

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

1051 SCOMM 28: JOINT GAS PIPELINE COMMITTEE. 1981-82

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

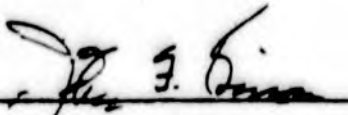
This Amendment No. 3 and the obligations of the Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska hereunder are subject to all applicable laws, rules, orders and regulations of United States federal, state or local governmental authorities having jurisdiction and, 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.

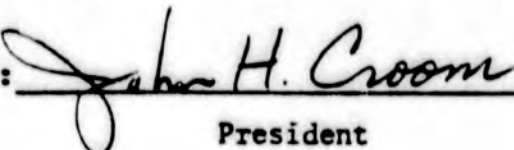
IN WITNESS WHEREOF, the parties have executed this Amendment No. 3 as of the day and year first written.

ATTEST:

COLUMBIA ALASKAN GAS TRANSMISSION
CORPORATION



Assistant Secretary

By: 

President

ATTEST:

Joseph T. Wales

ATTEST:

ATTEST:

[Signature]

TETCO FOUR, INC.

By: H. Wayne Hodge

TEXAS GAS ALASKA CORPORATION

By: _____

TRANSCANADA PIPELINE ALASKA LTD.

By: R. B. [Signature]

ALASKAN NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY

By each of its Partners:

ATTEST:

John McMillan

ATTEST:

ATTEST:

ATTEST:

NORTHWEST ALASKAN PIPELINE COMPANY

By: John McMillan

NORTHERN ARCTIC GAS COMPANY

By: _____

PAN ALASKAN GAS COMPANY

By: _____

CALASKA ENERGY COMPANY

By: John C. [Signature]

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

[Signature]
Assistant Secretary

By: *[Signature]*

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. Kalen

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:

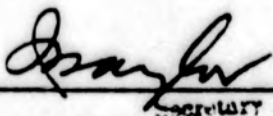
PAN ALASKAN GAS COMPANY

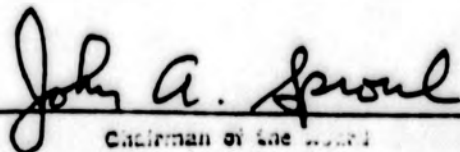
By: _____

ATTEST:

CALASKA ENERGY COMPANY

By: _____


Secretary


Chairman of the Board

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. Chebikoff

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.

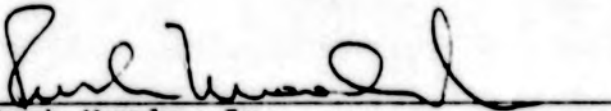
Any person desiring to be heard or to make any protest with reference to said application should on or before _____, 1980, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of 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

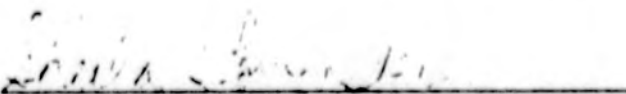
VERIFICATION

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

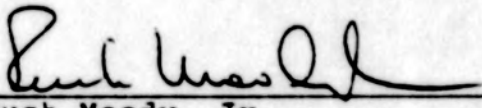
My Commission Expires:

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.**

EXXON COMPANY, U.S.A.

POST OFFICE BOX 2180 • HOUSTON, TEXAS 77001

MARTIN N. ERICK
CHIEF ATTORNEY
NATURAL GAS

October 8, 1980

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

Northwest Alaskan Pipeline Company,
Docket No. CP78-123, et al.

To All Parties of Record in Docket Nos. CP80-435
and CP78-123, et al. Restricted Service List

Reference is made to the Technical Conference held September 3, 1980, in Hearing Room "A", FERC Office Building pursuant to the Notice of Application issued by the Commission on August 1, 1980. Among other matters, discussion involved matters of pipeline design and design changes. In connection therewith, Exxon made the following statement:

"This proceeding relates to the Application filed on July 1, 1980, which describes the pipeline as beginning at the discharge of the proposed plant to condition the Prudhoe Bay gas. The Applicant and the Commission are fully aware that Exxon's position is that the conditioning plant is and should be an integral part of the transportation system itself; its function is to permit transportation, not production. To this end, Exxon and the other major Prudhoe Bay producers have entered into two agreements with the Applicant; one involves the expenditure of several hundred millions of dollars to optimize and complete the design, engineering and final cost estimates for the entire system as a unit, i.e., the conditioning plant and the pipeline together. The second agreement is to study the financing for the entire system.

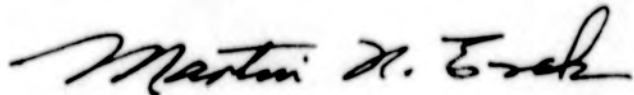
"Since the Application does not include the conditioning plant, our question is -- it is correct to presume (1) that

the results of the design and engineering and finance work will become a part of these proceedings at the time of completion of such work next year? And, (2) that the Application will be amended to take into account the results of such work?"

So that the record in the captioned dockets will reflect the facts reflected by the foregoing, Exxon is furnishing the interested parties with a copy of documents pertinent thereto. These are enclosed, as follows:

1. Application For Rehearing Of Exxon Corporation Of Order No. 45 In Docket No. RM79-19 And Order No. 31A in Docket No. RM78-12
2. Cooperative Agreement For Design And Engineering Of Alaska Gas Pipeline And Conditioning Plant
3. Joint Statement of Intention

Very truly yours,



Martin N. Erck

MNE:bjp
Enclosures

c: Mr. John B. Adger, Jr. - w/o enclosures

NORTHWEST ALASKAN PIPELINE COMPANY

1120 20th Street, N.W.
Suite 5-700
Washington, D.C. 20036
(202) 872-0280

REA-80-1088

November 6, 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:

During the September 30, 1980 technical conference in the above-captioned proceeding, the Alaskan Delegate asked Alaskan Northwest to prepare a report listing factors affecting lay rates, providing lay rates from actual pipeline construction projects around the world, comparing the Alaska segment lay rate estimate with that of the 1977 estimate, and discussing the differences in expected lay rates for the Alaska and Yukon segments of the ANGTS. The enclosed "Lay Rate Report of Alaskan Northwest Natural Gas Transportation Company" is being submitted in fulfillment of the Delegate's request and for the information of the participants in the technical conferences. The submittal of this report completes the outstanding information request concerning the Alaska segment lay rate estimate.

Sincerely yours,

NORTHWEST ALASKAN PIPELINE COMPANY

Cuba Wadlington, Jr. (44)

Cuba Wadlington, Jr.
Director, Regulatory Affairs

cc: Restricted Service List
RDM index

CW:paw

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

. In the Matter of:

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

LAY RATE REPORT OF
ALASKAN NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY

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

Richard Berman
Director of the Division of Cost and Audit Analysis, OFI

On July 1, 1980, Alaskan Northwest Natural Gas Transportation Company filed the Certification Cost Estimate (CCE) for the Alaska segment of the Alaska Natural Gas Transportation System with the Federal Energy Regulatory Commission. The CCE contains a productivity estimate for pipe installation, or "lay rate,"^{1/} of 40 joints or 3200 feet per calendar day for non-insulated pipe, and 35 joints or 2800 feet per calendar day for insulated pipe. During the technical conferences established by the Commission's August 1, 1980 "Notice of Application and Order Establishing Procedures," the Alaskan Delegate requested Alaskan Northwest to prepare and submit for the record a report on lay rates which: (1) explains the factors affecting lay rate; (2) relates the lay rate in the CCE to actual lay rates experienced in other pipeline projects around the world, including Alyeska; (3) compares the lay rate in the CCE to that projected by Alcan Pipeline Company in its 1976 certificate application; and, (4) discusses the differences in expected lay rates for the Alaska and Yukon segments of the ANGTS. This report is submitted in response to the Delegate's request and for the information of the Commission and participants in these conferences. We are also taking this opportunity to comment briefly upon the Williams Brothers lay rate working paper, which was submitted for inclusion in the conference transcripts on October 22, 1980, and correct misunderstandings evidenced in the Trial Staff's summary of the technical conference's lay rate discussions.

^{1/} The lay rate is set out in the work papers supporting the CCE. See, e.g., Restated Vol. 31, p. 0149.

I. FACTORS AFFECTING LAY RATES

In assessing and comparing lay rates, it is necessary to know the various factors which will affect the lay rates. Among the more important factors that affect lay rates and which must be taken into consideration in establishing a realistic lay rate estimate are the following:

1. Labor

- a. Availability of a qualified, experienced, and competent labor force and proper support staffing. The less qualified the labor force the lower the productivity or rate of progression that will be obtained on any given job. Additionally, an execution contractor's ability to obtain a qualified labor force is affected by simultaneous construction of other pipeline projects.
- b. Willingness of the labor force to meet the expected level of performance both as to the quality of work and productivity.
- c. The effect of weather and climate on labor productivity. For example, productivity is reduced in shoulder and winter months in harsh climates, and the more construction scheduled in these months the lower the productivity.
- d. Quality and terms of the labor agreement.

2. Machinery and Equipment

- a. Adequacy and availability of necessary equipment.
- b. Proper maintenance of equipment and availability of mechanics and service vehicles.
- c. Effect of climate on equipment. Extreme cold will cause additional wear because of the need constantly to idle equipment. Extreme heat on the other hand will cause a breakdown of lubricants, seals, and wiring.
- d. Availability of adequate fuel supplies.
- e. Effect of soils and topography on equipment. For example, sand and dust will clog filters and contaminate lubricants and oils.

3. Terrain Topography

- a. Construction in flat terrain normally will yield the highest rate of progression and this rate is reduced accordingly in rolling, hilly and, particularly, mountainous terrain since equipment tends to perform less effectively in these terrains.
- b. Bends and grading required by terrain can significantly reduce productivity.
- c. Streams and swamps also lower the productivity due to increased working time for both the equipment and labor force.

4. Soils

- a. Numerous soil and subsoil conditions affect the ease or difficulty in ditching, and therefore, the lay rates that can be expected. For example, extreme soil variations such as sand, clay, rock, continuous and discontinuous permafrost will affect productivity.
- b. The presence of ground water affects ditch stability and maintenance and also reduces productivity.
- c. The amount of open ditch allowed.

5. Availability of Job Supplies, Tools, and Spare Parts

- a. Ability to acquire and store efficiently all necessary material and particularly to replace immediately needed supplies, such as welding rods, broken skids, etc.
- b. Potential delays from strikes of vendors and suppliers of parts.

6. Design of Line

- a. The pipe specifications and length, all of which affect welding productivity.
- b. The type of coating specified.
- c. Bending restrictions.
- d. The type of weights that are utilized in streams and swamps.

7. Highway Load Limits and Seasonal Availability

- a. Effects of weather, particularly spring thaw, on roads and workpad. Any required repair of roads used to move equipment and labor will reduce the rate of progression.
- b. Highway load limits may require the dismantling and reassembly of equipment, which reduce the rate of progression.

8. Management

- a. Qualifications and performance of spread superintendents and crew foremen.
- b. Project management competence and especially its effectiveness in scheduling, logistics, purchasing, etc.
- c. Qualification and performance of inspectors and the timeliness of inspections and approvals.

