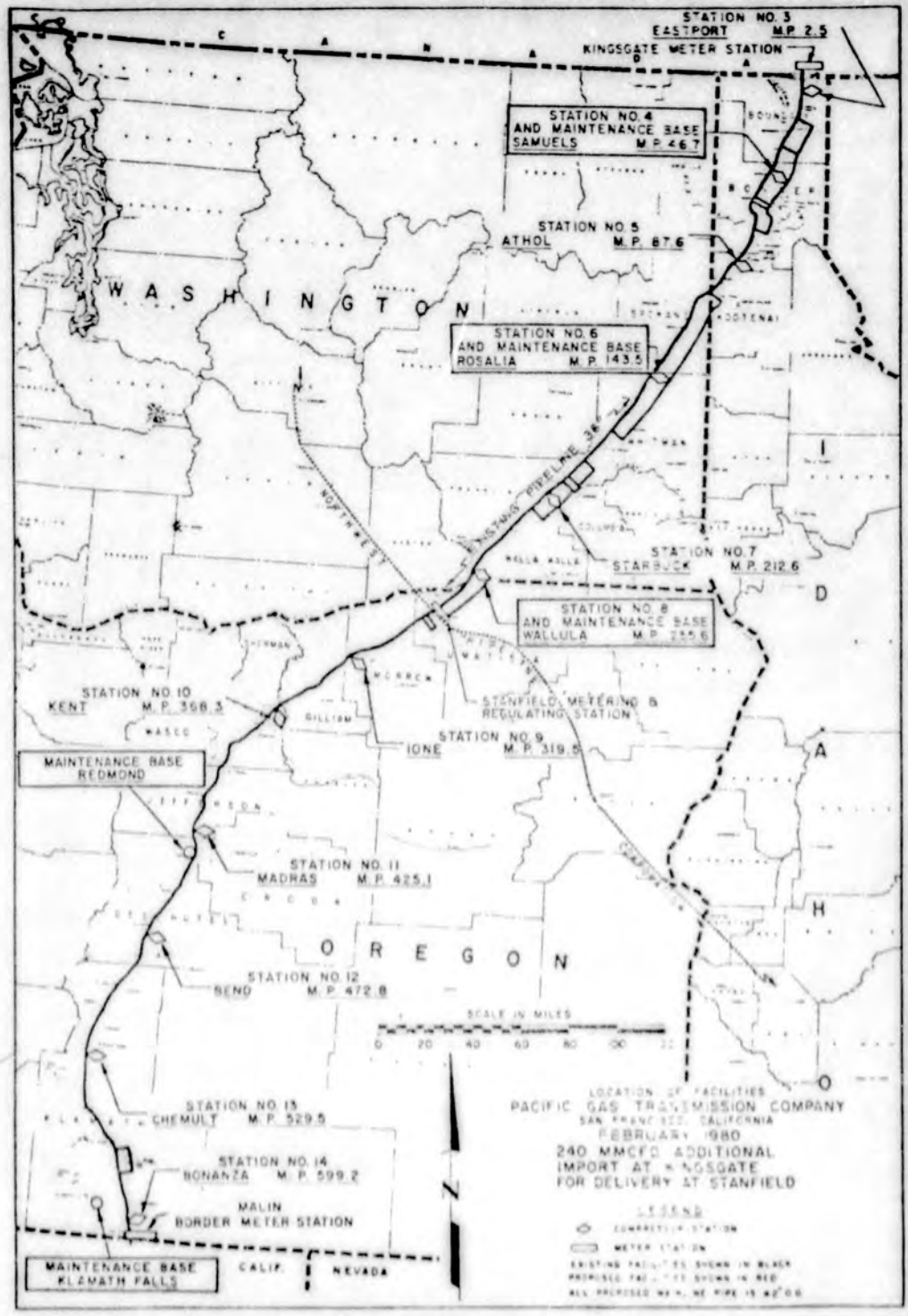
PRE-BUILD

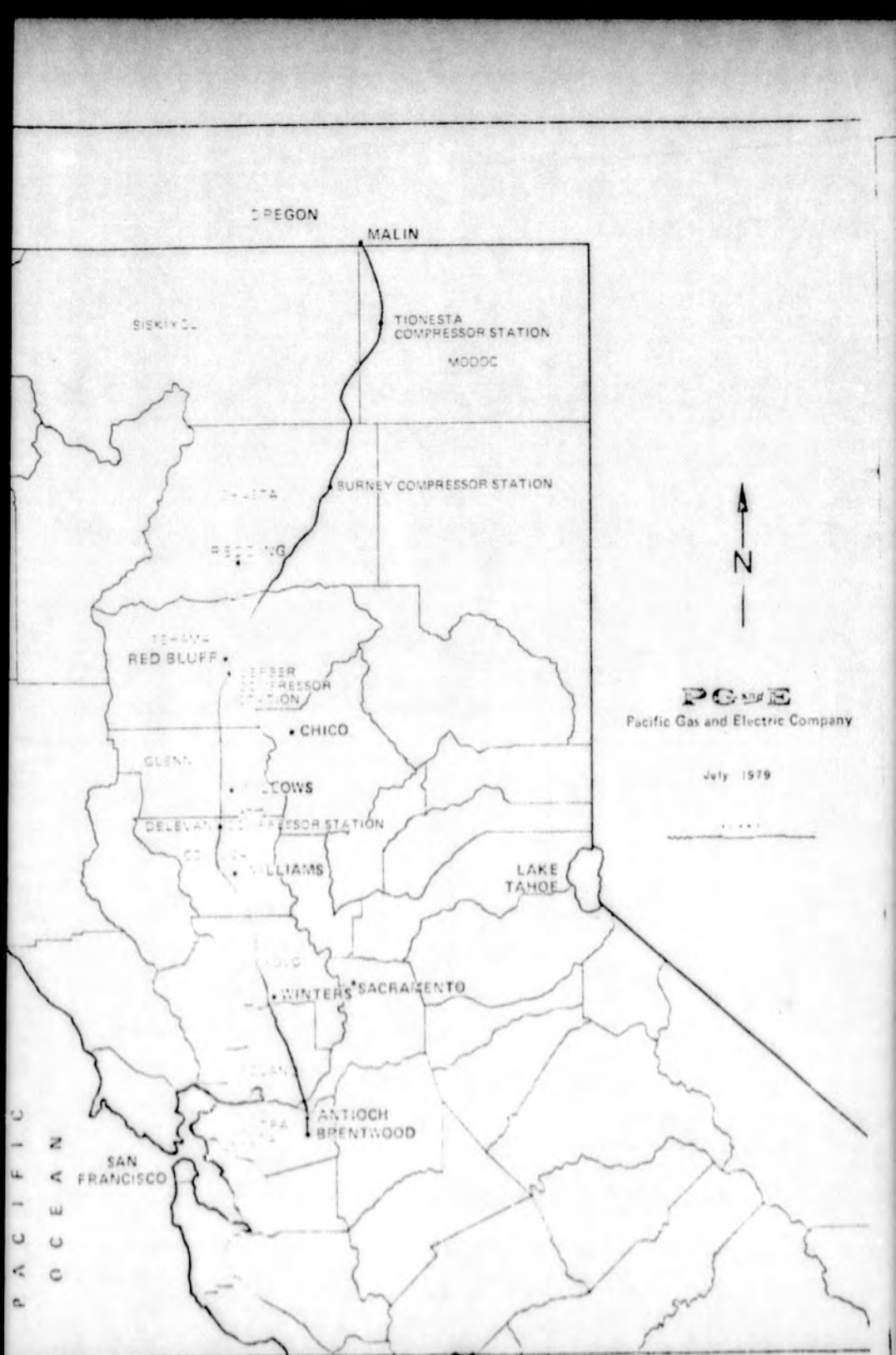
Parts of the Canadian, Eastern and Western Legs have been planned for early construction and operation prior to completion of the Alaskan segment, to bring to the lower 48 Canadian gas which that country has determined to be excess to its needs. Facilities proposed for pre-build are:

Canada: 527 miles of pipeline and 3 compressor stations, constituting the entire Canadian system south of about Caroline Junction, Alberta, plus a short segment of trunk north of Caroline Junction.

