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October 27, 1980

FILE
PROJECT CODE NO.

Honorable Kenneth F. Plumb
Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

Re: Northwest Alaskan Pipeline Company - Docket No. CP78-123

Dear Mr. Plumb:

Northwest Alaskan Pipeline Company and Alaskan Northwest Natural Gas Transportation Company submit herewith, for filing, pursuant to the Alaska Natural Gas Transportation Act and the Natural Gas Act, an original and 19 copies of Notice of Amendment to Partnership Agreement notifying the Commission of an amendment to the Partnership Agreement for the purpose of admitting Columbia Alaskan Gas Transmission Corporation, Tetco Four, Inc., Texas Gas Alaska Corporation, and TransCanada PipeLine Alaska Ltd. to the Partnership. Together with said Notice, there is also submitted:

1. A copy of Amendment No. 3 (effective August 1, 1980) to the Alaskan Northwest Natural Gas Transportation Company Partnership Agreement.

2. A proposed Notice of Filing of Notice of Amendment to Partnership Agreement.

3. A certificate of service.

Copies are being served on parties designated by the Commission on the service list for Docket No. CP78-123.

Very truly yours,

Rush Moody, Jr.

Enclosures

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

In the Matter Of:	)	
	)	Docket No. CP78-123, et al.
Alaskan Northwest Natural	)	
Gas Transportation Company	)	

NOTICE OF
AMENDMENT TO PARTNERSHIP AGREEMENT

Comes now Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest), 1/ a partnership, having heretofore received a conditional certificate 2/ for the construction and operation of the Alaska Natural Gas Transportation System (ANGTS), and respectfully advises the Federal Energy Regulatory Commission (Commission) of the following:

I

Effective August 1, 1980, the Partnership Agreement of Alaskan Northwest was amended (Amendment No. 3) 3/ to admit

---

1/ A general partnership organized under the laws of the State of New York and comprised of Northern Arctic Gas Company, Northwest Alaskan Pipeline Company, Pan Alaskan Gas Company, Calaska Energy Company, Pacific Interstate Transmission Company (Arctic), United Alaska Fuels Corporation, and American Natural Alaskan Company.

2/ Alcan Pipeline Company, et al., Docket Nos. CP78-123, et al. (December 16, 1977). The certificate issued to Alcan was transferred to Alaskan Northwest by order of June 30, 1978.

3/ Amendment No. 1 pertained to the discount schedule set forth in Section 5.2 of the Partnership Agreement. The amendment was noted at mimeo p. 7, fn. 6 of the Commission order issued in the captioned docket on June 30, 1978. Amendment No. 2 was filed February 6, 1980 and was the subject of a notice and order requesting comments issued in the above-captioned docket on August 1, 1980. This Amendment No. 3 is the third amendment to the Partnership Agreement, and is attached hereto as Appendix A.

four additional partners: Columbia Alaskan Gas Transmission Corporation, an affiliate of Columbia Gas Transmission Corporation; Tetco Four, Inc., an affiliate of Texas Eastern Transmission Corporation and Transwestern Pipeline Company; Texas Gas Alaskan Corporation, an affiliate of Texas Gas Transmission Corporation; and TransCanada PipeLine Alaska Ltd., an affiliate of TransCanada PipeLines Limited. Affiliates of each of these new participants operates a major pipeline transportation network, the first three in the United States subject to regulation by the Commission, and the latter in Canada subject to regulation by the National Energy Board (NEB).

II

On January 31, 1978, the Alaskan Northwest Partners entered into a general partnership agreement for the purposes of constructing and operating the Alaskan segment of the ANGTS. The terms of this agreement were accepted by the Commission in an order issued June 30, 1978. Section 11 of the Partnership Agreement provides for the admission of additional partners after the formation of the Partnership upon terms and conditions of admission determined by the Partnership.

Pursuant to that section, effective Janaury 1, 1980, the Partnership and American Natural Alaskan Company (American Natural Alaskan) agreed that American Natural Alaskan would become a Partner according to the following terms and conditions:

1. American Natural Alaskan agrees to abide by all conditions and obligations of the Partnership Agreement, unless specifically waived.

2. American Natural Alaskan will make a cash contribution to the capital account of the Partnership in an amount equal to that contributed by any individual Partner for the period between the formation of the Partnership and January 7, 1980. This contribution will be paid-off in increments with each future cash call so that the total paid by American Natural Alaskan will be twice that of any other Partner until the full amount has been equalized.

3. American Natural Alaskan will have the right to submit to the Board of Partners for inclusion in the American Natural Alaskan Capital Account certain sums, called Qualified Expenditures, expended prior to admission that the Partners determine to be of value to the project.

4. American Natural Alaskan will be entitled to a representative on the following committees of the Partnership: Executive, Audit, and Compensation.

5. For purposes of the admission of American Natural Alaskan, the Partnership agrees that solely for purposes of Section 5 of the Partnership Agreement, American Natural Alaskan will be deemed to have been a Partner on or before March 17, 1978. This acts to waive the requirement of Section 5.2 that a Partner admitted after that date is subject to a special allocation of profits, losses and credits.

6. The admission of American Natural Alaskan is conditioned upon the approval by the Commission of the terms and conditions of admission.

These terms and conditions were incorporated into Amendment No. 2 to the Partnership Agreement, which was filed with the Commission on February 6, 1980. Accompanying this submittal was an expression by the Partnership of its willingness to offer the same terms and conditions of membership to any other eligible person for a period of thirty (30) days following the issuance by the Commission of the notice of Amendment No. 2.

The Commission notice was issued August 1, 1980 and included a request for comments and reply comments with respect to certain areas of concern. 4/ Although comments were requested on these specific points, the Commission stated that it was inclined to approve the admission of American Natural Alaskan as a partner, the waiver of the discount schedule for that purpose, the use of the thirty-day grace period for admittance of new partners without penalty, and the use of a discount schedule for new partners entering after the grace period.

The Partnership filed initial comments on August 22, 1980 and reply comments on September 5, 1980. In the initial comments, the Partnership explained further the reasoning in support of Amendment No. 2 and the offer of a grace period. By the time the reply comments were due, the Partnership was able to advise the Commission that four companies (Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska) had responded favorably to the Partnership offer and agreement had been reached on the terms and conditions of their admittance.

4/ The notice and order of the Commission issued August 1, 1980 invited comments on the following: (1) the waiver of the discount schedule (Section 5.2 of the Partnership Agreement) for the purpose of admitting American Natural Alaskan as a partner; (2) the acceptance of the thirty-day grace period for possible additional membership, (3) the appropriate level of discount to put into effect at the end of the grace period (assuming the grace period is approved), and (4) the appropriateness of using particular events to determine changes in the discount schedule.

The formal agreement expanding the Partnership Agreement to include the four new members is the attached Amendment No. 3 (Appendix A). In addition to the acceptance of the terms and conditions agreed on between the Partnership and American Natural Alaskan, as set forth previously, the Partnership, including American Natural Alaskan, and the four new Partners agreed to further condition membership on the following:

(1) Commission approval of the thirty-day grace period as tendered in the February 6, 1980 filing,

(2) Commission approval of Amendment No. 3,

(3) an understanding that Section 4.3.1 of the Partnership Agreement is not intended to require, and will not be construed to require, any Partner to assume a Partnership interest greater than that interest elected under Section 4.3.1.

The above matters are incorporated into Amendment No. 3.

The Commission will note that in the letter agreement between Columbia Alaskan and the Partnership whereby Columbia Alaskan agreed to become a Partner, which was filed with the Commission on September 5, 1980, a condition was added providing for a waiver of the last sentence of Section 3.6 and waiver of Section 11.1.4 of the Partnership Agreement, together with the receipt by Columbia Alaskan of an order or orders from the Securities and Exchange Commission (SEC) authorizing Columbia Alaskan's participation in the Partnership and the performance of its obligations thereunder. The cause of this condition is the Public Utility Holding Company Act of 1935, which is administered by the SEC, and which is applicable to Columbia Alaskan. Section 3.6 of the Partnership Agreement requires each Partner to represent that it is not subject to that Act, and Section 11.1.4 requires that the admission of any new Partner will not result in the Partnership becoming subject to the Act. As previously stated, the Partnership has agreed to the waiver of these requirements.

III

The instant filing serves to notify the Commission that four more companies have joined the Partnership. The Partnership is now comprised of the original six members, whose participation was approved by the order of June 30, 1978, and five new members (American Natural Alaskan, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska), whose joinder has not yet received Commission acceptance. The Partnership does not believe the Commission 5/ or any interested person 6/ has or could have any objection to the proposed expansion of the Partnership.

The admission of new Partners is a positive step toward the successful completion of the ANGTS. Additional Partners will facilitate project financing by broadening the base of equity support, spreading the risk of the current investment, and committing greater resources to the Project. Although much of the regulatory risk has been or is about to be overcome, substantial risks remain after Commission certification. The willingness of the new Partners to commit considerable resources to the ANGTS demonstrates their faith in the viability of the Project, reinforces the determination and foresight of the original Partners, and justifies the Partnership's offer of a thirty-day grace period to attract new members. Under these circumstances, the Partnership strongly suggests that the public interest will best be served by Commission approval of both Amendment Nos. 2 and 3.

WHEREFORE, Alaskan Northwest respectfully advises the Commission of the amendment to its Partnership Agreement and petitions the Commission to review and accept the amendment, as offered, and the joinder of the new Partners in accordance therewith.

Respectfully submitted,

Rush Moody, Jr.
Attorney for Alaskan Northwest Natural Gas Transportation Company

Northwest Alaskan Pipeline Company

Of Counsel:

AKIN, GUMP, HAUER & FELD
1333 New Hampshire Ave., N.W.
Suite 400
Washington, D.C. 20036

5/ In the August 1, 1980 notice and order, the Commission stated in footnote 7 at page 5 that it was inclined to find the admission to the Partnership of American Natural Alaskan was not inconsistent with the requirements of the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System.

6/ In response to the August 1, 1980 notice and order, no person filed a comment objecting to American Natural Alaskan becoming a Partner. The Partnership anticipates that the instant submittal will not engender any opposition.

AMENDMENT NO. 3
AGREEMENT DATED AS OF AUGUST 1, 1980
BETWEEN
ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
AND
COLUMBIA ALASKAN GAS TRANSMISSION CORPORATION,
TETCO FOUR, INC., TEXAS GAS ALASKA CORPORATION,
AND TRANSCANADA PIPELINE ALASKA LTD.

THIS AGREEMENT dated as of August 1, 1980 (Amendment No. 3) by and among ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY, a New York general partnership, ("Partnership") formed pursuant to the Alaskan Northwest Natural Gas Transportation Company General Partnership Agreement effective as of January 31, 1978 ("Partnership Agreement"), and Columbia Alaskan Gas Transmission Corporation, a Delaware corporation ("Columbia Alaska") and a wholly-owned subsidiary of Columbia Gas System, Inc., a Delaware corporation; Tetco Four, Inc., a Delaware corporation ("Tetco Four") the capital stock of which is owned fifty percent by Texas Eastern Transmission Corporation and fifty percent by Transwestern Pipeline Company, Delaware corporations; Texas Gas Alaska Corporation, a Delaware corporation ("Texas Gas Alaska") and a wholly owned subsidiary of Texas Gas Transmission Corporation, a Delaware corporation; and TransCanada PipeLine Alaska Ltd., a Nevada corporation ("TransCanada-Alaska") all of whose capital stock is owned indirectly by TransCanada PipeLines Limited, a Canadian corporation.

WITNESSETH THAT:

WHEREAS, on February 6, 1980 by a filing in Docket No. CP78-123, et al., the Partnership gave notice to the Federal Energy Regulatory Commission ("Commission") of Amendment No. 2 to the Partnership Agreement, which set forth the terms and conditions agreed to for the admission into the Partnership of American Natural Alaskan Company ("American Natural Alaskan"), and the Partnership further notified the Commission that for a period of thirty days ("grace period") following the issuance by the Commission of a notice of the filing of Amendment No. 2 that membership in the Partnership would be available to other eligible, interested persons on the same terms and conditions agreed to with American Natural Alaskan; and

WHEREAS, on August 1, 1980 the Commission issued its Notice Of The Filing Of A Notice Of Amendment To Partnership Agreement, And Order Inviting Comments setting forth the terms of Amendment No. 2 and the offer of a grace period for additional membership, and requesting comments; and

WHEREAS, in response to the Partnership offer of a grace period, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska have separately requested to be admitted as a Partner on the terms and conditions set forth in this Amendment No. 3, and the Partnership is willing to admit each one as a Partner on such terms and conditions; and

WHEREAS, the terms of the admission of Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska to the Partnership, as set forth in Amendment No. 3, require the amendment or waiver of certain terms, conditions, or provisions in the Partnership Agreement, and the Partnership is willing to agree to such amendments or waivers;

WHEREAS, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska are ready, willing and able to abide by and comply with all the terms, conditions, and provisions of the Partnership Agreement, as amended hereby; and

NOW, THEREFORE, the Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska, intending to be legally bound hereby, agree as follows:

I

In accordance with the provisions of this Amendment No. 3, and the Partnership Agreement as amended hereby, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska shall each become a Partner in the Partnership as of August 1, 1980 (hereinafter called the "Admission Date"). In consideration of becoming a Partner, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska shall each make capital contributions to the Partnership on the terms and subject to the conditions of Section 4 of the Partnership Agreement, as amended by Amendment No. 2, and as further amended by this Amendment No. 3.

II

Section 1 of the Partnership Agreement is amended, effective as of the Admission Date, to add new sections 1.8 through 1.11 to read as follows:

> "1.8 COLUMBIA ALASKAN GAS TRANSMISSION CORPORATION, (hereinafter called 'Columbia Alaskan'), a corporation organized under the laws of the State of Delaware, with its principal corporate offices at 20 Montchanin Road, Wilmington, Delaware 19807. Columbia Alaskan

represents that: (a) all of its capital stock is owned by Columbia Gas System, Inc., a Delaware corporation; and (b) Columbia Alaskan or an Affiliate intends to become a Shipper."

"1.9 TETCO FOUR, INC. (hereinafter called ('Tetco Four'), a corporation organized under the laws of the State of Delaware with its principal corporate offices at One Houston Center Houston, Texas 77002. Tetco Four represents that: (a) fifty percent of its capital stock is owned by Texas Eastern Transmission Corporation and fifty percent by Transwestern Pipeline Company, Delaware corporations; and (b) Tetco Four or its Affiliates intend to become Shippers."

"1.10 TEXAS GAS ALASKA CORPORATION, (hereinafter called 'Texas Gas Alaska'), a corporation organized under the laws of the State of Delaware, with its principal corporate offices at 3800 Frederica Street, Owensboro, Kentucky 42301. Texas Gas Alaska represents that: (a) all of its capital stock is owned by Texas Gas Transmission Corporation, a Delaware corporation; and (b) Texas Gas Alaska or an Affiliate intends to become a Shipper."

"1.11 TRANSCANADA PIPELINE ALASKA LTD., (hereinafter called 'TransCanada-Alaska'), a corporation organized under the laws of Nevada, with its principal corporate offices at 54 Commerce Court, Toronto, Ontario, Canada M5L 1C2. TransCanada-Alaska represents that: (a) all of its capital stock is owned indirectly by TransCanada PipeLines Limited, a Canadian corporation; and (b) TransCanada-Alaska or an Affiliate may become a Shipper."

III

Section 3.6 of the Partnership Agreement is amended, effective as of the Admission Date, to read as follows:

"3.6 <u>Representations and Warranties Concerning Formation of Partnership</u>: Each Partner represents and warrants that, subject to the receipt of all necessary regulatory approvals relating to this Agreement and the investment of the Partners in this Partnership, the execution and delivery of this Agreement, the formation of the Partnership and the performance hereof will not contravene any provision of, or constitute a default under, any indenture, mortgage or other agreement of such Partner or any Affiliate of such Partner or any order of any court, commission or governmental agency having jurisdiction, and this Agreement is a valid and enforceable Agreement against such Partner except insofar as enforcement hereof may be limited by bankruptcy, insolvency or other similar laws related to or affecting the enforcement of creditors' rights. Each of the Parties to this Agreement, other than Columbia Alaskan, represents that it is not subject to or is exempt from the jurisdiction of the SEC as a public utility holding company within the meaning of the Public Utility Holding Company Act of 1935."

IV

Section 4.2 of the Partnership Agreement is amended by changing Section 4.2.5 and by including new sections 4.2.7 and 4.2.8, effective as of the Admission Date, to read as follows:

"4.2.5 On or before December 1, 1979, and on or before each succeeding December 1 in the event the Commitment Date is estimated to occur after such succeeding December 1, the Board of Partners shall determine, taking into account budgeted costs and contractual commitments which will accrue if the Project is suspended, the anticipated cash requirements of the Partnership for the period from January 1, 1980 (or from any succeeding January 1) through the date then estimated to be the Commitment Date. Immediate notice of each such determination shall be given to all Partners. Each Partner agrees, subject to the withdrawal rights specified in Section 4.4.3, to contribute to the Partnership, for the period commencing January 1, 1980 and ending with the Commitment Date, an amount equal to (i) the amount by which the anticipated cash requirements of the Partnership during such period exceeds the total of the amount contributed by American Natural Alaskan pursuant to Section 4.2.6, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to Section 4.2.7, and Columbia Alaskan pursuant to Section 4.2.8, divided by (ii) the number of Partners.

4.2.7 Tetco Four, Texas Gas Alaska, and TransCanada-Alaska severally agree, notwithstanding anything to the contrary in Section 4.4.3, which Section shall not be applicable to this Section 4.2.7, to contribute to the Partnership that amount which is equal to the amount contributed by any Partner named in Sections 1.1 through 1.6 pursuant to Section 4.2 from the Formation Date through August 12, 1980. Until Tetco Four, Texas Gas Alaska, and TransCanada-Alaska shall have each contributed to the Partnership the entire amount required to be contributed by it pursuant to this Section 4.2.7, each shall, notwithstanding anything to the contrary in Section 4.4, contribute to the Partnership pursuant to this Section 4.2.7, on each date on which a capital contribution pursuant to Section 4.2.5 shall become due and payable, an amount equal to the lesser of (i) the highest amount contributed by any Partner named in Sections 1.1 through 1.6 pursuant to Section 4.2.5 on such date or (ii) the balance remaining to be contributed separately by Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to this Section 4.2.7. The contributions made by Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to this Section 4.2.7 shall be in addition to the contributions of Tetco Four, Texas Gas Alaska, and TransCanada-Alaska pursuant to Section 4.2.5.

4.2.8 Upon the receipt by Columbia Alaskan of authorization from the SEC to participate in the Partnership pursuant to the Public Utility Holding Company Act of 1935, which shall occur after the Admission Date and subsequent to one or more requests for cash contributions pursuant to Section 4.2.5, as of the next such request for a cash contribution, Columbia Alaskan shall contribute an amount equal to the sum of (i) the amount previously paid by a Partner subject to both Sections 4.2.5 and 4.2.7 plus (ii) the cash contribution then requested, computed as if Columbia Alaskan were subject to the provisions of Section 4.2.7. Thereafter, for the purposes of cash contributions under Section 4.2.5, the contribution of Columbia Alaskan shall be calculated according to the provisions of Section 4.2.7 as if Columbia Alaskan were included therein on an equal basis with Tetco Four, Texas Gas Alaska, and TransCanada-Alaska."

V

Notwithstanding anything in the Partnership Agreement, as amended, that may be to the contrary, the Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska agree that Section 4.3.1 of the Partnership Agreement is not intended to require, and will not be construed to require, any Partner to assume a Partnership interest greater than that interest which such Partner has elected pursuant to Section 4.3.1.

VI

Notwithstanding anything in the Partnership Agreement, as amended, to the contrary, each Partner agrees that solely for purposes of Section 5 of the Partnership Agreement, Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska shall be treated as if they had executed the Partnership Agreement on or before March 17, 1978.

VII

Section 8.3.1 of the Partnership Agreement is amended, effective as of the Admission Date, to read as follows:

"8.3.1 The Executive Committee shall consist of a Chairman and ten members. Each Partner named in Sections 1.1 through 1.11 (or any substitute Partner succeeding to its interest hereunder) shall designate a representative to serve on the Executive Committee, and the Chairman of the Board of Partners shall also be the Chairman of the Executive Committee. Any vacancy on the Executive Committee occasioned by the withdrawal of a Partner named in Sections 1.1 through 1.11 (or any substitute Partner succeeding to its interest hereunder) shall be filled by the Board of Partners."

VIII

Section 8.4.1 of the Partnership Agreement is amended, effective as of the Admission Date, to read as follows:

"8.4.1 The Audit Committee shall consist of ten members. No member of the Audit Committee shall be affiliated in any manner with Northwest, and each Partner (other than Northwest) admitted to the Partnership prior to September 1, 1980 shall have one representative on the Audit Committee. The Board of Partners shall designate one member of the Audit Committee to serve as Chairman of the Audit Committee. Decisions of the Audit Committee shall be by a majority vote of the members. The members shall serve on the Committee at the will of the Board of Partners."

IX

Section 8.5.1 of the Partnership Agreement is amended, effective as of the Admission Date, to read as follows:

"8.5.1 The Compensation Committee shall consist of ten members. No member of the Compensation Committee shall be affiliated in any manner with Northwest, and each Partner (other than Northwest) admitted to the Partnership prior to September 1, 1980 shall have one representative on the Compensation Committee. The Board of Partners shall designate one member to serve as Chairman of the Compensation Committee. Decisions of the Compensation Committee shall be by majority vote of the members. The members shall serve on the Committee at the will of the Board of Partners."

X

For the purposes of Section 11.1 of the Partnership Agreement, execution of this Amendment No. 3 shall (a) satisfy the requirement that a new Partner execute a counterpart of the Partnership Agreement, and (b) except for Columbia Alaskan with respect to Section 11.1.4, constitute a warranty and representation by Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska that each has satisfied the conditions for admission to the Partnership set forth in Sections 11.1.2 through 11.1.4, and (c) constitute satisfaction of the requirements of Section 11.1.1.

XI

This Amendment No. 3 shall be governed by and interpreted in accordance with the laws of New York. Terms used in this Amendment No. 3 which are defined in the Partnership Agreement are, unless the context otherwise requires, used herein as therein defined.

XII

This Amendment No. 3 may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

XIII

This Amendment No. 3 embodies the entire agreement and understanding between the Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska and supersedes all prior agreements and understandings relating to the terms and conditions of the admission of Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska as Partners and any other matters which are the subject of this Amendment No. 3.

XIV

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

The Partnership and Columbia Alaskan, Tetco Four, Texas Gas Alaska, and TransCanada-Alaska agree that admission to the Partnership is subject to a condition subsequent of Commission approval of the thirty-day grace period as tendered in the February 6, 1980 Partnership filing and Commission approval of this Amendment No. 3.

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

ATTEST:

COLUMBIA ALASKAN GAS TRANSMISSION CORPORATION

[signature]
Assistant Secretary

By: John H. Croom
President

ATTEST: | TETCO FOUR, INC.

Joseph V. Walter | By: H. Wayne Hodge

ATTEST: | TEXAS GAS ALASKA CORPORATION

____________ | By: ____________

ATTEST: | TRANSCANADA PIPELINE ALASKA LTD.

[illegible] | By: [illegible]

ALASKAN NORTHWEST NATURAL GAS
TRANSPORTATION COMPANY

By each of its Partners:

ATTEST: | NORTHWEST ALASKAN PIPELINE COMPANY

John Mason | By: John G. McMillian

ATTEST: | NORTHERN ARCTIC GAS COMPANY

____________ | By: ____________

ATTEST: | PAN ALASKAN GAS COMPANY

____________ | By: ____________

ATTEST: | CALASKA ENERGY COMPANY

____________ | By: John [illegible]

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] By: Gordon Severa

Assistant Secretary 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: K.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

[signature] Secretary By: John A. Sproul 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 G. Chebikott

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. ERCK
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

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 S-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. (pw)

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

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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

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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 t[illegible] greater the pipe wall thickness, the more time is required t[illegible] 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 ÷ 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. <u>Compare</u>, <u>e.g</u>., 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 No. Joints	No. Feet	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)
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	40-45	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

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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 ÷ 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 that 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 susceptable 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 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

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 Certifiction Cost and Schedule Estimate and a Center Point <u>cannot</u> and <u>should</u> 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 threshhold 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, inlcuding 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

1120 20th Street, N.W.
Suite S 700
Washington, D.C. [illegible]
(202) [illegible]

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 anlaysis. 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.

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, specificially detailing the nature of such concerns.

(G) If for any reason a requested document cannot be produced, the reason for its nonproduction must be stated. If such a document is no longer in the possession, custody, or control of Alaskan Northwest, please set forth the control of said document and the identity of the person who currently is in possession, custody, or control such document.

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

1. 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 of 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

1120 20TH STREET, N.W.
SUITE 700
WASHINGTON D.C. 20036
(202) [illegible]

September 29, 1980
REGA 80-1144

John B. Adger, Jr.
Director Alaska Gas Project Office
941 North Capitol Street, N.E.
Room 3004
Washington, D.C. 20426

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

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 [signature]
John G. McMillian, Chairman
Northwest Alaskan Pipeline Company,
Operator

OFFICE OF THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
IRVINE FIELD OFFICE
2222 Martin Drive, Suite #155
Irvine, California 92715

Sec #13 p6

October 2, 1980

MEMORANDUM

TO: John Adger, Alaska Delegate

FROM: Amos Mathews, Director, Alaska Field Office
Earle Ausman for

SUBJECT: Major Outstanding Design Issues Related to Alaskan Leg

The FERC, in it's August 1, 1980, "Notice of Application and Order Establishing Procedures," requested the OFI to prepare for circulation, at the earliest possible time, a brief report identifying the major outstanding design issues. Attached in response to this request, is a report prepared by our contractor, Unified Industries Inc. Supplemental comments from the OFI staff may be provided during the next conference on Tuesday, October 7, 1980.