9. Government

- a. Delay potential in receipt of necessary permits and Notices-To-Proceed.
- b. The degree of multi-layered inspections, the delay potential from lack of timely inspections, and changes in inspection procedures.
- c. Variances in interpretation of stipulations and specifications. Additionally, the time it takes to get an interpretation will affect productivity.

Each of the above subjective factors is considered in estimating a lay rate for any given project, for each can significantly impact on the lay rates that will actually be experienced. Thus, it is obviously impossible to quantify precisely a mathematical relationship between lay rates actually experienced on any two projects.^{2/} It is equally difficult to compare mathematically the lay rates actually achieved on a

^{2/} For example, a South Gulf Coast Texas project will have flat terrain that can be easily ditched, very little rainfall to damage the ditch, easy access to job supplies and work site, and therefore, a minimum number of days of lost production. On the other hand, a project in the mountainous regions of Colorado will have relatively low production due to the amount of rock that must be ditched, rough terrain requiring more bends, steep slopes requiring equipment to be winched into position, poor access to the work sites, and many more days of lost production at some times of the year.

project with the lay rates estimated for that project. Nonetheless, we have attempted in the ensuing sections to set out lay rates actually experienced on other projects, the factors affecting such lay rates, and the qualitative reasons for the differences in those projects vis-a-vis the estimated lay rate for the Alaska segment of the ANGTS. Prior to such discussion, we shall review the bases for the lay rates utilized in Alaskan Northwest's July 1, 1980 CCE and the reasons for the differences between that lay rate vis-a-vis those projected by Alcan Pipeline Company in its 1976 cost estimate.

II. THE JULY 1, 1980 LAY RATE

The July 1, 1980 lay rate was developed by a group of experienced representatives from Fluor and highly qualified Execution Contractors. 3/ These experts met in roundtable discussions to develop a realistic lay rate based upon their nearly 170 years of collective experience on pipeline construction projects around the world, including bidding and construction on all six spreads of Alyeska. They were instructed by Northwest Alaskan to develop a single lay rate for the entire Alaska segment as though they were preparing a bid as a joint venture partnership.4/

The lay rate team began by determining the particular operation that would govern the rate of progress for pipe installation. As with most pipeline construction projects, they concluded that the joining of the pipe was the pacing operation. Thus, the key crews are the ones responsible for aligning and welding together the lengths of pipe. These are the pipe gang and welding crew.5/ The pipe gang and welding crew are the two crews whose progress is measured in joints

3/ The members of the lay rate team were C.M. ("Mac") Hoffman, Vice President, Willbros Energy Service Company; T.L. Beard, Vice President, Reading & Bates Construction Company; Travis Smith, Construction Management Consultant and Chairman of the Board of Directors for Professional Contractors, Inc., of Anchorage, Alaska; Eugene L. Kulawik, General Superintendent, Peter Kiewit and Sons (Fairbanks); V.E. (Gene) Seale, Vice President, Curran Houston, Inc. (subsidiary of Houston Contracting Co.); David Argetsinger, Chief Engineer, Alaska Area, Green Construction Co.; Paul E. Macy, President, Pipeline Construction Services, Inc.; and J.W. McCarthy, Gordon D. Eastling, and Frank W. Wetzel, all with Fluor Engineers and Constructors, Inc. Descriptions of their backgrounds and experience are found in the transcript for the October 22, 1980 technical conference.

4/ The instructions furnished to the lay rate team have been provided to the conference and are contained in the October 23, 1980 transcript.

5/ In the work papers, the pipe gang corresponds to line-up and hot pass (Operation No. 606) and the welding crew corresponds to firing line (Operation No. 607). See, e.g., Restated Vol. No. 31 at 0149-0155.

per day. The pipe gang lines up the lengths of pipe and makes the initial welds joining the pipe. The welding crew completes the weld.

They next considered the factors that could affect the performance of those operations, including the factors listed in Section I above. In particular, they considered the type of pipe (48 inch diameter), the length of pipe to be joined (assumed effective length of 80 feet), the pipe wall thickness (0.600 and 0.720 inches), 6/ the great variances in the Alaska terrain along the 745 mile route, normal Alaska weather, the competition for skilled labor, the weld quality required, and the degree to which they could overcome the "Alyeska syndrome." After taking all of the controlling factors into account, they decided that 40 joints, or 3200 feet, per calendar day was the optimum average rate of progress for the entire Alaska segment that reasonably could be expected to be achieved by the pipe gang and welding crew for noninsulated pipe. The lay rate for insulated pipe was reduced to 35 joints, or 2800 feet, per calendar day because of the difficulties associated with handling insulated pipe, in order to avoid damaging the insulation, necessarily slowing down all of the various operations connected with joining pipe.

Having decided that 40 joints per day generally was the average rate that could reasonably be expected to be attained for the total Alaska segment for non-insulated pipe, the lay rate team established crew sizes that could realize this average. Separate crews were established for each of the six spreads 7/.

After two sections of pipe have been aligned, the pipe gang welders join them with a stringer bead, i.e., root weld, and two hot passes. In the hot passes, the welders add more metal to the root weld to prevent the metal from cooling too fast and cracking. Twelve welders are assigned to the line up and hot pass operation, four each for the root weld and the two hot passes. 8/ Four welders are the most that can efficiently work around a joint at any one time. On some days, these welders will achieve less than 40 joints and on other days will exceed 40 joints depending upon weather, terrain, and other factors previously noted.

6/ Generally, the larger the diameter of the pipe, the longer the lengths of pipe, and the greater the pipe wall thickness, the more time is required to line up and join the sections of pipe.

7/ Separate crews were also established for Atigun Pass because of the very difficult construction anticipated in laying pipe through the Pass.

8/ See, e.g., Restated Vol. 31 at 0152, which provides for 12 welders in the Line-up/Hot Press Operation for Spread 6.

The welds are completed by the welding crew during the firing line operation. The firing line welders, sometimes referred to as backend welders, build up the welds to the thickness of the pipe. In determining the number of welders necessary to realize 40 joints per day on average, the lay rate team assumed that each firing line welder would complete, on average, 1.3 welds per day. Two such welders would work on a joint at the same time. Based on 1.3 welds per day, approximately 30 welders would be needed to average 40 joints per day ($40 \div 1.3$ approximately equals 30). Recognizing that welder productivity always suffers because some welders will miss days due to sickness, normal weather, and other reasons, the firing line crew size was increased by four welders to help assure the 40 joint daily average. The addition of four welders to the crew was based upon the lay rate team's prior experience, which demonstrated a need to increase the crew by 12½ percent to avoid such delays.^{9/} The 12½ percent is not a contingency, but is a normal expected cost for a known occurrence, and reflects normal Alaska weather, in accordance with the instructions given the lay rate team. Although expressed as a percentage in the work papers, this allowance was not derived through any formula. It is based solely in the judgement and experience of the lay rate team and is one component in the process by which they arrived at 34 firing line welders per welding crew.

The other crews, such as ditching, hauling, and stringing, were established to keep pace with the pipe gang and welding crews. Their progress rate is measured in feet per day, and they were designed to be capable of maintaining an average 3200 feet per calendar day.

Both the 40 and 35 joints and 3200 and 2800 feet per calendar day rates are, in the final analysis, necessarily judgemental numbers. The lay rate is not susceptible to mathematical precision. The multitude of factors affecting lay rate must be carefully balanced by persons with experience with the type of pipe and conditions under which it will be installed. With nearly 170 years of experience in pipelining, the team of persons assembled by Alaskan Northwest was uniquely qualified to derive the projected lay rate.

^{9/} The discussion of the 12½ percent allowance appears erroneously in the Line-up/Hot Pass portion of the work papers. In fact, it properly belongs in the Firing Line portion of the work papers, because the 34 welders are the Firing Line welders. Compare, e.g., Restated Vol. 31 at 0149 with 0153, 0155.

III. COMPARISON OF ALCAN PIPELINE COMPANY'S 1976 PROJECTED
LAY RATE WITH THAT OF ALASKAN NORTHWEST

In preparing its cost estimate in support of its 1976 certificate application before the Federal Power Commission to construct and operate the ANGTS, Alcan Pipeline Company, predecessor in interest to Alaskan Northwest, projected a lay rate of 50 joints, or 4000 feet, per calendar day. This projected lay rate was predicated upon construction of what has been referred to as a "conventional" 42-inch diameter pipeline. More specifically, that filing contemplated very little frost heave mitigative measures, less than 100 miles of insulated pipe, no deep ditch burial, or use of select backfill to mitigate potential frost heave problems. The biggest factor in the reduction from 50 to 40 joints is the increase in pipe diameter from 42 to 48 inches. This single factor alone reduces the 50 joint rate to 43.75 joints.^{10/} The further reductions are due primarily to a 30 percent increase in the amount of insulated pipe, the increased frost heave mitigative measures now being proposed, and the increase in construction during the shoulder months vis-a-vis that contemplated four years ago.

IV. COMPARISON WITH ALYESKA LAY RATES

The execution Contractors' recollections of the average lay rates for 80-foot pipe experienced on four Alyeska spreads which extended from Prudhoe Bay to Delta Junction range from a low of 31 joints, or 2,480 feet, to a high of 37 joints, or 2,960 feet.^{11/} While the Alyeska pipe was also 48 inches in diameter, 80% was 0.420-inch wall thickness and 20% was 0.512-inch wall thickness compared to Alaskan Northwest's pipe which is all 0.600-inch or greater. Thus, Alaskan Northwest will have to deposit much more weld metal per weld than Alyeska. Since progress is controlled by the pipe gang and the welding crew, Alaskan Northwest's estimated lay rates would be higher than the estimated 40 joints per day, or 3,200 feet, if it utilized pipe of the same thickness as Alyeska.

^{10/} $50 \text{ joints} \div \left(\frac{48 \text{ inch}}{42 \text{ inch}} \right) = 43.75 \text{ joints.}$

^{11/} These recollections are apparently significantly higher than the average lay rate which was actually achieved on the TAPS pipeline, which may, in part, be because they did not include pre- and post-production time when the crews were mobilized and demobilized. Mr. V.A. Breitenbach, Sohio's Manager of Cost Engineering and Economics, and a member of the TAPS Owners' Cost Committee, stated for the record that "Broadly speaking, the rates actually achieved in building the TAPS pipeline ranges in the general area of 1,700 per day up to 2,500 per day with an average of perhaps 2000." (Transcript of October 22, 1980 at 38.)

V. LAY RATES FOR WORLD-WIDE PROJECTS

Below is a comparison of Alaskan Northwest's projected lay rate of 3200 feet per day and the actual lay rates of other projects in Louisiana, Texas, the Province of Alberta, Holland, Mexico, Iran, and Saudi Arabia. The comparison was limited to projects utilizing either 42-inch or 48-inch diameter pipe. The comparison illustrates how the previously discussed factors affect lay rates from project to project. As shown below, none of the projects exhibited the same factors that will affect the Alaska segment's lay rates. For example, none faced the extreme variations in temperature and terrain that will affect the Alaska project.