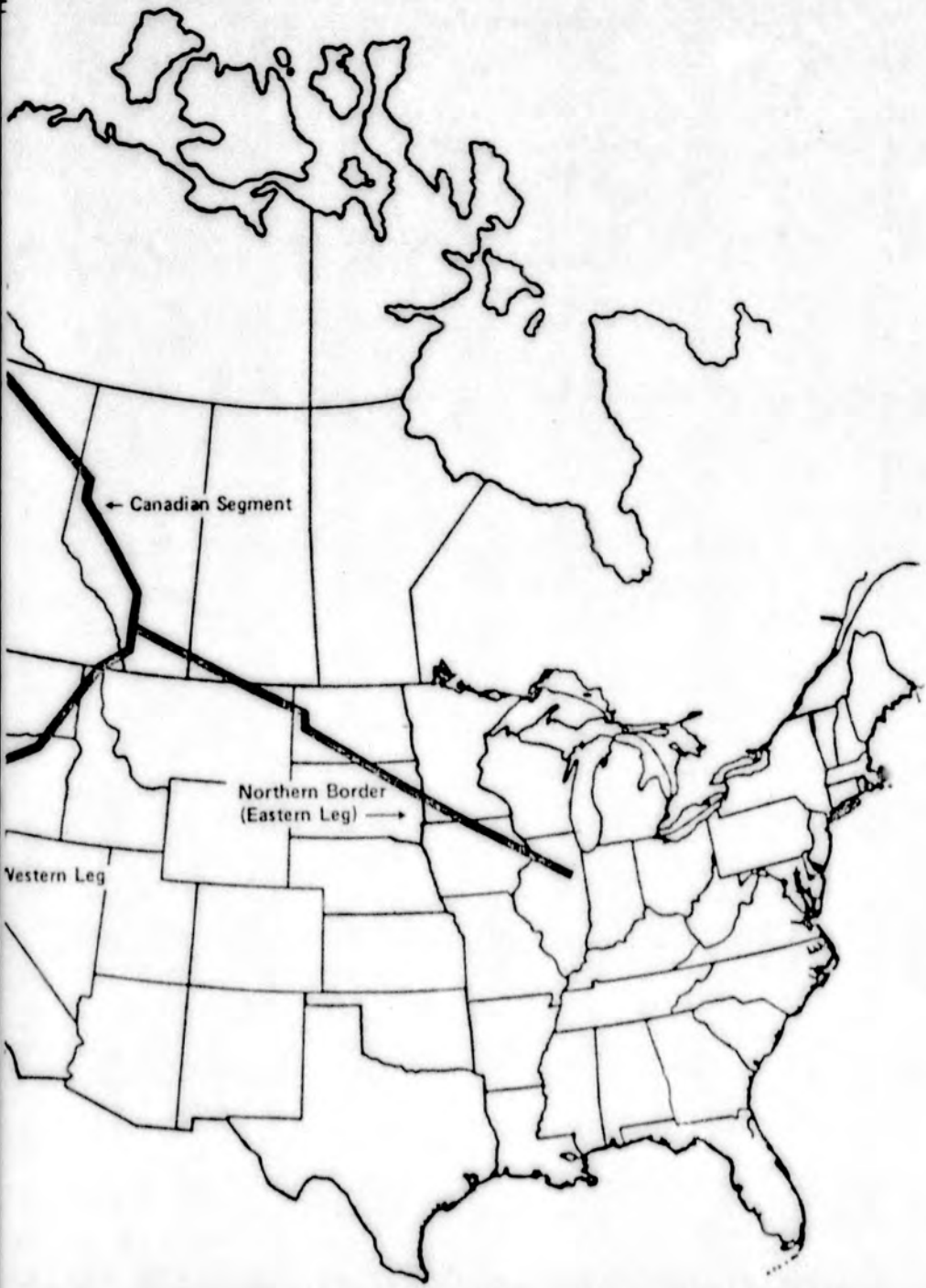

Alaska Natural Gas Transportation System
COMPANY
LENGTH
1--NORTHWEST ALASKAN 741
2--FOOTHILLS - S. YUKON 510
3---------- N. BRIT. COL. 439
4---------- ALBERTA 806
5---------- S. BRIT. COL. 106
6---------- SASK. 180
7--NORTHERN BORDER 1,117
8--PACIFIC GAS TRANS. 612
9--PACIFIC GAS & ELECTRIC 298
10-PROPOSED MACKENZIE LINE 4,790 Miles
KILOMETERS
WILES
BARROW
PRUDHOE BAY
ALASKA
FAIRBANKS
Mackenzie
DELTA
ANCHORAGE
NORTHWAY
VALDEZ
WHITEHORSE
JUNEAU
WATSON LAKE
YELLOWKNIFE
FT. NELSON
P.R.
DAWSON CREEK
P.G.
EDMONTON
VICTORIA
SEATTLE
CALGARY
OLYMPIA
REGINA
SALEM
WINNIPEG
HELENA
BISMARCK
BOISE
ST. PAUL
PIERRE
S. FRANCISCO
CHICAGO
OMAHA
D.M.
OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
WASHINGTON, D.C. 20004


ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
LOCATION OF FACILITIES
ALASKA SEGMENT OF THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM
Prepared May 1980
LEGEND
Existing TAPS Oil Pipeline and Pump Stations
Proposed Gas Pipeline (with Key Mileposts), Compressor Stations and Metering Stations
Construction Camps and Airfields, Existing and Proposed
Prudhoe Bay
CANADA
UNITED STATES
RIVER
Deadhorse Airfield
TAPS - Pump Station - 1
Franklin Bluffs Camp
M.P. 45 (FUTURE)
M.P. 80
M.P. 114 (FUTURE)
M.P. 141
M.P. 179 (FUTURE)
M.P. 235 (FUTURE)
Coldfoot Camp
M.P. 321 (FUTURE)
M.P. 381
M.P. 432 (FUTURE)
M.P. 494
M.P. 535 (FUTURE)
Delta Camp
Allen Army Airfield
Proposed Knob Ridge Camp
Tanacross Airfield
Proposed Tok Camp
M.P. 634 (FUTURE)
M.P. 686
Proposed Northway Camp
M.P. 721 (FUTURE)
M.P. 743
Galbraith Camp
Atigun Camp
Toolik Camp
Happy Valley Camp
Old Man Camp
Fairbanks International Airport
Fairbanks Headquarters
P.S. - 2
P.S. - 3
P.S. - 4
P.S. - 8
C.S. - 11


STATION NO. 3
EASTPORT M.P. 2.5
KINGSGATE METER STATION
STATION NO. 4
AND MAINTENANCE BASE
SAMUELS M.P. 46.7
STATION NO. 5
ATHOL M.P. 87.6
WASHINGTON
STATION NO. 6
AND MAINTENANCE BASE
ROSALIA M.P. 143.5
NORTHWEST PIPELINE
STATION NO. 7
STARBUCK M.P. 212.6
STATION NO. 8
AND MAINTENANCE BASE
WALLULA M.P. 255.6
STATION NO. 10
KENT M.P. 398.3
STANFIELD METERING &
REGULATING STATION
STATION NO. 9
IONE M.P. 319.5
MAINTENANCE BASE
REDMOND
STATION NO. 11
MADRAS M.P. 425.1
OREGON
STATION NO. 12
BEND M.P. 472.8
SCALE IN MILES
0 20 40 60 80 100
STATION NO. 13
CHEMULT M.P. 529.5
STATION NO. 14
BONANZA M.P. 599.2
MALIN
BORDER METER STATION
MAINTENANCE BASE
KLAMATH FALLS
CALIF.
NEVADA
LOCATION OF FACILITIES
PACIFIC GAS TRANSMISSION COMPANY
SAN FRANCISCO, CALIFORNIA
FEBRUARY 1980
240 MMCFD ADDITIONAL
IMPORT AT KINGSGATE
FOR DELIVERY AT STANFIELD
LEGEND
COMPRESSOR STATION
METER STATION
EXISTING FACILITIES SHOWN IN BLACK
PROPOSED FACILITIES SHOWN IN RED
ALL PROPOSED MAIN LINE PIPE IS 42" O.D.