The design on which the NWA Certification Cost Estimate and these reports are based was frozen in March 1980. Significant progress is currently being made in the finalization of that design. The intent of these reports is to identify areas containing design options that should be considered as the design is finalized.

These areas are under continuing review by the OFI and the reports do not necessarily represent the final views of the Office. They are intended for purposes of discussion at the conference scheduled to begin on October 7.

SUMMARY REPORT ON MAJOR OUTSTANDING

DESIGN ISSUES

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

09-TR-0006-3

WBS 1.01.22.02

CONTRACT NUMBER

OFI 80-0001

October 1980

U. J. Baghurst

for Ashraf M. Mirza
Engineering Manager

Richard K. Shogren

Richard K. Shogren
Project Manager

UNIFIED INDUSTRIES, INCORPORATED
2222 Martin Drive
Irvine, California 92715

TABLE OF CONTENTS

1.0 INTRODUCTION

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

Item 10. Less Conservative Frost Heave Mitigation

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

Item 11. An Increase of One Year in Construction Schedule

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

Item 19. Compressor and Metering Station Estimate Concerns

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

Compressor Station	Milepost	Chiller Load-Tons NWA	Chiller Load-Tons 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	]4	Delete "or".

NOVEMBER 10

22	4	Change "begun" to "began".

NOVEMBER 11

12	13	Delete "point".
13	1	Should read "MR HUARD: I believe the point we are making is we've asked".
34	14	Change "84-35" to "80-435".

NOVEMBER 12

39	4	Change "ever" to "every".
41	1	Change "80" to "90".
"	16-17	Change "20th to 70" to "720".
58	15	Change "and" to "to the"
65	11	Change "so" to "from".
66	6	Change "is" to "as".

NOVEMBER 13

10	14	Delete first "you".
"	21	Change "proceeded" to "proceed".
13	18	Change "files" to "filings".
15	6	Chaange "is" to "are".
29	23	Change "by" to "of".
40	25	Change "continuance" to "contingency".

NOVEMBER 14

3	16	Change to "trial staff."

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

NOVEMBER 17

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

NOVEMBER 18

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

NOVEMBER 19

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

NOVEMBER 20

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

John P. Roddy
Commission Staff Counsel

CERTIFICATE OF SERVICE

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

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

John P. Roddy
Commission Staff Counsel

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

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1/ See *e.g.*, Opinion No. 101, *Columbia Gas Transmission Corp.*, denying Columbia's request to include CAGSL costs in rate base without prejudice to its seeking recovery of such costs if it or an affiliate become a partner in ANNGTC.

provision was made for answering pleadings by parties like New York concurring in the Office of the Chief Accountant's recommendations. Accordingly, New York requests the Commission to clarify or modify its December 15, 1980 Order to Show Cause to provide a period, to be no less than 30 days after service of the last response to the Show Cause order, for responsive pleadings by all "interested persons" and parties, including the Commission staff, who might wish to support the Chief Accountant's recommendations.

Respectfully submitted,

THE PUBLIC SERVICE COMMISSION OF
THE STATE OF NEW YORK

Peter H. Schiff
General Counsel
Empire State Plaza
Albany, New York 12223

Richard A. Solomon
Wilner & Scheiner
1200 New Hampshire Avenue, N.W.
Suite 300
Washington, D.C. 20036
(202) 861-7800

Its Attorneys

December 23, 1980

CERTIFICATE OF SERVICE

I, Richard A. Solomon, do hereby certify that I have this day served a copy of the foregoing "Motion for Clarification or Modification of Order to Show Cause," by first class mail, postage prepaid, upon all interested parties in this proceeding.

Richard A. Solomon

December 23, 1980

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

PROJECT CODE NO.

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 explicity 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 used 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

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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 s 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;

- the IROR should provide just and reasonable compensation for investors so that sufficient capital may be attracted to finance the project; and,

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

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. <u>See</u> 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 <u>filed design</u>, will increase, thereby reducing the absolute dollar amount of contingency as well as the percentage relationship. Indeed, the Commission itself recognized this fact. (<u>See</u> 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:

	Dollars (MM)	Percent of Base Estimate
Base Estimate 7/1/80	7,050	
Contingency	846	12.0
Center Point	2,271	32.2
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:

Capital Cost Reductions ($ Million)	Decrease in Annual Cost of Service ($ Million)	Decrease in Annual Cost of Service ($MMBTU)	Increase in Incentive Rate of Return (%)
$ 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.

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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 readdress 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 elements[4]; 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 concensus 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 uncertainity 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 undertainty 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.

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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 distributions[7] (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 ancedotal 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.)

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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 phenomen 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

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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 areprobably 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 been less if final design was more complete.[18] Staff then alleges that since the costs of OFI approved design changes will be added to the CCE without regard to the Commission approved contingency, the Sponsors will reap a "windfall contingency." To eliminate this claimed windfall, it suggests the Commission recommend to OFI that "...prior to the approval of costs for a design change, the OFI should first ascertain whether the additional substituted costs of the design change are covered by or included in the contingency before ordering any increase in the Certification Cost Estimate." (Staff comments at 10). This argument demonstrates Staff's lack of understanding of the IROR mechanism approved by the Commission and what the contingency proposed by Alaskan Northwest covers. That contingency includes 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 <u>on current project definition</u>. Thus, any further design change costs would 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.

In normal industry practice, the Staff's position regarding the relationship between an engineering estimate and normal contingency is correct. As a project reaches a definitive design, the normal contingency theoretically would be reduced while costs previously covered by the contingency account would appear in the engineering estimate. Under the rules of the IROR this is not possible because Order Nos. 31 and 31-B require that the CCE (including contingency) be set prior to issuance of the unencumbered certificate. Any changes in the Projected Capital Costs from that time on will be for design and scope changes only. These change procedures are limited and will not allow any adjustments for changes in several components of the CCE, <u>e.g</u>., change in prices or productivity assumptions. Both of these components are part of the assessment of normal contingency. Because the Sponsors cannot change their assumptions for these components under the design change procedure, normal contingency should not be changed after the issuance of the unencumbered certificate.

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18 Staff comments at 10.

II. CENTER POINT

As in the case of contingency, Staff agrees with the basic methodology for developing the expected Center Point value. Staff, however, has some specific disagreements with certain of the 36 Center Point events contained in Volume 5 of the filing. More particularly, Staff does not believe unknown-unknowns (Event No. 36) and capital market conditions (Event No. 25) will affect project costs and should, therefore, be eliminated. Staff would also reduce the expected values for certain other events where Staff substitutes its judgement for the upper values or alleges double-counting of risks already accounted for elsewhere in the engineering estimate or contingency. The Staff adjustments total $923.8 million and reduce the filed expected Center Point value from $2,271.1 million (the correct filed amount, as amended, is actually $2,304 million) to $1,347.3 million. As we demonstrate below, Staff's approximate one billion dollar adjustment is without valid justification.

A. Events Eliminated by Staff

1. Unknown-Unknowns (Event No. 36)

Staff would eliminate altogether this event from Center Point because Staff believes unknown-unknowns are not valid considerations for this project. Even if they were, Staff objects to 6.25 percent of the CCE as the expected value for the Center Point. Staff also urges elimination of unknown-unknowns on its belief their inclusion would render the project "totally free of risk," would set a "dangerous" precedent for other pipelines, and would duplicate protection contained in the Project Risk Premium.

The requested CCE and requested Center Point do not make the project risk-free. There is only a 50 percent chance that the Actual Project Costs will come in at or below the CCE and Center Point. Therefore, this is not a riskless investment. The equity dollars that Alaskan Northwest must invest in excess of the target costs will earn the penalty rate of eight percent. The Sponsors could earn a better return than that by depositing these same dollars in a neighborhood savings and loan. Moreover, other riskless investments such as U.S. Treasury bills are currently yielding an even higher percentage.

Because of where and how the Alaska segment is to be constructed, it is a unique, non-traditional pipeline project. Moreover, contrary to Staff's assertion, unknown-unknowns occur in traditional projects as well as first generation or higher technology projects. There are many examples of unknown-unknowns occurring in traditional projects, e.g., the recent incident of a drilling rig under contract to Texaco drilled into a salt mine in Louisiana, draining a small lake; the creation of earthquake swarms near the Rocky Flats Arsenal in Colorado due to the subsurface injection of radioactive wastes; the discovery of the snail darter fish which delayed the Telico Dam Project; and the failure of the frames of new Grumman Flxible Buses.19

19 See Los Angeles Times, December 21, 1980, p. 4, col. 4.

Although Staff quarrels with the 6.25 percent value for costs impacts from unknown-unknowns, it does not suggest any alternative method for developing such a value. In fact, the 6.25 percent value is conservative given the magnitude of the project. Essentially, this low value for unknown-unknowns indicates that the costs from all unidentified abnormal events are expected to rise no more than 6.25 percent above the CCE. Thus, this value reflects our confidence in the filed cost estimate. A report by the Rand Corporation on project cost growth shows that the filed value for unknown-unknowns events is reasonable.[20] This report states that exogenous (abnormal) events and scope changes (which are very narrowly defined under the IROR orders) are primary contributors to cost growth. Further, this study compares the ratios of actual to estimated costs for over 200 traditional and non-traditional projects. In this analysis, even highway projects, which have very low uncertainty, have an average ratio of 1.2621 times the estimated cost.[22] This is much greater than the current staff position which includes no estimates for design and scope changes while the Rand report includes many design changes in cost estimates established just prior to construction. Furthermore, the expected actual cost increase in highway projects is 1.26 times the estimate (including contingency). In contrast, Alaskan Northwest has requested a Center Point of 1.282 times the CCE, i.e., the engineering cost estimate plus contingency. Certainly a Center Point value of 1.282 including $490 million for unknown-unknowns and abnormal events is not unrealistic when compared to highway cost growth experience of 1.26.

Staff's "precedent" argument against unknown-unknowns is a red herring. Staff's argument that unknown-unknowns should not be allowed because no other pipeline project has included them is premised on Staff's erroneous view that this project is comparable to conventional pipelines. To the contrary, the size, location, and schedule of this project make it nonconventional. Moreover, inclusion of unknown-unknowns in the Center Point would not set a precedent for other pipelines because no other projects are subject to the incentive rate-of-return concept required by the President's Decision and implemented by Order Nos. 31 and 31-B. No other pipeline project has had to bear the risks of costs overruns within the meaning of IROR. Similarly, no provision for unknown-unknowns was made in the 1977 estimate, because there was no IROR requirement at that time.[23]

Staff's contention that unknown-unknowns duplicate risk protection provided by the Project Risk Premium is another example of Staff's lack of understanding of Order No. 31. The Project Risk Premium is designed to compensate the Sponsors for the risk of non-completion. Order No. 31 states as follows:

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20 See Rand Corporation, "A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants," 89 (July, 1979).

21 Id. at 87.

22 The ratio was developed using estimates made just prior to construction as opposed to the CCE which is established several years prior to construction. Also, the estimates included contingency.

23 We would note that Event No. 36 does not relate to unknown design related matters, but is intended to provide protection to the Sponsors for unknown events that could occur during the construction phase of the project.

The Project Risk Premium is added to the Operation Phase Rate to compensate investors for their risk exposure during the construction of the pipeline. The possibility of not completing the pipeline is the major risk faced by investors in the ANGTS. (Order at 72.)

...the Project Risk Premium compensates for a reasonable estimate of non-completion risk. (Id. at 74) (footnote omitted).

Once construction commences, the risk of non-completion will substantially be lessened. Thus, the Project Risk Premium does not cover the costs of abnormal events during construction.

Several of Staff's other comments regarding unknown-unknown events are also erroneous. First, unknown-unknown events were not intended to be an inflation protection mechanism. Inflation protection is included in the inflation adjustment procedures as defined in Order Nos. 31 and 31-B.

Second, it is not obvious that costs would be reduced if 60-foot joints of pipe were used instead of 40-foot joints. In fact, an analysis of this very scenario was conducted by Fluor. The use of 60-foot joints rather than 40-foot joints involves a trade off between welding with associated cost increases. Two 40-foot joints can be double jointed at a double jointing facility and hauled to the site as an 80-foot joint. It is highly impractical to double joint two 60-foot lengths and haul the resultant 120-foot lengths to the site. Special and expensive transportation and handling equipment would be necessary for this process. Therefore, 60-foot lengths could not be practicably double joined. For a 240-foot section of 60-foot joints three field welds would be required with associated handling and transportation costs during construction, whereas for the same 240-foot section using 40-foot joints four shop welds and four field welds would result. Since it is basic that a shop weld is cheaper than a field weld the Staff has incorrectly assumed that the use of 60-foot joints would categorically reduce costs.

Third, as discussed earlier in this section, the inclusion of unknown-unknown events does not yield a risk-free project. Staff's approach to Event No. 36 again demostrates lack of objectivity. The 6.25 percent value for unknown events can only be viewed as being conservatively low and must remain in the Center Point in order to provide Alaskan Northwest the opportunity to earn the incentive rate of return which the Commission, after considerable deliberations, has deemed to be just and reasonable, rather than the penalty rate of 8 percent.

2. Capital Market Conditions (Event No. 25)

Staff would also totally eliminate the expected value of $21.4 million for this event which has been included to protect against a capital squeeze which impacts the EC's, all subcontractors, their suppliers, and thus the Sponsors. This event was not included to reflect varying market conditions on project debt costs as Staff erroneously presumes.

In view of the current conditions of the capital markets, it is difficult to see how Staff can state "that capital market conditions will not effect direct construction costs...."[24] A change in the capital markets will obviously increase

24 Commission Staff Comments at 18.

the borrowing costs of a contractor or subcontractor engaged in a project. For example, contractors use short term lines of credit extensively to pay their suppliers and labor while awaiting repayment by the owner. They will include these borrowing cost impacts in their bids as part of their overhead as a real cost, not as contingency. Thus, contrary to Staff's position, the Cost Performance Ratio will be affected.

The engineering cost estimate assumed stable capital market conditions. Abnormal Event No. 25 only assesses a 10 percent probability that the current stable conditions would change. Given today's market conditions the filed values are reasonable and must be included in the Center Point.

3. Determination of Proximity of Aggregate After Final Design (Event No. 8)

Staff would eliminate the $65.8 million expected cost impact for this event because it believes this risk has already been covered by the 30 percent allowance in the base estimate for shrinkage of aggregate. Staff also raises this contention in its discussion of the base estimate. (Staff comments at 35.) As we more fully explain infra in our response, there is no double-counting here. The 30 percent allowance, which Staff agrees is reasonable, is to compensate for the predictable and certain loss of gravel during the transportation from the gravel pit to the right-of-way. Event No. 8 is concerned with the risk that aggregate haul costs will increase beyond those expected, because mining permits will not be issued for optimally located aggregate sites or such sites will not contain as much aggregate as is expected. Thus, the 30 percent allowance goes to expected, normal costs for the gravel itself, and Event No. 8 goes to abnormally high costs to haul the gravel. Alaskan Northwest believes that Staff's position is due to a misunderstanding of the purpose of Event No. 8. This event must remain in the Center Point.

B. Events Reduced by Staff

1. Vendor Quality Assurance and Quality Control Problems (Event No. 15) and Vendor Failure to Perform (Event No. 17)

Staff's total proposed reduction of the expected cost impacts for Event Nos. 15 and 17 are grounded in Staff's opinion that the testing program in the base estimate should preclude the occurrence of any cost impacts from vendor QA or QC problems and a vendor's failure to perform will have no adverse cost impacts. Neither opinion has any support. First, the base estimate item only provides for testing. While testing can reduce Vendor QA and QC problems, it cannot eliminate them completely. Vendor QA and QC problems can in fact add costs to the project, including: increased manufacturing costs billed to the purchaser, premium transportation changes to deliver late material to the job site, delays awaiting material, and rework when poor quality material is replaced. Each of these impacts can also have severe ripple effects. For example, problems with pipe quality (even with continuous in-the-mill inspection) frequently require rework in the field. Because this is not encountered until hydrotesting, the cost impacts are much greater than the additional cost of one joint of pipe (the supplier will be liable for only the cost of the additional joint). The vendor ordinarily will not assume responsibility for any additional costs other than the cost to provide a replacement or repair a defective part.

Second, vendor failure to perform can result in substantial additional costs, whether the failure occurs in the early or late stages of construction. For example, if other vendors were booked up with orders, Alaskan Northwest would have to wait until a new vendor's schedule could accommodate Alaskan Northwest's order. The delay would result in additional real costs. Alternatively, Alaskan Northwest might have to pay premium prices for expedited treatment or for the vendor to expand its capacity. Also, in case of vendor failure, there might not be time to resort to competitive bidding. Even if there was sufficient "catch-up time," real costs will be incurred. Thus, Staff's position must be rejected.

2. Sabotage, Vandalism, and Theft (Event No. 31)

Staff believes that the combination of these three items in the same event attributes excessive probabilities to sabotage and excessive cost impacts to vandalism and theft. Therefore, Staff would divide this event into two events: Sabotage (Event No. 31-A) and Vandalism and Theft (Event No. 31-B) and assign reduced probabilities and cost impacts to the new events. In essence, all Staff is doing is substituting its naked judgement for that of the experts who went through the rigorous encoding procedures to develop the values for Event No. 31. Staff offers no support for its contention that subdivision of this event should reduce the overall potential cost impacts.[25] Staff's approach should be rejected.

3. Center Point Events 9, 12, 13, 14, 15, 19, 21 and 23[26]

Staff requests a total dollar reduction of $218.4 million in the Center Point value for Events 9, 12, 13, 14, 15, 19, 21 and 23[27] based upon its belief that such amount was included either in the base estimate as part of the EC's lay rate estimate and Joint Venture bid, or in the pipeline and civil portion of the overall 12 percent normal contingency.

The overview of the relationship of the different components of Alaskan Northwest's cost estimate, and how risks have been allocated to the components, helps establish a base from which specific responses to Staff positions can be made. Generally, it must be stated that: (1) Staff has only analyzed Events 9, 12, 13, 14, 15, 19, 21, and 23 with respect to pipeline construction, and not the complete scope of the project; (2) Staff gives little or no justification for its

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25 Staff's allegation that the loss for major theft for all of Alyeska is $150,000 is absurd. Perhaps Staff's definition of major theft only includes stolen aircraft.

26 Event No. 9 - Impact of Weather on Construction.
Event No. 12 - Terms and Conditions of Project Labor Agreement.
Event No. 13 - Strikes and Slowdowns.
Event No. 14 - EC Quality Assurance and Quality Control Problems.
Event No. 15 - Vendor Quality Assurance and Quality Control Problems.
Event No. 19 - Domestic Outlets for Construction Materials.
Event No. 21 - Domestic Outlets for Construction Equipment.
Event No. 23 - Domestic Outlets for Craft Labor/Foreman.

27 Staff proposes a $71.8 million reduction for Event No. 9 and a $146.6 million reduction for the remaining events.

values,28 (3) Staff's experience with this project, Alaskan conditions, and pipeline construction is limited; (4) groups of events are lumped together to form a plug figure for Staff's "EC risk" category; and, (5) Staff has inadvertently reduced its own revised values for specific events in making its adjustment for EC risk.

In addition Staff fails to understand how the cost effect of the risks included in the pertinent Center Point items will be passed on to the Sponsors. For example, in bidding for construction contracts, contractors will qualify their bids to protect themselves from losing money under fixed-price contracts. They will attach qualifications to their bids because they do not have the resources or time to conduct the same thorough analysis of the project that Alaskan Northwest will have completed by that time. These qualifications will allow them to seek relief from the Sponsors for cost increases resulting from elements of the bid which have been qualified. Most bid qualifications will include cost impacts resulting from inaccurate or complete designs at the time of bidding, abnormal weather, ripple effects from other activities, and government actions such as permitting delays.

If Alaskan Northwest adopted a very restrictive bid qualification policy contractors would either increase their contingency or refuse to bid.29 If they refuse to bid, then Alaskan Northwest will be forced to develop a new bid qualification policy and resubmit bid packages. The delay would be expensive and contractors will have received a more liberal bid qualification policy. Either way, Alaskan Northwest will bear the riskof increased costs.

Contractors will also have the ability to pass through to Alaskan Northwest the risk of cost increases resulting from differences between actual construction conditions and designs (including design and scope changes) and those described in the bid packages. This will be accomplished through change in scope orders.30 Thus, deviations from the bid package will allow contractors to receive cost relief. Examples of potential change orders are: changes in government monitoring

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28 The Sponsors question whether the Staff and its consultants went through a rigorous encoding process to determine their revised values? Whether many experts were consulted? Whether everyone had a clear concept of the definitions of the components of project risk? Whether the encoders understood the IROR procedure? Whether specific scenarios were questioned? There is no evidence to support that any of the required procedures were followed. In fact, there is ample evidence to the contrary.

29 Contractors will expect a liberal change order policy for this project due to its complexity, size, and previous experience in Alaska. As in the case of bid qualifications, Alaskan Northwest is not in the position to adopt a restrictive change order policy, because either contractor contingency would increase dramatically or else Alaskan Northwest would not receive any bids. In fact, members of the Execution Contractor panel stated that this project must have a liberal change order procedure if it is to recieve competitive bids. See Transcript of November 20, 1980 at 11.

30 These change in scope provisions must be distinguished from the change in scope mechanism adopted by the Commission in Order Nos. 31 and 31-B.

procedures, changes in mode type in a given area due to a change in soil conditions, changes in schedule resulting from unanticipated fish streams or timing of salmon migration, and ripple effects from other construction activities which impact a contractor's costs.

Another example of a change in scope is a strike of pipeline construction workers despite an anticipated no-strike clause in the Project Labor Agreement. If this occurs, the Sponsors could be directly liable for any direct costs associated with time lost during the strike, as well as ripple effects which are created by the strike. Such ripple effects could include subsequent changes in wage rates or work rules and impacts on common trades working on compressor stations. Because the PLA will be signed before bid packages are prepared, contractors will make the Sponsors responsible for all labor actions by means of scope changes. Thus, if a strike occurs, they will request cost relief under this mechanism.31

Other categories which present significant risks to both Alaskan Northwest and its contractors are the domestic and world markets for labor, transportation services, materials, construction equipment, and qualified contractors. The EC's will absorb only part of this risk for the resources they supply.32 However, in growing anticipation of shortages they will include their expectations of their risk in their bids and petition for relief from ripple effects created by other components of the project which are outside their control. This liability includes not only potential increase in unit prices (which are adequately treated in the IROR inflation adjustment procedure), but also the ripple effects created by tighter delivery schedules, poorer quality materials and equipment, and inexperienced labor. These conditions will exist if the demand in the world market for materials and supplies increases significantly as it did in 1974. This looms as a serious problem to Alaskan Northwest because all available information points to a worldwide construction boom during this project, e.g., the synthetic fuel facilities planned in the U.S. and abroad, and the recently proposed 2000 mile gas pipeline in Russia. Subsequent to the filing, the Sponsors have initiated more detailed studies on the conditions of world markets for key project resources during the life of the project. All available information suggests serious problems during the construction phase of the Alaska segment.

With this background we now analyze Staff's specific concerns relating to each event.

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31 This example highlights one of the major direct liabilities facing Alaskan Northwest. That is, Order Nos. 31 and 31-B establish a scope change mechanism that is much more restrictive than the provisions, including force majeure clauses, which normally appear in construction contracts. Consequently, Alaskan Northwest has included many abnormal events in its Center Point analysis which, under normal construction practice, would be covered by scope changes or force majeure clauses.

32 For example, Alaskan Northwest will absorb the risks for all materials it directly purchases, such as mainline pipe, compressors, camps, etc. These latter costs are not the EC's risk because Alaskan Northwest has assumed the responsibility to assure that all necessary materials are available on a timely basis and in the proper quantities and according to project and bid specifications.

a. Impact of Weather on Costruction(Event No. 9)

The impact of weather on construction activities is one of the most obvious examples of an abnormal event. There is no doubt that it exists and that abnormal weather will impact the project during each of the three years of heavy construction activity. Despite this, Staff believes that there is only a 1 in 10 chance that there will be eight days of delay due to abnormal weather in the entire project.33

Furthermore, its expected case considers only four days of abnormal weather, or 1.3 days per year. This is a remarkedly optimistic view of Alaskan weather and it is not supported by either the record or detailed weather data.

Members of the EC panel were brought to Irvine on November 20, 1980, solely to entertain the Staff's questions. The transcript of that day's session is in direct contradiction with the following Staff statement: "The ECs stated that the average lay rate established for this project included the weather they actually experienced for Alyeska construction (both normal and abnormal weather)."34 In fact, the transcript summary of November 20, 1980, states at page 8 "that they didn't include anything for what they called abnormal weather...." Furthermore, they stated that they would "qualify their bids to state that they covered only normal weather." They went on to say that they would bill the client for any delays greater than two to three days in a month. They defined this as abnormal weather.

In developing this event, Alaskan Northwest considered deviations from average weather (1976 was an average year and provides the basis for the EC weather experience) as abnormal weather. Any weather that is worse than 1976 will be either built into the EC's bid or be passed through to Alaskan Northwest as part of the bid qualification procedures or via a force majeure clause.

In view of the weather data available, the record, and significant Alaskan construction experience, the sponsors consider that the filed values are the best available assessment of the impact of weather on construction.

b. Terms and Conditions of the Project Labor Agreement (PLA) (Event No. 12)

It is difficult to understand Staff's logic and inconsistent treatment of this event. On one hand, it includes the full value of the event in its suggested values. On the other hand, it substracts part of it out when Staff makes its adjustment for "EC Risk." This is an even more glaring example than Event 15 of Staff's misunderstanding of how risks identified will become actual costs for which either the EC's or Alaskan Northwest will be responsible. Potential cost impacts cannot vanish.