Job Description	Loc.	Base	Average Lay Rates/Day		Factors That Should Produce Lay Rates Greater Than 3,200'/Day (40 Joints of 80' Pipe)	Factors That Should Produce Lay Rates Less Than 3,200'/Day (40 Joints of 80' Pipe)
			No. Joints	No. Feet		
15 miles 48" x 0.406" wt. 40' long pipe	LA	Work days	43	1,717	Thinner wall pipe with less resultant welding by pipe gang, less line up time due to short joints	More welds/day because of 40' pipe lengths, boggy terrain, fewer welders by pipe gang (same welders ran stringer bead and hot pass)
		Project days	31	1,232		
17 miles 42" x 0.406" wt. 40' long pipe	TX	Work days	55	2,217	Smaller diameter pipe, thinner wall pipe with less resultant welding by pipe gang, good terrain, less line up time because of short joints	More welds/day because of 40' pipe lengths
		Project days	48	1,856		
30 miles, 42" dia. 67' long pipe	So. Alberta	Project days	30	2,000	Smaller diameter, thinner wall pipe with less resultant welding in pipe gang	Extremely poor relations between welders and management. 67' pipe length
44 miles 42" dia. 67' long pipe	So. Alberta	Project days	80	5,300	Smaller diameter, thinner wall pipe, excellent relations between welders and management	More welds/day because of 67' pipe length
48" x 0.500" wt. 40' long pipe	Holland	Work days	30-32	1,250	Thinner wall pipe with less resultant welding, less line up time due to short joints	More welds/day because of 40' pipe lengths, very wet ground, whole length had to be subsurface dewatered by using well pointing
102 kilometers 48" x 0.600 X-65	Mex.	Work days	48-45	1,700	Good climate, reasonable terrain	Poor quality labor with no training and experience, many repair welds after test
		Project days	30-35	1,300		
522 Kilometers 48" 0.438" wt. 80' joints	Saudi Arabia	Work days	60	4,800	No labor union, terrain mostly flat, thinner wall pipe	Some mountainous terrain
117 Kilometers 40" 0.406" wt. 80' joints	Iran	Work days	75-80	6,200	Smaller diameter, thinner wall pipe, reasonable terrain	Very poor welding quality (3 mos. spent repairing welds after test)
		Project days	35-40	3,100		
36" 0.312" wt. X-52 and 0.439" wt. X-60 40' joints	South LA	Project days	45-50	2,000	Smaller diameter, thinner wall pipe, flat terrain	Very bad soil conditions (mud, cane fields), 40' pipe lengths

VI. FOOTHILLS - ALASKAN NORTHWEST LAY RATE COMPARISON

Foothills' most recently filed cost estimate reflects an average lay rate of 3375 linear feet and 50 joints per calendar day for the 48-inch section of the South Yukon segment. ^{12/} Foothills' lay rate is premised upon an average standard joint length of 72 feet reduced to an effective average of 67.5 feet to account for the effects of short joints and transition pieces. Alaskan Northwest's projected lay rate of 40 joints per day for uninsulated pipe ^{13/} is premised upon a standard joint length of 80 feet. Thus, in order to compare the two estimates on a joints per day basis, the Foothills estimate must be recalculated assuming standard 80-foot lengths. This follows because it is Foothills' view that an increase in joint length would not result in an increase in footage per day. Rather, the average number of joints completed per day would be reduced. This is because Foothills believes that the other elements of the construction operation other than front-end welding cannot be efficiently scaled to allow the spread to progress faster than 3375 feet per day on average regardless of joint length. Given a standard joint length of 80 feet and average daily progress of 3375 feet, and assuming that the effective average joint length would remain 6.25% less than the standard due to the effects of short joints and transitions pieces, Foothills would achieve an average of 45 joints per day in the South Yukon. ^{14/} Thus, when the necessary adjustments are made, the difference between Foothills' rate and that of Alaskan Northwest is only 12.5% (i.e., 45 joints per day vs. 40 joints per day). This relatively small difference is due to the combined effect of a number of factors, including the following:

1. The Alaska segment covers a total distance of 745 miles with much more variation in climate and terrain than the 48-inch Foothills segment, which is only approximately 225 miles long. Differences in terrain, particularly in the amount of permafrost encountered, logically suggest that progress on the South Yukon section should be somewhat faster than on the Alaskan segment of ANGTS. Permafrost conditions, which affect

^{12/} As Foothills has stated on this record, its estimate is a preliminary estimate and experience this past summer in constructing the "prebuild" project in Alberta has indicated that the productivity projections included in the estimate may have been somewhat optimistic. See transcript of October 1, 1980 at 32.

^{13/} Since Foothills has no insulated pipe on the South Yukon segment, Northwest's projected lay rate for uninsulated pipe must be used as the starting point in the comparison.

^{14/} That is, a standard length of 80 feet, reduced by 6.25% = an effective average length of 75 feet. $3375 \div 75 = 45$.

ditch production and backfill requirements, are anticipated on only 40% of the South Yukon section, as opposed to approximately 67% on the Alaskan segment of ANGTS.

2. Differences in labor practices and labor relations have historically resulted in somewhat higher rates of progress on pipeline construction projects in Canada versus those in the U.S.

3. As a group, Canadian workers have more experience working in harsh weather conditions than their U.S. counterparts. Their performance, therefore, will likely be somewhat less dramatically affected by the harsh conditions anticipated on this project.

When these factors and the numerous other factors which can impact upon productivity are taken into account, the lay rate projects of both Northwest and Foothills are compatible and consistent.

VII. WILLIAMS BROTHERS LAY RATE STUDY

During the conference of October 21, 1980, representatives of the Williams Brothers Engineering Company submitted for discussion an approach for consideration of the lay rate for the Alaska segment of ANGTS. This approach is premised upon certain erroneous assumptions which are addressed below.

First, the Williams Brothers discussion paper presumes that the Alaskan Northwest lay rate is based "upon the experience [the execution contractors] had on the Alyeska Project." This is simply incorrect. As demonstrated at pp. 5-8 supra, the execution contractors' (EC's) experience in Alyeska was only one of many factors assessed in establishing the lay rate.

Second, the Williams Brothers discussion paper states that while the Alaskan Northwest lay rate

...is probably close to that actually experienced on the Alyeska Pipeline, it appears that this rate includes all of the contingencies and time delays experienced on the Alyeska project because of it being the first major pipeline project in Alaska and also because of its unique design. In particular, approximately 50 percent of the Alyeska line is aboveground on pipe supports and 50 percent is below ground...

We would note that our projected lay rate is significantly

higher than that experienced by Alyeska. ^{15/} Moreover, as explained by the execution contractors on the record on October 22, 1980, there are no contingencies included in the 40 joints per day (Tr. 24). In preparing their joint venture bid, the EC's excluded contingencies in accordance with the instructions given to them. Given the fact that each of the EC's ultimately will bid on the project, it was agreed that they would be excluded from the contingency assessment so that they would not be "locked in" to a specific contingency in the ultimate bidding process. Finally, the "unique design" on Alyeska referred to by Williams Brothers has no affect on lay rates. The simple fact is that a pipe and weld gang will achieve the same lay rate whether the pipe is to be above or below ground, assuming identical conditions for both.

Third, the Williams Brothers discussion paper arrives at a lay rate that they believe could be achieved on what they refer to as a "nice work day in Alaska." A cursory review of what Williams Brothers believes is a "nice work day" clearly demonstrates that such conditions yield a perfect day -- something very rare and unusual anywhere in the world, let alone Alaska. Williams Brothers then performs a time and motion study for the pipe gang, again theoretically assuming a perfect day in a perfect world, and establishes efficiency factors for the various seasons for each spread of construction to come up with a range of 47 to 50 joints per day. These efficiency factors were "based on [Williams Brothers] experience and judgment." There lies the key. Any projected lay rate is based upon experience and judgement, and the end result is subjective. Simply speaking, it is not possible to project mathematically a lay rate for cost estimating purposes. For this very reason, Alaskan Northwest sought the help of EC's, whose collective experience in pipeline cost estimating and construction exceeds 170 years, in establishing a lay rate from which costs would be estimated. Their collective judgement is that they would not risk their money on anything above 40 joints per day. In fact, none of the EC's could or would recommend to their management that a bid be submitted on anything above 40 joints per day.

^{15/} See Footnote 11. See also the November 5, 1980 letter of Mr. V.A. Breitenbach to Cuba Wadlington which notes that Williams Brothers, in joint venture with Brown & Root, made a cost estimate study for Alyeska which determined that approximately 2000 feet per day would be the pacing activity for laying 48-inch pipe in Alaska.

VIII. TRIAL STAFF SUMMARY OF LAY RATE FACTS

The Trial Staff listed in the October 1, 1980 transcript at pages 16 to 18 its understanding of certain "facts" about the projected lay rate for the Alaska segment, which Staff distilled from discussions with the persons who developed the lay rate. We would like at this time to correct several evident misunderstandings. First, the projected lay rate is neither low nor "conservative," but represents a realistic assessment by experienced execution contractors. Second, the lay rate is affected by weather. As we have previously stated, normal Alaska weather has been factored into the base estimate lay rate. Third, the 3200 feet per day progression cannot be "easily accomplished." The rate of progression is governed by numerous factors identified in this report and the conference discussions which will affect whether the lay rate is ultimately attained. Fourth, we have never stated that the 12½ percent allowance utilized in determining the appropriate number of firing line welders is a contingency, and it is in fact not a contingency. The 12½ percent factor was only one component in the judgmental process by which the execution contractors decided that 34 firing line welders per crew were necessary to realize an average of 40 joints per day.

CONCLUSION

Any projected lay rate is largely the product of a judgemental process and is not susceptible to a precise mathematical determination. The lay rate contained in Alaskan Northwest's July 1, 1980 filing was developed by a team of experts with over 170 years of world-wide pipeline contracting experience, including work under Arctic conditions. Alaskan Northwest sought the help of these EC's in preparing its July 1, 1980 cost estimate because their vast experience would yield the most realistic lay rate and, accordingly, the most reasonable CCE possible. The technical conferences have demonstrated that the projected lay rate is in fact both reasonable and realistic. An informed comparison of our estimate with the actual lay rates from around the world, including Alyeska, shows that our estimate is not overly pessimistic or conservative and may be slightly optimistic. ^{16/} Furthermore, our estimate also compares favorably with that of Foothills' Yukon segment, notwithstanding the differences noted between the two segments. Alaskan Northwest believes, therefore, that its lay rate estimate is fully supported by the manner in which it was prepared and by reference to lay rates actually achieved on other projects.

ALASKAN NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY

November 6, 1980

^{16/} This was also the conclusion of a member of the Cost Committee of the Alyeska owners. See transcript of October 22, 1980 technical conference at 37-38.

McHENRY & STAFFIER, P.C.

ATTORNEYS AT LAW

4TH FLOOR

1300 NINETEENTH STREET, N. W.

WASHINGTON, D. C. 20036

(202) 467-5880

November 3, 1980

Mr. Raymond James
FERC Technical Staff
825 N. Capitol Street
Room 730-A
Washington, D.C. 20426

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

Dear Mr. James:

At the October 23, 1980 technical conference in the above-referenced proceeding, you asked me to obtain from Mr. John Ellwood of Foothills, certain additional information about the Calgary Frost Heave Test Report which was discussed during the October 22 session. The answers to your additional questions are as follows:

1. Question - Please explain why the data on the restrained section is difficult to interpret.

Answer - The empirical frost heave model we are currently developing states that the frost heave rate, or ice segregation ratio, is dependent upon the effective stress at the frost front, as well as other parameters. An in-depth analysis of the pressure effects on the restrained section would require the determination of the stress at the frost front along the entire length of the section for the complete period of its operation.