OREGON
MALIN
TIONESTA
COMPRESSOR STATION
MODOC
BURNEY COMPRESSOR STATION
RED BLUFF
CHICO
WILLIAMS
LAKE
TAHOE
WINTERS
SACRAMENTO
ANTIOCH
BRENTWOOD
SAN
FRANCISCO
PACIFIC
OCEAN
N
PG and E
Pacific Gas and Electric Company
July 1979

EASTERN LEG, ANGTS



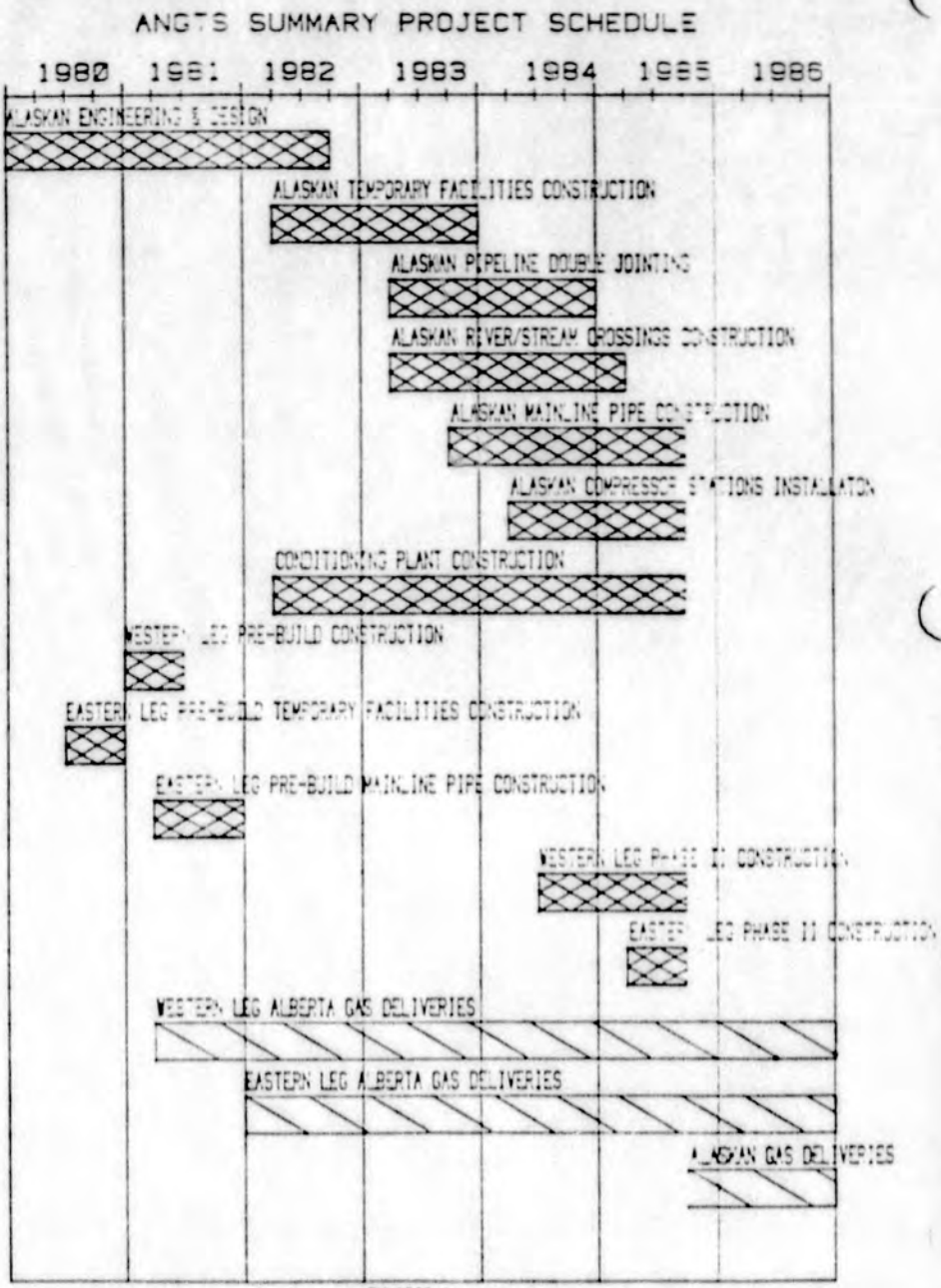

ANGTS SUMMARY PROJECT SCHEDULE
1980
1981
1982
1983
1984
1985
1986
ALASKAN ENGINEERING & DESIGN
ALASKAN TEMPORARY FACILITIES CONSTRUCTION
ALASKAN PIPELINE DOUBLE JOINTING
ALASKAN RIVER/STREAM CROSSINGS CONSTRUCTION
ALASKAN MAINLINE PIPE CONSTRUCTION
ALASKAN COMPRESSOR STATIONS INSTALLATION
CONDITIONING PLANT CONSTRUCTION
WESTERN LEG PRE-BUILD CONSTRUCTION
EASTERN LEG PRE-BUILD TEMPORARY FACILITIES CONSTRUCTION
EASTERN LEG PRE-BUILD MAINLINE PIPE CONSTRUCTION
WESTERN LEG PHASE II CONSTRUCTION
EASTERN LEG PHASE II CONSTRUCTION
WESTERN LEG ALBERTA GAS DELIVERIES
EASTERN LEG ALBERTA GAS DELIVERIES
ALASKAN GAS DELIVERIES

EXHIBIT 1

Public Law 94-586
94th Congress

An Act

To expedite a decision on the delivery of Alaska natural gas to United States markets, and for other purposes.

Oct. 22, 1976
[S. 3521]

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

Alaska Natural Gas Transportation Act of 1976.

SHORT TITLE

SECTION 1. This Act may be cited as the "Alaska Natural Gas Transportation Act of 1976". 15 USC 719 note.

CONGRESSIONAL FINDINGS

SEC. 2. The Congress finds and declares that— 15 USC 719.

(1) a natural gas supply shortage exists in the contiguous States of the United States;

(2) large reserves of natural gas in the State of Alaska could help significantly to alleviate this supply shortage;

(3) the expeditious construction of a viable natural gas transportation system for delivery of Alaska natural gas to United States markets is in the national interest; and

(4) the determinations whether to authorize a transportation system for delivery of Alaska natural gas to the contiguous States and, if so, which system to select, involve questions of the utmost importance respecting national energy policy, international relations, national security, and economic and environmental impact, and therefore should appropriately be addressed by the Congress and the President in addition to those Federal officers and agencies assigned functions under law pertaining to the selection, construction, and initial operation of such a system.

STATEMENT OF PURPOSE

SEC. 3. The purpose of this Act is to provide the means for making a sound decision as to the selection of a transportation system for delivery of Alaska natural gas to the contiguous States for construction and initial operation by providing for the participation of the President and the Congress in the selection process, and, if such a system is approved under this Act, to expedite its construction and initial operation by (1) limiting the jurisdiction of the courts to review the actions of Federal officers or agencies taken pursuant to the direction and authority of this Act, and (2) permitting the limitation of administrative procedures and effecting the limitation of judicial procedures related to such actions. To accomplish this purpose it is the intent of the Congress to exercise its constitutional powers to the fullest extent in the authorizations and directions herein made, and particularly with respect to the limitation of judicial review of actions of Federal officers or agencies taken pursuant thereto. 15 USC 719a.