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33 Staff has derived a maximum impact of $24 million. This translates to eight days of delay based upon a spending rate of approximately $3 million per day.

34 The EC's definition of weather that would stop work was -35°F, white out conditions, and winds in excess of 20 miles per hour for welding depending upon the direction of the wind with respect to the position of the welders.

As with all of Staff's divisions between EC and Alaskan Northwest risk, Staff's allocation of 50 percent of the risk of this event to the ECs is questionable. The transcript of November 17, 1980, at pages 37 and 38 states that the PLA will probably "be in place at the time of going out for bids. So in effect, the damage on this point might well be done by the time the Execution Contractors signed up." This demonstrates that the risks for this event will accrue to the Sponsors and will be reflected in the EC bids. In summary, the filed value should be included in the Center Point because Staff (a) is in agreement with the filed value and (b) has improperly divided the risk between Alaskan Northwest and the EC's.

c. Events No. 13, 14, 19, 21, and 23: Strikes and Slowdowns, EC Quality Assurance and Quality Control Problems, Domestic Markets for Construction Materials, Domestic Markets for Construction Equipment and Domestic Markets for Craft Labor/Foremen

The same criticisms of Staff's approach can be applied to these events. However, for these events there is no discussion of values, there is only an assumption of 100 percent EC risk. Furthermore, Staff assumes that these events will only impact pipeline construction costs. It uses pipeline costs as a basis to establish the value of EC risk despite the fact that these events are not limited to pipeline construction.

The transcripts for November 17, 1980 and November 20, 1980 demonstrate that the EC's will not bear 100 percent of the risk of these events. With regard to strikes and slowdowns (Event 13), the transcript states that "in no event did the project sponsors expect that they would have no exposure to costs associated with strikes and slowdowns.35 Regarding EC QA and QC problems, the values established by Alaskan Northwest included scenarios requiring continuous or multi-tiered inspection.36

Events No. 19, 21, and 23 are primarily project wide EC risks. However, the EC's current evaluation of their contingency is based upon current market conditions. When they actually bid, they will be looking at the real market conditions at that time. The values included by Alaskan Northwest for these events reflect an estimate of market conditions during construction which are likely to be reflected in the EC bids.

Market conditions will be tight during the actual construction period. This will cause EC's to hire fewer trained personnel, use a greater mix of used or poorer quality equipment, etc. These factors will cause problems above and beyond the basic increase in costs (no unit price cost increases were included in these events because they are covered by the IROR inflation adjustment mechanism). These ripple effects are the costs that the ECs will include in their bids based upon market conditions when they submit their bids.

In view of the above, Staff's arguments must be rejected.

35 Transcript of November 17, 1980 at 38.

36 Transcript of November 20, 1980 at 13.

III. DESIGN ISSUES/COST ESTIMATE

A. Introduction

Staff urges that if any of its "alternative" designs are ordered the CCE be reduced to the extent of any net savings realized. Alaskan Northwest rejects this approach. It not only evitiates Order Nos. 31 and 31-B by removing any incentives to adopt cost saving design changes, incentives which will inure to the benefit of the ANGTS ratepayer, but significantly increases the risks to the Sponsors.

As Staff admits, Order Nos. 31 and 31-B do not require cost reductions to the CCE resulting from later approved design changes not known to the Sponsors at the time of certification. The underlying rationale behind this decision is to give the Sponsors "...a strong incentive to propose design changes that reduce the ultimate costs to consumers...." (Order No. 31-B at 41). The Commission quite properly recognized that absent this incentive the Sponsors may not propose cost saving design changes -- a result which would contravene the public interest by increasing capital costs without a commensurate reduction in the return to the Sponsors. An example of this result and the net effect of Staff's proposal is seen <u>supra</u> in the second schedule at page six and the text on page seven of our comments. That schedule demonstrates that as total project costs fall, the rate of return increases and the total dollar cost of service decreases, as does the per unit cost of gas. Therefore, the higher the rate of return earned, the lower the cost of service to the consumer, since the cost of service is significantly more sensitive to total cost reductions than to rate of return increases.

Staff's rationale for eliminating the Sponsors' incentive to achieve a higher rate of return and a lower cost of service is premised upon two faulty assumptions: (1) Order Nos. 31 and 31-B did not contemplate the existence of "outstanding design alternatives for which costs are unknown...at the point the CCE and CP are determined..."; and, (2) Alaskan Northwest has agreed to Staff's approach for certain selective issues in any event and, therefore, such approach should be extended to all design alternatives for the sake of consistency.

Staff's first assumption defies logic. The Commission, in Order Nos. 31 and 31-B, clearly recognized that the CCE would not, and could not, be based upon a final design. Staff's suggestion that no design alternative exist at the time of Commission certification demonstrates an ignorance of the realities of this project. In any pipeline project, especially one of this magnitude, design changes will occur until construction is completed; and, it is simply unrealistic to expect the Sponsors to anticipate and cost out every conceivable design alternative prior to certification. Additionally, 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.

Staff's second assumption is factually incorrect. With respect to the costs of tunnelling rather than traversing Atigun Pass, the potential utilization of a crack arrestor approach, and the costs of the communication system design, Alaskan Northwest informed Staff it would agree to adjust the CCE to reflect actual costs -- whether higher or lower than those approved in the base estimate -- in establishment of the Cost Performance Ratio, subject to the approval of both the Commission and the OFI.[37] Conversely, although Staff would require a reduction in the CCE to reflect the net savings of any design changes, Staff does not advocate that the CCE be increased where adoption of a design alternative increases costs.

The difference between the above two approaches is both obvious and significant. And while Alaskan Northwest is willing to adjust the CCE to reflect actual costs for these three items in an attempt to reach a settlement of certain issues with Staff, it would be remiss if it did not mention that the ratepayer is far better off if the provisions of Order Nos. 31 and 31-B are followed without deviation.[38]

Alaskan Northwest also agreed to substitute actual costs for those three potential design changes because it recognizes that these three areas remain open as to design -- that is Alaskan Northwest is willing to modify its design in these areas, if necessary. Because there has been no significant alternate design work done in these three areas, the potential costs of the alternative designs are currently unknown. However, the remaining "alternative" designs suggested by Staff have neither been proposed nor recommended by the Sponsors given their confidence in the current design for these areas. As will be explained below, the remaining so-called "alternative" designs identified by Staff in its comments are not technically feasible and/or would not result in cost savings, notwithstanding Staff's assertions to the contrary.

1. <u>Project Directorate</u>

a. <u>Third Party Monitoring Costs</u>

As previously reported in Alaskan Northwest's and Staff's December 15 submissions, Alaskan Northwest has agreed that the Cost Performance Ratio would not be adjusted to reflect government monitoring costs incurred because of the fault of Alaskan Northwest. However, third monitoring costs should not be automatically disallowed from the Cost Performance Ratio upon an allegation that they were occassioned by the fault of Alaskan Northwest. Alaskan Northwest must first have the opportunity to demonstrate that it was not at fault before any such costs may be disallowed.

Staff recommends that the $203.4 million in costs for the State of Alaska be excluded from the CCE. (Staff Comments at 31). We restate our position that these costs must stay in the CCE although we are not in a position to verify their accuracy. However, estimated costs must be replaced by actual costs for determining the cost performance ratio to avoid penalizing the Sponsors for costs beyond their control.

Should a court decision or similar action invalidate the reimbursement terms of Federal or state statutes, the Projected Capital Costs should be reduced only if and to the extent that Alaskan Northwest actually benefits from such decision or action.

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37 See Report of Alaskan Northwest Natural Gas Transportation Company, on its understandings of Agreements received with the Commission Staff regarding the Certification Cost and Schedule Estimate (filed December 15, 1980).

38 <u>See</u> the second schedule on page six <u>supra</u>.

b. Pre-Certification Costs

Staff and Alaskan Northwest agree that $130.344 million of pre-certification costs should be included in the CCE, provided that the CCE will be adjusted to reflect the actual amount of such costs approved by the Commission in Docket No. CP78-123, et. al. Staff further states, however, that any contingency applied to Project Directorate should not apply to pre-certification costs. In fact, a contingency has never been applied to such costs. The contingency workpapers show that no encoding values were developed for such costs. (See Vol. 33, p. 48, Activity 8-00-019).

c. EEO Compliance and Minority Training Program

Alaskan Northwest submitted its affirmative action plan to OFI on December 16, 1980. Training plans have yet to be developed, however, to comply with the DOI Right-of-Way Grant. Furthermore, the State of Alaska has not specified what training requirements it may impose. By its recommendation that estimates for the costs of such hiring and training programs be filed within 30 days of their approval by OFI, the Staff now recognizes that it would have been impractical to include realistic estimates for these costs in the CCE and that such costs are more appropriately reviewable by OFI. Because OFI must approve any affirmative action or training programs, it is in the best position to analyze and approve the costs of such programs. Approved training costs should be treated as design changes pursuant to Condition No. 9.

2. Atigun Pass Tunnel; Yukon River Crossing; Communications Systems

The Staff stated that Alaskan Northwest has agreed that if it adopts alternatives other than the designs contained in the filing for these items, their actual costs will be substituted in the Project Capital Costs if the alternatives prove to be less costly than the present design. Alaskan Northwest clarifies that it understands the agreement to be that the actual costs of these alternatives will be included in Project Capital Costs whether the actual costs are greater or less than the costs included in the CCE, providing that OFI approves the alternative as a design change and permits inclusion of the actual costs in Projected Capital Costs. However, as previously stated Alaskan Northwest believes that the costs included in the CCE for these items should be handled in accordance with the provisions of Condition No. 9 of Order No. 31-B.

3. Thermal Workpad

Alaskan Northwest believes the structural workpad design contained in the CCE is adequate to protect the haul road and the Alyeska fuel gas line from thaw settlement problems that could be occassioned by construction of the gas pipeline. However, Alaskan Northwest recognizes that a thermal workpad could be required on a site-specific basis. While workpad costs will go up in this event, Alaskan Northwest does not believe the additional costs will exceed the $73 million specified by Staff and will likely be less.

Alaskan Northwest submits that the use of a thermal w rkpad is a design change and can be handled in accordance with the provisio s of Condition No. 9 of Order No. 31-B.

4. Reduction of Workpad in Spreads 5 and 6

The Staff has mistated Alaskan Northwest's design criteria for workpad. Contrary to Staff's assertions that "[t]he design basis for this workpad was stated to be 700 passes of an 85 ton haul vehicle during the spring thaw" (Staff comments at 33), the criteria contained in the filing are that the workpad must be capable of supporting 700 passes of a 35 ton vehicle over three construction seasons. Thus, Alaskan Northwest has obviously not utilized "the most stringent design" for workpad. In fact, our design is similar to Alyeska's and is consistent with the U.S. Army Corps of Engineer experience. In any event, any changes in workpad design would be a detailed final design step that should be treated in accordance with Condition No. 9.

5. Ambient Temperature Pipeline in Spreads 5 and 6

Because Alaskan soils are characterized by the presence of continuous and discontinuous permafrost, it has long been recognized that the Alaska segment of the ANGTS would be a chilled gas pipeline in order to avoid thaw settlement problems. Thus, the President's Decision found as follows:

> All of the pipeline in Alaska and the first 41 miles of pipeline in the Yukon lie in the continuous and discontinuous permafrost region. This section will be operated in a chilled state (i.e., below 32°F.) to prevent degradation of the permafrost regime39.

The geotechnical data concerning frozen soil conditions along the Right-of-Way, including numerous borehole samples, developed or gathered by Alaskan Northwest confirm the prudence and necessity of a chilled pipeline design for the entire Alaska segment because significant amounts of ice-rich soils are found in all spreads. In particular, Spreads 5 and 6 contain 30 to 50 percent permafrost. A warm, or ambient temperature, pipe traversing such soils would thaw the permafrost causing loss of soil support and settlement of the pipe. Differential settlement would place excessive strains on the pipe threatening its integrity and increasing the risks of breaks in the line. Because the mitigation of thaw settlement on spreads 5 and 6 would require above ground construction, the costs for an ambient temperature pipeline on those spreads would be considerably higher than Alaskan Northwest's cold pipe design and would be similar to the costs of the alternative embankment design submitted to the Delegate and Division Director on November 11, 1980.

In addition, as explained in the letter attached hereto as Appendix A, Staff's ambient temperature proposal would, if adopted, cause significant difficulties for the Canadian section of the ANGTS.

While Staff purports to show construction and operating cost savings as justification for an ambient temperature pipeline, it stops short of actually recommending the adoption of an ambient temperature pipeline design. Moreover, the

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39 Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaska Natural Gas Transportation System 14 (September 1977).

claimed 40 percent cost savings for refrigeration fuel is insignificant when compared with the total throughput of the system. It must be remembered that only two stations are located in Spreads 5 and 6. A 40 percent savings in fuel at these stations represents a savings of only 0.16 percent and 0.14 percent, respectively, of total throughput at the two stations.

6. Less Conservative Frost Heave Mitigation

The fact that the benefit to the ratepayer from a reduction in rate base resulting from less insulation requirements would more than offset any gain in rate of return for Alaskan Northwest is illustrated on pages six and seven of these Reply Comments.

7. Temporary Facilities

In order to reduce costs and minimize adverse environmental impacts Alaskan Northwest has chosen to purchase existing construction camps from Alyeska. Thirteen of the Alyeska camps will be utilized at their present locations. Rehabilitation of these camps will be necessary prior to their use. For example, while the existing housing units are structurally in good condition, some items needing repair or replacement include roofing, insulated ceiling panels, wall and floor covering, laundry washer and dryer units, water closets, lavatories, and stall showers. Utility systems will be tested and repaired where necessary. While shops, warehouses, and utility buildings appear to be in satisfactory condition, it is anticipated that some major mechanical equipment items will be replaced, such as incinerators, sewage treatment units, sewage lift stations, pumps, and power generators.

Alaskan Northwest also will purchase from Alyeska three camps that will be required to be moved and relocated along the portion of the pipeline running from Delta Junction to the Canadian Border. The CCE includes an amount for the revegetation of the sites from which the three camps will be removed. Because these camps will be moved onto new sites, site preparation will be necessary, which will include a pad, flow control management reservoir (or other method for wastewater disposal), five-day emergency wastewater holding pond, bulk fuel depot, water supply source, and utility distribution systems.

The compressor station construction camps, situated next to the seven compressor station sites, will be constructed using eight surplus Alyeska pump station construction camps. Certain of these facilities must be moved and these will be disassembled, transported to the new sites, erected, and renovated for the construction period.

In addition to the construction camps already discussed, due to the rerouting of the pipeline required by order of the Department of Interior, currently ongoing field programs that had been anticipated to use existing Alyeska pump station camps must now be housed in added fly camps obtained for this purpose. The amounts for the use of the fly camps, plus certain other additions to the temporary facilities estimate, have been included in the CCE.

The use of existing camps and the placing of new camps has been based on the following criteria: implementation of the spread management concept; minimization of travel time by the construction work force; minimization of the number of camps necessary in order to avoid adverse impacts to the environment by multiple concentrations of new population centers; minimization of the cost of support facilities; and, maintenance of construction progress through the elimination of crew accommodation constraints.

The total costs for the acquisition, renovation, and relocation of the 23 camps has been estimated at $361.7 million. Of this amount, $95.7 million is the estimated cost of acquisition of the Alyeska camps.

Staff has obtained materials from the TAPS proceeding (Docket No. OR78-1) from which it has attempted to derive the cost, in 1980 dollars, of new camps, and then compare this figure with those of Alaskan Northwest. While Alaskan Northwest does not have the TAPS figures that have been made available to Staff, we can make certain observations about the new camp cost approach utilized by Staff. First, certain of Alyeska's camps were constructed in 1969 and 1970, others in 1974. Accordingly, the "April 1977" cost escalated by Staff to 1980 dollars does not truly represent the cost in 1980 dollars. Second, the Alyeska camps were constructed under entirely different standards than those currently in effect. New health, safety, and environment regulations have been promulgated by the State of Alaska which would cause a significant increase in the costs of constructing new camps today vis-a-vis the costs experienced by Alyeska. Third, if new camps are utilized there would be significant delays in project scheduling because of the time required to obtain needed permits for new sites. Simply stated, the camps could not be in place in time to begin construction as currently scheduled. None of these factors have been considered by Staff in its comments.

Alaskan Northwest has calculated the cost of new camps in January 1980 dollars to be $485.3 million, which is $123.6 million more than that required for the planned acquisition and renovation of the Alyeska camps. This figure includes the costs of the additional field programs required due to the new location of camps. Additionally, this figure assumes that new camps do not cause any slippage in the construction schedule although slippage would be likely. The same $485 million cost estimate for new camps has also been developed by escalating the recollections of persons who worked on Alyeska as to the costs of constructing the Alyeska camps to 1980 dollars and taking into account the costs of new state permitting requirements (estimated to be $50 million). In view of the significant cost differential, Alaskan Northwest requests that the costs included in the CCE for the purchase of existing construction camps be approved, provided, however, Alaskan Northwest has stated previously that the contingency for acquisition of the camps can be removed if the CCE is adjusted to reflect the actual costs of purchasing the camps and certain geotechnical information from Alyeska.

Staff also states it cannot reconcile the 15,300 bed camp facilities proposed by Alaskan Northwest with the purchase of 15,800 bed camp facilities from Alyeska. First, the acquisition cost will be the same regardless of whether the number is 15,300 or 15,800. While Alaskan Northwest requires only 15,300 beds, it cannot split a camp in half to obtain the exact number of beds. Additionally, some of the beds acquired will not be utilized because some sleeping areas will be converted into kitchen and office areas.

8. Estimate Borrow Quantities - Aggregate and Common

The Staff erroneously equates the 30 percent volume allowance for shrinkage of aggregate contained in the base estimate with Center Point Event No. 8, "Determination of Proximity of Aggregate after Final Design." Shrinkage covers the loss of aggregate between the gravel pit and the work site. For example, some gravel will always be blown or spilled off of the trucks hauling the gravel. Shrinkage is a known, predictable occurrence in construction work. Experience teaches that approximately 30 percent of the in-site aggregate is lost during excavation, loading, hauling, unloading, placement, and compaction. Therefore, the amount of aggregate quantities in the estimate must be increased by this percentage to offset such shrinkage. Staff does not dispute this.

Event No. 8, however, does not reflect any uncertainty in the quantities of aggregate necessary for construction. Event No. 8, as its name implies, is concerned with uncertainty in costs associated with hauling the aggregate from the gravel pits to the right-of-way. Alaskan Northwest must obtain permits to mine the aggregate. Event No. 8 is designed to cover the risks of increased hauling costs because permits are not issued for sites nearest the right-of-way or optimally located pits do not contain enough aggregate. It does not cover the risk that more aggregate is necessary. Thus, the 30 percent allowance covers a normal, predictable cost for aggregate, while Event No. 8 covers the impact of unexpected transporation costs.

Staff also claims that there are several discrepancies in borrow quantities between the civil alignment sheets and the estimate workpapers. In fact, the alignment sheets and workpapers are not inconsistent. The borrow quantities shown on the alignment sheets were derived by the civil engineers from typical cross-sections. The cost estimators added borrow quantities to the civil engineering estimate to compensate for expected variations in the ditch wall that results from back-hoe ditch excavation techniques. The cost estimators had more information on the shape of the ditch and adjusted the civil engineering borrow estimate accordingly.

9. Line Pipe Specifications and Price

As in the case of alternatives to the current design, Alaskan Northwest has agreed to substitute the actual costs of a less tough pipe with mechanical crack arrestors for the current tough pipe design assuming the alternative design approach is mandated. Again, we note that the actual costs for an alternative design will be substituted regardless whether they constitute a reduction or an increase in costs, providing the design and costs are approved by the Commission and OFI. However, Alaskan Northwest believes this would be a design change and should be treated in accordance with Condition No. 9.

Alaskan Northwest believes its method of estimating the line pipe price fully comports with the Commission's instructions in Order No. 31 to develop a realistic cost estimate that is neither overly optimistic or overly pessimistic. (Order at 46). We cannot know now where the line pipe will come from. We do know that it will come from more than one source. Therefore, an average of bids from likely sources presented the most reasonable approach.

Although we agree with Staff that the assumption on percentage of foreign and domestic pipe (5/6 and 1/6, respectively) should probably have been used in assessing freight cost effects in the engineering estimate, Center Point, and contingency rather than the 75 percent foreign and 25 percent domestic pipe assumption utilized, we believe that the cost effect of reconciling the 75/25 split with the 5/6 / 1/6 split is de minimus.

10. Compressor and Metering Stations - Refrigeration

Staff's position on refrigeration requirements displays a total lack of understanding of our refrigeration design. First, contrary to Staff's statement, refrigeration capacity in the CCE has not increased by 25 percent from the March 1977 estimate. The total refrigeration tonnage specified in the CCE has actually decreased 27 percent, or from 73,000 tons at 8 compressor stations in the 1977 estimate to 57,000 tons at 7 compressor stations in the CCE.

Second, the design in the CCE does not provide for 100 percent refrigeration capacity backup. In fact, there is no capacity backup. Although the design calls for multiple refrigeration units at each station (Exhibit K, Vol. 2, p. K-0-2), the additional unit at each station is not a backup unit. During peak summer months, all of these refrigeration units will be operating. Staff may be confused because the estimate provides for two units at each station. For operating flexibility, the July 1, 1980 design contains two 10,000 BHP units rather than a single large unit rated at 20,000 BHP. For example, during non-peak periods, it is more efficient to operate one 10,000 BHP unit at a station rather than operating a 20,000 BHP unit at half capacity.

Third, we disagree completely that the pipeline can be safely operated for up to 20 days or more without refrigeration. If refrigeration is out at a station, the gas will exit that station at a temperature significantly above 32°F. Ice in the frost bulb downstream from that station will immediately begin to thaw, releasing abnormal amounts of water into the soil, resulting in erosion problems and settlement of the pipe. As the ground settles, the pipe will strain and the integrity of the pipeline will be jeopardized. Significant thaw settlement will occur well before the end of the 20-day period which Staff believes acceptable.

Finally, it is a totally meaningless comparison for Staff to state that "compressors are not spared," because, as we have previously shown, the design does not provide for backup refrigeration capacity at each station. Moreover, Staff is in error when it suggests that gas can be heated at each compressor station. As our filing clearly shows, gas heaters will be provided only at Compressor Station No. 2 and No. 4. (See, e.g., Exhibit Z-9.0, Vol. 6, p. 2-4).

11. Environmental

Both the route proposal in the July 1, 1980 filing through the Fairbanks area and the route now required by the DOI ROW Grant cross similar terrain with similar levels of biological productivity. Northwest Alaskan has examined both routes and has concluded that both represent comparable levels of environmental impact. Specific aspects of the two routes are listed below:

a. Fisheries

Both routes offer similar types of fish habitat. The number of waterbodies crossed is increased with the required route (27 versus 21), but the number of those waterbodies which are known to be fish sensitive is decreased (9 versus 16). Multiple crossings of single creeks is drastically reduced with the required route -- that route crosses Moose Creek only once, while the old route crossed Moose Creek three times, and French Creek five times. Major fish habitats crossed by both routes include Treasure Creek, Moose Creek, Knokanpeover Creek, and the Chena River. Fisheries investigations were conducted on the required route as part of the fall 1980 field studies. Of the seventeen waterbodies investigated, fish presence was noted in five. Field investigations will continue into the sprint of 1981.

b. Endangered Species

There is a peregrine falcon nest site at Grapefruit Rocks near mile 39 of the Elliott Highway. The original route, at old NWA MP 425, passed within approximately 1.5 miles of this nest site. The new route, closer to the Elliott Highway, passes within approximately 1.0 miles of the nest area. This nest area is, however, located on the opposite side of a hill from the Elliott Highway. Alaskan Northwest is of the opinion that the closer proximity, when viewed in the context of activities along the Elliott Highway, is an acceptable location. On these birds, Elliott Highway Activities, our consultants Roseneau and Bente (1980) report:

> In 1979, the pair of peregrines successfully fledged three nestlings even though intense construction activities, including the regular detonation of large amounts of explosives, took place about 0.4 mile away (Roseneau and Bente 1979, 1980). In 1980, what was probably the same pair of peregrines returned, nested at a new location about 0.7 mile farther from the highway and, again, successfully fledged 3 nestlings (Roseneau and Bente 1980).

The required route passes within about 1.4 miles of a historical peregrine falcon site (P-84) on the Chena River. This nest has apparently not been used since the early 1960's. The presence of this nest poses a slightly increased probability of peregrine-pipeline interaction as compared to the old route. A goshawk nest, active in 1979, on Moose Creek Bluffs (Roseneau and Bente 1979) near the old route, will not experience the potential for pipeline-related impact as a result of the new route. Raptor nest surveys will be conducted over the new route.

c. Birds

While both routes exhibit waterbird habitat, the new route crosses a greater amount of wetland area than the old route. The new route crosses approximately twelve miles of flat terrain between the Little Chena River and Moose Creek, which includes the Potlatch Ponds area identified as a waterfowl nesting area by Hemming and Morehouse (1976). The old route crossed near a spring waterfowl concentration area at the Chena Floodplain Project (Richie, 1980). Summer and fall use of this area by waterbirds was not important (Richie and Hawkins, 1980). Upland game birds should be slightly more abundant along the northerly portions of the new route than along the old route because the new route is further from areas of intensive human activity. Neither route, however, is known to traverse any concentration area for upland birds, and no significant difference in potential impact on upland birds is expected between routes.

d. Mammals

The potential impact of the new route on big game may be less than that of the old route because the old route passed through a high density moose wintering area (Hemming and Morehouse 1976). No such area has been identified along the new route, although moose summer range is of fairly good quality near the Little Chena River (R. A. Rausch, personal communication). Beaver are known to be abundant at the new route's crossing of Smallwood Creek (G. Halsey, personal communication).

e. Cultural Resources

The old route would have impacted the Chugwater archaeological site (FAI-035) at Moose Creek Bluff and would have also crossed the Davidson Ditch historic feature (LIV-073). The new route will avoid the Chugwater site at Moose Creek Bluff and any other known prehistoric cultural resource. The new route will, however, still cross the Davidson Ditch historic feature. The new route will be field investigated during the 1981 summer season. The field survey will identify any cultural resource not presently known along the new route.

f. Air Quality, Wastewater, Solid Waste, and Oil/Hazardous Materials

No camps or compressor stations are affected by the new route. Support systems for solid waste and wastewater from the construction spread itself will, of course, shift from the original to the new route, but will not change in scale or extent.

g. Erosion Control and Revegetation

As similar terrain is crossed by both routes, no changes are expected in these aspects.

h. Visual Resources

The new route is somewhat more remote from public roads, and presents less visual impact than does the original route. This is especially true with the avoidance of the crossing of Moose Creek Bluff on the Richardson Highway.