The determination of the pressure along the pipe is complicated due to the fact that the pipe is tilted and bowed, as shown in the Report. Also, in order

to make such a determination, the size of the frost bulb at all positions along the pipe must be known. This data is not available because temperature strings were placed only at the center of the pipe sections.

Because of these factors, we have not attempted to carry out a detailed analysis of the pressure induced effects on the frost heave on the restrained section. This pressure dependence shows up qualitatively, however, when the frost heave data for the control, deep burial, and restrained sections is compared.

2. Question - Are there any plans to publish additional reports on the Calgary frost heave tests?

Answer - Mr. Lorne Carlson of Foothills, together with Mr. John Ellwood and two co-authors plan to present a report entitled "Field Test Results of Operating a Chilled Buried Pipeline In Unfrozen Ground", to the Fourth Canadian Permafrost Conference, to be held in Calgary in March, 1981. The abstract of the report is as follows:

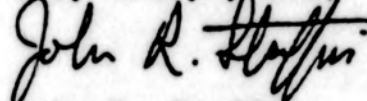
In order to study the behavior of a chilled large diameter pipeline buried in frost susceptible ground, a field test facility was constructed in Calgary, Alberta. This facility, which contained four non-insulated test sections of 1.2 m diameter pipe, buried in frost susceptible soil, has been operational since March 1974. Two insulated sections of 1.2 m diameter pipe were installed in late 1978. This paper describes the placement and instrumentation installed around the pipe sections. Results are presented, of the growth of the frost bulb around the pipe section, together with the heave of the pipe sections and the soil around the pipe. The results of these full scale frost heave field tests have aided in developing an understanding of frost

Mr. Raymond James
Page 3
November 3, 1980

heaving around a chilled pipeline. The results show the effects of increased overburden pressure and decreasing frost penetration rates on frost heave. The seasonal effects of warm summer ground temperatures are also indicated.

If I can be of any further assistance, please contact me.

Very truly yours,



John R. Staffier
Counsel for:
Foothills Pipe Lines
(Yukon) Ltd.

JRS:tdf

cc: All parties on the
restricted service list

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

October 31, 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:

By way of a letter dated October 28, 1980, addressed to you both, Mr. Wadlington of Alaskan Northwest indicated that the promised information on a tunnel under Atigun Pass would not be submitted as proposed. The letter further stated that such material as design feasibility, cost, and risk would not be developed this year due to various difficulties, particularly weather. Mr. Wadlington concluded that should a tunnel approach be ultimately selected, it will be presented to the Office of the Federal Inspector as a design change as defined by Commission Orders 31 and 31B.

The Commission staff is compelled to inform the presiding officers and the parties that it is dismayed and concerned over Alaskan Northwest's failure to provide information on an issue that it has often stated is one of only two that it deemed worthy of addressing for cost and risk consequences.

The potential of a tunnel under rather than a ditched pipeline over Atigun Pass is one of the greatest potential design changes that is known at this time. The staff believes that the order creating this procedure requires that a Certification Cost and Schedule Estimate and a Center Point cannot and should not be determined absent an evaluation of the cost, risk, and potential design of all major, known, and unresolved design issues. (See Order of August, 1980, mimeo at 10).

At the request of the Alaskan Delegate, the Commission staff filed comments in part, on the extent of the design change mechanism and how, or whether, it should be modified. The staff was the only party or participant to state its position on the issue. To avoid unneeded length to this letter, we, at this time, include here by reference those comments and make them a part of this letter.

A change in the proposed Alaskan segment of the magnitude of a tunnel at Atigun Pass is clearly beyond argument a major design change and not a design refinement. As it has been addressed by the Department of the Interior in its right-of-way grant and in the interim report of the Alaskan Delegate, it is clearly an alternative known prior to the granting of any portion of final certification. The interpretation of Condition No. 9 of Order Nos. 31 and 31B by the applicant is just as clearly intended to rush the Commission to the brink of decision on a CCE and Center Point without the information it determined was necessary at the time the IROR orders were issued. Alaskan Northwest's position is seemingly that everything and anything not determined at an arbitrary date set by them becomes a design change. In view of the outstanding major deficiencies in the application, there is no public interest served by hastily rushing to decision on the CCE or CP. Nor is there any support whatsoever in Commission orders for the interpretation of the design change mechanism as espoused by the applicants.

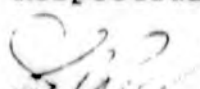
Finally, the brief letter from the applicants fails to respond to two threshold questions:

First, information concerning the Atigun tunnel was initially promised at the first conference commencing on September 3, 1980. At that time, a date of mid-November was indicated for production of the information. On October 2 (Tr. at 34), that date was changed to an earlier date of October 27. Now we are informed, a day after the date the applicant agreed to supply the information, that no information will be submitted in this subproceeding. Therefore, questions arise as to the state of the information, what time next year will it be completed, and why did it take so long to inform all concerned of this new position.

Second, Alaskan Northwest does not indicate the reasons the Design and Engineering Board concluded that "it would be imprudent to submit any cost information at this time" (letter at 2). The letter also begs the question as to why initial cost data and Center Point analysis can not be done with certain geologic and geotechnic presumptions. Even with the meager data furnished to the staff so far, a range of estimates has been formulated to be between one hundred and five hundred million dollars. 1/

In conclusion, the staff believes that this failure of the applicants to provide information on an issue that everyone agrees is major and relevant, more than amply indicates the prematurity of determining a CCE and Center Point. Particularly, this failure precludes evaluation of the most major potential design alternative known at this time. Should this situation continue, the staff believes that the Delegate's report must conclude that a CCE and Center Point cannot be determined without further proceedings due to the very unsettled state of the design and evaluation of major alternatives. As required by the Commission Order granting the subproceeding: "The deliberations at the Conferences shall be based on the most current pipeline design alternatives, and the final report shall be based on the pipeline design that is current as of the date of the final conference, including all major design alternatives under consideration by the project sponsors, whether or not such design alternatives are identified in the application." (See, Order discussed August 1, 1980, mimeo at 12).

Respectfully,


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

cc: Restricted service list

1/ Staff further raises the question, ab initio, of producer participation on the Design and Engineering Board, when the same is clearly in violation of the President's Decision (p. 38) and ANGTA.

NORTHWEST ALASKAN PIPELINE COMPANY

1170 20th Street, N.W.
Suite 5100
Washington, D.C. 20037
(202) 671-0280

REA-80-1084

October 28, 1980

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

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

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

Gentlemen:

In its July 1, 1980 application for a final certificate for public convenience and necessity authorizing construction and operation of the Alaskan segment of the ANGTS, Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest") proposed to traverse the Atigun Pass in Alaska with the use of a chilled buried pipeline. The particular route chosen was along the haul road with the installation of the pipe inside the bar ditch of the haul road. The location along the haul road was selected because it has been shown to be a relatively stable area. This is in contrast to most of the rest of Atigun Pass which is geologically known as an area of unstable and unique soils.

Since the submission of the original filing, Alaskan Northwest has commenced an investigation of the feasibility of tunnelling Atigun Pass and the development of a cost estimate for such tunnelling. Alaskan Northwest has contracted with Michael Baker, Inc. to determine the geology of the general area of Atigun Pass, to examine which of several tunnel routes might be feasible, and to recommend a specific route for thorough investigation. After examining five possible tunnel routes, Michael Baker picked the specific route they believed should be investigated.

In order to evaluate the tunnel route selected and prepare a reasonable cost estimate, it will be necessary to drill deep boreholes over the approximate 22,000 feet of tunnel distance and portal holes to a depth of about 100 feet all to sample the type of rock and soil to be encountered. The initial program is to drill eight deep holes and two portal holes with any additional drilling to be determined by the results of this work.

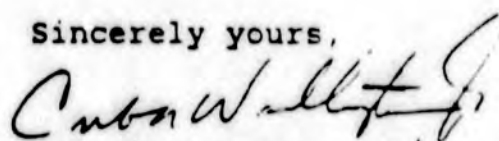
Unfortunately, the weather in Atigun Pass has made operations very difficult. There is already four-to-five feet of snow in the general area and the entire drilling operation has had to be supported by helicopter. If the evaluation of the initial two holes justifies further investigation of the route selected, drilling will be commenced on six additional deep holes and two portal holes. These holes cannot be completed this year because of the adverse weather. Therefore, the comprehensive drilling data and laboratory analyses needed both to confirm the route selection and to prepare a reliable cost estimate will not be available until next spring. It should also be noted that another route has recently been suggested by a representative of the Office of the Federal Inspector. If that route is also pursued, it would require a complete new investigation with the drilling of both portal and deep holes in that route area.

While a reliable cost estimate could not be prepared without detailed drilling data, it was anticipated that a relatively reliable cost range might be developed by a surface examination and review of existing geological information. On October 23, 1980, the Design and Engineering Board determined that the unknowns involved in estimating the tunnel cost required the development and analyses of all necessary geological data. Further, that without such data, it would be impossible to make a risk analysis. The Board therefore concluded that it would be imprudent to submit any cost information at this time.

Alaskan Northwest intends to complete the required drilling and geological analyses as soon as possible next year and then make a cost estimate for the tunnelling approach. In the event the tunnelling approach is ultimately selected over the method currently contemplated, it will be presented to the Office of the Federal Inspector for approval as a design change pursuant to the terms of Condition No. 9 of Order Nos. 31 and 31-B.

If you have any further questions in this regard, please do not hesitate to contact me.

Sincerely yours,



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

CW/paw

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

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

SUPPLEMENTAL INTERROGATORIES PROPOUNDED
BY THE COMMISSION STAFF

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, specifically 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. How does Applicant intend to measure or monitor the actual pipe strain due to frost heave once the pipeline is buried?
2. Please provide the pipe specifications, including toughness and the bases of bid supplied to each vendor submitting quotations.
3. What role has the Design and Engineering Board played in the management and/or operations of the project?
4. What is the best available range of estimated costs associated with tunneling Atigun Pass?
5. When is it anticipated that precise costs estimation can be available for tunneling Atigun Pass?
6. What cost savings were effected by reducing from 8 to 7 the number of planned compressor stations, and please identify the stations you intend to build initially.
7. What cost change was effected by the 25% increase in refrigeration capacity and doubling of electrical generation capacity (p. K-8-1)?
8. What cost change was effected by the increased building size and standby design, as well as increased water, sewer, and waste disposal design of planned compressor stations?
9. Why does the 1980 estimate contain such radical cost increases over the 1977 estimate for disposal site development, disposal erosion control, and revegetation?
10. Why was the cost of access roads underestimated so substantially in the 1977 estimate?
11. Please elaborate on the reasons the 1977 estimate contained no specific estimates for ditch insulation, as-built surveys, string river weights, oil spill cleanup, nor Atigun Pass.