89-139 (497) O - 76

Alaska Natural Gas Transportation Act, 10/22/76 (P.L. 94-586)

Purpose: provide for expeditious:

1. selection of a transportation system
2. construction and initial operation, while still achieving quality of construction, cost control, safety, and environmental protection

Provisions to expedite construction and initial operation are as follows:

Sec. 15	Authorizes appropriations of funds for:
Sec. 7(a)(5)	-Appointment of a Federal Inspector, with advice and consent of the Senate who shall: A. establish a joint surveillance and monitoring agreement with Alaska B. monitor compliance with laws, terms and conditions of permits, etc. C. monitor actions taken to assure timely completion, quality of construction, cost control, safety, environmental protection D. have power to compel submission of information, by subpoena if necessary E. make quarterly reports to President and Congress
Sec. 9(a)	Requires Federal agencies to grant all necessary authorizations at the earliest practicable date.
Sec. 9(b)	ANGTS applications to take precedence over similar ones.
Terms and Conditions	
Sec. 7(a)(6)	President's Decision may specify terms and conditions to be included in ANGTS authorizations.
Section 9(c)	Federal agencies cannot include terms and conditions only permitted by law which would change basic nature and general route or which would prevent or impair the expeditious construction and initial operation.
Section 9(d)	Federal agencies may add to, amend or

	abrogate terms and conditions, subject to the provisions of 9(c).
Section 9(e)	President's terms and conditions (Sec. 7(a)(6 shall be included in any authorization, excep that inclusion shall not limit Federal agencies' authorities under Sec. 9(d).
Supplemental Enforcement Authority	
Sec. 11(a)(b)(c)	In addition to existing enforcement authorities, Federal agencies may issue a compliance order, if violation of a law or an authorization occurs; civil action (not to exceed $25,000 per day) may be brought for violations of the compliance order.
Waivers	
Sec. 8(g)	Provides for President to recommend and Congress to approve waivers of laws necessary to permit expeditious construction and initial operation.
Limits on Judicial Review	
Sec. 10(a)	Federal agency acts pursuant to Sec. 9 shall be subject only to the limited judicial review described in Sec. 10.
Sec. 10(c)(1)(2)	Following may be filed only with U.S. (D.C.) Court of Appeals which shall render a decision within 90 days unless extended to satisfy Constitution:
Sec. 10(b)(1)	Claims of invalidity of Act not allowed later than 60 days after President's Decision.
Section 10(b)(2)	Claims that an action is unconstitutional not allowed later than 60 days after the action.
Section 10(c)(3)	Challenge of legal and factual sufficiency of EIS not allowed after approval of President's Decision.
Financing	
Sec. 7(c)	President's Decision must contain financial analysis.

Sec. 7(e)	Approval of President's Decision not to be construed as amending existing laws so as to grant any new financing authority as may have been specified pursuant to Sec. 7(c).
EEO	
Section 17	Prohibits discrimination; agencies shall promulgate rules to implement, similar to those in effect under title VI of the Civil Rights Act of 1964.
Common Carrier Alaska's Royalty Gas	
Sec. 13(a)	Degree of ownership of ANGTS shall not be basis for discrimination in giving permission to transport gas in ANGTS.
Sec. 13(b)	State of Alaska is authorized to ship its royalty gas in ANGTS and to use this gas in Alaska.
Limits on Export of Alaska Gas	
Sec. 12	Before export of more than 1,000 Mcf/d (to other than Canada or Mexico) President must find that exports won't: 1) increase cost to U.S. consumer and 2) diminish total quality or quantity of U.S. energy.
Antitrust	
Sec. 14	Antitrust laws not affected by ANGTA.
Separability	
Sec. 16	If part of ANGTA is held invalid, the rest of ANGTA is not affected.

(Complete copies of the ANGTS Act are available from OFI)

Executive Order No. 12142 (6/21/79)

Establishes Executive Policy Board (EPB) = DOA, DOE, DOL, DOT, DOI, EPA, COE, FERC; (may elect additional members)

Chairman; 1 year, majority vote

Functions:

- -advise FI on policy issues regarding law or agency policies.
- -advise FI and AAOs (through FI) on matters concerning enforcement actions.
- -semi-annually, assess problems and make recommendations to FI.

FI shall:

- -keep EPB informed of progress and problems.
- -notify EPB when FI determines that existing agency enforcement policies and procedures are inconsistent with Section 9 of ANGTA.
- -abide by agency rules for ex-parte in enforcement actions.
- -issue standards of conduct pursuant to Executive Order No. 11222.

Departments shall:

- -cooperate with and furnish necessary information and assistance to EPB.

Federal Register
Vol. 44, No. 123
Monday, June 25, 1979

Presidential Documents

Title 3—

The President

Executive Order 12142 of June 21, 1979

The Alaska Natural Gas Transportation System

By the authority vested in me as President by the Constitution and laws of th United States of America, including Section 301 of Title 3 of the United State Code and Sections 201 and 205 of Reorganization Plan No. 1 of 1979, it hereby ordered as follows:

1-101. Reorganization Plan No. 1 of 1979, not having been disapproved b Congress (S. Res. 126, 125 Cong. Rec. S 6563-64 (May 23, 1979); H. Res. 199, 1 Cong. Rec. H 3950-51 (May 31, 1979)), shall be effective on July 1, 197

1-102. In accord with Section 201 of that Plan, there is hereby established th Executive Policy Board for the system for the transportation of Alaska natur gas ("the System") as such system is defined in the Alaska Natural Ga Transportation Act of 1976 (15 U.S.C. 719 *et seq.*).

1-103. The Board shall consist of the Secretaries of the Departments Agriculture, Energy, Labor, Transportation, and the Interior, the Administrat of the Environmental Protection Agency, the Chief of Engineers of the Unite States Army, and the Chairman of the Federal Energy Regulatory Commissio Additional members may be elected to the Board by vote of a majority of th members. The Board will by majority vote elect a Chairman to serve for a one year term.

1-104. The Board shall perform the following functions:

(a) Advise the Federal Inspector for the Alaska Natural Gas Transportatio System (the "Federal Inspector") established by Reorganization Plan No. 1 1979, on policy issues in accord with applicable law and existing Departmen al or Agency policies.

(b) Provide advice, through the Federal Inspector, to the officers represent and exercising the functions of the Federal Departments and Agencies th concern the System ("Agency Authorized Officers").

(c) Advise the Federal Inspector and the Agency Authorized Officers on matter concerning enforcement actions.

(d) At least every six months, assess the progress made and problem encountered in constructing the System and make necessary recommenda tions to the Federal Inspector.

1-105. The Federal Inspector shall keep the Board informed of the progres made and problems encountered in the course of construction of the Syste

1-106. Whenever the Federal Inspector determines that implementation Departmental or Agency enforcement policies and procedures would requir action inconsistent with Section 9 of the Alaska Natural Gas Transportatio Act of 1976, the Federal Inspector shall issue a written statement of suc determination including a complete factual and legal basis for the determina tion. A copy of each statement shall be forwarded promptly to the Board an made available to the public by the Federal Inspector.

1-107. After written notice of a proposed enforcement action is given by t Federal Inspector, the Federal Inspector will be subject to the rules of proce dure for *ex parte* contacts as reflected in the guidelines and policies Departments and Agencies from which the specific enforcement authority i transferred.

1-108. The Federal Inspector and all employees of the Office of the Federal Inspector shall be subject to the provisions of Executive Order No. 11222, concerning standards of conduct for Federal employees. The Federal Inspector shall issue standards of conduct, pursuant to the Order, for the Office of the Federal Inspector.

1-109. To the extent permitted by law, each Department and Agency shall cooperate with and furnish necessary information and assistance to the Board in the performance of its functions.

1-110. This Order shall be effective on July 1, 1979.

Jimmy Carter

THE WHITE HOUSE,
June 21, 1979.