12. Labor Cost Inflation Index

While the Commission rejected the inclusion of actual labor cost inflation in the Cost Performance Ratio, the Commission has never passed on whether inflation adjustment included in the Project Labor Agreement could be used as a measure of inflation. Moreover, the Commission in Order No. 31-B expressely invited the Sponsors to suggest alternative methods for measuring inflation on labor costs during construction. (Order at 29.) We believe that establishment of an inflation index in advance of negotiation of the PLA will weaken rather than strengthen our bargaining position. The proper labor cost index compenent to the composite index for the inflation adjustment mechanism should be that index or indices which are explicitly defined in the terms and conditions of the PLA.

CONCLUSION

In developing the CCE and Center Point the Sponsors strictly adhered to the Commission's directive that a realistic cost estimate be presented for approval, one that provides the Sponsors the opportunity to earn an incentive rate of return, while minimizing cost overruns, thereby lowering the overall cost to the comsumer. Contrary to this directive the Staff urges approval of an unrealistic estimate and changes to Orders No. 31 and 31-B which not only would destroy the incentives recognized by the Commission as necessary to "...provide just and reasonable compensation for investors so that sufficient capital may be attracted to finance the project...." (Order No. 31 at 22), but would also penalize both the Sponsors and the ANGTS gas consumers. Staff's arbitrary and unsupportable reductions in the contingency and Center Point values are without support and cannot be accepted. Accordingly, the IROR values filed by Alaskan Northwest -- a CCE of $8,178 million including contingency and a Center Point of 1.282 -- should be recommended to the Commission for approval.

Respectfully submitted,

Cuba Wadlington, Jr. (JEH)

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

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 22 day of December, 1980.

Jeffrey Goodman for

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

Appendix A

FOOTHILLS PIPE LINES (YUKON) LTD.

G.B. LIPSETT VICE PRESIDENT,
ENGINEERING AND ENVIRONMENT

1600 BOW VALLEY SQUARE II
205 - FIFTH AVE. S.W. BOX 9083
CALGARY, ALBERTA T2P 2W4
PHONE (403) 237-1422

December 19, 1980

NORTHWEST ALASKAN PIPELINE CO.
One La Fayette Centre
1120 - 20th Street N.W.
Suite S-700
WASHINGTON, D.C. 20036

Attention: Mr. Darrel Mackay
Vice-President Regulatory
and
Governmental Affairs

RE: Alaskan Northwest Natural Gas Transportation Company
FERC Docket No. CP 80-435

Dear Darrel:

It is my understanding that the FERC staff has proposed, in the above-referenced proceeding, that Alaskan Northwest alter its present plans to operate the entire Alaskan segment of the ANGTS chilled. Instead, Staff recommends that the portion of the line "extending from the discharge of Compressor Station 13 (on Section 5) to the Canadian Border" be operated at "ambient temperature." (Commission Staff Comments, filed in the above-referenced proceeding on November 7, 1980, at 5). Staff maintains that such a change is "technically feasible" and would, if adopted, bring about substantial "cost savings." (Id. at 5 and 6). You and your staff are obviously uniquely qualified to comment upon the technical feasibility and economic impact of the staff's proposal insofar as the Alaskan segment is concerned. To avoid any possible confusion, however, we wish to make it clear that adoption of such an approach would necessitate significant design modifications, with resulting increased costs, on the South Yukon segment of the line in Canada.

Foothills' present design assumes that the gas will be delivered chilled at the Border by Alaskan Northwest. Foothills does not plan to install any refrigeration capacity in the South Yukon. Nevertheless, the line will operate chilled from the Border to the first Canadian compressor station, located about 64 km from the Border, as a result of the temperature of the gas when delivered. We estimate that approximately 13 km of that 64 km segment will require frost heave mitigation. Since the gas will flow at a temperature below $0^{o}C$, thaw settlement is, by definition not now a concern on that segment.

If the staff's "ambient temperature" proposal is adopted, the gas will, contrary to present assumptions, obviously not be chilled when delivered at the Border. There appear to be two approaches available to Foothills in order to deal with such a change in plans. First, Foothills could simply abandon its present plan to operate the line chilled for the first 64 km of the South Yukon segment. That approach would, by definition, eliminate frost heave as a concern. Nevertheless, because the gas would flow at a temperature above $0^{o}C$, thaw settlement would become a concern in those locations along the route where thaw susceptible soils are present. For obvious reasons, Foothills has not undertaken definitive studies to identify the precise locations of thaw susceptible soils along the first 64 km of the South Yukon segment. We believe, however, that approximately 54 km of that segment is thaw susceptible and would, therefore, require implementation of thaw settlement mitigation measures. Thus, the staff's "ambient temperature" proposal, would eliminate 13 km of frost heave mitigation in the Yukon, but add approximately 54 km of thaw settlement mitigation, for a net increase of approximately 41 km of thermal mitigation.

As you know, both frost heave and thaw settlement result from thermal interaction between the pipeline and the surrounding soils. Because the cause is similar, the range of solutions to the problems is similar, consisting primarily of various techniques to insulate against thermal interaction between the pipeline and the native soils and/or to replace the native soils with select backfill not subject to heave or settlement. As a rule of thumb, we estimate that the costs of such mitigation measures are at least approximately $2-3 million/km, depending upon site specific circumstances. Using this rule of thumb, and recognizing that a site specific design and cost estimate is not available, we estimate that the extra 41 km of thermal mitigation which the staff's "ambient temperature" proposal would add to the South Yukon segment, would increase our costs on that segment by approximately 80-120 million.

As an alternative to simply abandoning plans to operate the line chilled in the South Yukon, Foothills could install refrigeration capacity at the border. Our preliminary analysis shows that, to implement this approach, refrigeration units would be added to the first Canadian compressor station, which would be relocated to the Border from its presently planned location at kilometer post 64. For operational reasons, the third Canadian station would have to be moved from its present location at kilometer post 215, to kilometer post 200. Thus, the gas would be chilled in Canada for approximatley 200 kilometers, as opposed to the presently planned 64 kilometers.

Absent a definitive study, it is quite difficult to estimate accurately the cost impact of such a major design change. Cost increases, however, would fall into three main categories. First, the refrigeration units themselves would cost approximately $25 million. Second, because the line would be chilled for an extra 136 kilometers (i.e. between kilometer posts 64 and 200), frost heave mitigation costs would increase. Third, the relocation of two compressor stations would, in and of itself, require additional environmental and engineering studies, etc. which would be costly, although at this preliminary stage we are hesitant to attempt a specific estimate.

Putting all of this together, we believe that adoption of the second alternative could increase capital costs on the South Yukon segment by $100 million. Given present uncertainties as to the extent of the additional frost heave mitigation which would be required, and as to the base costs of compressor station relocation, the net increase could well be as much as $200 million. In addition, of course, the installation of refrigeration units on our line would increase fuel use in the Yukon once operations begin.

I hope this material is helpful to you. If you have further questions, please do not hesitate to contact me. In that regard, you should be aware that John Ellwood and I conveyed all of this information to Messrs. Hart and Roddy of the FERC staff, and responded to all of their inquiries about it, during a conference call on December 12, 1980.

Best regards,

G.B. Lipsett

GBL/bt

UNITED STATES OF AMERICA
Before The
FEDERAL ENERGY REGULATORY COMMISSION

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

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

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

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

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

1. Project Directorate Estimate Issues

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

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

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

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

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

2. DOI Reroute

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

3. Embankment Construction Mode

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

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

4. Snowpad - Snow Route Construction

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

5. Atigun Pass Tunnel

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

6. Thermal Workpad

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

7. Aerial Crossing of Yukon River

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

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

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

9. Ambient Temperature Pipeline in Spreads 5 and 6

See response to Item 8.

10. Less Conservative Frost Heave Mitigation

See response to Item 8.

11. An Increase Of One Year In Construction Schedule

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

12. Communications System Design

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

13. New Construction Camps

See response to Item 8.

14. Pipeline Lay Rate

See response to Item 8.

15. Pipeline Construction and Contingency for Weather and Delay

See response to Item 8.

16. Ditch Gravel Quantity Error

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

17. Line Pipe Specifications and Price

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

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

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

18. Miscellaneous Unspecified Materials

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

19. Compressor and Metering Station Estimate Concerns

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

20. Temporary Facilities and Service Estimate Concerns

See response to Item 8.

21. The Communications and Supervisory System Estimate

See response to Item 12.

22. Environmental Concerns

See response to Item 8.

Respectfully submitted,

Cuba Wadlington, Jr.

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

cc: Restricted Service List
Docket No. CP80-435

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

Comments Of The State Of Alaska
With Respect To The Proposed Treatment Of
Monitoring and Socio-Economic Impact Expenditures

The State of Alaska ("Alaska") offers these comments with respect to the procedure for examining Alaskan socio-economic impact assistance costs proposed by the Alaskan Delegate and the Director, Audit and Cost Analysis, Office of Federal Inspector in their July 1981 "Report to the Commission on Certification Cost Estimate and Related Incentive Rate of Return Issues for the Alaskan Segment of the Alaska Natural Gas Transportation System" (hereinafter "Adger/ Berman Report"). Alaska reserves the right to reply to any other issues raised by the initial comments of other parties.

The costs in question are proposed expenditures for socio-economic impact assistance programs by the State of Alaska and for monitoring of ANGTS by State regulatory authorities. ANGTS proposes to reimburse the State for some of these costs. The issues presented by these expenditures, as well as their nature, are addressed in full in the State's February 13, 1981, Memorandum ("Memorandum"), a copy of which (minus appendices) is attached hereto and incorporated by reference.

The Adger/Berman Report proposes that these costs be considered in a separate subproceeding which could commence immediately. Because of the issues raised and the timing of the submission, the Adger/Berman Report recommends further proceedings to develop fully the factual and legal basis for the socio-economic costs filed by Alaska in the subproceeding. The subproceeding would not only address the issues raised by staff and Alaska but would seek to ascertain federal policy on this issue.

The proposed procedure is not objectionable *per se* to Alaska but Alaska must raise the question whether the additional proceeding is necessary to a favorable resolution of this issue. With respect to socio-economic impact assistance, the basic fact of the matter is that Alaska, after examining the Commission precedent and other authorities cited in the Memorandum, elected to seek reimbursement from ANGTS for only those impact assistance costs directly caused by pipeline workers and their families -- "Type I" assistance costs. These amounts are slightly less than $20 million (1980 dollars). The balance of the impact assistance costs identified by Alaskan government officials in the State budgetary process will be borne by the State of Alaska. These costs exceed by several times the less than $20 million that Alaska proposes for ANGTS to bear. Alaska believes that the proposed sharing of socio-economic impact costs is fair to all concerned and should be accepted by the Commission.

It is possible that the course suggested by the Adger/Berman Report may prove more complicated and time consuming than necessary.

Alaska believes therefore that there is a solid basis in the record for approving the inclusion in the cost estimate of the approximately $20 million of socio-economic impact costs Alaska seeks from the ANGTS as well as the monitoring costs it has described. Alaska believes there is no record that would support the exclusion on a legal or factual basis of these costs.

On the other hand, Alaska questions whether it is necessary to determine overall federal policy on the issue of socio-economic impact assistance in the context of this single project. Adding national policy implications to the resolution of this issue can only add to the political visibility and consequences of the issue which may only aggravate the resolution of a relatively straightforward question.

Although the Adger/Berman Report questions the timing of Alaska's memorandum relative to the issuance of this report, the only timing question is why the Adger/ Berman Report did not further address the issue. Alaska's memorandum was filed on February 13, 1981. Six months have passed since the submission of Alaska's Memorandum. Authorizing a further subproceeding may only lengthen the time needed to resolve what in the overall context of the project is not a major issue although one quite important to Alaskans.

The Commission staff has suggested that the absence of explicit statutory authority requiring the payment of these costs by the ANGTS. As Alaska has repeatedly suggested to the Commission staff, the absence of express authority could be quickly remedied by the passage of new legislation in the Alaskan legislature. Alaska has also pointed out that if legislation is introduced the legislature may feel that the project should bear a far larger share of costs of the impact it will cause in Alaska. Alaska can inform the Commission that legislation is being considered that will require the ANGTS to bear socio-economic impact assistance costs. The extent and magnitude of the socio-economic costs the legislation would impose will be determined by the legislature.

Therefore, if the Commission believes that it would be a fruitful expenditure of the time of Alaska, the staff, the applicant and others to address this issue and to consider the arguments about federal national policy on this point, it will abide by the Commission's determination to have a subproceeding. Alaska believes it is clear the Commission could not enter an order excluding these costs from the cost estimate on the basis of the present record.

There is a major factual error in the Adger/Berman Report with respect to the discussion of monitoring costs. The Adger/Berman Report suggests "the State's cost estimate has changed" and the figure for surveillance costs has allegedly more than doubled. (Adger/Berman Report at p. V-7.) This is not correct. This same statement was made in the draft Adger/Berman Report. On May 19, 1981, Alaska submitted a three page letter explaining the draft report's error and asking a correction. This letter unexplicably was ignored by the final Report. In fact the 1981 surveillance costs are somewhat lower than the July 1980 numbers and the misimpression that the numbers have doubled is due to the format in which they were presented by the Northwest application.

Accordingly, Alaska respectfully suggests that the Commission consider the arguments advanced here and in the attached Memorandum and enter an order approving the inclusion in the cost estimate of the socio-economic impact and monitoring costs stated in the February 13, 1981 Memorandum. In the alternative, Alaska suggests that the Commission promptly institute a proceeding to address these issues.

Respectfully submitted,

Robert H. Loeffler

MORRISON & FOERSTER
1920 N Street, N.W.
Suite 800
Washington, D.C. 20036

Attorney for the State Of Alaska

September 18, 1981

VERIFICATION

DISTRICT OF COLUMBIA : ss

Robert H. Loeffler, being duly sworn, deposes and says that he is one of the attorneys for the State of Alaska; that as such he has signed the foregoing Comments of the State of Alaska With Respect To The Proposed Treatment Of Monitoring and Socio-Economic Impact Expenditures; that he is familiar with the contents thereof; and that the matter and things therein set forth are true to the best of his knowledge and belief.

Robert H. Loeffler

Subscribed and sworn to before me this 18th day of September 1981.

Notary Public

... Expires January 31, 198?

CERTIFICATE OF SERVICE

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

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

Robert H. Loeffler

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

MEMORANDUM OF THE STATE OF ALASKA REGARDING RECOVERY OF MONITORING AND SOCIO-ECONOMIC EXPENDITURES AND SUBMISSION OF REVISED ESTIMATE OF SUCH COSTS

The State of Alaska ("Alaska") submits this memorandum in support of its position that certain costs of mitigating the socio-economic impacts of the Alaska Natural Gas Transportation System ("ANGTS" or "the project") in Alaska, as further described below, are properly included in the Certification Cost Estimate ("CCE") and borne by the project. As an appendix to this legal memorandum, the State is submitting a summary of its most current budgetary information describing the cost and nature of the monitoring and socio-economic impact assistance programs that the ANGTS will be asked to support.1/ The budgetary information does not include data as to highway impact costs which are still being formulated nor does it include any costs associated with the socio-economic impact of the conditioning plant which, according to Order 45, is not part of ANGTS.2/ Generally stated, Alaska's position is that the Commission has already ruled that prudent socio-economic impact costs should be included in

1/ Alaskan Northwest Natural Gas Transportation Company ("Northwest") will formally submit this material as an amendment to its cost estimate as a substitute for the earlier information now in that application. Alaska will supply to the Commission Staff, Northwest, and the Office of the Alaskan delegate a copy of the basic budgetary data from which the impact cost figures are drawn. Should any other party on the restricted service list request a copy, Alaska will supply a copy of this data.

2/ Any costs associated with these issues will be formulated and supplied at an appropriate time.

the cost estimate and hence that they are properly borne by the ANGTS; that the recovery of such costs from the project is well supported legally, economically, and socially; and that the objection of the Commission staff to the recovery in principle of such costs is neither timely nor well-founded.

Alaska's concerns with the socio-economic impacts of the ANGTS are neither newfound nor casual. They spring directly from Alaska's traumatic experience with the construction of the TransAlaska oil pipeline. Dramatic increases in almost every category of undesirable economic and social behavior occurred. These included but were not limited to housing shortages, rampant inflation in the local cost of goods and services, an explosion in domestic problems such as divorce and child- and spouse-abuse, an increase in crime generally as well as the importation of crimes not seen before in Alaska, and destruction, at least short-term, of some of the amenities that attracted many early Alaskans to the State. The shock of this activity was amplified by its occurrence over a small period of time -- the construction years -- but, several years later, the wound has not healed completely and the scar tissue of Alaskans is tender.

That is not to say that there are not benefits to Alaskans from petroleum development. Alaska's wealth has increased and the State government has attempted to bring the benefit of this new wealth directly to its citizens although these efforts have met at least temporary obstacles.3/

3/ In 1980, Alaska enacted legislation providing for the distribution of "dividends" to Alaska residents to be paid from part of the Permanent Fund. The Fund is comprised of a percentage of the State's rentals, royalties and lease sale proceeds received from oil and gas development in the State. Although all dividends are of equal amount, the number of dividends received by each Alaska resident corresponds to the number of years he or she has been a resident since statehood. The Alaska Supreme Court upheld the dividend program in a challenge to its constitutionality on equal protection grounds. Williams v. Zobel, No. 2201 (Alaska Sup. Ct., Oct. 24, 1980). However, distribution of the dividends was stayed by the U.S. Supreme Court pending disposition of an appeal from the Alaska Supreme Court's decision. Zobel v. Williams, No. 80-1146 (U.S. Sup. Ct., Order of November 17, 1980).

Money alone is not the answer; the answer is a concentrated effort to avoid or mitigate the impact of any new major projects in Alaska.

For these reasons, when proceedings were initiated before the Federal Power Commission to consider the competing proposals for the transportation of Alaska natural gas to the Lower Forty-Eight states, Alaska did not stop with announcing its favored proposal but identified as one of its critical concerns the socio-economic impacts of any Alaska gas pipeline and asked that the costs of preventing and remedying those social ills be placed on the pipeline. Alaska said that, "unless ... they are internalized to the project, natural gas consumers in the Lower Forty-Eight states would have an undeserved bargain at the expense of the taxpayers and residents generally of Alaska." Statement of Position of the State of Alaska, El Paso Alaska, et al., docket number CP75-96 et al. at 2 (April 7, 1975).4/ This statement of concern was made quite apart from the issue of selection of a particular pipeline proposal. It is a concern that Alaska maintains to this day.

The question of the recovery of socio-economic impact costs was next raised in the Commission's Incentive Rate of Return rulemaking (RM78-12). The Upper Tanana Development Corporation proposed that socio-economic expenditures should constitute a fifth category of change in scope events. The Commission chose a different approach:

> "For the reasons discussed below, prudent expenditures of that nature should be included in the certification cost estimate at the outset, and should not be included in the change in scope mechanism." Order 31, at 125 (June 8, 1979).

The Commission staff applied for rehearing of this order on many points but nowhere in its 78 page application did it raise or even mention the Commission's determination on socio-economic costs. See generally, Application for Rehearing of the Commission Staff, Docket RM78-12 (July 24, 1979). Moreover, the Commission did not modify its determination in any regard in Orders 31-A or 31-B.

4/ In the El Paso Alaska proceeding, Alaska presented testimony on the socio-economic impact of TAPS and the projected impact of ANGTS.

For that reason, when Alaska Northwest Natural Gas Transportation Company was in the process of preparing its certification cost estimate, it approached Alaska through the State Pipeline Coordinator's Office and asked for an estimate of third party monitoring and socio-economic impact assistance costs. Since the formal State budgetary process that would generate and review such costs had not begun, Alaska's Pipeline Coordinator asked the various state agencies what their best estimate was of the socio-economic impact costs of the ANGTS. These estimates were compiled and supplied to Northwest and they were included in Northwest's application.

When these figures became a point of controversy in the informal proceedings conducted by the Office of the Federal Inspector and the Alaskan Delegate with regard to the certification cost estimate (Docket CP80-435), Alaska informed all parties that revised figures would be filed upon completion of the State budgetary process. By letter of November 24, 1980, Alaska informed all parties that it would supply revised figures no later than December 15, 1980, following the State budget process. By subsequent letter of December 14, 1980, the parties were informed that the budget process was still continuing and a new target date early in January was projected. Now the process is complete and revised numbers are available. Alaska regrets the delay but believes the additional time it spent will ultimately advance the process in which the Commission is engaged.

The revised figures, explained further below, are in 1980 dollars, \$51,255,900 for surveillance, and \$19,784,100 for socio-economic impact assistance in the nature of specific programs, as opposed to the creation of a general fund, for a total of \$71,040,000.5/ Socio-economic impact assistance costs have been requested only for impact costs incurred directly as a result of pipeline construction workers and their families, not for the induced impact that will be caused by those attracted to Alaska but not employed by the project. These numbers do not include highway indemnification costs nor do they include such socio-economic impact assistance costs as may be associated with the construction of the conditioning plant.

The Staff position is asserted in its comments of November 7, 1980, which state that third party monitoring (surveillance) costs should remain in the cost estimate unless the statutory basis for those costs is upset by the federal or state courts. Beyond that, the Staff objects to the inclusion of socio-economic impact mitigation costs as

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5/ In actual dollars (as spent), these figures are \$72,697,100 for surveillance, \$28,312,700 for socio-economic impact assistance, and a total of \$101,009,800.

"not required by statute and may be more properly supported by tax and royalty revenues from the project" and asks that they be deleted from the CCE. Staff Comments, Docket CP80-435, at 4 (November 7, 1981).

Northwest's position is that both monitoring and socio-economic costs should be retained in the CCE but, as to the latter, assets that they be retained in the CCE pending a determination by the FERC of their "allowability." As to both costs, Northwest agrees that the cost performance ratio should be adjusted to reflect actual costs. Report of Alaskan Northwest Natural Gas Transportation Company on Its Understanding of Agreements Reached With the Commission Staff Regarding the Certification Cost and Schedule Estimate, at 1-2 (December 22, 1980).

ARGUMENT

1. The Commission Has Already Ruled That Socio-Economic Impact Costs Should Be Included in the Certification Cost Estimate.

At the outset, Alaska does not believe that, *in principle*, the propriety of inclusion of socio-economic costs in the cost estimate is unresolved. Order 31 is quite definite in directing that prudent costs of this nature be included in the cost estimate. *Order 31* at 125. *A fortiori*, this is a determination that *in principle* such costs are properly assignable to the project. Alaska recognizes that a determination whether particular categories of socio-economic expenditures are prudent requires further rulings but the principle of recovery of certain of these costs from the project has been decided. That order is final, both as to rehearing and as to judicial review. The Commission staff had its opportunity to seek rehearing on this point but did not do so. Thus, the principal issue raised by Staff -- whether such costs should be part of the CCE -- is decided and the Staff's arguments should not be heard now except perhaps insofar as they relate to the recovery of particular costs rather than to the permissibility of including *any* costs of this nature. Further, the appropriate time to address the prudency of such costs would not appear to be this proceeding since determinations of prudency generally are made *after*, not before, expenditures of funds by a natural gas company. Nonetheless, given the special nature of this proceeding, Alaska will endeavor to address this issue now.

2. That Alaska Will Suffer Adverse Socio-Economic Impact Is Indisputable.

There is and can be no dispute that Alaska will suffer substantial socio-economic impact from construction of the ANGTS. Construction will last only a few years but it will attract to Alaska not only thousands of construction workers and their families but many others seeking work in peripheral activities related to the project or opportunities in Alaska they may never realize. According to the budget information developed by the State government, more than 35,000 job seekers will come to Alaska in hopes of finding project related employment. As many as 13,171 workers are expected to be employed directly on construction. Yet Alaska's entire population is only 400,481. (1980 census, Preliminary Count). Much of its population is located in the Anchorage SMSA (173,992, 1980 Census, Preliminary Count). But the communities that will experience the most impact are much smaller and nearer the pipeline corridor. For these, the effect of a sudden increase in activity and population from the pipeline can be a severe and immediate shock. Moreover, the level of services necessary to accommodate the impact is not generally that which state and local government are typically called upon to provide, for it is necessary for the few years of the construction period only. It makes no sense for Alaska governments to expand staff and construct permanent facilities for an impact of but a few years duration.

Population increases, housing shortages, local economic changes and sudden and heavy demands on limited public services as a result of increased crime, alcoholism and family problems are all expected as a result of construction of the Alaskan Natural Gas Transportation System. These effects were addressed in the environmental impact statements for ANGTS and more recent studies by the State continue to document their occurrence. No party, not even Staff, disputes that these effects will occur and that they will occur as a result of construction of the ANGTS. Thus, the basic question is of responsibility for mitigating the acknowledged impact.