12. Please explain in greater detail individually the following cost estimate increases:
 - (a) Total construction equipment increased 180%;
 - (b) Total indirect labor increased 350%;
 - (c) Parts and tires increased 306%;
 - (d) Maintenance increased 614%;
 - (e) General haul increased 776%;
 - (f) Aerial crossings increased 294%;
 - (g) Royalties increased 372%;
 - (h) Overhead and profit increased 255%; and
 - (i) Total land rights increased 227%.
13. Please elaborate in greater detail why the following were not accorded any value in the 1977 estimate and received the following quantification in the 1980 estimate:
 - (a) Ditch insulation, \$31 million;
 - (b) Epoxy costs, \$60 million;
 - (c) Project management, \$403 million; and
 - (d) Field programs, \$42 million.
14. Please explain the increased thickness now estimated for the workpad along the Haines Right-of-Way.
15. What geotechnical considerations dictated the increased estimation of required backfill from 3.6 million to 7.02 million cubic yards?
16. Please elaborate in greater detail the increases in estimated ditch excavation from 9 million to 13 million cubic yards.
17. Please elaborate in detail the causes necessitating the increase in estimated use of insulated pipe/field joints from 105 to 156 miles.
18. Please elaborate the decreases reflected by the estimate in select material haul, as well as the increase in workpad embankment haul, and increased estimated internal pipe coating.
19. Please explain the adjustment entry (pk-13-16) for the Yukon River Bridge for 2,300 linear feet.
20. Please identify the presently selected sites for frost heave testing, elaborating in detail when they have or will be constructed, and when results from the several tests sites can be first anticipated.
21. Please attach copies of all stipulations between applicant, or its agents, and any state or Federal agencies with regard to this project.

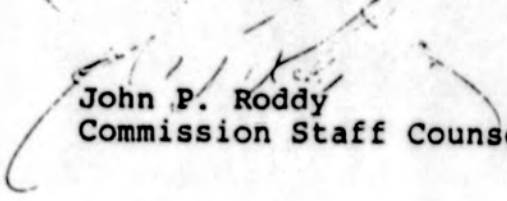
22. With respect to refrigeration specifications sent to vendors, please provide:
- (a) Inlet temperature of gas stream;
 - (b) Required outlet temperature;
 - (c) Rate(s) of change of inlet temperature of gas stream;
 - (d) Data on response to upset conditions;
 - (e) Flow diagrams;
 - (h) Physical arrangements other than outside dimensions;
 - (g) Turn down ratio or rates of change; and
 - (h) Requirements of extended shut down for winter operation.
 - (i) Are Applicant's refrigeration calculations predicated on insulated or uninsulated pipe?
23. How much of the refrigeration data contained in the filing was provided to vendors, and what data in excess of that filed did they receive?
24. A) To what degree was the Alyeska manhour and cost information considered in estimating the cost of Applicants' projected compressor and metering stations? (B) Please explain the bases upon which the ratio of manhours to total costs for Alyeska's pump stations and terminals is exceeded so substantially by the ratio of estimated manhours to total cost for NWA's compressor and metering stations.
25. Does Applicant intend to remove the \$1.548 million entry from the CCSE as filed now that it no longer intends to purchase Pump Station #1?


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 6th day of November, 1980.


John P. Roddy
Commission Staff Counsel

NORTHWEST ALASKAN PIPELINE COMPANY

DARRELL B. MACKAY
VICE PRESIDENT
REGULATORY & GOVERNMENTAL AFFAIRS

September 29, 1980
REGA 80-1144

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Richard Berman
Director, Office of Audit & Cost Analysis
Office of the Federal Inspector
1200 Pennsylvania Avenue, N.W.
Washington, D.C.

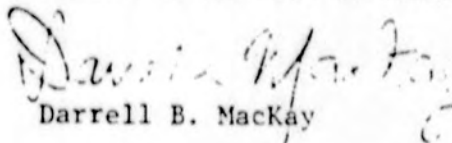
Re: Alaskan Northwest Natural Gas Transportation
Company - Docket CP80-435

Gentlemen:

Attached is a letter from the Design and Engineering Board describing why the July 1, 1980, filing by Alaskan Northwest Natural Gas Transportation Company in Docket CP80-435 is a valid basis to proceed. This letter along with our comments filed this same date constitute the material to be submitted in response to your questions at the conference on September 3 and 4, 1980.

Very truly yours,

NORTHWEST ALASKAN PIPELINE COMPANY


Darrell B. MacKay

DBM/dm

Attachment

cc: Restricted Service List

NORTHWEST ALASKAN PIPELINE COMPANY
1801 K Street, N.W.
Washington, D. C. 20005
(202) 455-5650

September 18, 1980

Mr. Darrell B. MacKay, Vice President
Regulatory and Governmental Affairs
Northwest Alaskan Pipeline Company
1801 K Street, N.W., Suite 901
Washington, D. C. 20006

Dear Mr. MacKay:

On July 1, 1980 Alaskan Northwest Natural Gas Transportation Company filed in Docket No. CP80-435 an application under the Natural Gas Act and the Alaska Natural Gas Transportation Act of 1976 for a certificate of public convenience and necessity authorizing construction and operation of the Alaskan segment of the ANGTS. On August 1, 1980 the Commission issued its "Notice of Application and Order Establishing Procedures" directing the Commission's Alaskan Delegate to convene a series of technical conferences to consider the Certification Cost and Schedule Estimate and Center Point proposed by Alaskan Northwest and prepare a report to the Commission at the conclusion of such conferences. In its Notice the Commission stated that the deliberations at the conferences should be based on the "most current design alternatives," and that the Delegate's Report should be based "on the pipeline design that is current as of the date of the final conference, including all major design alternatives under consideration by the project sponsors...."

At the first technical conference, held September 4, 1980, the Alaskan Delegate requested Alaskan Northwest, and its operating partner Northwest Alaskan, to state on or before September 29, 1980 what design changes, if any, were being contemplated by the Design and Engineering Board for the Alaskan segment of ANGTS and which were not reflected in Alaskan Northwest's July 1, 1980 certificate filing.

The purpose of this letter is to inform you that the Board does not presently contemplate any major design changes in the pipeline design of the Alaskan pipeline segment of ANGTS, as submitted by Alaskan Northwest in its

July 1, 1980 filing, except as to (1) changes now being made as required by the proposed Department of Interior right-of-way grant which specifies a minimum separation of 200 feet, with certain exceptions, from the Trans-Alaska Oil Pipeline system, rather than 80 feet separation distance applied for by Alaskan Northwest; and (2) changes which may occur as a result of studies now being made at Atigun Pass.

The Board is currently engaged in an extensive review of the entire Alaskan segment of ANGTS, and should further design changes be necessary or desirable, the Commission and participants in the technical conferences will be fully and timely apprised. Additionally, should appropriate authorities determine that the plant required to condition natural gas for delivery to the ANGTS be a part of the system, the Board will fully inform the Commission of the changes necessary to accomplish that objective.

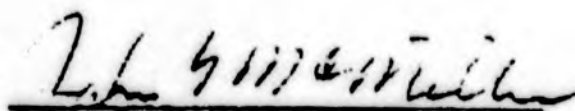
Based upon all the foregoing, the Board believes that Alaskan Northwest's proposed design is a valid basis upon which the technical conferences can proceed and the Commission can review the CCE and Center Point requested.

We hope this letter is responsive to the concerns voiced by the Alaskan Delegate at the September 4 conference.

Sincerely yours,

THE DESIGN AND ENGINEERING BOARD

By



John G. McMillian, Chairman
Northwest Alaskan Pipeline Company,
Operator

See #13 pg 6

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 *Eula Gusman 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

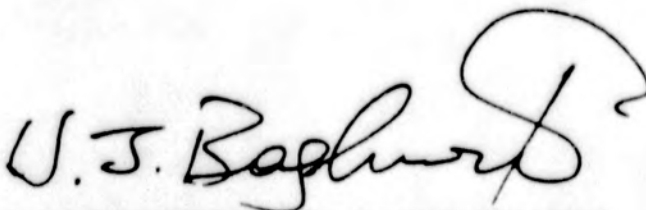
09-TR-0006-3

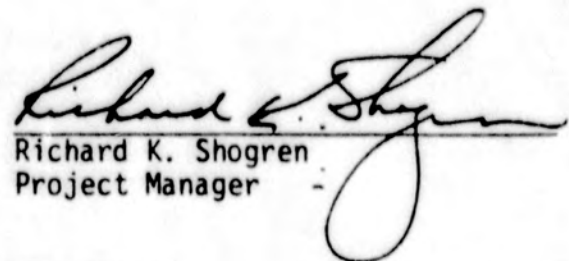
WBS 1.01.22.02

CONTRACT NUMBER

OFI 80-0001

October 1980


for Achraf M. Mirza
Engineering Manager


Richard K. Shogren
Project Manager

UNIFIED INDUSTRIES, INCORPORATED
2222 Martin Drive
Irvine, California 92715

TABLE OF CONTENTS

<u>Section</u>	<u>Page</u>
1.0 INTRODUCTION	1
2.0 TECHNICAL AND ENVIRONMENTAL ISSUES	2
3.0 ORGANIZATIONAL AND SCHEDULE ISSUES	8

1.0 INTRODUCTION

The Northwest Alaskan Pipeline Company's (NWA) certification cost estimate submitted to the Federal Energy Regulatory Commission (FERC) for the construction of the Alaskan segment of the Alaska Natural Gas Transportation System (ANGTS) contains a substantial amount of information regarding 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
ROOM 2413, POST OFFICE BUILDING
1200 PENNSYLVANIA AVENUE
WASHINGTON, D.C. 20044

OCT 7 1980

MEMORANDUM

TO: John Adger
Alaska Delegate

FROM: *Paula Chapman 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.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Alaska Northwest Natural Gas
Transportation Company

Docket No. CP80-435

Notice of Technical Conferences
(October 10, 1980)

Notice is hereby given of the scheduling of further technical conferences to consider for rate of return purposes the materials filed by the sponsors of the Alaska segment of the Alaska Natural Gas Transportation System in this docket on July 1, 1980, as well as certain supplementary materials expected to be filed during the course of the conferences. These conferences are being held pursuant to the Commission's order issued in this proceeding on August 1, 1980.

Four additional conferences are being scheduled at this time. The first will cover the methodology utilized by the project sponsors to develop the normal contingency and center point values contained in the July 1 filing. That conference will convene at 8:30 a.m. on Thursday, October 16, 1980 at the Commission's offices in Washington, D.C. The conference will be in the nature of an informational session such as was held in mid-September on other subjects, and is expected to last only one day. There will be no moderator for this session, and no transcript will be taken, although conference participants will be asked to summarize it for the record at the conference beginning on October 28, 1980 (see below). The precise location of this conference at the Commission's offices will be posted on the day of the conference, on the second floor bulletin board at 825 North Capitol Street, Washington, D.C. Further information about this conference can be obtained from Miss Jeanne Barrie at (202) 357-8900.

The next succeeding conference will be held at the headquarters of the Fluor Corporation at 3333 Michaelson Drive, Irvine, California. It will begin at 8:30 a.m. on Tuesday, October 21, 1980. The conference will address the following subjects from the sponsors' July 1 filing, in order:

- (1) compressor and metering facilities;
- (2) operation and maintenance (O&M) facilities;
- (3) temporary facilities and services;

- (4) communications and supervisory systems;
- (5) frost heave--problem definition and mitigation techniques;
- (6) pipeline installation productivity ("lay rate");
- (7) any other subjects covered by the "pipeline" portion of the July 1 filing.

This conference is expected to last three (3) days. It will be moderated and a summary transcript will be prepared, as agreed to by the Alaskan Delegate and the Office of the Federal Inspector (OFI) Division Director at the first of these conferences. The precise location of the conference will be posted at Fluor's headquarters on the day of the conference, and can be obtained in advance by calling Frieda Whiteside at (714) 975-6032.