[FR Doc. 79-19636
Filed 6-22-79; 9:13 am]
Billing code 3195-01-M

President's Decision and Report to Congress (September, 1977)

The Decision:

1. Designates Alaska Highway Pipeline Project as selected ANGTS
2. Establishes requirements for project sponsors (applicant)
3. Outlines Federal organization for project (See Reorganization Plan No. 1 of 1979, Executive Order No. 12142, and ANGTA for details)

Terms and Conditions

Applicant shall comply with:

1. general terms and conditions in Decision
2. stipulations establishing general standards of environmen and construction performance (to be established by appropriate agencies)
3. site-specific terms and conditions for particular segment

Construction Costs and Schedule, Management and Organization

Applicant must:

- submit a detailed overall management plan for FI approval, prior to certification
- use fixed price contracts unless FI approves otherwise
- specify insurance, bonding, etc. requirements of its contractors
- provide analysis of proposed cost and schedule control techniques, prior to construction
- submit 70% (FI may relax) final design, design-cost estimate, and construction schedule for FI approval befor construction.
- submit methods for supplying general and specialized equipment, spare parts, etc.
- submit information on labor relations procedures, includi resolution of disputes (without litigation for contracts with execution contractors)
- submit detailed Quality Assurance/Quality Control program (including environmental protection, corrosion control, welding) to be approved by FI and implemented before construction

- not initiate any pipeline-related activity before receiving appropriate authorization to proceed

- develop affirmative action plan for minority business enterprise participation (also applies to contracts valued at $150,000 or more)

Safety and Design

Applicant must:

- construct, operate, maintain and terminate system in accordance with Federal safety regulations and good engineering practice

- receives FI approval of design, including technical construction specifications, before starting construction of any portion of system

- brief FI on project status

- insure FI access to all project facilities

- submit plan for conducting its own inspections of facilities

- develop a seismic monitoring system

Environment

Applicant must:

- conduct all activities with concern for environment

- provide for timely integration of restoration or mitigation techniques with activity creating the need for such restoration.

- develop plan for implementing special environmental safeguards through education of field personnel both before and during construction

- establish a monitoring system to ensure performance in keeping with environmental concerns

Finance and Antitrust

- no Federal debt guarantees; all private financing

- consumers not required to bear risks of non-completion

- applicant to arrange financing before construction

- FERC to establish variable rate of return on equity to reward applicant for completion under budgeted cost (and reverse); thus cost overruns shared by equity holders and consumers.

- Producers of Alaska gas may not own ANGTS; they may provide guarantees for project debt.

- FERC shall approve all contracts and collateral agreements regarding sale of Alaskan gas

- Producers and State of Alaska should participate in financing either directly or in form of debt guarantees

- Provision of debt service in event of service interruption borne by consumers through a tariff which becomes effective only after initial operation

Agreement on Principles Applicable to a Northern Natural Gas Pipeline (between U.S. and Canada) provides:

- Canadian taxation shall be non-discriminatory; i.e., similar to that in effect for other pipelines

- socieconomic impact assistance ($200M) required of Canadian companies will not affect cost of service to U.S. consumers

- no charges for Native claims settlements to be levied against Canadian companies

- supply of goods and services to be on generally competitive terms

- both U.S. and Canadian sections to be privately financed, with variable rate of return

- both governments shall appoint senior official for consultation

- specifies allowed direct charges on pipeline

- U.S. agreed to share costs of extending Dempster Highway Lateral from Dawson to Whitehorse and, prior to construction of this segment, to provide Alaskan gas to remote communities in Canada. (Equal volumes of Canadian gas will be made available for export to U.S. simultaneously.)

  - U.S. share of cost based on cost overruns on Canadian segments and on proportion of U.S. gas transported.

Other:

Secretary, DOE, to specify capacities of Eastern and Western Legs prior to Certification

Waivers: Sec. 103, Energy Policy and Conservation Act and Sec. 3, Natural Gas Act to allow for exchanges of Alberta and Alaska gas.

Decision and Report to Congress on the Alaska Natural Gas Transportation System

Executive Office of the President
Energy Policy and Planning

September 1977

TO THE CONGRESS OF THE UNITED STATES:

Natural gas has become the Nation's scarcest and most desired fuel. It is in our interest to bring the reserves in Alaska to market at the lowest possible price. Consequently, I am today sending the Congress my decision and report on an Alaska Natural Gas Transportation System.

The selection of the Alcan project was made after an exhaustive review required by the Alaska Natural Gas Transportation Act of 1976 determined that the Alcan Pipeline System will deliver more natural gas at less cost to a greater number of Americans than any other proposed transportation system.

The Alcan proposal, taken together with the recently signed Agreement on Principles with Canada, demonstrates that our two countries working together can transport more energy more efficiently than either of us could transport alone.

Unnecessary delay would greatly increase the total cost of the pipeline system. I urge the Congress to act expeditiously to approve this important project.

Jimmy Carter

THE WHITE HOUSE,
September 22, 1977

President's Decision and Report on ANGTS

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PREFACE - STATUTORY REQUIREMENTS FOR A DECISION ON AN ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Section 7(a)(4) of the Alaska Natural Gas Transportation Act of 1976 (ANGTA) states:

> If the President determines to designate for approval a transportation system for delivery of Alaska natural gas to the contiguous States, he shall in such decision-
>
> (A) describe the nature and route of the system designated for approval;
>
> (B) designate a person to construct and operate such a system, which person shall be the applicant, if any, which filed for a certificate of public convenience and necessity to construct and operate such system;
>
> (C) identify those facilities, the construction of which, and those operations, the conduct of which, shall be encompassed within the term "construction and initial operation" for purposes of defining the scope of the directions contained in Section 9 of this Act, taking into consideration any recommendation of the Commission with respect thereto; and
>
> (D) identify those provisions of law, relating to any determination of a Federal officer or agency as to whether a certificate, permit, right-of-way, lease, or other authorization shall be issued or be granted, which provisions he finds (i) involve determinations which are subsumed in his decision and (ii) require waiver pursuant to Section 8(g) in order to permit the expeditious construction and initial operation of the transportation system.

As part of these determinations, an Agreement on Principles concluded with the Government of Canada prescribes various terms and conditions applicable to the construction and operation of the pipeline. The Agreement on Principles is attached hereto as Section 7 of this Decision and made an integral part of the Decision by this reference.

With the incorporation of the aforesaid Agreement, and the finding that it is in the national interest to expeditiously undertake to construct an Alaska Natural Gas Transportation System, the system designation and related statutory determinations are as follows:

SECTION 1 - DESIGNATION OF PERSON TO CONSTRUCT AND OPERATE THE SYSTEM

The Alcan Pipeline Company, now a wholly owned subsidiary of Northwest Pipeline Corporation[1/], or its successor, is hereby designated to construct and operate the portion of the system within the State of Alaska.

The Northern Border Pipeline Company, a partnership consisting of subsidiaries or affiliates of Columbia Gas Transmission Corporation, Michigan-Wisconsin Pipeline Company, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipe Line Company, and Texas Eastern Transmission Corporation, or its successor, is hereby designated to construct and operate the portion of the system from the United States-Canada border near Monchy, Saskatchewan, to a point near Dwight, Illinois.

The Alcan Pipeline Company, or its successor, and the Northern Border Pipeline, or its successor, shall be publicly held corporations or general or limited partnerships, open to ownership participation by all persons

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1/ Northwest Pipeline owns and operates a 4,300-mile pipeline system for transporting gas in the states of Colorado, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming. Northwest Pipeline is a wholly-owned subsidiary of Northwest Energy Company, a holding company whose principal asset is all the outstanding common stock of Northwest Pipeline.

without discrimination, except producers of Alaskan natural gas.

The Pacific Gas Transmission Company is hereby designated to construct and operate the portion of the system from the United States/Canada border near Kingsgate, British Columbia, to the border between the States of California and Oregon.

The Pacific Gas and Electric Company is hereby designated to construct and operate the portion of the system from the border between the States of California and Oregon through the State of California.