3. Reimbursement of Socio-Economic Impact Costs Is Prudently Undertaken By The ANGTS

The duty to identify and mitigate socio-economic impact, and to expend funds to that end, is no different in principle then the now well accepted responsibility to identify and mitigate harm to the physical environment. 18 C.F.R. Sections 2.69, 2.80, 2.82. This duty arises not only from the National Environment Policy Act (NEPA) but from the public interest standard itself. No one today would suggest that any major project licensed by the Commission could leave impact to the physical environment unredressed by saying it belonged to the landowners and governments at the site of the project. Injury to the social environment, while less tangible, also properly comes within the duty to mitigate harm to the "environment."6/

That there is an obligation by Commission licensees to address socio-economic impact7/ is recognized in Commission precedent. In Virginia Electric and Power Company (VEPCO), the presiding Administrative Law Judge referred to the requirements of NEPA as "[carrying] with . . . [them] a duty to take reasonable steps within the agency's jurisdiction to ensure that adverse impacts [on the social environment] are mitigated as far as possible." See Limited Decision Issuing License for the Bath County Pumped Storage Project, issued September 20, 1976, Project No. 2716, at p. 48, approved and adopted by the Commission, Opinion 785, January 10, 1977. At issue was whether an applicant for a license to construct power-generation facilities could be required by the Federal Power Commission to bear certain costs associated with the socio-economic impacts anticipated from a large influx of construction-related people. The Administrative Law Judge was persuaded that the applicant should bear some of those costs and that it was the obligation of the Commission to ensure that such impacts were properly mitigated. The Administrative Law Judge ruled that:

> the license should be conditioned to require the licensee to extend financial assistance to Highland County to mitigate the impact upon the County's fisc resulting from the influx of project workers, their families and others who accompany them . . . during the period of project construction. The assistance is necessary in the following areas of additional costs, to the extent they are not covered by increased tax revenues and fees attributable to the presence of project workers or increased financial assistance from other levels of government: (1) education; (2) law enforcement; (3) solid waste disposal; (4) general

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6/ The nature of socio-economic impact from a particular project will vary according to its size, nature, and location. Nonetheless, Alaska knows, based upon its TAPS experience, that such impact can be identified and predicted, especially in as unique a social environment as Alaska.

7/ NEPA is not limited to concern with the physical environment. Hanley v. Mitchell, 460 F.2d 640, 647 (2d Cir.), cert. denied, 409 U.S. 990 (1972). Accord, Chelsea Neighborhood Associations v. U.S. Postal Service, 516 F.2d 378, 388 (2d Cir. 1975); Monarch Chemical Works, Inc. v. Exon, 466 F.Supp. 639, 655-56 (D.Neb. 1979).

government costs; and (5) welfare and other social services. VEPCO Limited Decision, at 56.

This decision does not stand alone. See, e.g., Appalachian Power Company, Opinion and Order of the Commission Granting a License for the Construction of the Blue Ridge Project, issued June 14, 1974, Project No. 2317 (mitigation measures required in the form of financial assistance for moving expenses, personal property losses, and increased mortgage interest costs); Pacific Alaska LNG Company, et al., initial decision, issued August 13, 1979, Docket No. CP75-140 (applicant required to establish experimental bus program and identify and protect cultural values of native Americans). In fact some of the costs that are recognized by the Commission's rules and regulations as standard pipeline cost items are properly characterized as socio-economic impact costs.8/

Thus, Commission precedent recognizes a duty to address socio-economic impact although the particular means that the applicant must select naturally varies according to the circumstances.

The effect of this duty is to ensure that socio-economic costs are "internalized" to a major energy project such as the ANGTS. The "costs" of a major energy project are not limited to impact upon the physical environment alone and mitigation costs also should not be so limited. The "internalization" of social costs is comparable to, and makes just as much sense as, the inclusion of the costs of environmental mitigation, which the President has identified as part of the cost of pipeline construction. See as to environmental costs, President's Decision, at pp. 33-36; 18 C.F.R. Section 2.69, 18 C.F.R. Section 2.80; 18 C.F.R. Section 2.82.

On economic policy grounds, socio-economic costs are also properly a responsibility of the project. Recent Congressional enactments requiring the conservation and efficient use of our natural resources establish that the price of energy resources provided to the public actually

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8/ See, e.g., The Instructions for Carrier Property Accounts, "3-3, Cost of Property Constructed" include as costs: (6) protection, including "amounts paid to municipal corporations for fire protection ... and analogous items;" (8) privileges and permits, including "compensation for ... use of private or public property or of streets, in connection with construction work;" (10) rent, "including quarters used for construction work;" and (5) cost of contract work performed by others.

should reflect the full cost of their production and transportation, including social and environmental costs. See, e.g., National Energy Conservation Policy Act, Title I, Section 102, 42 U.S.C. Section 8201; Powerplant and Industrial Fuel Use Act of 1978, Title I, Section 102, 42 U.S.C. Section 8301; Public Utility Regulatory Policies Act of 1978, Section 2, 16 U.S.C. Section 2601. Unless these costs are included in the price to the consumer, the result will be an artificially low price which does not reflect actual costs or conform to national policy. Stated more succinctly, "if external social costs are not somehow incorporated in the costs of production, demand may be distorted by reason of incorrect price signals reflecting only internalized costs." Energy Law Service, M5A.74 (Callahan & Co. 1979). Thus, the price to consumers should reflect a true cost of producing a depleting resource. Artificially reducing the price by excluding these costs tends to distort the price signal consumers receive. Conservation and efficient use of our natural resources require that all costs, including the cost of mitigating socio-economic impacts, be included in the "rate base" for the computation of the pipeline tariffs. Only in this manner will the true cost of an energy resource be spread among its recipients.

These policy considerations support the Commission's determination in Order 31 that prudent socio-economic costs be included in the certification cost estimate. Having made that determination, the question pending in this proceeding is the appropriateness of the particular programs as a means of addressing the socio-economic impact of ANGTS. And it is to that question we now turn.

4. The Costs Alaska Has Described Are A Reasonable Response to ANGTS' Duty To Mitigate Socio-Economic Impact

Once the duty to address socio-economic impact is acknowledged, a question of prudency may still arise as to the particular expenditures that are proposed. The programs must be reasonably related to the objective of mitigating impact and likely to achieve that goal. Also relevant may be the scope of the programs --are they focused on project impact or are they aimed at the population at large? Scrutiny of Alaska's programs demonstrates that they meet these tests.

Funds requested are limited to those necessary to address solely impact associated with construction workers and their families, not that from the far larger population attracted to Alaska because of real or perceived opportunities on the pipeline. Stated another way, the State seeks funds only to cover those socio-economic costs directly related to providing natural gas to the Lower Forty-Eight.

The nearly twenty million dollars9/ that ANGTS will bear is for programs to be administered by the Departments of Natural Resources, Public Safety, Health and Social Services, and Labor.

Approximately 30% of these funds will be expended by the Department of Natural Resources. It will establish Impact Information Centers and a Citizen's Socio-Economic Advisory Council as a means of informing citizens along the pipeline corridor of the expected impacts and to assist communities and citizens in meeting those impacts as well as providing a channel for Northwest, State, and local officials to work together on meeting the common problem of socio-economic impact. These activities are aimed at preventing sudden shocks from pipeline construction by providing those most likely to be affected with adequate advance information and guidance so that they can anticipate and perhaps avoid the worst part of negative socio-economic impact. These centers are regarded by the State as a direct response to avoiding the surprises of the Alyeska experience and it is believed that they will be effective in implementing ANGTS's duty to mitigate adverse socio-economic impact.

The programs of the Department of Labor to address socio-economic impact are directed to the more than 13,000 workers who will be employed directly on the pipeline in the peak period. It is estimated by the Department of Labor that more than 35,000 job seekers will come to Alaska in search of employment on the project. Department of Labor impact assistance funds will be spent for safety inspections, to enforce occupational and health regulations, to process and, as necessary, adjudicate employment compensation claims for work-related injuries, and for retraining workers injured on the gas line. The balance of the Department of Labor funds will be used to handle administrative services for pipeline-related applications such as unemployment claims.

Department of Public Safety funds would be expended on additional personnel and equipment necessary to enforce vehicle size and weight laws and to license the additional vehicles of workers coming into the State as a result of the pipeline construction. This increased activity will directly benefit ANGTS because it will promote the free flow of truck traffic essential to pipeline construction.

9/ Since there has been no significant controversy regarding reimbursement for permitting, monitoring and surveillance programs, this memorandum focuses on the socio-economic programs question principally. The twenty million dollars is for socio-economic mitigation only, not monitoring, as is made clear above.

The Department of Health and Social Services would expend its impact assistance funds for health services, such as inspection of x-ray equipment, monitoring for communicable diseases in pipeline camps and emergency medical services along the pipeline corridor, and for alcoholism and drug abuse programs along the pipeline corridor. Funds will also be expended for social services. The Department estimates that the influx of pipeline workers and their families will give rise to 500 additional cases of child abuse and child neglect. It expects related needs for foster care (29,200 days per year) and institutional care (7,300 days per year), all for pipeline workers and their families. Finally, a small pipeline liaison office will be created to assist in the administration of these programs.

It bears emphasis that the funds sought are but a small fraction of the socio-economic impact costs identified in the State budget process10/ and likewise much less than the impact in quantifiable terms that the State expects from construction of the Alaska Natural Gas Transportation System. Alaska is prepared to absorb the cost of the more general, "Type II", impacts.

What this means is that there will be a sharing of the burden of socio-economic impact between ANGTS and the responsible governments in Alaska. Such a sharing is not only consistent with the principles established by *VEPCO*, *supra*, but is also a recognition that the problem is mutual. The actual division of expenditures between the project and the Alaska government, while soundly based in this case, is less important than the assumption by the project of at least some of the impact it is causing. It is fitting that the impact most directly caused by, and identified with, the project -- that of the pipeline construction workers and their families -- is the share of the burden that ANGTS is asked to assume.

Also, none of these dollars will go toward the creation of a special fund or funds to be distributed as grants to Alaska citizens as general "compensation" for project-caused disruption. Instead, specific programs have been designed, consistent with the mandate of NEPA and the Commission's responsibility to serve the public interest, to mitigate or avoid adverse socio-economic impact.

10/ The Type I impact funds described herein are about 20% of the total impact funds needed to respond to total pipeline impact, according to State agencies.

5. <u>Payment Of These Funds Would Not Trigger The U.S. - Canadian Agreement On Principles</u>

The specific programs for impact caused by construction workers and their families, described above, are quite different in nature than the general fund or funds which the U.S. - Canadian Agreement on Principles is intended to guard against.11/ That agreement limits inclusion in the cost of service to U.S. shippers of <u>indirect</u> socio-economic costs for the Yukon Territory and bars public authorities from requiring a special fund or funds in connection with the construction of the pipeline in the Yukon. The exception to that agreement is what may be thought to raise a question. It states: "should public authorities in the State of Alaska require creation of a special fund or funds, financed by contributions not fully reimbursable, in connection with construction of the pipeline in Alaska, the Governments of Canada or the Yukon Territory will have the right to take similar action." <u>President's Decision</u> at 56-57.

The question is the meaning of a "special fund" as used in the Agreement on Principles."12/ The meaning of the limitation on "special funds" is best understood by reference to the Canadian proposals -- pre-dating the Agreement on Principles -- for the creation of special funds to be borne by the pipeline and passed on to United States consumers to mitigate Canadian socio-economic impact. Specifically, Dean Kenneth M. Lysyk had conducted an inquiry into the social and economic impact of a gas pipeline through the southern Yukon at the direction of the Canadian Government. Dean Lysyk filed the report of his board on July 29, 1977. The report, which followed the decision of the Canadian National Energy Board, specifically recommended that $200 million be paid by the pipeline to capitalize a Yukon Heritage Fund to be administered by and for Yukoners. The $200 million was to meet "unquantifiable socio- and economic costs and for changes following in the wake of the pipeline that would detract from the quality of life in the Yukon." The fund was not directed at mitigating pipeline related projects nor "as a response to any specific impact, but to improve aspects

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11/ "Agreement between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline," <u>see</u> <u>President's</u> <u>Decision</u> at 47-66.

12/ The term "fully reimbursable" is also ambiguous because it conceivably could refer to reimbursement from the cost of service.

of the quality of life in the Yukon." Lysyk Report, 149.13/ The fund was in addition to "regulatory measures and responsive government programs" directed at minimizing the negative impacts of the project. Id.

Thus, prior to the negotiations with Canada, United States gas consumers appeared to be facing the prospect of supporting new general purpose funds in the Yukon which would be in the nature of a bonus payment to Yukon residents for the disruption caused to their life by the pipeline. Thus, the subsequent provisions of the agreement between the United States and Canada limiting special funds can fairly be read as aimed at preventing the sort of general fund proposed by the Lysyk inquiry unless the State of Alaska should require such a fund to be established.

As is demonstrated by the specific socio-economic costs which have been described above, Alaska is not seeking such a general purpose fund. It is seeking to recover in a limited way some, but by no means all, of the costs of the expanded State services necessary to accommodate construction workers and their families during the period of construction of the ANGTS. As such, Alaska's proposals do not fall within the literal language or intent of Section 5(b)(ix) of the Agreement on Principles.14/

6. The Staff Position Is Not Well-Founded

Despite the clear and unequivocal order of the Commission that "socio-economic expenditures" be included in the Certification Cost Estimate, the trial staff has commented that the socio-economic costs described by the State are not

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13/ The earlier decision of the NEB had also recommended a $200 million fund, exclusive of the costs of the monitoring authority, to encompass identifiable indirect socio- and economic costs of the pipeline project north of the 60th parallel. NEB, Reasons For Decision, 1-147-48. Although the details were vague, this fund appeared to be somewhat more closely related to specific impact assistance needs.

14/ Annex IV of the Agreement contains examples of direct charges by public authorities that are permissible within the meaning of Paragraph 11 of the Agreement, a related provision. These include "other items specified in environmental stipulations." The socio-economic assistance programs to be funded by the pipeline will be required by the environmental stipulations attached to the right-of-way lease of the State of Alaska and so may be considered direct rather than prohibited indirect charges.

required by statute and "may be more properly supported with tax and royalty revenues from the project." Staff Comments, Docket CP80-435, at 4 (November 7, 1981). In fairness to the Staff, Alaska notes that these comments were made with respect to the early estimates of the State and incorporated by Northwest in its application. The Staff may well reconsider its position in light of the revised information and authority contained in this memorandum. The Staff should reconsider it position for the following reasons.

First, the Staff has not responded to the direct command of Order 31 that socio-economic costs be included in the cost estimate. That Order is a sufficient answer to the Staff's request that such costs not be included in the CCE.

Second, the reliance upon a statutory requirement vel non is misplaced. An expenditure can be prudently incurred regardless of whether a statute requires its payment. An example would be expenditures to mitigate damage to the physical environment such as those for revegetation. No one would assert a statutory requirement as a test for the prudency of such expenditures. Alaska has, on repeated occasions, indicated to Northwest that the ANGTS will be required to assume a share of socio-economic impact costs. If nowhere else, these expenditures could be required as part of the right-of-way leasing process. Alaska could enact legislation directed to this subject but it is plainly not necessary to do so.15/

Third, staff does not give fair recognition to the fact that Alaska, its citizens, and its subordinate governments will bear a large share of the socio-economic impact costs of this project and are seeking from the project only a small share of the total impact caused by the project. Thus, some Alaska tax revenues inevitably will be devoted to ameliorating the impact caused by ANGTS despite the Northwest contribution. The question is whether ANGTS should stand a share of impact costs.

Further, Staff's suggestion that royalty revenues should support these costs is misdirected. Royalties are paid for the privilege of occupying or exploiting the property of the State. Magruder v. Supplee, 316 U.S. 394 (1942). The royalties to be paid by the producers constitute consideration to the State as the landowner of mineral rich property. To require the State to expend its royalty revenues for the mitigation of socio-economic impacts is to take from the State the only

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15/ If the issue were presented to the Alaska legislature, it is quite likely, although not certain, that ANGTS would be required to bear a far greater share of the impact it causes.

compensation it is to receive for allowing the exploitation of its natural resources. Mitigation of such impact is not the purpose of royalties generally nor is it consistent with the purposes for which those lands were given to Alaska.

A major purpose of the Statehood Act was to enable Alaska "to achieve full equality with existing States, not only in a technical juridical sense, but in practical economic terms as well." H.R. Rep. No. 624, 85th Cong., 1st Sess. 2 (1957). One of the ways this was to be achieved was by "making the new State master in fact of most of the natural resources within its boundaries." Id. at 2. It was expected that Statehood would

> the economy of the Territory than would be possible under territorial status. Many witnesses have testified to the Committee regarding the wealth of untapped resources in Alaska." (Id. at 10).

The Senate shared the purposes expressed in the quotations above from the House Report. Alaska was to be admitted into the Union "as a full and equal sovereign State." The lands and resources transferred from Federal to state ownership were intended "to permit the new State to earn its continuing economic independence and growth." Sen. Rep. No. 1163, 85th Cong. 1st Sess. 1 (1957). A national interest in Alaska's self-sufficiency is thus well established. And the dedication of vast national resources to Alaska was implicitly a commitment to Alaskan economic self-determination: Alaskans would be allowed to decide how best to use those resources for their own healthy growth in the manner that they saw fit.16/

16/ The policy encapsulated in Section 13(b) of the Alaska Natural Gas Transportation Act of 1976, P.L. 94-586, is but another expression of the national interest in Alaskan self-sufficiency and economic self-determination. Section 13(b) is a Congressional recognition of Alaska's proper entitlement to use its gas for its own purposes. Congressman Young of Alaska explained the rationale for including this provision in the Act:

> "Use of Alaska's royalty gas within Alaska may help end Alaska's status as a ward of the Federal government. The national interest in the self-sufficiency of Alaska was expressed in the Alaska Statehood Act as well as in other declarations of national policy. Under that Act, Alaska was permitted to select large quantities of land from the Federal domain with the hope that the land so selected -- and the minerals which it contained -- would provide a basis for building a healthy economic order in Alaska." Cong. Rec. E5808 (October 26, 1976).

It cannot be said that dedicating Alaska's royalty or even severance tax revenues to alleviating short term impact from this national project is consistent with the purposes of the severance and royalty taxes or the grant of ownership of public lands to the State of Alaska. For these revenues would be expended upon a social service infrastructure, which would have outlived its usefulness upon the completion of the project. They would not contribute to Alaska's self-sufficiency nor return a long range benefit to its citizens.

That is not to say Alaska and subordinate governments will not receive tax revenues from the ANGTS. Tax revenues probably will be generated although their amount and nature are uncertain because of pending litigation involving the corporate income tax and the possibility of changes in Alaska's tax regime generally.17/ But, revenues from such taxes as then may exist will help meet the cost of impact from the ANGTS that it is not being asked to fund and the unfunded amount is, according to today's best estimates, far larger than what the ANGTS is asked to bear. See p. 11, n. 10 supra. Thus, Alaska's government and citizens will bear a large share of the impact this project will create. But, Alaska's extraction taxes and revenues properly should not be diverted to this purpose and a share of the direct socio-economic impact costs of the ANGTS is properly borne by it.

CONCLUSION

For the foregoing reasons, the ANGTS properly should bear a share of the burden of mitigating the adverse socio-economic impact it will cause, inclusion of the State's

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17/ State severance taxes are also being challenged in a case pending before the U.S. Supreme Court.

revised estimate of such costs in the Certification Cost Estimate is procedurally correct, and the costs of the programs therein described are prudently incurred.

Respectfully submitted,

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February 13, 1981.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMISSION STAFF COMMENTS

I) On July 1, 1980, Alaskan Northwest Natural Gas Transportation Company (NWA or Applicant) filed a partial application for a final certificate of public convenience and necessity to construct and operate a natural gas pipeline across Alaska as part of the Alaska Natural Gas Transportation System (ANGTS). The incomplete application requested that two issues be addressed at this time, a Certification Cost and Schedule Estimate (CCE or CCSE) and Center Point (CP) determination.

On August 1, 1980, the Commission established a limited "subproceeding" to address the possible resolution of the CCE and CP. The object of the subproceeding is to aid the presiding officers, through a series of technical conferences, in the preparation of a report to the Commission. The report is directed to set out, to the extent possible, the areas of agreement among the parties if any, the areas on which the parties disagree, and to make substantive and procedural recommendations for Commission resolution of all issues within the subproceeding.

The Commission trial staff has actively participated in the technical conferences as well as served data requests and formal Interrogatories. 1/

II) One element mentioned as a concern of the Commission in its Order of August 1, 1980, is the existence of known, yet unresolved, design alternatives at the point of Commission determination of the CCE and CP. The ordering paragraph creating the subproceeding states:

> "... (T)he final report shall be based on the pipeline design that is current as of the date of the final conference, including all major

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1/ While the present proceeding is a "subproceeding", the Commission has not in any way limited the trial staff from performing its traditional role. Therefore, the staff has actively investigated the issues within the subproceeding as well as the many areas that must be addressed before final certification can issue.

design alternatives under consideration by the project sponsors, whether or not such design alternatives are identified in the application." (Ordering Paragraph C, mimeo at 12).

At the request of the presiding officers, the staff has previously provided: 1) A list of outstanding, unresolved design alternatives; in addition to the four mentioned in the right-of-way grant material and the interim report of the presiding officers dated September 26, 1980; 2) Comments of how or whether such outstanding design issues may be handled in determining the CCE and CP consistent with Commission Orders 31 and 31B. (Comments filed October 3, 1980).

III) At the technical conference of October 23, 1980, (Tr 37, 38), the presiding officer requested that trial staff provide by November 7, 1980, a summary document concerning the various outstanding design issues. Each such issue was to be discussed delineating the staff's understanding of the potential for resolution of the issue by stipulation or more formal proceedings such as cross-examination of witnesses where information is deficient.

The staff agreed to provide such a document on the understanding that it be deemed a preliminary statment of the staff's position. (Tr. 40). The lack of requested information and time to review that which was provided on the design issues, renders certain the need for revision should long-sought and essential information be provided in the future conferences or as answers to Interrogatories.

The staff believes that its outstanding design issues fall roughly into three categories: 1) Those issues where sufficient information has been received for adequate analysis and where an atmosphere exists for some formal stipulation to be entered into by the parties when a proper vehicle for entering such stipulation presents itself; 2) Those substantial issues where sufficient information exists to presume the need for full hearing or other formal inquiry by the Commission prior to addressing the granting of final certification; 3) Those issues where essential information is still lacking to such an extent as to preclude a determination by the staff as to which approach to resolution is appropriate.

The staff's tentative positions on those matters are listed below (see <u>VI</u> <u>infra</u>).

IV) The technical conferences to date have addressed many elements of the CCE and CP. At times, certain areas were discussed through question and answer in great detail. However, the staff has not taken a position, even tentatively, on the many areas discussed and no opportunity to do so has appeared.

Therefore, for the purposes of a complete record as well as informing the presiding officers and all parties, the staff has included its tentative position on as many additional areas of disagreement herein as time would allow.

Staff has two major concerns with the Certification Cost Estimate (CCE) of $8.79 billion filed by Alaskan Northwest Natural Gas Transportation Co. (NWA) on July 1, 1980, and amended to $9.1 billion on October 27, 1980. The first concern is with the methodology of the estimates, the embedded contingencies, and the appropriate contingency and Center Point given the estimate content. The second concern is with major design changes identified by the parties and the appropriate treatment of these changes. The potential cost impact of the staff concerns with sufficient information to estimate costs amount to an aggregate reduction in the CCE of $929 million and/or to an aggregate increase in excess of $846 million excluding contingency and finance charge. The Staff finds the methodology of engineering and design to be conservation and a minimum risk approach. The Staff will explore the appropriate contingency and Center Point values in the final technical conference in the subproceeding on November 10-20, 1980.

V) Two additional items should be stressed at this time:

First, the application of July 1, 1980, was substantially amended on or about October 27, 1980, reflecting the rerouting of the proposed pipeline consistent with the terms of the right-of-way grant issued by the Department of the Interior. In addition to the change in location, the amendment reflects the additional costs associated with the changes. The material is some 10 volumes in length and effects nearly half the proposed route.

Second, at the conference of October 7, 1980, the staff made an offer of settlement to NWA potentially to resolve part of the list of outstanding design issues. (Tr. 59-61). In sum, the offer addressed those outstanding design issues known prior to certification but as to which NWA either does not wish to or cannot provide design, cost, and risk which will result in a net reduction in project costs. The staff suggested that if such design alternatives are later adopted, NWA would request a reduciton of its CCE to the extent of the savings. The staff continues to believe that major design alternatives known prior to certification should be analyzed for design, cost, and center point effect prior to the determination of the CCE and CP.

VI) TENTATIVE STAFF POSITIONS

1. <u>PROJECT DIRECTORATE ESTIMATE ISSUES</u>

The issues involved in third party monitoring costs were discussed by the parties in the technical conference of October 27-29, 1980. Only $75.2 million of the $278.6 million estimated for third party monitoring are required by Federal and Alaska statutes. Staff notes that the Federal statute, the Mineral Leasing Act, is being challenged in court by Pacific Gas Transmission Co. and Northern Border Pipeline Co., and as a result \$53.6 million of the \$75.2 million at least has a possibility of not being expended.

The remaining \$203.4 million in costs to the State of Alaska is not required by statute and may be more properly supported with tax and royalty revenues from the project. These costs appear to be related to financing participation by Alaska which is not presently at issue or filed with the Commission in this subproceeding.

NWA has requested that third party monitoring costs not be included in the project Cost Performance Ratio since they are not under the control of NWA. Staff could possibly agree to such a position provided that costs caused by fault or non-performance on the part of NWA not passed through, a procedure to which NWA has given preliminary consent.

Project Directorate costs include pre-certification costs for which approval is pending before the Commissionin Docket No. CP78-123, et al. Staff believes that CP78-123, et al., is the appropriate forum for approval of pre-certification costs and that the CCE should be adjusted accordingly.

The parties have noted the absence of costs for a minority training program and an EEO compliance program in the CCE. All parties agreed to the immediate requirement for these programs. Accordingly, the staff believes that costs should be immediately included in the CCE for such programs.