The third conference will be held at the Commission's headquarter's in Washington, D.C., beginning on Tuesday, October 28, 1980 at 10:00 a.m. This conference will begin with a report on the information conference of October 16, and proceed to consideration of, and any appropriate discussion about, the methodology and parameters utilized by the project sponsors to develop the normal contingency and center point values contained in the July 1 filing. The conference will then consider and discuss the design and scope change processes as specified in the Commission's Orders No. 31 and 31B in Docket No. RM78-12, and as interpreted in the project sponsors' July 1 filing. The conference will then consider the project directorate category of costs contained in the sponsors' July 1 filing.

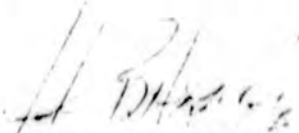
This conference will be moderated and a summary transcript will be prepared. It is expected to be adjourned no later than Friday, October 31. Certain preliminary materials to be considered in this conference, prepared by the Alaskan Delegate and the OFI Division Director, will be filed and served on all parties to this proceeding during the week of October 13. The precise location of this conference at the Commission's offices will be posted on the day of the conference, at the location specified above. Further information about this conference can be obtained from Miss Barrie at (202) 357-8900.

The final conference to be scheduled at this time will begin at 1:30 p.m. on Wednesday, November 12, 1980 at Fluor's headquarters in Irvine, California. This conference will begin with consideration of the revisions to the July 1 filing occasioned by the August, 1980 decision of the Department of the Interior to require a minimum separation of 200 feet between the gas pipeline and the Trans-Alaska Oil Pipeline System (TAPS), rather than the 80 feet minimum separation contemplated by the July 1 filing. The conference will then consider

potential revisions to the July 1 filing which would be occasioned by a decision to use a tunnel of approximately 2-1/2 miles in length to transit the Brooks Mountain Range in Northern Alaska rather than the Atigun Pass as was contemplated by the July 1 filing. Supplementary materials to be prepared by the project sponsors for consideration in these discussions are to be made available by the sponsors to the parties to this proceeding no later than October 27, 1980.

The conference will then proceed to discuss other potential design changes and pipeline adjustments, center point and contingency and finance charges as contained in the July 1 filing, and any other issues or subjects remaining from prior conferences. The conference will continue through Friday, November 14, 1980 and resume on Monday, November 17, 1980 continuing on through that week until the subject matter is exhausted. It is expected that the conference will not continue past Friday, November 21, 1980.

This conference also will be moderated and a summary transcript prepared. The precise location of this conference will be posted at Fluor's headquarters on the day of the conference, and can be obtained in advance by calling Ms. Whiteside at (714) 975-6032.


John B. Adger, Jr.
Alaskan Delegate

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 representatives 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:

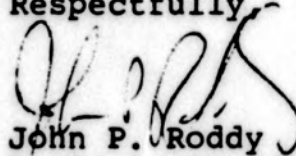
Compressor Station	Milepost	Chiller Load-Tons	
		NWA	Staff
No. 15	684.92	7970	7706
No. 13	579.69	7197	5740
No. 11	494.15	7809	6760
No. 9	380.93	7708	6970
No. 7	273.93	7942	7834
No. 4	141.32	3717	3283
No. 2	80.06	4013	3778

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	Change "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

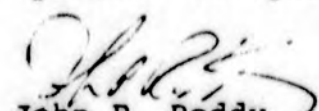
3	16	Change to "... trial staff".
3	21	Change to "...trial staff".
9	9	Change to "unk-unks, unknown-unknowns..."
17	1	Change "acknowledged" to "knowledgeable".
28	9	Delete "that".
29	4	Delete "not".
47	18	Change "whish" to "which".
48	2	Change "possible" to "impossible".
54	21	Change "always" to "also".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

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/}

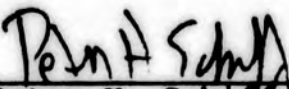
By the December 15, 1980 Show Cause order "interested persons" disagreeing with the data and opinions of the Office of the Chief Accountant were given 60 days to respond. But no

^{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



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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

MARK

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Alaskan Northwest Natural Gas)
Transportation Company)

Docket No. CP80-435

REPLY COMMENTS OF
ALASKAN NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY

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

Richard Berman, Director
Division of Audit and Cost Analysis, OFI

On July 1, 1980, Alaskan Northwest Natural Gas Transportation Company filed its application for a final unconditional certificate of public convenience and necessity to construct and operate the Alaska segment of the Alaska Natural Gas Transportation System (ANGTS). Therein, Alaskan Northwest seeks (1) approval of its Certification Cost Estimate (CCE) and Center Point request; (2) utilization of the labor index or indices explicitly defined in the terms and conditions of the Project Labor Agreement to deflate actual project labor costs; and, (3) adjustment of the CCE to reflect the actual third-party monitoring and other government related costs in calculating the Cost Performance Ratio.

In its order of August 1, 1980, the Commission agreed to resolve these outstanding Incentive Rate of Return parameters, including the Certification Cost Estimate and Center Point, in advance of the filing of the financing plan and accompanying cost of service, marketability, and other economic support necessary for a final determination that the ANGTS continues to be in the national and public interest. The Commission also ordered the convening of technical conferences to be presided over by the Alaskan Delegate and the Director, Division of Audit and Cost Analysis, Office of the Federal Inspector. Pursuant to this directive more than 20 days of technical conferences were held in Washington, D.C. and Irvine, California, commencing September 3 and concluding on November 20, 1980. At the close of these conferences the Delegate asked the Commission Trial Staff to file a report by December 15, 1980 setting forth the Staff's positions on issues developed during the conferences. The Delegate provided Alaskan Northwest an opportunity to file a response to Staff's positions on December 22, 1980. These Reply Comments respond to the positions taken by Staff in its December 15 comments on the unresolved issues in accordance with the procedures established by the Delegate.

Staff agrees with Alaskan Northwest's \$7,302 million engineering estimate and with the basic methodologies utilized in establishment of the normal contingency and Center Point. Essentially, Staff's dispute with Alaskan Northwest's filing is limited to the following contentions:

Normal Contingency

1. A more rigorous encoding procedure should have been used for approximately eight percent of the 720 cost elements analyzed in the development of normal contingency.
2. The use of calibration should not have been used to compensate for central bias.
3. The expected values for five of the 720 cost elements are too high.

Center Point

1. Abnormal Event No. 36, "Unknown-Unknown Events," should be eliminated because presently unknown events will not occur, inclusion of this event would render the project risk free, and because Staff fears a dangerous precedent will be set for conventional pipeline projects.
2. The expected cost impacts from certain other abnormal events must be eliminated or reduced because these impacts have already been accounted for elsewhere in the engineering estimate or contingency.

In addition Staff requests the following modifications to Order Nos. 31 and 31-B and the IROR mechanism itself: (1) a reduction of the CCE to the extent of any cost savings realized from design changes ordered by OFI, and (2) ascertainment by OFI whether the additional costs resulting from design changes are already covered by the normal contingency. Finally, Staff continues to recommend consideration of certain alternative designs for construction of the Alaska segment.¹

Staff's contentions and requests will be answered in detail. At the outset, however, it must be observed that Staff's positions, and the arbitrary reductions

¹ During the course of the technical conferences the OFI submitted two documents describing 25 design issues and indicating that these were the type of issues Alaskan Northwest should consider during the detailed final design process. The Delegate requested that Alaskan Northwest respond to the matters raised by OFI and such response was submitted on December 15, 1980. Most of these items involve refinements of the filed design that may occur during the final design process. Any design changes resulting from this process will be administered by OFI in accordance with Condition No. 9. However, in Alaskan Northwest's view, none of these possible changes would so alter the basic nature of the system that such changes would call for an alternative CCE and Center Point value. Similarly, certain design changes for areas currently under study, such as the best method for crossing the Brooks Range (the tunnel alternative), the use of the Yukon River Bridge, and pipe metallurgical design (crack arrestor alternative) are not issues requiring alternative CCE and Center Point values. Therefore, in responding to Staff's comments, Alaskan Northwest proposes that only one CCE and Center Point be established.

proposed to the CCE and Center Point values even where ample justification and support for such values was provided to Staff, evidence either a misunderstanding of or a refusal to accept the IROR mechanism and the concepts embodied in Order Nos. 31 and 31-B. Obviously, without an understanding and acceptance of these concepts, one will not understand and appreciate how the CCE (i.e., engineering estimate plus contingency) and Center Point were developed and prepared.

In Order No. 31 the Commission outlined the purpose of the IROR mechanism as follows:

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...Cost estimates for most large projects tend to increase as more is known about the detailed design of the system....

The Commission's problem is to be fair to the project sponsors, given the realities of the cost estimation process, while protecting gas consumers from being exposed to an uneconomic project. 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.

The Commission views the IROR mechanism as one of a number of policy tools that the Federal government will use to ensure that the construction of the ANGTS continues to be in the public interest. The Commission believes that the IROR mechanism it has developed can legitimately be expected to achieve the following objectives:

- o the development of the best possible cost estimates prior to commencement of construction; and
- o the provision of a workable incentive to construct the ANGTS within the parameters provided by approvals or authorizations which may be granted by the Commission and the Federal Inspector.

Order No. 31 at 15-17.

The Commission further stated why the IROR mechanism will provide the most appropriate balancing of benefits between the Sponsors and the consumers:

In competitive industries the rate of return on equity is usually related to cost control. The IROR attempts to establish the same rate-control relationship in a regulated situation. To reach this goal, the Commission has made use of the following principles in designing the IROR:

- the IROR should provide incentives to reward cost control performance and avoid or minimize cost overruns;

- o the IROR should provide just and reasonable compensation for investors so that sufficient capital may be attracted to finance the project; and,
- o the cost to consumers should be lower where cost overruns have been minimized and investors have received an incentive return.

Id. at 22.

In acceptance and reliance on the above Commission statements Alaskan Northwest took steps to develop the most realistic possible cost estimate within the framework of the IROR mechanism. First, Alaskan Northwest assembled a team of highly experienced and capable cost estimators, cost engineers, design and process engineers, and other experts representing every discipline necessary for designing, engineering, constructing, and controlling the cost of a unique "mega" project. This group includes the key experts involved in constructing TAPS and practically every other major construction effort in Alaska and Canada, as well as multi-billion dollar projects around the world. The result of the efforts of this group of experts is the most accurate possible CCE and Center Point that could be constructed at this time.² A synopsis of the CCE and Center Point as filed and as amended to reflect the costs of reroutes required by the Department of Interior's Right-of-Way Grant is as follows:

	1980 \$ (Million)	
	<u>As Adjusted</u>	<u>As Filed</u>
Engineering Estimate	\$7,302	\$7,050
Contingency Estimate	<u>876</u>	<u>846</u>
Base Estimate	<u>8,178</u>	<u>7,896</u>
Expected Value of Abnormal Events	<u>2,304</u>	<u>2,304</u>
Contingency Percentage	<u>12%</u>	<u>12%</u>
Center Point Ratio	<u>1.282</u>	<u>1.292</u>
Potential Design/Scope Change	<u>Unquantified</u>	<u>Unquantified</u>

The CCE and the Center Point were based upon the "Four Basket" concept envisioned in Order Nos. 31 and 31-B. That is, Alaskan Northwest has conscientiously segregated the expected cost of the project into four separate categories -- engineering estimate, the contingency estimate (normal events), the Center Point request (abnormal events), and design and scope changes.