Reorganization Plan No. 1 of 1979 (effective 7/1/79)

Creates OFI, in effect until one year after initial operation of ANGTS

Transfers to FI exclusive responsibility for all functions related to enforcement (including monitoring and other compliance or oversight) of laws and regulations and terms and conditions and stipulations of agencies' authorizations

- Functions transferred are those of: EPA, COE, DOT, DOE, FERC, DOI, DOA, DT (Treasury) and responsibilities in ANGTA and President's Decision.

- Any agency may delegate any other relevant statutory function to FI.

FI shall:

1. coordinate expeditious discharge of non-enforcement agency activities, including scheduling for issuance of authorizations and may serve as "one window" for all data gathering and permit application and issuance activities.

2. unless inconsistent with Section 9 of ANGTA, FI shall carry out normal enforcement policies and procedures of the agencies. FI determination shall prevail.

Each agency shall appoint an AAO who shall:

-be detailed to, and under supervision of, FI
-be delegated authority to enforce their agency's authorizations subject to (2) above.

Makes Executive Policy Board (EPB) advisory to FI

-EPB reviews FI budget

deral Register
l. 44, No. 114
esday, June 12, 1979

Presidential Documents

tle 3—

he President

REORGANIZATION PLAN NO. 1 OF 1979

Prepared by the President and transmitted to the Senate and House of Representatives in Congress assembled. April 2, 1979, pursuant to the provisions of Chapter 9 of Title 5 of the United States Code.

Office of the Federal Inspector for Construction of the Alaska Natural Gas Transportation System

Part I. Office of the Federal Inspector and Transfer of Functions

Section 101. *Establishment of the Office of Federal Inspector for the Alaska Natural Gas Transportation System*

(a) There is hereby established as an independent establishment in the executive branch, the Office of the Federal Inspector for the Alaska Natural Gas Transportation System (the "Office").

(b) The Office shall be headed by a Federal Inspector for the Alaska Natural Gas Transportation System (the "Federal Inspector") who shall be appointed by the President, by and with the advice and consent of the Senate, and shall be compensated at the rate now or hereafter prescribed by law for Level III of the Executive Schedule, and who shall serve at the pleasure of the President.

(c) Each Federal agency having statutory responsibilities over any aspect of the Alaska Natural Gas Transportation System shall appoint an Agency Authorized Officer to represent that authority on all matters pertaining to pre-construction, construction, and initial operation of the system.

Section 102. *Transfer of Functions to the Federal Inspector*

Subject to the provisions of Sections 201, 202, and 203 of this Plan, all functions insofar as they relate to enforcement of Federal statutes or regulations and to enforcement of terms, conditions, and stipulations of grants, certificates, permits and other authorizations issued by Federal agencies with respect to pre-construction, construction, and initial operation of an "approved transportation system" for transport of Canadian natural gas and "Alaskan natural gas," as such terms are defined in the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719 *et seq.*), hereinafter called the "Act", are hereby transferred to the Federal Inspector. This transfer shall vest in the Federal Inspector exclusive responsibility for enforcement of all Federal statutes relevant in any manner to pre-construction, construction, and initial operation. With respect to each of the statutory authorities cited below, the transferred functions include all enforcement functions of the given agencies or their officials under the statutes as may be related to the enforcement of such terms, conditions, and stipulations, including but not limited to the specific sections of the statute cited. "Enforcement", for purposes of this transfer of functions, includes monitoring and any other compliance or oversight activities reasonably related to the enforcement process. These transferred functions include:

(a) Such enforcement functions of the Administrator or other appropriate official or entity in the Environmental Protection Agency related to compliance with: national pollutant discharge elimination system permits provided for in Section 402 of the Federal Water Pollution Control Act (33 U.S.C. 1342); spill prevention, containment and countermeasure plans in Section 311 of the Federal Water Pollution Control Act (33 U.S.C. 1321); review of the Corps of Engineers' dredged and fill material permits issued under Section 404 of the

Alaska Natural Gas Transportation System

Agency Authorized Officers

Mr. John Adger
Federal Energy Regulatory Commission
Room 3004
941 N. Capitol Street, N.W.
Washington, D.C. 20426

Mr. R. Dobie Langenkamp, Deputy Assistant Secretary
Resource Development & Operations
Department of Energy
12th & Pennsylvania Ave., N.W., Room 3426
Washington, D. C. 20461

Mr. Lloyd W. Ulrich
Department of Transportation
NASSIF Building, Room 8105 (DMT-50)
400 Seventh St., S.W.
Washington, D.C. 20590

Col. Robert Bauchspies, Asst.Director of Civil Works
Office of the Chief of Engineers
U.S. Army Corps of Engineers
Pulaski Bldg., Room 7233, (DAEN-CWZ-H)
20 Massachusetts Ave., NW
Washington, D.C. 20314

Dr. Ned Bayley, Staff Assistant
Office of the Secretary
U.S. Department of Agriculture, Room 231
14th & Independence Ave.
Washington, D.C. 20250

Miss Lillian Pitcaithly
Office of the Secretary
U.S. Department of Labor, Room S-2312
200 Constitution Ave., NW
Washington, D.C. 20210

Mr. William Toskey, Project Manager
Alaska Natural Gas Transportation System
Department of the Interior
Bureau of Land Management (105)
18th & C Sts., NW
Washington, D.C. 20240

Mr. Earl Kari
Environmental Protection Agency
701 C Street, Box 19
Anchorage, Alaska 99501

EXECUTIVE POLICY BOARD
Office of the Federal Inspector
Alaska Natural Gas Transportation System
Post Office Building, Room 2413
1200 Pennsylvania Avenue
Washington, D.C. 20044

JUN 20 [illegible]

MEMORANDUM

TO: BG Hugh Robinson, Corps of Engineers, Chairman *
Dr. M. Rupert Cutler, Department of Agriculture
R. Dobie Langenkamp, Department of Energy
William N. Hedeman, Jr., Environmental Protection Agency
John Adger, Federal Energy Regulatory Commission
Guy Martin, Department of the Interior
Nancy Barrett, Department of Labor
Howard Dugoff, Department of Transportation

* Subject to change August 1, 1980
due to transfer of duty station

EXECUTIVE COORDINATION COMMITTEE (ALASKA)

ECC MEMBERS

Environmental Protection Agency 701 "C" Street - Box 19 Anchorage, Alaska 99513	Jim Sweeney 5003
Environmental Protection Agency 900 W. 5th Ave - Suite 740 Pouch 6619 Anchorage, Alaska 99502	Earl Kari 5534
United States Geological Survey 733 W. 4th Suite 400 Anchorage, Alaska 99501	Harry Hulsing 271-4138 Charlie Sloan
Fish and Wildlife Service 1101 East Tudor Road Anchorage, Alaska 99513	Keith Schreiner 276-3800 Lee Roy Soul
Corps of Engineers P.O. Box 7002 Anchorage, Alaska 99510	Col. Nunn 752-2605 Dave Robbins 277-0411
Office of Special Projects 701 "C" Street Anchorage, Alaska 99513	Arlan Kohl 271-5031
State Pipeline Coordinator's Office 1001 Noble St. - Suite 450 Fairbanks, Alaska 99701	Charles Behlke 456-4835 Al Ott
Bureau of Land Management 18th & C Street N.W. Washington, D.C. 20240 ATTN: Director (105)	Curt McVee 271-5076 Earl Boone 5736
Office of Federal Inspector 900 W. 5th Ave - Suite 740 Pouch 6619 Anchorage, Alaska 99502	

THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
ROOM 2413 POST OFFICE BUILDING
1200 PENNSYLVANIA AVENUE
WASHINGTON D.C. 20044

Charter of the

Citizens' Environmental Advisory Committee

I. Federal Inspector Policy: The Federal Inspector (hereafter FI), Alaska Natural Gas Transportation System (hereafter System) established by Reorganization Plan No. 1 of 1979, in consultation with the Executive Policy Board (hereafter EPB) established by Executive Order 12142, finds it in the public interest to charter a Citizens' Environmental Advisory Committee (hereafter Committee).