All remaining Project Directorate costs will be examined in the Technical Conference of November 10-20, 1980.

2. DOI REROUTE

NWA filed an amended design and CCE on October 27, 1980, for the reroute mandated by the DOI right of way grant. The increase in cost of \$200 million in pipeline, of \$402.2 million in temporary facilities, and of \$12.3 million in project directorate will be examined during the technical conference of November 10-20, 1980.

3. EMBANKMENT CONSTRUCTION MODE

NWA was to provide cost estimates to the parties by November 7, 1980, for alternative embankment construction modes.

4. SNOW PAD - SNOW ROAD CONSTRUCTION

NWA was to provide cost estimates to the parties by November 7, 1980, for snow pad and snow road construction.

5. ATIGUN PASS TUNNEL

NWA was to provide a cost estimate for the 22,000 foot Atigun Pass Tunnell alternative to the parties by October 27, 1980. NWA declined to develop this information by letter dated October 28, 1980. Staff independently estimates that a tunnel to carry a road and four pipelines, but excluding the costs of constructing the road and the pipeline, at a range of $100 million to $700 million. Any split of costs proposed between Alaska, Alyeska, and NWA is unknown. At the very least, all costs associated with Atigun Pass should be deleted from the CCE until the tunnel option is decided.

6. THERMAL WORKPAD

Staff believes that concerns of Alyeska and of the State of Alaska relating to thaw degradation of the Prudhoe Bay haul road and of the soil surrounding the Alyeska Fuel Gas Pipeline will force NWA to use a thermal workpad adjacent to the haul road. NWA has proposed only a structural workpad.

Staff estimates a cost increase of $73 million for installing 1.5 inches of insulating board in the workpad on Sections 1 through 4.

7. AERIAL CROSSING OF YUKON RIVER

Alyeska presently holds the rights to use the vacant easterly Yukon River Bridge pipeline crossing carriage. NWA's estimate is based on obtaining the rights to use this existing crossing. If NWA fails to obtain those rights, an aerial crossing of the Yukon River would be required. The staff estimates the cost of this crossing at $18.5 million. A reduction of $10 million in crossing royalty cost would give a net cost estimate increase of $8.5 million for the crossing excluding reroute costs.

8. REDUCTION OR ELIMINATION OF WORKPAD IN SPREADS 5 & 6

The staff has designed a minimum workpad in Spreads 5 and 6 based on considerations of equipment movement and the proprietary geotechnical data of the sponsors. The staff design would result in a cost reduction of $91 million. The staff notes that NWA has reduced the average workpad thickness from 42 inches to 36 inches for these spreads in the amended CCE "filing" of October 27, 1980.

9. AMBIENT TEMPERATURE PIPELINE IN SPREADS 5 & 6

The staff has studied the proprietary data provided by NWA that indicates the existence of a thaw bulb along the Haines Pipeline right of way, and delineates the soil types encountered. The staff notes the thaw bulb is so extensive that NWA is studying moving the chilled gas pipeline 12 to 15 feet off the stripped right of way in order to reach non-thawed soil.

Based on the proprietary data, the staff believes that an ambient temperature pipeline extending from the discharge of Compressor Station 13 to the Canadian Border is technically feasible. Two alternate pipeline designs are feasible depending on the assumptions:

1. Convential buried pipeline assuming that any thaw settlement has already occurred along the Haines right-of-way. This option would result in a cost savings of $221 million.

2. Conventional buried pipeline alternating with gravel embankment construction over permafrost soils containing greater than 7 percent silt and greater than 50 percent passing 200 mesh. The embankment made of construction material should mitigate thaw settlement in the permafrost soils. This option would result in a cost savings of $171 million.

Operating (fuel) costs would decrease by 40 percent for a non-chilled pipeline in that an increase in compression horsepower is more than offset by elimination of refrigeration horsepower.

10. LESS CONSERVATIVE FROST HEAVE MITIGATION

NWA expects that insulation thickness may be reduced from the CCE design based on test results from the frost heave test facilities. It is probably impossible to quantify these savings without data from the facilities. It may be possible to prove that any reduction in rate base from cost savings in this area would be of more benefit to the ratepayer than any gain in the rate of return on equity.

11. INCREASE OF ONE YEAR IN CONSTRUCTION SCHEDULE

NWA takes the position that the pipeline and conditioning plant will be available for service on schedule despite some indications to the contrary. Presumably NWA is willing to accept the risk of a 6 month to 1 year delay in the conditioning plant, and a mechanism could be crafted to allocate the risk properly.

12. COMMUNICATIONS SYSTEM DESIGN

As previously stated, the communications system design is based on two alternate scopes and is not equipment specific. Presumably a less expensive system or a more expensive, but more reliable, system may emerge in final design.

13. NEW CONSTRUCTION CAMPS

Staff has been unable to obtain the cost of new construction camps from NWA in order to compare with purchase, renovation, and relocation of Alyeska camps.

14. PIPELINE LAY RATE

The pipeline lay rate of 3200 feet (40 joints) per day for bare pipe and 2800 feet per day for insulated pipe forms the basis of the entire estimate. This lay rate was determined by a panel of experienced Execution Contractors (EC's) and represents their collective best judgement based on Alaskan and worldwide experience with pipeline construction. However, this lay rate of 3200 ft. (40 joints) contrasts with the March, 1977, estimate of 4000 feet or 50 joints per day, with the projected Foothills lay rate of 3600 feet or 54 joints per day, and with a Williams Brothers estimated lay rate of 4000 feet or 50 joints per day. Thus, the filed lay rate contains some embedded contingency for Alaskan experience which must be accounted for in establishing the values of contingency and Center Point.

15. PIPELINE CONSTRUCTION CONTINGENCY FOR WEATHER AND DELAY

The cost estimate for pipeline construction is based on a ten percent factor for weather and a two and one half percent factor for delay. This is applied to the Line Up/Hot Pass welders and all other pipeline operations are coordinated and staffed to this central function. This twelve and one half percent factor is further stated in the workpapers supplied for "Haul and String" and for "Haul and String Weights". Although NWA claims that this is a standard estimating practice, the staff maintains that it represents, rather, a contingency for weather embedded in the estimate that must be taken into account when setting values for contingency and Center Point.

16. DITCH GRAVEL QUANTITY ERROR

The estimated gravel requirements for ditch backfill in the amended cost estimate is approximately three times the ditch volume available to be backfilled. Correcting this error for material site stripping, crushing, hauling, and indirect costs results in approximately a $200 million reduction in the amended estimate. Although NWA stated that this error in the original estimate would be corrected, the staff notes that an incomplete correction was made in NWA's submission of October 27, 1980.

17. LINE PIPE SPECIFICATIONS AND PRICE

The staff has requested the exact specification provided to the line pipe manufacturers as a basis of bid quotation, but NWA has not provided this information to date. A general statement is made that one half the pipe will have a Charpy Impact specification of 70 ft.-lb. and one half will have a specification of 105 ft.-lb. and that these two toughness levels will be randomly placed in the pipeline for crack propagation resistance. The staff believes that such a random placement would not be realistic, and that costs for planned placement logisitics and control should be added to the estimate. At this time the staff has insufficient information to estimate the costs of planned-versus-random placement.

NWA has also stated that a lower toughness specification and the use of crack mechanical arrestors is still under active study. the staff, again, has insufficient information to evaluate the cost impact of such a design change. The staff understands that the cost of the higher toughness pipe is substantial and any approval of the CCE should stipulate that the associated costs should be lowered should the arrestor approach be eventually chosen.

Finally, the line pipe price in the estimate is based on an average of prices from six suppliers, five foreign and one domestic. This procedure presumes that equal amounts of pipe will be purchased from each supplier, whereas freight is estimated (temporary facilities) on the basis of 75 percent foreign and 25 percent domestic. A further complication is the inability of the domestic manufacturer to meet the toughness specification at present although NWA, without demonstrated justification estimated on the basis that adequate toughness spcifications could be met at the future time of purchase.

Purchase of the pipe from the low bidder rather than the average price would result in a cost savings of $133 million. Purchase of 75 percent of the pipe from the low bidder and 25 percent domestic would result in a cost savings of $84 million. Should a strong "Buy American Act" be legislated, assuming that the domestic manufacturer can meet the delivery and specifications, costs would increase by $64.7 million.

18. MISCELLANEOUS UNSPECIFIED MATERIALS

Pipeline materials segment of the estimate contains a line item for miscellaneous unspecified material equal to 25 percent of all specified miscellaneous materials. This line item, stated to be based on current estimating practice, may contain some inherent contingency.

19. COMPRESSOR AND METERING STATION ESTIMATE CONCERNS

The refrigeration capacity requirement calculated by the FERC-AGPO computer model is 40 percent of the refrigeration capacity specified by NWA. The staff is continuing to investigate this anomaly and its potential for a cost estimate reduction of $70 million as well as substantial operating cost savings.

It should be noted that the NWA specified refrigeration capacity increased by 25 percent from the March, 1977, Estimate to the current CCE and is based on bare pipe heat transfer whereas much of the pipe will be insulated. Taking a credit for the insulation should reduce costs further.

The material price for compressors and turbine drivers was established by averaging four of ten quotations received. The staff has requested, but has not received, a quotation summary for all ten quotations. Staff also requested the quotation for the refrigeration equipment used for the $20 million estimate for testing equipment; the same has not been received. In addition, the NWA estimate included certain allowances in the material takeoffs. The staff believe the $20 million and the material takeoff allowances and definite factors in the consideration in the consideration of contingency and should be discussed at the November conference.

The staff has also requested information concerning Fluor's cost overrun experience in constructing the TAPS pump stations but has not yet received the information although the Morrison-Knudsen study would indicate that it is available. This information would be very helpful in analyzing the validity of NWA's contingency estimates for the compressor and metering stations.

20. TEMPORARY FACILITIES AND SERVICES ESTIMATE CONCERNS

The purchase of compressor station construction camps from Alyeska is a confused issue with NWA claiming during the sub-proceeding that it plans to purchase eight pump station camps whereas the workpapers in support of the estimate show the purchase of nine pump station camps. The additional camp in question has already been sold to ARCO by Alyeska, but it remains in the CCE at an average cost of $10.8 million to purchase, relocate and refurbish. If NWA requires eight pump station camps, the $10.8 presently shown for the ninth camp million should be removed from the estimate. If NWA requires nine camps, the cost of constructing a new station camp should be included in the estimate.

The staff has requested NWA to supply information on the cost of new camps, but NWA has refused to do so until negotiations with Alyeska are completed. NWA has stated that negotiation should be concluded by Mid-November and information will then be promptly provided to the staff. The cost of new camps is required to compare with purchase, relocation, and renovation of the 24 or 25 camps to be obtained from Alyeska. These costs are also required to evaluate the appropriate values for contingency and Center Point in the event that purchase negotations with Alyeska are not successful.

NWA has estimated that 40 percent of the camp sewage treatment facilities must be replaced and 60 percent can be renovated. The latest NWA consultant study on the treatment facilities cannot be made available to the staff until December, 1980. The staff observation of some of the facilities indicates a requirement for 100 percent replacement.

The cost for restoring and revegetating the Alyeska camp sites after purchase and relocation of the camps is included in the NWA estimate. The staff believes that this cost properly should remain the responsibility of Alyeska or that a transfer of the responsibility to NWA should reduce the purchase price of the camps.

Finally, the staff notes that an office space leasing figure of $2.10 per square foot per month for the Fairbanks area has been utilized in the temporary facilities and in the communications system estimates. This cost compares to a Fairbanks average of $1.36/sq. ft./month and a lowest rate of $.75. Although the total amount of money is not worth argument, this rate is an additional and cogent example of the conservative approach in the estimate.

21. COMMUNICATIONS AND SUPERVISORY SYSTEM ESTIMATE

The estimate filed by NWA is based on an average of two quotations for a microwave-based, terrestial system and two quotations for a satellite-based system. These systems were quoted to satisfy performance specifications, and do not provide quantities or prices of materials from which the Office of the Federal Inspector would be able to track design changes. The quoted facilities do not include costs for an interface with the Foothills facility at the Canadian border.

A Support Service line item for $236 thousand is for an undefinable consulting service if required. This amount certaintly appears to fit the category of contingency. The Staff believes the design basis to be overly conservative; any approval of the CCE should stipulate the associated costs should be lowered should the existing system be utilized.

22. ENVIRONMENTAL CONCERNS

At present there are three areas of concern to the staff. First is the the roughly 300 miles of rerouting around the Fairbanks area. No environmental baseline material has been provided for this segment nor has there been any discussion of access to this area. Secondly, the staff remains concerned about the increasing quantities of gravel estimated to be needed. To what extent will new material sites be required? What is the magnitude of the anticipated extensions to existing sites over and above the original proposal? What environmental baseline data is available for the new sites and/or what efforts are being taken to obtain such information? Lastly, the Atigun Pass tunnel is also of concern. The primary items of interest are the locations and extent of the adit points and construction work areas, the quantity of excavated material and the method and locations of disposal or use of this large volume of material, and disruption of the environment by disposal of excavated material and by blasting at the adits.

The currently proposed pipeline design involves many modifications in mile-by-mile design and routing which are markedly different from the design and routing contemplated in the original proposal. Many of these modifications go beyond the scope of the environmental impact statements prepared for the project. The staff believes that there must be an assessment of the environmental significance of the filed modifications as well as future major modifications to avoid delays based on environmental considerations.

Respectfully submitted,

John P. Roddy

David L. Huard

Thomas J. Burgess
Commission Staff Counsel

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service 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 7th day of November, 1980.

John P. Roddy
Commission Staff Counsel

On another matter, the ERA rejected a request by United Gas Pipe Line Co. to examine in this proceeding the matter of the exclusionary provisions in the contract between Border Gas and PEMEX as they might apply to additional Mexican imports above the 300,000 Mcf/d currently authorized. This issue, the ERA said, is not germane to the issues raised in the application. The ERA referred to reasons set forth in Opinion No. 15 wherein it concluded that it would be premature to address this issue in the context of the volumes presently authorized. However, the ERA reiterated that it does not intend to give even tacit approval to the exclusionary provisions insofar as they apply to volumes in excess of the initial 300,000 Mcf/d, and reserves the right to examine the issues raised by United when it is asked to approve additional volumes.

The ERA directed that initial submissions be served by 8/25/80 and rebuttal submissions by 9/15/80. Upon ERA's own motion or at the request of the parties, it may be determined that an evidentiary hearing or an oral argument will be required. Any party making a request for hearing or oral argument in either the initial or rebuttal submissions must include factual issues in dispute, and suggest a procedural schedule.

FERC Establishes Procedures for Consideration of Alaskan Northwest's Application to Construct Alaskan Segment of ANGTS

On 8/1/80 the FERC issued notice of, an established procedures with respect to, the application filed on 7/1/80 by Alaskan Northwest Natural Gas Transportation Co. (CP80-435) for a final certificate authorizing construction and operation of the Alaskan segment of the Alaska Natural Gas Transportation System. The Commission, among other things, directed the Alaskan Delegate to convene a series of technical conferences to consider the Certification Cost Estimate and Center Point values proposed by Alaskan Northwest, and to consider all related Alaskan segment incentive rate of return issues not previously decided by the Commission that are now ripe for decision.

Alaskan Northwest is a partnership comprised of affiliates of seven major pipelines -- Northwest Pipeline Corp., Michigan Wisconsin Pipe Line Co., Northern Natural Gas Co., Pacific Gas Transmission Co., Pacific Interstate Transmission Co., Panhandle Eastern Pipe Line Co. and United Gas Pipe Line Co. The Alaskan segment of the ANGTS comprises 743 miles of 48-inch pipeline extending from the Prudhoe Bay area along a route generally parallel to TAPS to Delta Junction (south of Fairbanks) and then running east to a point of interconnection with Foothills Pipe Lines (Yukon) on the Alaskan-Yukon border. The line is designed to transport up to 2 Bcf/d initially, capable of expansion to 3.2 Bcf/d with installation of nine additional compressor stations. Based on design as of April 1980, the application showed an estimated total construction cost for the Alaskan segment of $8.8 billion (in January 1980 dollars) including finance charges ($7.9 billion excluding finance charge or allowance for funds used during construction), or about 166% higher than the March 1977 cost estimate of $3.3 billion (restated in a comparable cost format and in January 1980 dollars) considered in the President's Decision dated September 1977 approving the ANGTS. The application requested (1) approval of the remaining parameters necessary to implement the Incentive Rate of Return mechanism previously established by the FERC (in compliance with a condition of the President's Decision) to control cost overruns -- the Certification Cost Estimate and the Center Point; (2) approval of Alaskan Northwest's plan for the private financing of the Alaskan segment of the ANGTS; and (3) a determination that the project costs reflected in the 1980 Certification Cost Estimate are not "unreasonably different" from March 1977 cost estimates considered in the President's Decision and that the project therefore continues to be in the national and public interest.

However, Alaskan Northwest recognized that the Commission can presently take no action to approve a private financing plan for the Alaskan segment since no such plan has been executed as yet. Alaskan Northwest noted in this regard a "Joint Statement of Intention" recently signed with the three principal North Slope gas producers regarding development of a financing plan. The Commission also cannot determine that the ANGTS continues to be in the national and public interest, Alaskan Northwest asserted, until it submits pro forma statements of operating revenues, expenses, and income for the first five years of operation at full capacity, a projected cost of service for the Alaskan segment, and an analysis of the marketability of Alaskan gas during the life of the project. This material, omitted from the instant application, will be provided with Alaskan Northwest's financing exhibits. Pending review of such material, Alaskan Northwest said the Commission must defer comparison of the 1977 and 1980 cost estimates. (See REPORT NO. 1269, pp13-16.)

In the instant order, the Commission noted a number of matters associated with final certification of the Alaskan segment which must await submission of the financing plan. These include marketability of the gas, the continuing relationship of the project to the national interest, and the relationship of project costs to those considered at the time of the President's Decision. Because the financing plan has not yet been filed, the Commission decided to defer such matters to a final certification proceeding which would be initiated upon submission of the financing plan.

However, in order to resolve outstanding matters regarding the IROR mechanism as it applies to the Alaskan segment, the Commission instituted a special subproceeding to deal with the sponsors' proposed Certification Cost Estimate and Center Point values, plus the remaining IROR matters which could now be resolved. Rather than an adjudicatory proceeding, the Commission will use notice and comment procedures in order to satisify the ANGTA for expedition. However, these notice and comment procedures will be preceded by a series of technical conferences to resolve many of the issues and clarify the others.

The technical conferences will be presided over by the Alaskan Delegate in conjunction with the Office of the Federal Inspector through the Director of its Division of Audits and Cost Analysis. The Alaskan Delegate will hold the conferences at places and dates to be determined and any party of record may participate, including any party the Alaskan Delegate decides should participate. Also, in order to minimize confusion and reduce burdens on the parties, the Commission decided not to consolidate the instant application (CP80-435) with the overall proceeding (CP78-123 et al.), although it will deem all parties in the consolidated proceeding as participants. Because the matters to be discussed at the technical conferences are highly technical and complex, the Commission decided that the service list would be restricted only to those parties requesting inclusion therein and those added at the discretion of the Alaskan Delegate.

The first conference should be held in early September in Washington, the Commission said, to determine procedures for future conferences which may be held in Washington, California, Alaska or any other appropriate place. When the Alaskan Delegate and the OFI Division Director determine that further conferences are unnecessary, they are to report to the Commission on the issues about which there is general agreement and those which the parties disagree, and make substantive and procedural recommendations to the Commission to resolve all issues. At the first conference, the Alaskan Delegate must determine whether transcripts will be kept of the technical conferences. Also, the Alaskan Delegate will be authorized to make rulings with respect to discovery of information and production of documents.

The Commission expressed particular concern that certain design issues remain outstanding despite the contemplation in its orders establishing the IROR mechanism that all such issues would be resolved before filing of the Certification Cost Estimate. Because of this concern, the Commission directed the Alaskan Delegate to conduct the conferences so as to identify completely all of the major outstanding design issues and address the cost consequences of alternate resolutions thereof. At present, the Commission added, it is not certain how to deal with the question of outstanding major design issues at the time of approval of the Certification Cost Estimate and Center Point values. Hence, the Commission also directed that the technical conferences address the question of alternative values for these parameters, depending on the alternative resolutions of the major outstanding design issues. In this connection, the Commission made clear that the project sponsors have an affirmative obligation to disclose voluntarily, promptly and fully all design alternatives which they may have considered and which could have a significant impact on the cost estimates set forth in their applications.

In order to have the benefit of the views of interested parties on these procedures for the technical conferences, the Commission directed that comments may be filed with the Alaskan Delegate by 8/15/80, which will then be reviewed with participants at the first conference. Thereafter, the Alaskan Delegate may advise the Commission of any recommendations as to procedural revisions.

Fifth Circuit Affirms FERC Rejection of Settlement Permitting Dorchester Gas to Retain Escrowed Funds for Use in Drilling Projects Because of Additional Incentive Provided in NGPA

On 7/30/80 the U.S. Court of Appeals for the Fifth Circuit issued a per curiam decision affirming an 8/1/79 order of the FERC rejecting for the second time a settlement offer proposed by Dorchester Gas Producing Co. (G-18671) whereunder it would use escrowed funds in gas exploration and development programs in lieu of refunding such monies to the pipeline involved. The Fifth Circuit had remanded the Commission's rejection of the proposed settlement the first time for reconsideration in light of the natural gas shortage. In the instant decision, the Court concluded that the Commission properly acted under the remand and its decision to reject the second settlement offer must be affirmed. Dorchester Gas Producing Co. v. FERC, Nos. 79-3431.

The 8/1/79 order represented the third time the Commission denied a settlement proposal whereunder Dorchester would establish an exploration and development program to obtain forgiveness of refunds owed to Northern Natural Gas Co. under the terms of Opinion No. 586 in the Hugoton-Anadarko Area Rate Proceeding (AR64-1 et al.). On 4/14/75 the Commission found Dorchester's proposal to release $5.2 million in escrowed refund monies to explore for new gas to be dedicated to Northern as inconsistent with the settlement approved in the Hugoton-Anadarko area rate case -- to which Dorchester was a signatory party -- excusing refund of 100% of excess amounts collected prior to 1961 and 30% of excess amounts collected in 1961 and 1962, but excusing no refunds for excess collections after 1962. Subsequently, however, the Commission granted rehearing to consider Dorchester's exploration proposal if it could show, under the test laid down in the Permian I area rate decision, that it is entitled to refund forgiveness or a higher rate for past periods because it would be deprived of funds sufficient to cover out-of-pocket operating expenses.

After further hearings, Dorchester submitted a revised settlement offer providing for institution of a gas exploration and development program with refund monies owed to Northern. In support, Dorchester presented evidence designed to show, among other things, a negative return on investment in interstate gas operations.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMISSION STAFF COMMENT TO REVISED ESTIMATE OF SOCIO-ECONOMIC EXPENDITURES

On February 13, 1980, the State of Alaska served on the restricted service list its memorandum regarding the recovery of monitoring and socio-economic expenditures and the submission of a revised estimate of such costs.

In response, the Commission Staff continues its assertion that those cost incurred by the State of Alaska which are not specifically required by statute would be more properly mitigated by tax and royalty revenues from the project. 1/

The State of Alaska argues that Commission Order 31 requires that such costs be fixed in the Certification Cost Estimate (CCSE). Order 31 at 125. Staff contends that Order 31 directs that such cost not be included under the change of scope mechanism. In so directing the Commission provided a forum to review the appropriateness of internalizing such cost to the project. That forum is the ongoing review by the Commission of the proposed CCSE. After considerable examination staff views these costs as inappropriate for inclusion in the CCSE.

In addition, Staff contends that the costs in question appear to be related to the State of Alaska's participation in the financing of the project.

The statutory authority enabling the State to make any such recovery, leaving aside the magnitude and prudency of such costs, was specifically premised on the State's active participation in the financing of the project. 2/

1/ See: Technical Conference on Alaskan Segment, Docket No. CP80-435, October 8, 1980, Transcript pages 11-19.

2/ Alaska Statutes, Supplement §44.55.100(13)(D) and (E). See also: Financial and Alaska Impact Plan; A Report to the First Session of the Eleventh Legislature, The Alaska Gas Pipeline Financing Authority, March 14, 1979.

Even if inclusion of the cost in the CCSE were allowed in principle, unless and until Alaska's project financing participation becomes a reality, the parties herein have no legitimate basis upon which to discuss the subject recoveries.

Therefore, Staff believes that discussion of the subject cost items is inappropriate at this time and should be postponed until such time as the State of Alaska formalizes its participation in the financing of this project.

Respectfully submitted,

Thomas J. Burgess

John P. Roddy
Thomas J. Burgess
Commission Staff Counsel

cc: Restricted service list

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 26th day of February, 1981.

John P. Roddy
Commission Staff Counsel

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Alaskan Northwest Natural Gas Transportation Company) Docket No. CP78-123, et. al.

ORDER MODIFYING ORDER TO SHOW CAUSE

(Issued February 23, 1981)

On December 15, 1980, the Commission issued in the above-captioned proceeding an order to show cause, within 60 days, why the Commission should not adopt, for purposes of rate base determination, the data and opinions set forth in three Reports on Results of Audit prepared by the Office of the Chief Accountant. On January 14, 1981, in response to a motion filed by the Public Service Commission of the State of New York, the Commission issued an order authorizing any interested person to submit, no later than March 16, 1981, pleadings responsive to any pleadings submitted within the 60 day period provided by the December 15 order.1/

On January 29, 1981, Alaskan Northwest Natural Gas Transportation Company (ANNGTC) filed a motion for leave to file a response to any pleading submitted in answer to the pleading that ANNGTC apparently intends to file within the 60 day initial period. ANNGTC states that it has the burden of proof on these matters, that it needs an opportunity to respond to whatever points might be raised in pleadings filed on or about March 16, 1981, that ANNGTC would be prepared to file its reply no later than March 31, 1981, and that this additional two week extension will not unduly delay the proceeding.