The engineering estimate was based upon a preliminary design with scope of work detailed drawings, material take-off, productivity rates, equipment reliability, material and labor prices, and schedule of activities.

² Regarding Staff's implicit suggestion that a final design be prepared prior to Commission certification, we would note that the Sponsors cannot place at risk the costs associated with preparation of a final design -- an amount in excess of \$1.5 billion -- without a final certificate approving a CCE and Center Point. Additionally, neither the President in his Decision and Report nor the Commission in Order Nos. 31 and 31-B contemplated such a result.

The contingency amount was based upon in-scope (normal uncertainties associated with the estimate of each cost value.

The Center Point request was based upon uncertainties resulting from abnormal or unexpected events which impact costs.

The potential design and scope changes were identified on the basis of design and scope changes which may occur during planning, permitting, and construction of the project. Design changes represent changes occurring subsequent to the CCE, but prior to final design approval. Scope changes represent changes that occur after final design approval.

In accordance with the intent of the IROR mechanism, the CCE and Center Point must be viewed as one entire package with several independently developed parts, yet interdependent upon each other. If the integrity of one basket is upset, the integrity of the remaining baskets are affected.

Even though Staff has indicated agreement with the engineering estimate portion of the CCE, it has done so in a fashion that critically disturbs the integrity of the other baskets within the whole IROR mechanism. Its agreement is premised upon the erroneous assumption that there is overlapping of the baskets, that is the same elements of cost may be included in more than one basket. Nothing could be further from the truth. The manner in which each basket was prepared assures that no double-counting or encroachment occurred. Staff's erroneous assumption has led it to a totally unacceptable conclusion -- a contingency of 7.1 percent and a Center Point of 1.184. (Staff's Center Point properly calculated would be 1.172. See page six.)

Staff's first evidences its misunderstanding of how the CCE and Center Point were derived on page three of its comments. There Staff describes the engineering estimate as being the base estimate. Yet the base estimate is equal to the sum of the engineering and contingency estimate. The engineering and contingency estimate together constitute the expected cost of the project, as defined in-scope, and the normal uncertainties surrounding the defined scope. Therefore, the base estimate can only be defined to include both. This is a significant point to understand because of the effect it has on the determination of the Center Point.

Staff then suggests that future design changes should not have the approved contingency percentage applied to the cost impact and that the normal contingency must be evaluated in the future to determine whether the costs of future design changes have already been accounted for in that contingency. These proposals again illustrate Staff's misunderstanding of the estimate. It is fundamental that a design change as well as the initial engineering estimate is subject to: 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.

Alaskan Northwest would agree that as the design process moves forward the CCE, as based upon the filed design, will increase, thereby reducing the absolute dollar amount of contingency as well as the percentage relationship. Indeed, the Commission itself recognized this fact. (See Order No. 31 at 15-17.)

Yet, any future design changes by definition can bear no relationship to in-scope estimating uncertainties for the existing design, but would relate only to the newly proposed design component. As such, these costs by definition are not covered by Alaskan Northwest's filed normal contingency. The difference between Staff's suggestion and what is proper should be clear. Therefore, the suggestion must be rejected.

Staff's analysis of the July 1, 1980, estimate provides further evidence of its basic misunderstanding of the IROR mechanism. On page three of its comments, it sets out the following chart as representing the Alaskan Northwest request:

	<u>Dollars (MM)</u>	<u>Percent of Base Estimate</u>
Base Estimate 7/1/80	7,050	
Contingency	846	12.0
Center Point	<u>2,271</u>	<u>32.2</u>
Total	10,167	44.2

Staff's analysis suggests that the Center Point should be based upon \$2,271 million (this number should actually be \$2,304 million) divided by \$7,050 million (engineering estimate) which results in a ratio 1.322 (if the proper expected value for abnormal events of \$2,304 million had been used the 1.322 would have been 1.326) as compared to Alaskan Northwest filed ratio of 1.292. Staff's approach to determining the Center Point would improperly inflate the Center Point in violation of Order Nos. 31 and 31-B.

Staff also requests that Order Nos. 31 and 31-B be amended to require that the CCE be reduced to the extent of any net savings realized from design changes ordered by OFI. (Staff comments at 31.) This request is extremely short-sighted. The Commission exercised considerable forethought in designing the IROR mechanism. The mechanism as it presently stands would provide the best incentive for the Sponsors to reduce costs while benefitting the consumer at the same time. The following chart indicates the positive relationship between cost reduction, the Sponsors return, and consumer benefits:

<u>Capital Cost Reductions (\$ Million)</u>	<u>Decrease in Annual Cost of Service (\$ Million)</u>	<u>Decrease in Annual Cost of Service (\$MMBTU)</u>	<u>Increase in Incentive Rate of Return (%)</u>
\$ 50	\$ 4	\$.02	.05
100	8	.04	.10
200	16	.08	.20
300	24	.12	.29
500	40	.20	.50

This chart supports the Commission's intent in establishing the IROR mechanism, and that intent should not be vitiated because of an erroneous perception by Staff that only the Sponsors would benefit from cost reductions resulting from approved design changes. To put this in perspective, in the case of a cost reduction of \$500 million, benefits over the life of the project would be approximately \$437 million for the ratepayer and \$63 million for the Sponsors.

In summary, Staff's approach to this subproceeding is simply that the Sponsors should not be given even the opportunity to earn the center rate of return on equity already established for this project in Order Nos. 31 and 31-B. Staff's disagreement with the end result reached by the Commission in those orders stems from its continuing belief that the ANGTS is a conventional pipeline project and should be treated as such.³ This belief and the desire to revise substantially the IROR mechanism renders Staff incapable of objectively evaluating the CCE and the Center Point request.

³ See, e.g., Staff's comments at page 20 where it states that "...the [Alaska] project is not sufficiently different from a pipeline such as Northern Border...." Suffice it to say that it should not be necessary to read-dress herein the many reasons why this project is different from Northern Border and other lower 48 pipeline construction. The Commission has recognized these differences time and again in Order Nos. 31 and 31-B. See, e.g., Order No. 31 at 63, 70-71, and 79-80.

I. NORMAL CONTINGENCY

The Staff agrees with Alaskan Northwest's probabilistic approach to the development of normal contingency, including the basic probability encoding process utilized. In addition, the Staff has independently verified the mathematical computations which support the submitted normal contingency. Thus, Staff's concerns are limited to the following: (1) its belief that a more rigorous encoding process was necessary for certain cost elements⁴; and, (2) the use of calibration to compensate for central bias. Substituting its judgment for that of the estimators, the Staff has also proposed specific modifications to several cost elements. Each point will be addressed separately.

A. Probability Encoding Process

While the Staff does not take issue with utilization of the probability encoding process, it alleges that the results reached may not be valid because "[a]ll encoding was accomplished in approximately 36 hours, for an average of three minutes per cost element" and that "[n]o attempt was made to verify the results after encoding." (Staff comments at 5.) Both statements are a gross distortion of fact.

First, the encoding process was completed not in a few hours, but over a period of a month, which allowed the experts sufficient time to evaluate thoroughly and reach agreement on the uncertainties inherent in each activity. The average attendance at any one encoding session was approximately eight persons, and the total direct encoding effort represented approximately 300 man-hours of direct effort. Overall, more than 50 individuals were involved in various encoding sessions.⁵ In addition, hundreds of additional hours were spent prior to the encoding process. Much effort was spent in describing to the experts the encoding process, the definitions of the four baskets -- engineering estimate, contingency, Center Point, and design and scope changes -- and the values the experts were encoding. Substantial effort was also spent in casting the engineering estimate into meaningful activities and cost elements which could be used for encoding. The resulting breakdown was consistent with the project Work Breakdown Structure and was composed of more than 300 cost activities that fully defined the scope of the project.

Because the encoding sessions occurred in the last month of an intensive six-month effort to estimate the project cost components, these 50 individuals collectively spent over 50,000 man-hours with the specific cost estimates for which in-scope estimating uncertainties were assessed. It is important also to point out that most participants had at least 20 years in the engineering, design, and construction of large projects and many had prior experience with constructing pipelines and other projects in Alaska. With regard to the verification of results,

4 At the November 12, 1980 technical conference, Staff's consultant Mr. Anderson stated that Staff believed a more rigorous analysis would be necessary for only 60 out of the 720 cost elements.

5 The participants included cost estimators, design engineers, cost engineers, and members of Fluor and Northwest Alaskan management.

each session ended with a consensus among experts and a review of values for consistency. In certain instances where the encoded values appeared inappropriate, the experts were re-interviewed.

Second, a brief review of the encoding process demonstrates the significant and time-consuming effort that took place and should suffice to dispel Staff's concerns. Each encoding session covered the following sequence of steps: (1) a general review of the quantities to be encoded and their relationships; (2) instruction to participants; (3) discussion and clarification of instructions; (4) individual estimation; (5) reaching a consensus among session participants; and, (6) review of values for consistency.

The instructions provided to each participant in the encoding sessions were as follows: (1) normal in-scope estimating uncertainty should include accuracy of material quantities, accuracy of material prices, human productivity assumptions, equipment reliability assumptions, engineering/design development, normal schedule variance, and accuracy of bid specifications based on current project definition; (2) normal in-scope estimating uncertainty does not include impacts from abnormal events, impacts from design changes, or impacts from changes in scope; (3) an abnormal event does not include impacts from in-scope estimating uncertainty, ripple effects from other abnormal events, design changes, or changes in scope; (4) values encoded represent the subjective judgement that there is a 10 percent probability that costs could be x percent below the engineering estimate and that there is a 90 percent probability that costs will not exceed y percent above the engineering estimate; and, (5) encoded values include the impact on real costs (other than inflation costs) resulting from schedule delays.

The costs used to establish the modal values were the same as those used in the engineering estimate, except where costs were expanded or contracted to an appropriate level of detail. The values were carefully checked to assure that the total of costs input into the computer model equaled the engineering estimate. In addition, costs within each activity were broken down into the different types of resources included in that activity. For example, most pipeline activities include four cost subcategories: labor; construction equipment; spare parts and other materials; and, fuel, oil, and lube.⁶

After costs had been determined for each activity, the groups of experts met to establish the in-scope estimating uncertainties associated with each cost value. Abnormal events and design and scope changes were defined before starting the encoding process, and in-scope estimating uncertainty was carefully defined to separate its impact on project costs from the impact of unexpected events, design changes, and changes in scope. Uncertainties were expressed as percentages of the values contained in the engineering estimate. Confidence ranges were established at the ten percent probabilities of occurrence.

After an introductory review discussion of the way in-scope estimating uncertainty fits into overall project uncertainty (including abnormal events, design changes, and changes in scope), the experts began encoding their judgments. Each activity was discussed separately, leading to agreement on the percent change that could be expected for each activity.

⁶ The further subdivision of the 300 activities into these components yields the total 720 cost elements which were analyzed in developing contingency.

Schedule impact of cost uncertainties was reflected by adjusting the range of each activity's cost to reflect the potential for schedule variation, and activities which were time-sensitive were identified. The cost range was adjusted to reflect time uncertainties under the assumption that potential delays would cause an increase in effort (and therefore, dollars), but the activity would be completed as scheduled. No adjustments were made to cost ranges for those activities which were not time-sensitive. --

In summary, the above-described encoding process provided ample time for the experts to assess in-scope estimating uncertainties and provided for verification of their projections.