II. Purpose of Committee: To provide advice to the FI relating to environmental matters pertinent to the Alaska segment of the System that are of concern to the Committee or the FI.

III. Nature of Committee Advice: Determinations of areas of inquiry to be undertaken by the Committee shall be made by mutual agreement between the Committee and the FI. While the Committee's advice may take the form of suggestions and recommendations, the Committee shall have no authority to commit the FI or his staff to any course of action.

IV. Committee Membership: The Committee shall consist of five individuals who collectively, represent fairly the views of the environmental community on environmental matters pertinent to the Alaska segment of the system.

V. Nomination and Selection of Committee Members:

A. Nomination: As soon as practicable following the effective date of this charter, the FI shall call for nominations to Committee membership. The call for nominations shall be published in the Federal Register and in newspapers of general circulation in Alaska. Each nomination shall be accompanied by, but not necessarily restricted to, a resume providing: (1) the nominee's full name, address of residence, and occupation; and (2) a summary of academic and experience backgrounds supporting the nomination. The nomination period shall close 60 days after publication in the Federal Register, and selection shall be made promptly after the closing date. The names of persons selected for Committee membership shall be published in the Federal Register and in newspapers of general circulation in Alaska.

B. Selection: The FI shall select Committee members from an initial roster of no fewer than 10 nominees following consultation with the Council on Environmental Quality. In the selection of members, the FI shall consider the following: (1) nominations by citizens' environmental groups, (2) persons having extensive knowledge of the Alaskan environment, and (3) recommendations of the Council on Environmental Quality. Selections shall be made with a view toward balance in terms of environmental points of view represented and the Committee's purpose.

C. Duration of Membership: Initially, three members shall be appointed to two-year terms and two members shall be appointed to one-year terms. Thereafter, Committee members shall be appointed for two-year terms. Members may be reappointed. These terms of membership shall be followed for the duration of the Committee.

D. Filling Vacancies: In the event that a vacancy occurs in Committee membership, the FI or the Executive Secretary shall seek nominations of persons to fill the vacancy. Procedure for nomination and selection shall follow Section V. A. and B. above. The call for nominations shall be issued within 45 days of the date the vacancy occurs, or the FI is informed that the vacancy will occur, whichever is earlier. There shall be a minimum of three nominations for each vacancy.

VI. Duties of Committee and Relationship to the FI: The Committee shall:

A. Report directly to the FI or, at the FI's option, report to the Executive Secretary.

B. Have direct access to the FI upon written request of a simple majority of the Committee membership.

C. Meet with the FI periodically, but no less often than once each quarter.

D. Be informed of decisions consistent with the purpose of the Committee, and given the opportunity to attend meetings of Federal officials where appropriate as determined by the FI.

VII. Committee Chairperson and Meetings:

A. Chairperson: The FI shall call the first meeting of the Committee at which time the Committee members shall select a chairperson, a vice chairperson, and establish the Committee's

rules and procedures. The chairperson and vice chairperson shall be Committee members and they will be selected for one-year terms. The chairperson shall be the primary spokesperson in communicating the Committee's advice to the FI.

B. Subject to Section VIII. D., the Committee shall meet at the call of the Chairperson or at the request of a majority of the members, but at least quarterly.

VIII. Federal Executive Secretary to Committee:

A. The FI shall designate an employee who will be the Executive Secretary to the Committee and who shall attend each meeting.

B. Meetings may not be convened without the presence of the FI or the Executive Secretary.

C. The FI or the Executive Secretary, whenever it is determined to be in the public interest, may adjourn any Committee meeting.

D. All Committee meetings, and agendas for such meetings, must have the advance approval of the FI or the Executive Secretary.

IX. Procedures:

A. Timely notice of each meeting shall be published in the Federal Register and by such other means as are appropriate.

B. Interested persons shall be permitted to attend meetings, appear before, or file statements with the Committee.

C. Subject to Section 552 of Title 5, and the procedures established thereunder by the FI, the records, reports, transcripts, minutes, appendixes, working papers, drafts, studies, agendas, or other documents which were made available to or prepared for or by the Committee shall be available for public inspection and copying at a single location in the offices of the FI. Requests for such material must be made to the FI. Charges for copies of the above materials may be imposed, but shall not exceed actual cost of duplication.

D. Detailed minutes of each Committee meeting shall be kept and shall contain a record of the persons present, a complete and accurate description of matters discussed and conclusions reached, and copies of all reports received, issued, or approved by the Committee. The accuracy of all minutes shall be certified to by the Chairperson. A copy of all such minutes shall be provided to the FI.

X. Committee Staff Support and Responsibilities:

A. Committee Staff Support: Staff support to the Committee (including clerical support) shall be provided by the FI. The level of staff support provided to the Committee shall be determined by the FI.

B. Committee Staff Responsibilities: Staff assigned to support the Committee will:

1. Give priority to Committee work.

2. Be the day-to-day liaison with other FI staff.

3. Receive guidance and general supervision from, and be accountable and report to, the FI or the Executive Secretary.

XI. Committee Member Compensation: Committee members shall be compensated at a rate appropriate for services rendered and consistent with their qualifications. The rate may not exceed the maximum rate of GS-15, Step 10 in the General Schedule. Factors to be considered when making compensation determinations include:

A. The grade and rate which would be applicable if the services were subject to the Classification Act;

B. The stature of the individual in his or her field and the extent to which unique personal qualifications contribute to the value of his or her services;

C. Any unusually burdensome and otherwise uncompensated aspects of his assignment, such as frequent need to work more than eight hours a day without overtime pay;

D. The pay earned in the member's regular occupation;

E. Whether any non-monetary rewards figure in the assignment;

F. The rate paid by other Government and private clients for the member's expert or consultant services, with consideration of similarities and differences in the services required by the several clients and the programs and circumstances under which they were rendered; and

G. The rates paid by the Government for similar services to other experts or consultants with comparable qualifications.

In addition, while engaged in the performance of their duties away from their homes or regular places of business, members will be allowed travel expenses as authorized by Section 5703 of Title 5 for persons employed intermittently in the Federal Government service.

XII. Federal Support to the Committee: Federal support to the Committee shall be provided by the FI and shall consist of:

A. Provision of space, necessary office equipment and furnishings, and telephone service.

B. Provision of necessary office supplies.

C. Use of duplicating machines under control of the FI.

D. Other administrative services as necessary.

E. Transportation, lodging and food sufficient to permit access to work areas and other activities authorized in Article XIII.

F. Such other support as determined by the FI and the Committee chairperson.

XIII. Responsibilities of the FI: The FI will:

A. Provide information adequate to permit the Committee to accomplish its purpose.

B. Assure that, as appropriate, the Committee has access to portions of the System in Alaska.

C. Keep such records as will fully disclose the expenditure of funds in support of the Committee.

XIV. Annual Report: The Committee shall file an annual report with the FI. Such report shall be made public.

XV. Termination or Renewal of Committee: The Committee shall terminate two years following the date this charter is filed unless renewed in accordance with Section 14(a)(2) of the Federal Advisory Committee Act.

XVI. Estimated Costs and Federal Support: It is estimated that total Federal costs associated with the Committee will be about $93,100.00, which includes 1.6 person-years Federal staff support.

MAY 29 1980

Date Signed

John T. Rhett
Federal Inspector

MAY 29 1980

Date Charter Filed

NORTHWEST ALASKAN PIPELINE CO.

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U. S. SENATE

Honorable Ted Stevens
United States Senate
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Lorraine Eide
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Juneau, Alaska 99802

Phone (907) 586-7132
(Hours: 8 a.m. to 1 p.m.)