We will grant ANNGTC's motion as an exercise of the Commission's discretion in response to the representations made by ANNGTC.

1/ We also take this occasion to correct a typographical error in the January 14, 1981 order. The ordering paragraph inadvertently identified the date as March 16, 1980 rather than March 16, 1981.

The Commission orders:

For the reasons stated above, any interested person who has previously filed a pleading within the 60 day period provided by the above referenced order of December 15, 1980, or has filed a responsive pleading within the March 16, 1981 deadline provided in the above-referenced order of January 14, 1981, may also file, no later than March 31, 1981, a pleading responsive to any new points raised in pleadings filed pursuant to the January 14, 1981 order. The matters at issue herein will be decided on the basis of all pleadings received by March 31, 1981; no further pleadings will be authorized.

By the Commission.

(S E A L)

Kenneth F. Plumb

Kenneth F. Plumb,
Secretary.

RHL

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

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

ORDER ATTACHING CONDITIONS TO CERTIFICATES

(Issued February 23, 1981)

On December 19, 1980, the Commission issued an order proposing the adoption of a condition to be appended to the final certificates of public convenience and necessity (for construction and operation of the Alaska Natural Gas Transportation System) issued by the Commission to Pacific Gas Transmission Company and Northern Border Pipeline Company in its orders of January 11 and April 28, 1980 in Docket No. CP78-123, et al.,1/ as well as to the conditional certificates issued December 16, 1977 in the same docket. The proposed condition (attached to this order as an appendix) implements an executive agreement between the United States and Canada with respect to reciprocal procurement procedures for the U.S. and Canadian segments of the system. That agreement is embodied in an exchange of notes, signed June 10, 1980, a copy of which was appended to the December 19 order.

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

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

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

No comments were received. Accordingly, the Commission concludes that no party objects to the attachment of the condition. The Commission's reasons for proposing to attach the condition were set forth in the December 19 order, need not be reiterated herein, and are hereby incorporated by reference.

The Commission further finds:

(1) The condition set forth in the appendix to this order is related to the overall construction and operation of the Alaska Natural Gas Transportation System within the meaning of Section 9 of the Alaska Natural Gas Transportation Act.

(2) The condition set forth in the appendix to this order is required by the public convenience and necessity.

The Commission orders:

(A) The condition set forth in the appendix to this order shall be attached to the final certificates of public convenience and necessity issued by the Commission to Pacific Gas Transportation Company and Northern Border Pipeline Company in the Commission's orders of January 11, 1980, and April 28, 1980, respectively, as well as to the conditional certificates issued by the Commission in its order of December 16, 1977, all in Docket No. CP78-123, et al.

(B) This order shall become effective on its date of issuance. Pursuant to Sections 9 and 10 of the Alaska Natural Gas Transportation Act, this order constitutes final agency action and is not subject to the provisions for rehearing set forth in Section 19 of the Natural Gas Act and in Section 1.34 of the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Kenneth F. Plumb

Kenneth F. Plumb,
Secretary.

Docket No. CP78-123, et al.

APPENDIX

CONDITION

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

NORTHWEST ALASKAN PIPELINE COMPANY

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

981.1

REA-81-1025
February 13, 1981

Mr. Kenneth F. Plumb
Secretary
Federal Energy Regulatory Commission
Room 9310
825 North Capitol Street, N.E.
Washington, D.C. 20426

RE: Docket No. CP78-123, et al.
Pre-Partnership Expenditures

Dear Mr. Plumb:

Alaskan Northwest Natural Gas Transportation Company (the Partnership) herewith submits for filing an original and nineteen (19) copies of its Fourth Supplemental Application for an Order Approving Past Expenditures in the above-referenced docket.

Respectfully submitted,

NORTHWEST ALASKAN PIPELINE COMPANY

Cuba Wadlington, Jr.

Cuba Wadlington, Jr.
Director, Regulatory Affairs

cc: All Parties of the Restricted Service List for CP78-123, et al.
RDM Index

CW:paw

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Alaskan Northwest Natural Gas Transportation Company) Docket CP78-123, et al.

FOURTH SUPPLEMENTAL APPLICATION OF ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY FOR AN ORDER APPROVING PAST EXPENDITURES

Alaskan Northwest Natural Gas Transportation Company (the Partnership), pursuant to the Alaska Natural Gas Transportation Act of 1976 (ANGTA), the Natural Gas Act, and the Commission's Order Vacating Prior Proceedings and Issuing Conditional Certificate of Public Convenience and Necessity issued December 16, 1977, herewith submits this fourth supplemental application for an order approving inclusion in rate base, the pre-Partnership "qualified expenditures" of Tetco Four, Inc. (Tetco Four) and Columbia Alaskan Gas Transmission Corporation (Columbia Alaskan).

I.

Background of Authorization Requested

A. The Partnership made an original filing on February 2, 1979, seeking review and approval of preliminary construction expenditures of $31.8 million (excluding AFUDC) attributable to expenditures incurred prior to the date of formation of the Partnership for four companies who were part of the Arctic Gas Consortium and who are now members of the Partnership, and $17.8 million (excluding AFUDC) expended by Northwest Alaskan Pipeline Company to prosecute its successful application, prior to the formation of the Partnership. 1/

On September 19, 1980, the Partnership filed the Third Supplemental Application including a request for approval of $8.0 million (excluding AFUDC) pre-Partnership expenditures of American Natural Alaskan Company (American Natural Alaskan). American Natural Alaskan, which was part of the Arctic Gas Consortium, became a member of the Partnership effective January 1, 1980, as approved by Commission Order issued December 15, 1980.

1/ This Application also requested review and approval of Partnership expenditures for the period February 1, 1978 through July 31, 1978. The Partnership made additional filings on August 14, 1979, July 16, 1980, and September 19, 1980 covering the actual Partnership expenditures covering the periods January 1, 1979 through March 31, 1980.

On August 1, 1980, Tetco Four and Columbia Alaskan became members of the Partnership, as approved by Commission Order issued December 15, 1980. Affiliates of both Tetco Four and Columbia Alaskan were members of the Arctic Gas Consortium. The instant supplemental application seeks the review and approval of the pre-Partnership expenditures, excluding AFUDC, of $7.9 million (Exhibit Z-13) for Tetco Four and $8.0 million (Exhibit Z-14) for Columbia Alaskan. These pre-Partnership expenditures as with the previous five Arctic Gas participants were reasonable and necessary to the success of the Partnership pipeline project, and are properly includable in the capital accounts of each such partner, and in the rate base of the Partnership.

II.

Justification and Argument

The legal authority for the Commission's ability to grant the requested approval is detailed in the Partnership's original and supplemental applications. Such applications also contain the arguments as to why the Partnership requests should be approved at this time. The Partnership herewith incorporates in the instant supplemental application all prior justifications and arguments for the approval of past expenditures necessary to place the Alaska segment of the ANGTS in service. 2/

The names, titles and mailing addresses of the persons to whom all correspondence and communications concerning this application should be addressed are as follows:

Mr. Darrell B. MacKay
Vice President
Northwest Alaskan Pipeline Company
Suite S-700
1120-20th Street, N.W.
Washington, D.C. 20036

2/ The Commission issued an Order to Show Cause on December 15, 1980 to which was attached an audit report from the Commission's Office of the Chief Accountant recommending rejection of the pre-Partnership expenditures of the four Arctic Gas participants covered in the initial application described previously. The Partnership believes that there are substantial and valid reasons why these costs were reasonable and necessary to place the Alaskan segment of the ANGTS in service and should therefore be included in the Partnership's rate base. The Partnership will file comments on February 13, 1981 supporting this position. Since the costs filed herein are part of the total Arctic Gas group expenditures, the justification described in those comments will apply equally to these expenditures.

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

*Rush Moody, Jr., Esquire
Akin, Gump, Strauss, Hauer & Feld
Suite 400
1333 New Hampshire Avenue, N.W.
Washington, D.C. 20036

WHEREFORE, the Partnership respectfully requests that the Commission issue an order pursuant to ANGTA, the Natural Gas Act, and the President's Decision, giving final approval to the expenditures described herein, as well as those expenditures described in the initial and supplemental applications for ultimate inclusion in the rate base for the Alaska segment of the Alaska Natural Gas Transportation System.

Respectfully submitted,

NORTHWEST ALASKAN PIPELINE COMPANY

Cuba Wadlington, Jr.

Cuba Wadlington, Jr.
Director, Regulatory Affairs

Dated February 13, 1981

---

* Designated to receive service in accordance with Section 1.17(c) of the Rules of Practice and Procedure.

Exhibit Z-13

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
GAS ARCTIC/NORTHWEST PROJECT STUDY GROUP - NOW ANNGTC PARTNER
QUALIFIED EXPENDITURES 1/

	Tetco Four, Inc.
1. GENERAL & ADMINISTRATION	
Direct Operations	$ 1,318,452
Indirect Operations	281,494
	1,599,946
2. OUTSIDE SERVICES	
Legal	406,578
Executive	39,060
Finance	242,100
Regulatory, Environmental and Civic Affairs	1,427,262
Administration	125,438
Public Relations	164,231
Engineering	3,478,016
	5,882,685
3. TERMINATION AND CLOSE-OUT COST	390,402
4. GOVERNMENT AGENCIES	16,535
5. OTHER COSTS	52,205
Subtotal	7,941,773
6. AFUDC 2/	5,157,291
Total Qualified Expenditures including AFUDC	$ 13,099,064

1/ Expenditures made prior to January 31, 1978.

2/ Includes only an interest component on funds spent accumulated through July 31, 1980 at prime plus 1%.

Exhibit Z-14

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY
GAS ARCTIC/NORTHWEST PROJECT STUDY GROUP - NOW ANNGTC PARTNER
QUALIFIED EXPENDITURES 1/

	Columbia Alaskan Gas Transmission Corporation
1. GENERAL & ADMINISTRATION	
Direct Operations	$ 1,328,836
Indirect Operations	283,712
	$ 1,612,548
2. OUTSIDE SERVICES	
Legal	409,780
Executive	39,368
Finance	244,007
Regulatory, Environmental and Civic Affairs	1,438,504
Administration	126,426
Public Relations	165,525
Engineering	3,505,411
	$ 5,929,021
3. TERMINATION AND CLOSE-OUT COST	393,477
4. GOVERNMENT AGENCIES	16,666
5. OTHER COSTS	52,616
Subtotal	8,004,328
6. AFUDC 2/	5,214,027
Total Qualified Expenditures including AFUDC	$13,218,355

1/ Expenditures made prior to January 31, 1978.

2/ Includes only an interest component on funds spent accumulated through July 31, 1980 at prime plus 1%.

<u>VERIFICATION</u>

THE DISTRICT OF COLUMBIA

I, CUBA WADLINGTON, JR., being first duly sworn on his oath, deposes and says:

That he is Director of Regulatory Affairs of Northwest Alaskan Pipeline Company and is duly authorized to make this affidavit, that he has read the foregoing and is familiar with the contents thereof, and that the facts and allegations contained therein are true and correct to the best of his information, knowledge and belief.

Cuba Wadlington, Jr.

Cuba Wadlington, Jr.

SUBSCRIBED AND SWORN TO before me this 13th day of February, 1981.

Patricia A. Walker

Notary Public

My Commission expires My Commission Expires January 1, 198_ .

CERTIFICATE OF SERVICE

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

Dated at Washington, D.C., this 13th day of February, 1981.

Cuba Wadlington, Jr.

Cuba Wadlington, Jr.

OFFICE OF THE FEDERAL INSPECTOR

news

ALASKA NATURAL GAS TRANSPORTATION SYSTEM
ROOM 2413. POST OFFICE BUILDING. 1200 PENNSYLVANIA AVENUE. WASHINGTON D.C. 20044

August 13, 1981
No. 36

Federal Inspector Approves Affirmative Action Plan for Alaska Gas Pipeline

John T. Rhett, Federal Inspector for the Alaska Natural Gas Transportation System, today announced approval of the affirmative action plan for employment and procurement for the 745-mile Alaska segment of the pipeline.

Approval of the Northwest Alaskan Pipeline Company plan followed several months of negotiation between the company and the Federal Inspector's staff.

The plan, which applies to the company, its contractors and subcontractors, sets goals for each of four minority groups and for females for each employment job group. Employment percentages by major job group for minorities and females for 1980 and 1981 are shown in the attached Fact Sheet.

The 1981 goal for minority business enterprise participation is $31 million, or 15 percent of contractable opportunities, and $4 million, or 2 percent, for female firms. Additional information on the goals is contained in the Fact Sheet.

An approved affirmative action plan covering both employment and procurement was required by regulations issued May 12, 1980, by the U.S. Department of the Interior. These comprehensive regulations, applicable only to the Alaskan gas pipeline project, required the sponsor's affirmative action plans be filed with and approved by the Federal Inspector.

The EEO regulations also require the sponsors to update their plan annually. These updates will adjust the goals, based on current information and anticipated level of project activity.

In light of the significant projected labor requirements of the Alaskan construction, a training task force has been organized, with representation from the Alaska State Pipeline Coordinator, the Alaska Department of Labor, the U.S. Department of Labor, the Office of the Federal Inspector (OFI), Northwest Alaskan Pipeline Company, organized labor, and Alaskan Native and minority organizations. This task force is currently Chaired by a representative of Northwest Alaskan Pipeline.

(more)

The task force will advise NWA on the planning and implementation of a training program to help people in Alaska qualify for work on the gasline project. The group will also provide a focal point for information that will help the Federal Inspector assure that the Federal affirmative action requirements are met. A total of 13,000 employees are expected to be working on the Alaska segment at peak construction, now estimated to be 1985.

The EEO/MBE regulations issued by the Department of the Interior allow preference for employment on the project be given to Alaskan Natives living on or near a reservation which is within commuting distance of any project activity, but only on that project activity.

Copies of the affirmative action plan for Alaska are available for inspection and copying in the Washington, D.C., Fairbanks and Anchorage Offices of the Federal Inspector.

-OFI-

For further information please contact:

Joyce R. Morrison
Washington Office
(202) 275-0586

Paul Steucke
Anchorage Office
(907) 271-3668

August 13, 1981

FACT SHEET

Northwest Alaskan Pipeline Company Affirmative Action Plan

Basic Facts on the Plan

The affirmative action plan (AAP) for the Alaska segment was filed September 2, 1980, by Northwest Alaskan; revised on December 11, 1980; and supplemented on March 2 and July 23, 1981, each time in response to requests by OFI. The affirmative action plan was approved by the Federal Inspector on August 10, 1981.

It totals about 600 pages and applies to all participants in the Alaska segment, including Northwest, its contractors and subcontractors. Some existing contractors must now file affirmative action plans for OFI approval. Excluded from the equal employment filing requirements are contractors with less than 50 employees or having a contract valued at less than $50,000. Contractors having a contract of $150,000 or more must submit an affirmative action plan for procurement, in addition to the employment plan.

Base information used by Northwest in formulation of its goals was 1970 Census information, updated to 1980.

Northwest will revise and update its affirmative action plan annually.

Employment

The plan contains employment goals for each year through completion of construction. However, because this information was based upon 1985-1986 project completion, the outyear goals will have to be revised to reflect the new schedule. The goals for 1980 and 1981 are shown below.

Average goal for operative or craft labor (except caterers) for 1980 was 17 percent for minorities. Of this 17 percent, 10.9 percent was for Alaska Natives.

The goal for female employment in the craft area was 7.02 percent during 1980.

1980 Employment

(Number of people employed by NWA, contractors, and subcontractors at end of 1980)

	Male	Minority	Female	Total Minority & Female
Officials and Managers	140	14	17	31
Professionals	448	45	50	95
Technicians	70	10	31	41
Clerical	38	11	109	120
Operative and Craft	179	26	14	40
Laborer	32	9	7	16

1981 Employment Goals

	Minority (%)	Female (%)
Officials & Managers	7.8	12.7
Professionals	9.4	8.7
Technicians	12.6	9.4
Clerical	20.0	45.6
Craft	14.9	2.9
Operatives	17.3	3.3
Laborers	21.5	5.5

Labor Force

Northwest is predicting that construction of the Alaska portion of the project will require a peak labor force of 13,000. Of these, about 9,650, or 70 percent, will be craft workers, operatives and laborers. Over 90 percent of this number will be provided by five unions: laborers (2,100); culinary workers (1,100); operating engineers (3,000); teamsters (2,000); and pipeline welders (1,000).

Contracting

The plan projects Minority Business Enterprise (MBE)/Female Business Enterprise (FBE) goals on an annual basis throughout construction. The goals are firm for 1980 and 1981, and projected for later years. The dollar goals are given in 1980 dollars and are based on a project cost estimate that is being reviewed by the Federal Energy Regulatory Commission. A detailed chart showing the contractable opportunities and goals is contained in the affirmative action plan. Because this chart was based upon a 1985-1986 project completion date, the specific out-year opportunities and goals will have to be revised to reflect the new schedule. A summary of the goals is given below:

Year	Contractable Opportunities	MBE/FBE (Millions $)
Pre 1981	150	15
1981	208	35
Outyears (1982-completion)	4.484	430
TOTALS	$4.842 billion	$480 million

MBE/FBE Achievement - 1980

During 1980 the sponsor and its contractors made 1,359 procurement commitments, including 107 contracts. Of the commitments, 54 were to minority businesses and 134 to female businesses. The dollar value of these was:

Minority businesses - $15.3 million or 22.7 percent
Female businesses - $2.8 million or 4.2 percent

These achievements are measured against actual contracts in 1980 of $67,665,574.

1980 goals were:

Minority businesses - $7.7 million or 12% of expected opportunities of $64,000,000

Female businesses - $2.6 million or 4% of expected opportunities of $64,000,000

Total performance, from initiation of the project through 1980, measured against actual contracts valued at $87,822,574 was:

Minority businesses - $15,859,250, or 18.1 percent
Female businesses - $3,356,711, or 3.8 percent

1981 Contracting Program

Total outside services planned for 1981 are $217.6 million. Total contractable opportunities for 1981 are about $208 million. Contract activity will be mainly in four accounts: temporary facilities, field programs, communications and supervisory control systems, and pipeline. The plan breaks out types of opportunities that might be available within these accounts.

1981 goals:

Minority businesses - $31 million, or 15 percent of contractable opportunities
Female businesses - $4 million, or 2 percent of contractable opportunities

Construction Information

Northwest has contracted with Fluor Corp. in Irvine, California, to be project manager for engineering, design, procurement and construction. In addition, they will have six general contractors or joint ventures, under fixed-price contracts, to perform the actual construction of the pipeline, as well as other major contractors to construct the compressor and metering stations and operations, maintenance, temporary and communication facilities. Northwest states that in the management of construction, substantial opportunities exist, particularly in the areas of quality compliance, affirmative action, and management information services. The key to significant minority and female participation in project construction is the extent to which such firms can joint venture with other companies. It has had success to date with this method of participation.

Training

Northwest's plan concludes that, based on current projections, pre-employment training will not be needed to meet estimated needs during the preconstruction and construction periods. On-the-job or classroom training of craft and clerical workers may be done during construction to ensure attainment of affirmative action goals.

It is expected that lower 48 labor markets will supply craft labor that the Alaskan market cannot supply. These trades will likely include operating engineers, plumbers and pipefitters, pipeline welders, and certain classifications of laborers.

Training will be given to selected personnel for the operational phase following completion of construction. The number of personnel required for operation will be small, however--less than 200.

Northwest has suggested that pre-employment training of craft workers by other organizations or agencies would be most useful if it were to occur the year prior to construction.

Alaskan Native Training

The Department of the Interior right-of-way permit to cross Federal lands is conditioned to require a company-sponsored pre-employment training program to help qualify Alaskan Natives for initial employment and for upgrading. The sponsors may either utilize existing training programs or develop their own program. It also requires an on-the-job training program for Natives. Further, the EEO regulations issued by the Department of the Interior allow preference in employment for Alaskan Natives living on or near land held by Native Corporations.

Monitoring and Enforcement

The Federal Inspector is responsible for assuring that Northwest is meeting the requirements of the regulations and its affirmative action plan.

In April 1981, the Federal Inspector issued enforcement regulations to assure that the sponsors comply with the Equal Opportunity Regulations and their affirmative action plans during construction of the U.S. portions of the 4,800-mile Alaska Natural Gas Transportation System. Both the law passed to expedite the project and the President's Decision selecting the system require minority and female participation in employment and procurement activities. Enforcement of the Equal Employment Opportunity Regulations, published in 1980, is the responsibility of the Federal Inspector. The enforcement regulations specify detailed OFI procedures which will assure sponsor, contractor, and subcontractor compliance with the sponsor's approved affirmative action plans. These procedures include complaint investigation, conciliation, and administrative and judicial tools.

Contact Points

Mr. Aaron Lovejoy
Manager, Affirmative Action
Northwest Alaskan Pipeline Company
3333 Michelson Drive
Irvine, California 92730
(714) 975-5651

Mr. John Alexander
Director of EEO/MBE
Office of the Federal Inspector
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20044
(202) 275-0582

Mr. Roy Roehl
Equal Opportunity Specialist
Office of the Federal Inspector
1001 Noble Street
Fairbanks, Alaska 99701
(907) 452-1008

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

Office of the Federal Inspector
Alaska Natural Gas Transportation System

Room 2413, Post Office Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20044

AUG - 4 1981

Refer to:
D0002634

MEMORANDUM

TO: All Parties on the Restricted Service List in Docket No. CP-80-435

FROM: J. Richard Berman
Director, Office of Audit and Cost Analysis

SUBJECT: Contacts with Northwest Alaskan Pipeline Company

The attached materials were received from Williams Brothers Engineering Company, summarizing all contacts between Williams Brothers and other parties to Docket No. CP80-435 since the last conference. This summary is being distributed to parties on the Restricted Service List in conformance with the notification procedures adopted in the conferences.

Attachments

WILLIAMS BROTHERS ENGINEERING COMPANY
A Resource Sciences Company

RESOURCE SCIENCES CENTER | 6600 S. YALE AVE. | TULSA, OKLAHOMA 74177
PHONE (918) 496-5020 | TELEX 49-7493 WBEC-TUL

D. D. GRASSMAN
Vice President

Rec'd: AC:
AUG - 3 1981

31 July 1981

Office of the Federal Inspector
Room 2428, Post Office Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20044

Attention: Mr. J. Richard Berman
Director, Audit and Cost Analysis

OL-050-OFI

Dear Mr. Berman:

Attached is a summary of a contact between Williams Brothers Engineering Company and Northwest Alaska. This contact together with the group submitted to you under our Letter Number OL-045 dated June 19, 1981 and Letter Number OL-038-OFI dated May 19, 1981, constitute all the contacts between Williams Brothers and other third parties since the March Technical Conference.

Sincerely,

WILLIAMS BROTHERS ENGINEERING COMPANY

D D Grassman

D. D. Grassman
Vice President by DC Pierce

DDG:DP:cb:4444
Attachment

WILLIAMS BROTHERS ENGINEERING COMPANY

INTER-OFFICE CORRESPONDENCE

DATE 31 July 1981

SUBJECT: Contact With Northwest Alaska

TO: Del Grassman

FROM: Doyle Pierce

COPIES:

Rec'd: AC AUG - 3 1981

On July 2, 1981, I called Cuba Waddington at NWA to advise him that we could not confirm the reconciled CCE numbers in Exhibit 9 (Rev.) submitted with the errata to the NWA Response on May 5, 1981.

The differences occured in the following catagories:

Category	Exhibit 9 ($1,000)	WBEC Compilation ($1,000)
Temporary Facilities	909,148	908,538
Pipeline	4,273,787	4,274,550
Project Directorate	1,261,095	1,261,125

Cuba took down these numbers, said he would have a check made, and that NWA would issue an additional errata if necessary.

D C Pierce

Doyle C. Pierce

DCP:cb

WILLIAMS
BROTHERS
ENGINEERING
COMPANY
A Resource Sciences Company

RESOURCE SCIENCES CENTER | 6600 S. YALE AVE. | TULSA, OKLAHOMA 74177
PHONE (918) 496-5020 | TELEX 49-7493 WBEC-TUL

Rec'd: ac:
JUN 25 1981

June 19, 1981

Mr. J. Richard Berman
Office of the Federal Inspector
Room 2428, Post Office Building
1200 Pennsylvania Ave., N. W.
Washington, D. C. 20044

Subject: Contacts with Northwest Alaska
OL-045-OFI

Dear Mr. Berman:

Enclosed are summaries of five contacts between Williams Brothers and Northwest regarding additional questions and answers on the NWA Response of May 1981.

In addition to these contacts, Williams Brothers was contacted by the Alaska State Pipeline Coordinator's Office (SPCO), including a meeting here in Tulsa. A summary of the Tulsa discussion was forwarded to you in our letter #OL-038-OFI dated May 19, 1981. Williams Brothers also attended a meeting in Irvine involving the OFI, NWA and Alaska SPCO. A summary of that meeting, which included some questions raised by us and answered by NWA, was included in NWA's comments dated June 2, 1981.

This letter summarizes pertinent contacts, between Williams Brothers and other parties to the proceedings, which have occurred since the March Technical Conference.