B. Adjustment for Central Bias

Central bias among estimators is a widely demonstrated phenomenon and can be compensated for by training or by calibration. Given the many participants involved in the probability encoding process, Alaskan Northwest chose to calibrate the stated probability inputs rather than attempt the impractical task of providing extensive training and feedback sessions for the estimators. Moreover, even if it had been practical to train all of the estimators, such training would not have completely eliminated the effects of central bias. The stated probability distributions were as follows: (1) a normal distribution was fitted to the results of the Monte Carlo simulation using the mean and standard deviation; (2) when the stated probability was 0.1, the calibrated probability was adjusted to 0.2; (3) when the stated probability was 0.9, the calibrated probability was adjusted to 0.7; and (4) two triangular segments were added to fit a polygonal distribution. Each of these steps was extensively discussed in the technical sessions and the Staff has been able to replicate the post-calibration 12 percent normal contingency figure.

The Staff has two fundamental concerns with the concept of calibration to compensate for central bias among estimators: (1) Staff does not believe that central bias should have been present in the judgments of the particular experts who provided the input data, and (2) Staff is troubled by skewed distributions⁷ (and skewed calibration) of cost estimates (and central bias) in a large, one-of-a-kind, complex construction project. Staff's concerns are unfounded.

1. Central Bias Exists Among Experts

Staff alleges that calibration would not be necessary if training and feedback were provided to estimators. Furthermore, Staff expresses surprise that cost estimators in general and Fluor's estimators in particular receive little feedback that would be valuable in improving their natural calibration. In fact, Fluor estimators and cost estimators in general do receive training and feedback on their single point engineering estimates. What Staff fails to understand is the difference between the engineering estimate components and the estimate of ranges of uncertainty around such components -- two very different things. Cost estimators at Fluor and elsewhere routinely receive feedback on their ability to make good "most likely" cost estimates, i.e. the modal values used in the risk

⁷ Transcript of November 15, 1980 at 6.

analysis. They do not receive feedback or training on their ability to predict accurately the confidence limits or ranges on their single point estimates.⁸ Therefore, since their training has no impact on their tendency to be centrally biased, calibration is required.

Staff also alleges there is substantial reason to believe that cost estimators, as individuals and as a class, are less subject to errors of central bias within their own expertise than the population as a whole. Staff provides absolutely no support for this statement. In fact, experts routinely exhibit central bias tendencies in their own field of expertise.⁹

The ARCO representative supported the existence of central bias stating that ARCO began focusing on the problem in 1973.¹⁰ Its and others' recognition of central bias in estimators shows that cost estimators do not usually receive feedback which allows them accurately to estimate uncertainty.

2. Skewed Distribution of Cost Estimates for Unique Construction Projects

As the Staff correctly points out, calibration will have no effect upon the amount of normal contingency unless it is assumed that the bias is non-normal. Alaskan Northwest has assumed that the removal of central bias would result in a positive skewing to the resultant distribution of costs. This assumption is based on the recognized fact that cost overruns are more prevalent than cost underruns. This is supported by the conclusions of a recent Rand report which states:

This report has reviewed cost estimation problems in four areas: major weapons systems; public works and large construction projects; energy process plants; and chemical process plants. Statistical findings in the first three areas and anecdotal evidence in the last suggest that difficulties in estimating the capital costs of major projects are widespread, and in at least some areas pose serious problems for decision-makers, both public and private. Despite wide differences in the items estimated and in market structures, the empirical findings are similar in important respects: Capital cost estimates tend to display a low bias, and there is considerable variance in the cost estimation errors. In addition, cost estimators for first-of-a-kind or one-of-a-kind systems display greater bias and variability than do estimates for more standard systems.¹¹ (Emphasis added.)

8 Transcript of November 12, 1980 at 45. Furthermore, it would be virtually impossible to provide meaningful feedback in a unique mega-project with an elapsed time of many years. To be effective, feedback must be repetitive and frequent. This cannot be done on such a mega-project.

9 Fischhoff, Slovic, and Lichtenstein, "Lay Foibles and Expert Fables in Judgements about Risk," to appear in Resource Management and Environment Planning, Edited by T. O'Riorden and R. K. Turner, Chichester: Wiley, June 1980.

10 Transcript of November 18, 1980 at 6.

11 Merrow, et al., A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants. (July, 1979) (prepared for U. S. Department of Energy by Rand Corporation).

It is important to note that the Staff attempted to relate the prevalence of overruns to factors other than central bias. It stated that overruns were a natural result of the acceptance of the lowest bids for construction contracts and the tendency of excess funds to be used to improve project profitability. There is no evidence to support these assertions. In fact, cost overruns occur in cost plus contracts, in situations where there are no competitive bids, and where actual costs are compared to pre-bid estimates.¹² It is not a phenomenon on low competitive bids. Logically, one expects cost increases more often than underruns. For example, for labor costs this results from the nature of the construction industry which relies upon cadence operations. In a cadenced operation the crews will be paced by the slowest unit. Therefore, a fast crew will be held up by its predecessor. On the other hand, a slow crew will create delays. Also, contractors and owners have more incentives under a fixed price contract to come in below costs than to overrun. Therefore, excess funds are not going to be spent to use them up.

The Delegate summarized statements by the ARCO representative supporting the tendency for an upwards skew in project costs as follows:

...despite training in dealing with central bias, underestimates of upside risk persist....¹³

...as a general rule, ARCO makes estimates of uncertainty on all its major projects, and I believe he reported that the company has a review team at the corporate planning level in the company, which sometimes makes upward adjustments in the ranges of cost estimates, which in his view are analogous to the calibration step that was included in the development of the normal contingency in the cost estimate at issue here.¹⁴

Fluor management also reported that it uses another approach similar to calibration. It uses a value that is higher than the expected value on the probability distribution. That is, it uses a 70 to 80 percentile number to establish contingency.¹⁵

Alaskan Northwest skewed the calibration for central bias in a manner which was conservative, *i.e.* not excessively skewed. To compensate adequately for low bias in the cost estimates for a unique project such as this requires that at least a 60 percent adjustment for central bias be imposed on the upper end of the distribution. In fact, a higher percentage, *e.g.*, 70 percent, is more realistic, but Alaskan Northwest chose to be conservative in its treatment of the non-normal distribution of cost estimates. If the higher percentage had been utilized, contingency would have been increased to 14 percent.

In summary, central bias did in fact exist among the experts used to encode subjective judgements about uncertainties around the engineering estimate

¹² Id.

¹³ Transcript of November 18, 1980 at 8.

¹⁴ Transcript of November 18, 1980 at 7-8.

¹⁵ Transcript of November 12, 1980 at 27.

components. To adjust for this central bias Alaskan Northwest utilized an accepted external calibration technique to represent accurately the in-scope estimating uncertainty associated with the engineering cost estimate.

C. Proposed Specific Modifications to Normal Contingency

In addition to the above concerns, the Staff proposes several modifications to the encoded input values used to estimate the uncalibrated normal contingency in three areas: Pipeline, Temporary Facilities, and Project Directorate. Staff's modifications to the expected values in Pipeline are premised on a misunderstanding of how the estimate, and in particular contingency, were developed. Furthermore, Staff's modifications to these encoded values are nothing more than arbitrary substitutions of Staff's unsupported "beliefs" as to the proper values for the values developed by the experienced cost estimators, engineers, and managers who participated in the preparation of the base estimate. Neither Staff nor its consultants have had experience in preparing a cost estimate for a project of this magnitude and complexity. In fact, Staff's consultants have indicated that they do not prepare cost estimates.

1. Pipeline

a. River Crossing

Staff states as follows:

NWA has suggested that the possibility exists to lose a ditch or float the pipeline which would result in a total rework of the crossing. The Staff agrees that such possibilities exist but with the multitude of crossings the chances of having major problems are probably one in ten as opposed to 100 percent (emphasis added).¹⁷

By these statements, Staff demonstrates that it has failed to understand the risk analysis process or the meaning of the encoded values. For example, the total engineering cost estimate for river crossings in Pipeline Section 1 is \$12.9 million. (Vol. 33, p. 36, Activity No. 6-11-005.) This is composed of: labor - \$8.1 million; tools, consumables, and other costs - \$0.6 million; construction equipment - \$3.5 million; fuel and lube - \$0.7 million. Excluding fuel and lube costs, the estimated cost for river crossings is \$12.2 million. The encoding input values for this activity indicated that there is a ten percent probability (one in ten chance) that labor, tools, consumables, and other costs, and construction equipment costs would be 20 percent below the estimated value. For example, actual labor costs could be only \$6.4 million for labor. Also, there is a ten percent probability (one in ten chance) that these costs could be 100 percent above the estimated value. Thus, labor costs for this activity could be as much as \$16.2 million. In essence, these encoded values exactly reflect the Staff's position as expressed in the above quoted material. Contrary to Staff's mischaracterization, the encoded values do not mean that Alaskan Northwest estimates a 100 percent chance of major problems in river crossings in Section 1.

¹⁷ Staff comments at 11.

b. Fuel and Lube

Staff believes that we have significantly underestimated the risk of higher prices for fuel and lube. (Staff comments at 11). While we appreciate Staff's concern for the "considerable risk" in the area of "Fuel and Lube," Alaskan Northwest cannot accept the favorable adjustment suggested by Staff. To do so would require us to approach the problem in a manner which is conceptually inconsistent with the IROR and the approach which we adopted in constructing the risk analysis. We believe the encoded values for "Fuel and Lube" are correct as filed. ---

c. Ditching and Pipegang and Tie-in-Backfill

For these activities Staff would arbitrarily reduce the upper encoded values from 80 to 30 percent for "Ditching" and from 55 to 25 percent for "Pipegang and Tie-in-Backfill." Staff's reductions are based solely in its erroneous belief that the EC panel which prepared the lay rate included some contingency in that lay rate. The lay rate is based on normal, expected conditions in Alaska. The EC panel was instructed that no contingency considerations were to be included in the base estimate. The EC's stated that they followed these instructions.

Moreover, as exhaustively explained in the technical conferences and the "Lay Rate Report of Alaskan Northwest," which was submitted at the request of the Delegate, the 12.5 percent allowance in the base estimate for firing line welders is not a contingency. It is a factor based in the experience of the EC's to compensate for expected normal delays in welder productivity.

2. Temporary Facilities

The experts who encoded the contingency values for temporary facilities knew that the camp purchase price was included within this cost element. They took this fact and the uncertain condition of the camps into consideration in setting the filed ranges of uncertainty for the cost estimate for temporary facilities. Alaskan Northwest is willing, however, to reduce the contingency associated with the purchase of the Alyeska camps to zero, if the actual negotiated costs for this item and the purchase of proprietary geotechnical data from Alyeska are allowed in the CCE. This does not mean, however, that there are no risks associated with the purchase price of these items from Alyeska, because the terms and conditions of sale will influence the 1980 dollar cost estimate for these items.

3. Project Directorate

Alaskan Northwest has agreed that contingency associated with third party monitoring costs and other governmental related costs should be removed if the Cost Performance Ratio is adjusted to reflect actual such costs. If this agreement is accepted, contingency on this item can be removed because these costs will have been fixed and, accordingly, Alaskan Northwest will not be at risk that actual costs exceed estimated costs.

D. Contingency and Level of Design

Staff states that because the contingency was determined for a engineering estimate based upon a five percent final design, the contingency would have