March 6, 1980

REGIONAL CORPORATION PRESIDENTS

Mr. Roy Tansy, President
Ahtna, Inc.
Drawer G
Copper Center, AK 99573
277-0136

Mr. Agafon Krukoff, President
The Aleut Corporation
833 Gambell Street
Anchorage, AK 99501
274-1506

Mr. Edward Hopson, Sr.
Arctic Slope Regional Corporation
P. O. Box 129
Barrow, AK 99723
852-3000

Mr. George Walters, President
Bering Straits Native Corporation
P. O. Box 1008
Nome, AK 99762
443-5252

Mr. Hjalmar Olson, President
Bristol Bay Native Corporation
P. O. Box 198
Dillingham, AK 99576
842-5261

Mr. Oscar Kawagley, President
Calista Corporation
516 Denali Street
Anchorage, AK 99501
279-5516

Mr. Edgar Blatchford, President
Chugach Natives, Inc.
903 W. Northern Lights
Anchorage, AK 99503
274-4558

Mr. Roy Huhndorf, President
Cook Inlet Region, Inc.
P. O. Drawer 4-N
Anchorage, AK 99509
274-8636

Mr. Tim Wallis, President (eff 3/17/8
Doyon Limited
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Mr. James F. Morse, President
Koniag, Inc.
P. O. Box 746
Kodiak, AK 99615
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Mr. John W. Schaeffer, President
NANA Regional Corporation
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Kotzebue, AK 99752
442-3261

Mr. Michael Chittick, President
Sealaska Corporation
Sealaska Plaza, Suite 400
Juneau, AK 99801
586-1512

Northern Pipeline Agency Canada | Administration du pipe-line du Nord Canada

THE NORTHERN PIPELINE AGENCY

-- FACT SHEET --

BACKGROUND:

The Northern Pipeline Agency was established by Act of Parliament in April 1978 in accordance with the Canada/U.S. Agreement of September 1977. The International Joint Agreement committed both governments to the efficient and expeditious construction of the Alaska Highway gas pipeline.

In approving the Northern Pipeline Act, all parties in Parliament recognized the exceptional nature of this project. In addition, the experience and the lessons learned in building the Alyeska oil pipeline in Alaska, and the concerns reflected in the Berger, Lysyk and Hill Inquiries, the National Energy Board Hearings and various other submissions emphasized the need to develop new approaches to to the control and regulation of this immense project.

ROLE:

The Agency was created to oversee the planning and construction of the Canadian portion of the Alaska Highway gas pipeline project. Rather than just another level of regulatory approval, the Agency was designed to function as a "single regulatory window" to streamline and expedite the approval process.

The single window concept allows for the many federal acts, which will apply to the construction of the pipeline in Canada, to be administered by a single regulatory authority -- the Northern Pipeline Agency. The powers of the National Energy Board are represented within the Agency by the Designated Officer.

Centering federal regulatory authority over all aspects of the pipeline in one Agency will minimize the added cost and disruption that could result if that authority were fragmented among several different departments -- as was the case in the U.S. with the Alyeska Line.

RESPONSIBILITIES

In summary, the Agency's responsibilities, as set out in Section 3 of the Northern Pipeline Act, are as follows:

- To facilitate the efficient and expeditious planning and construction of the pipeline avoiding excessive cost overruns.

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- To take into account local and regional interests, the interest of residents, particularly native people.
- Recognizing the responsibilities of the Government of Canada and other governments as appropriate, to ensure that any native claim related to the land on which the pipeline is to be situated is dealt with in a just and equitable manner.
- To facilitate consultation and co-ordination with the governments of the provinces, the Yukon Territory and N.W.T. in relation to the pipeline.
- To maximize the social and economic benefits from the construction and operation of the pipeline for Canadians.
- To minimize the adverse effect on the social and environmental conditions of the areas directly affected by the pipeline.
- To advance national economic and energy interests and to maximize related industrial benefits by ensuring the highest possible degree of Canadian participation in all aspects of planning, construction and procurement.

RMS & CONDITIONS: One of the Agency's major activities is the development of detailed socio-economic and environmental terms and conditions and technical requirements which will govern the actual construction of the pipeline by the Foothills group.

While the technical requirements will apply to the overall length of the system in Canada, the socio-economic and environmental terms and conditions are segmented to reflect the different areas through which the pipeline will pass: i.e.: Yukon, North B.C., Alberta, Saskatchewan and South B.C.

In developing the terms and conditions the Agency took into account the concerns expressed by many Canadians in the Berger, Lysyk and Hill Inquiries, the National Energy Board Hearings Report, as well as the undertakings made by Foothills before the National Energy Board when the certificate to build this pipeline was awarded in their favour.

UBLIC REVIEW: The effects of the Alaska Highway gas pipeline are potentially wide-ranging and varied but will be particularly significant on the sensitive areas of the Yukon and North B.C.

Because of this, the Agency is committed to public review of the socio-economic and environmental terms and conditions proposed for each of these areas to ensure that they are indeed adequate and appropriate.

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The Agency has no intention of conducting another Berger style inquiry. The Agency's public review process will be conducted in an informal and flexible way. The hearings panel will accept written briefs or will listen to oral presentations -- whichever best suits the participants. There will be no direct cross-examination that might inhibit anyone from speaking out on a pipeline related matter. The views expressed will be recorded verbatim and will be taken into account by the Agency in the development of the final sets of socio-economic and environmental terms and conditions to be applied to the pipeline companies.

Public hearings in the Yukon were completed in April 1979. Planning is now underway for hearings to be held in North B.C. in the fall, 1979.

COMPLIANCE:

Penalty for non-compliance with the terms and conditions, once finalized, may take one of four (4) forms. A fine not exceeding $10,000 per day of offence may be assessed by the Minister, or a fine not exceeding $10,000 per day of offence may be assessed through the courts. The Minister also has the right to have the work done himself and recover costs, or the Agency, through the authority of the Designated Officer, has the ability to halt construction until compliance is met.

The enforcement of the socio-economic and environmental terms and conditions and the technical requirements by the Agency will ensure that the pipeline is built in a way that maximizes its economic benefits to Canada and all Canadians, and prevents or minimizes adverse social, economic and environmental impacts on those areas directly affected by the pipeline.

DIFFERENT BY DESIGN:

The Northern Pipeline Agency is not, nor will it become a typical example of bureaucracy. The "sunset" nature of the legislation provides for the termination of the Agency within one year following the opening of the last section of the pipeline, unless authority is extended by Parliament for the construction of the Dempster Lateral. In addition, the Agency is classified as a separate employer, which means that resignation from the civil service is a condition of employment.

Initially about 60% of Agency management will be drawn from public sector levels while 40% will be drawn from the private sector. As we complete design and enter the construction phase, the Agency will draw its expertise

-- more --

from the private sector where the experience in pipeline building lies and these ratios will change. Patterned after an industrial organization the Agency's Commissioner and Chief Executive Officer, the Honourable Mitchell Sharp, is located at policy headquarters in Ottawa, and the Administrator and Chief Operating Officer, Harold Millicam, is located at operational headquarters in Calgary.

The Agency is low in numbers and will remain low in numbers. With four (4) offices across Canada, our staff now totals 72, with a provision to increase to 200 if required at the peak of construction. We are a small, action oriented team -- a unique blend of the public and private sectors sensitive to the needs of the project and the people affected and enthusiastic about the great challenge we face.

-- Different by design.

If you would like to learn more, please contact us at any of the following offices:

Public Relations Coordinator
Northern Pipeline Agency
140 Wellington Street
8th Floor, Box 1605
Station B
Ottawa, Ontario
K1P 5A0

Public Relations Officer
Northern Pipeline Agency
4th Floor Shell Centre
400 - 4th Avenue S.W.
Calgary, Alberta
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Elden Schorn
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Ken McKinnon
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Northern Pipeline Agency
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Whitehorse, Yukon
Y1A 4N7
(403) 668-4301

Office of the Federal Inspector

Alaska Natural Gas Transportation System

The Office of the Federal Inspector was created in 1979 to coordinate Federal agency approvals and enforce Federal requirements during construction of the Alaskan Natural Gas Transportation System. The network of pipelines that will enable U.S. consumers to tap the vast natural resources of Prudhoe Bay is the largest privately financed project ever undertaken in the world. Its successful completion will help reduce our dependence on imported fuel.

If you have a question or need additional information please contact:

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