Very truly yours,

WILLIAMS BROTHERS ENGINEERING COMPANY

D. D. Grassman

D. D. Grassman
Vice President

DDG:DP:rh:4444
Enclosures

1981 JUN 25 AM 9 30

cc: Cuba Wadlington, NWA

OFFICE OF
FEDERAL INSPECTOR

WILLIAMS BROTHERS ENGINEERING COMPANY

INTER-OFFICE CORRESPONDENCE

DATE: April 10, 1981

SUBJECT: NWA CCE Job 4444-804
Compressor & Metering Stations
NWA Vendor Bid Review

TO: Del Grassman

FROM: William E. Bailie

COPIES: [redacted]
J. S. Atkins

Rec'd: AC:
JUN 25 1981

The review of the vendor bids received from NWA and Fluor for the mainline gas compressors, refrigeration units and station power generator units was completed 4/8/81. Several questions developed from the vendor bid review and comparing the NWA data provided in the CCE for price averaging sheets. The price averaging sheets - Mainline compressors, page 369; refrigeration units, page 368 and power generator units, page 370 of Vol. 17 - were utilized in the vendor bid review. An attempt was made to reproduce NWA's figures and in a few instances we were able to do it. A list of questions was prepared which would aid us in determining just which bids were used etc. in the price averaging of the three major compressor station items. The list of questions are attached. Doyle Pierce called Cuba Wadington at Irvine and mentioned our questions and Cuba was to arrange for Bob Olson, Fluor to call us and answer or obtain answers to our questions.

Bob Olson, Lou Losorodo and Fritz Cromiller called this morning at approximately 10:15 a.m. I read each question one at a time and Olson or the other two gentlemen responded to it. The following is the verbal data received from Fluor on the subject.

Question #1. Bob Olson said there were work sheets made for the price averaging of the mainline compressors and refrigeration units. He would see that Cuba is given copies of them to be handled with us. These work sheets are similar to those we were furnished for price averaging of the station power generator units.

Question #2. Bob Olson mentioned which vendor bids were used in their price averaging.

Question #3. Lou Losorodo mentioned that in Vol. 14 page 39 the freight was removed from the mainline gas compressor average cost and on page 250 same was done to the station power generator unit average cost. I have reviewed these pages and found that the ocean freight was removed @ $20,500 from the mainline compressor average cost of $5,042,900. The figures are both different from those that are included in price averaging summary sheet page 369 Vol. 17, which are $5,038,857 per unit and averaged freight of $20,425. The differences in figures represents $3,968 per unit or $27,776 total higher in the CCE than necessary. When reviewing the power generator page 250, different figures were again used. Page 250 had $2,642,900 averaged station generator (2) unit cost less $700,000 per station for waste heat package removal and $25,000 per station for ocean freight. From Vol. 17 page 370 price averaging summary sheet for power generator units the following are $2,640,571 average price for generators units complete per station including $700,000 for waste heat package and freight @ $25,155 per station. The difference in these figures represents $2,484 per station or $17,388 total higher in the CCE than necessary. The above differences are not great but they do add up to increase the CCE. These also indicate the type of minor arithmetic and posting errors that are spotted throughout the CCE.

Question #4. The engineering fee as requested to be itemized separate in the vendor bids are supposed to be included in the price averaging per Lou Losorodo but he could not verify that they were. There is no mention or costs included for vendor engineering fee in the price averaging summary sheets for the mainline compressors, refrigeration units or power generator units.

Question #5. Several responded to this question but Bob Olson summed up the response. Fluor used 210 Yen/U.S. $ for one bid and 237 Yen/U.S. $ for the other Japanese bids. No exchange rate or conversion was made for Swiss Francs or German Marcs since those bids were not used in Fluor's price averaging work. I would like to mention Fluor used 245 Yen/U.S. $ in their price averaging work sheets for the power generator units. This does not correspond to what Fluor just provided and no reason given why two different exchange rates were used as mentioned above (210 and 237 Yen/U.S. $).

We discussed the different freight costs estimated for the mainline gas compressors. I asked why such a difference since all four manufacturers are in the same general section of the country or are very close to each other. No real reply was made but Olson said it did appear to be strange, one being at least three times the others. We also discussed the vendor's price used in the price averaging being too low. The way I read it, the price should be $128,117,920 as quoted. Fritz is to look into the matter - it may be a difference of intrepretation!

I asked Bob Olson if they were going to provide or furnish us any additional material or data to support their position relative to matters discussed during the conference here late March. He said Fluor was preparing the data they propose to furnish us. The data was to be printed over the weekend and would be submitted to NWA first of next week. Bob could not state when we would receive it, if any of it. He said it was up to NWA to decide. I said, "Fine," and that I was only incurring so I could possibly schedule my work to accommodate it. I thanked him for his information that he provided.

I guess if we are to receive any follow-up data from NWA, it most likely will be received late next week at the earliest.

Respectfully,

William E. Bailie

William E. Bailie

WEB:cb:3356
Attachments

WILLIAMS BROTHERS ENGINEERING COMPANY	SUBJECT: Questions for NWA relative to their Vendor bids	PROJECT NO: 4444-04	CLIENT: OFI
		PREPARED BY: W. E. Bailie	CHECKED BY:
		DATE: 4/8/81	SHEET OF

General Questions relative to NWA Vendor bid review.

1. Are there any NWA work sheets available that were used to develop the price averaging cost sheets for mainline gas compressors and also refrigeration units? There were work sheets available for the price averaging cost sheet for station power generator units.

2. Which vendor quotes were either used or not used?

3. Why was freight included in the price averaging for mainline gas compressors and station power generator units and not for refrigeration units?

4. Why was the engineering fee requested as separate item and NOT used in any of the price averaging work?

5. What foreign currency exchange rates used to convert Japanese Yen (¥), Swiss Francs (sFr) and German Marcs (dM) into US dollars?

C-O-N-F-I-D-E-N-T-I-A-L

FERC FILING

ESTIMATED COSTS

Mainliners	Vendor J	Vendor K	Vendor L	Vendor M
Gas Generator	RB-211	RB-211	LM-2500	LM-2500
Base Price - each -	$ 4,960,000*	$ 4,270,000	$ 4,093,946	$ 4,561,000
API Lube-Seal Oil Console w/air cooled			75,000**	75,000
Accoustical Enclosure w/Halon system	Included	Included	Included	Included
Pre-heating inlet air filter	Not Required	Not Required	84,000**	84,000
Compressor w/side inlet and exhaust	$ 200,000	Included	Included	Included
Local Control Panel	Included	Included		Included
Performance and String Testing	$ 150,000**	$ 200,000	$ 150,000**	$ 140,000
Long Term Storage	Included	Included	9,000**	8,720
Total	$ 5,310,000	$ 4,470,000	$ 5,221,946	$ 4,928,700
Each x 7 units	$37,170,000	$31,290,000	$36,554,000	$34,500,000
Seismic Qualifications	250,000**	250,000**	250,000**	250,000**
Freight - Estimated from Purchasing	329,000	105,000	90,000	47,890
TOTAL	$37,749,000	$31,645,000	$36,894,000	$34,797,890

AVERAGE $35,272,000 -> 5,038,857 each

Freight = $142,973 ÷ 7 = $20,425

Notes -

(a) All pricing FOB Manufacturer's plant

(b) ** Estimated data

JUN 6 1980

Exhibit V

PRICE AVERAGING

INQUIRY NO. 0704-4-468086

14 REFRIGERATION UNITS

Vendor D	$ 86,856,000	
Vendor E	$103,167,400	[illegible] be + spare part [illegible] fee.
Vendor F	108, 117 920 $100,067,820	Carrier
Average	$ 96,697,073	
Full Performance Test by Vendor F	$ 28,050,100	Carrier
TOTAL	$124,747,173	

Notes:

1) Vendor G was eliminated from price averaging due to lack of competiveness.

2) Vendor H was eliminated due to questionable credibility of their bid.

3) Vendor I was eliminated due to noncompliance with the specified requirement for unit responsibility.

4) Prices quoted are all F.O.B. Factory.

Carrier

JUN 6 1980

Exhibit IV

C-O-N-F-I-D-E-N-T-I-A-L

FERC FILING

ESTIMATED COSTS

Gas Turbine Generators	Vendor N	Vendor O	Vendor P	Vendor Q
	Single Shaft	Single Shaft	Two Shaft	
For 14 units				
Base Price w/Lube System in Base Gear & Generator	11,763,850	13,001,777	12,892,200	13,149,822
Accoustical Enclosure	Included	Included	Included	Included
w/Halon System			Included	Included
Inlet Air Filter	Included	Included	Included	Included
Waste Heat Boilers (14 units)	4,900,000	4,900,000	4,900,000	4,900,000
w/Exhaust Silencer	From Vendor AC Quote			
w/Supplemental Firing - (Per Vendor AC Quote) Quote)				
Local Control Panel Add to bring up to Job Req-Estimated	210,000	Included	350,000	210,000
Electro Hydraulic Start	Included		Included	Included
Dual Fuel	Included		Included	Included
Lube Oil Cooler	Included			Included
Spare Fan Installed	52,000*	52,000*	52,000*	52,000*
Long Term Storage	70,000*	70,000*	70,000*	70,000*
Diesel Day Tank, Pump and Filter	140,000*	140,000* Estimated	140,000*	140,000*
Full Load Performance	Included	Included	Included	Included
Test (14 Tests) ea.	Included	Included	Included	280,000
Total	17,135,850	18,163,777	18,404,200	18,801,822
Estimated Freight From Purchasing	294,000	140,000	150,000*	120,351
Seismic analysis/Tests	180,000	180,000*	180,000*	180,000
Total	17,615,850	18,483,777	18,734,200	19,102,173
Average		18,484,000 → 2,640,571 per station		

*Estimate

(use freight 176,088 total → 25,155 per station

Exhibit VI

JUN 6 1980

370

CLIENT NORTHWEST ALASKAN PIPELINE Co. **CONSTRUCTION COSTS** FLUOR

LOCATION ALASKA C.O. NO. 47R024 JOB NO.

PROJECT ALASKAN GAS PIPELINE AREA-UNIT 22-0W MADE BY FEATHERSTON APVD.

A/C NO.	ITEM & DESCRIPTION	QUAN.	UNIT	MANHOURS PER UNIT	MANHOURS TOTAL	MANHOURS RATE	COST/UNIT LABOR	COST/UNIT SUB CONTR.	COST/UNIT MAT'L	COSTS ( ) LABOR	COSTS SUB CONTRACT	COSTS MATERIAL	COSTS TOTAL
41	-06-TK-2	1	EA								47,070		
	RAW WATER STORAGE TANK												
	LESS OCEAN FREIGHT @ 9%												
	NET												
	WEIGHT												
	SIZE												
43	-07-MG-1												
	ELECTRICAL GENERATION PKG	1	EA		1350				2,642,900			2,642,900	
	LESS WASTE HEAT RECOVERY												
	PACKAGE (SEE 45 A/C)	<2>	EA						<350,000>			<700,000>	
	SUBTOTAL											1,942,900	
	LESS OCEAN FREIGHT											<25,000>	
	NET INCLUDING											1,917,900	
	MH/HP → (43 A/C CHART)												
	TURBINE GENERATOR SKIDS	2	EA		150								
	-07-MG-1-G-1 A,B												
	ELECTRICAL GENERATORS												
	-07-ME-1-GT-1 A,B												
	GAS TURBINE DRIVERS												
	3830 HP												
	-07-ME-1-GT-1 AC, BC												
	AIR COMPRESSORS												
	07-ME-1-F-2												
	FUEL GAS FILTER												
	SKID WEIGHT 50,000 lbs EA.												
	SIZE 28' x 9' x 10' H												
	L·W·H = 2520 CF (Y)^x												

JUN 6 1980

250

DATE 4-3-80 REVISION NO. 1 REVISION DATE 5-9-80 CODE PAGE NO.

PRINTED IN U.S.A. FORM E-193A REV.11/72

CONSTRUC..ON COSTS

FLUOR

CLIENT NWH

LOCATION ALASKA

PROJECT ALASKAN GAS PIPELINE — ASEH - UNIT 22-01

C.O. NO. 478021 JOB NO.

MADE BY FEATHERSTON APVD.

A/C NO.	ITEM & DESCRIPTION	QUAN.	UNIT	US MANHOURS GC PER UNIT	TOTAL	RATE	COST/UNIT LABOR	SUB CONTR.	MAT'L	COSTS (1980 $) LABOR	SUB CONTRACT	MATERIAL	TOTAL
43	PIPELINE GAS COMPRESSOR PACKAGE INCLUDING:	1	EA		3000	✓			5042,900			5,042,900	
	LESS OCEAN FREIGHT											<20,500>	
	NET											5,022,400	
	MH/HP → (43 A.K CHART)												
	COMPRESSOR SKID:	1	EA	(Y)*	150								
	-01-C-1 PIPELINE COMPRESSOR												
	-01-GT-1 PIPELINE COMPRESSOR GAS TURBINE DRIVER												
	SKID WEIGHT: 175,000 lbs												
	SIZE 45' X 12' X 12' H												
	L·W·H = 6480 CF (Y)*												
	PUMP SKID:	1	EA	(Y)*	80								
	-01-C-1-P-1 A,B COMPRESSOR LUBE OIL PUMP												
	-01-C-1-P-2 A,B COMPRESSOR SEAL OIL PUMP												
	-01-GT-1-P-1 A,B TURBINE LUBE OIL PUMP												
	SKID WEIGHT 25,000 lbs												
	SIZE 30' X 12' X 8' H												
	AN OVERHEAD SEAL OIL TANK	1	EA		20								
	WEIGHT 1224 lbs												
	SIZE 12" X 30" [illegible]												
	MH/L·D → (42 AK CHART)												
	AN OVERHEAD LUBE OIL TANK	1	EA		10								
	WEIGHT												
	SIZE 24" ⌀ X 6'												
	MH/L·D → (42 AK CHART)												

DATE 4-2-80 REVISION NO. 1 REVISION DATE 5-9-80 CODE PAGE NO.

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FORM E-153A REV. 11/78

115.1812

WILLIAMS BROTHERS ENGINEERING COMPANY

INTER-OFFICE CORRESPONDENCE

DATE May 8, 1981

SUBJECT: Questions asked of NWA and Fluor pertaining to the NWA response and the CCE.

TO: Del Grassman

COPIES: D. Pierce
OFI File

FROM: Jeff Wenzell
Jeff Wenzell

The following is a list of questions which were addressed to NWA and Fluor representatives followed by the answer to each question. The questions and answers are summarizations of the pertinent information received through telephone conversations of April 27 through April 29, 1981.

1. (Q) Response Volume I and Volume III, as relating to revegetation materials, do not appear to be using identical logic. Which is correct?

   (A) Volumes I and III were written separately, Volume I uses "Means" for reference while Volume III was developed using unit prices and specified application rates.

   There may be additional information regarding the two approaches provided in the near future.

2. (Q) Were the revegetation material application rates supplied by the environmentalists?

   (A) No, for the mulch and fertilizer. These are as specified in the filing, but were considered appropriate by sub-contractors who were contacted for quotes.

   For the seed, the native grass mixture was specified by the environmental people as was the $16.00 per pound price for the mix.

3. (Q) Were the unit prices for the materials estimated or are they quotes?

   (A) The unit prices are based on the revegetation sub-contractors quotes. Two were contacted.

WILLIAMS BROTHERS ENGINEERING COMPANY

4. (Q) How was the $75.00 per acre for watering after seeding computed?

(A) It is an estimated cost for providing irrigation pipe, sprinklers, pumps, etc., to keep the new seed wet in order to establish roots. This is required by the state of Alaska.

5. (Q) Was the 20% loss and waste factor for revegetation materials obtained from the revegetation subcontractors?

(A) Yes, they indicated 20% would be a percentage they would use to account for loss and waste of material.

6. (Q) Which of the two revegetation material analysis contained in the NWA response were used in the summary for adjusted costs?

(A) I believe the costs contained in Section 6 of the response were used in the adjusted costs.

7. (Q) There was no material site stripping quantity shown for Atigun Pass in the NWA response Section 6. Is this correct?

(A) No, these were inadvertently left out of the response. The correct volume of material site stripping quantity for Atigun Pass is as shown in the CCE, that is 5,000 bcy. This figure is a prorated portion of the total Section II material site stripping volume attributable to the Atigun Pass work. The section quantities shown in the CCE are for information only and do not represent the actual amount of stripping required for Atigun Pass.

WILLIAMS BROTHERS ENGINEERING COMPANY

8. (Q) What does the term, "Compacted Material on Embankment" specifically refer to as used on pages 6-34, 6-35 and 6-36 of the NWA response? (Reference workpad and access road maintenance.)

(A) It is the neat quantity of embankment material provided by Engineering.

9. (Q) Does "Compacted Material on Embankment" include the workpad and access road embankment quantities?

(A) Yes.

10. (Q) The moves as used in Section 6 of the response for workpad and backfill crushing refers to the moving from one site to another, is this true?

(A) Yes.

11. (Q) What is the water truck to be used for in the back-fill crushing operation?

(A) The water truck was included by the EC's and we believe it will be used for plant cooling water and dust control around the material site.

12. (Q) Why are two dozers applied to feeding the workpad crushing equipment while only one is applied to feeding the backfill crushing equipment?

(A) The workpad crushing equipment is operating at 500 tons per hour while the backfill crushing equipment operates at 300 tons per hour. The two dozers are required to provide adequate material for the workpad crushing operation while one dozer will be adequate to supply material for the back-fill crushing operation.

WILLIAMS BROTHERS ENGINEERING COMPANY

13. (Q) Why was one 773 (50 Ton) end dump used in feeding the workpad crushing equipment which operates at 500 tons per hour, while two 769 (35 Ton) end dumps were used to supply the backfill crushing equipment which operates at only 300 tons per hour?

(A) The material for the workpad crushing operation will be obtained from an area closer to the crushing equipment than the material for use in the backfill crushing operation. The additional haul distance associated with feeding the backfill crushing equipment necessitates two 769 end dumps.

14. (Q) What is the determining factor that determines the hourly production rate for the workpad and backfill crushing equipment?

(A) The bare production rates of 500 tons per hour and 300 tons per hour were supplied by the EC's based on their experience in Alaska.

15. (Q) What does the quantity for thermal degradation represent in workpad and access road maintenance?

(A) The thermal degradation quantity is for excess workpad embankment material that will be required where the toe of the haul road embankment has subsided due to thermal erosion.

16. (Q) How were these quantities estimated?

(A) The Michael Baker engineers identified problem areas from the aerial photographs, then determined quantities based on field investigations.

FLUOR ENGINEERS AND CONSTRUCTORS, INC.
SOUTHERN CALIFORNIA DIVISION
3333 MICHELSON DRIVE
IRVINE, CALIFORNIA 92730
TELEPHONE: (714) 975-2000
TELEX: 69-2488

May 12, 1981

Fluor Contract 4680

Williams Brothers Engineering Company
6600 South Yale Avenue
Tulsa, Oklahoma 74136

Attention: Jeff Wenzell

Re: Additional WBEC Questions Concerning CCE

Jeff,

The following comments have been prepared in response to your telex of 5/5/81.

These comments correspond numerically to the questions on the attached telex.

1. The alignment sheet quantities for spoil disposal from the workpad do not include access road disposal quantities. The CCE does not include any quantities for access road disposal, however, if there were any, the disposal material would be stored along the access road and no hauling would be required.

2. The right-of-way losses associated with select and common backfill material were not considered in connection with the workpad maintenance quantities. During construction, the majority of the workpad and access road maintenance material will be required prior to the back filling operation. Additionally, the CCE is based on stockpiling or wind rowing the back fill material along the working side of the ditch and not back on the workpad. Therefore, the material coming into contact with the ground surface is not recoverable and can not be utilized for maintenance.

   All maintenance material will come from either excess useable ditch excavation or from nearby material sites.

3. No, the ditch dimensions used to calculate the excavation quantities were established by PMC estimating personnel with the concensus of the EC's.

4. Yes, the operation was estimated on the basis that the crushing plants would be dismantled, moved and erected during the day. The day crews assigned to the crushing operations will be either involved in the moving operation or in preparing the new location. However, the night crews or second shift crews will be waiting for the plants to be moved. Therefore, two shifts per moving day were estimated to account for the moving time of the first shift and the waiting or lost time of the second shift.

5. I am assuming that your first statement comes from the General Notes, No. 1 of the Typical Ditch Configurations shown in the Design Manual. As is quite apparent from the quantity of bedding and padding material calculated by Engineering, they did not adhere to this statement. This was a very preliminary note and was never used for the estimating of bedding and padding material either by Engineering or by PMC estimators. Engineering actually figured that all ditch would require bedding and padding and that all bedding and padding material, except in a few site specific areas of Type I ditch, would come from material sites. In a few areas of Type I ditch, they did figure that in situ material would be suitable for bedding and padding.

   Engineering did not include a right-of-way loss for excavated material reused as backfill because they assumed that this loss would be taken care of by the excess excavated material.

   The allowance provided by PMC for right-of-way loss is based on construction experience. Ditch spoil, if reusable, will be placed on the off-side of the ditch on a non stripped right-of-way. Spoil material coming into contact with the ground surface is not recoverable and cannot be utilized for back filling the ditch. This material will be regraded during restoration.

6. The civil progress schedule is applicable to the total material site operation.

7. This is an error. No material site losses should be applied to common material that is being reused from ditch excavation.

8. The asterisks were put there originally as reference to a footnote which stated that those unit quantities contained errors in calculation. If corrected, the numbers should read as follows: Common - Total 1.57, 1.47, 1.47, 1.38, 1.47, 0.71, 2.87, 3.72, 4.62, 5.57, 6.57, 2.30, 2.44, 2.57, 2.70 and 2.83 Select-Total 2.13, 2.05, 2.13, 1.92, 2.05, 1.78, 2.49, 2.49, 2.49, 2.49, 2.49, 3.15, 3.90, 4.70, 5.55 and 6.44. These corrections would change the Common-Total from 6,624,754 to 7,100,785 and the Select-Total from 8,676,731 to 9,274,935.

   Based on the fact that the CCE is only an estimate and has numerous variables, it was decided that these corrections would not be made. However, if you wish to make these corrections at this time, NWA/PMC has no objection.

9. The major reason that the material was not used as back fill is that it would not be cost effective to do so. If common material could be obtained from a nearby material site and hauled to the right-of-way at less cost then hauling excavated material a long distance along the right-of-way, the excavated material was not used. The majority of this excess excavated material (2,000,000 + BCY) is used for maintenance and the remainder is used for restoration.

10. Yes they were (Refer to No. 9)

11. No it will not. Normally, the hauling units will take the aggregate directly from the bin and will not require a loader for loading. However, a loader or a dozer will be required to bulk-up the material into stockpiles after the haul units have dumped the aggregate. A loader was used in lieu of a dozer because of its increased mobility and wider use potential.

12. The CCE is based on the assumption that the material will be windrowed along the right-of-way. This windrow is estimated to have an average base width of 8 LF. The bottom 6 inches of material in this windrow will not be recoverable. The following calculation was used: $0.14 \text{ BCY/LF} = \frac{7'+8'}{2} \times .5' \times \frac{1}{27}$.

   The 0.05 BCY/LF shown on the flow sheet represents an average loss along the entire pipeline length for common material obtained from material sites.

FLUOR

Williams Brothers Engineering Company
Attention: Jeff Wenzell

May 12, 1981
Page 4

13. The berm material over the Type II A ditch is common material. There has been no differentiation between common backfill material and the workpad material in the estimate.

14. The D.D.P.'s were developed by Engineering for the entire length of the pipeline.

    These D.D.P.'s were used by Engineering for estimating their excavation quantities. PMC estimators did not use these. The ditch cross sections were revised and the excavation quantities determined utilizing the March Charts and construction experience.

15. Refer to No. 14 above.

16. That is correct. Refer to No. 5

Very truly yours,

D. W. Brown
Project Controls Manager

RL
DWB:RL:km

4444-812

WILLIAMS BROTHERS ENGINEERING COMPANY

INTER-OFFICE CORRESPONDENCE

DATE May 13, 1981

SUBJECT: Questions asked of Fluor and NWA pertaining to the NWA response and the CCE.

TO: Del Grassman

COPIES: D. Pierce
OFI File ✓

FROM: Jeff Wenzell
Jeff Wenzell

The following are questions addressed to NWA by phone on April 30, 1981. When there was no response from Fluor by May 5, 1981, I called and found out NWA had not notified Fluor of the questions (as NWA had told me they would). The questions were then addressed to Fluor by telephone and confirmed by telex on May 5, 1981. The response to these inquiries were received May 13, 1981 by telecopy. The questions from the telex and the answers from the telecopy are listed below:

1. Do the alignment sheet quantities for spoil disposal from workpad also include access road disposal quantities?

A The alignment sheet quantities for spoil disposal from the workpad do not include access road disposal quantities. The CCE does not include any quantities for access road disposal, however, if there were any, the disposal material would be stored along the access road and no hauling would be required.

2. Were the select and common R.O.W. loss quantities considered in connection with workpad maintenance quantities? Are the R.O.W. losses credited towards maintenance?

A The right-of-way losses associated with select and common backfill material were not considered in connection with the workpad maintenance quantities. During construction, the majority of the workpad and access road maintenance material will be required prior to the back filling operation. Additionally, the CCE is based on stockpiling or wind rowing the back fill material along the working side of the ditch and not back on the workpad. Therefore, the material coming into contact with the ground surface is not recoverable and can not be utilized for maintenance.

All maintenance material will come from either excess usable ditch excavation or from nearby material sites.

WILLIAMS BROTHERS ENGINEERING COMPANY

3. Did the E.C.'s provide the excavation dimensions?

A No, the ditch dimensions used to calculate the excavation quantities were established by PMC estimating personnel with the concensus of the EC's.

4. Backfill crushing plant move times are in days then doubled for two shifts per day. Is this correct?

A Yes, the operation was estimated on the basis that the crushing plants would be dimantled, moved and erected during the day. The day crews assigned to the crushing operations will be either involved in the moving operation or in preparing the new location. However, the night crews or second shift crews will be waiting for the plants to be moved. Therefore, two shifts per moving day were estimated to account for the moving time of the first shift and the waiting or lost time of the second shift.

5. Engineers estimated only 25% of ditch would require bedding and padding and common backfill would only be used at site specific locations.

They did not include R.O.W. losses into their volumes of material to be reused from the ditch excavation. The CCE estimated R.O.W. losses for common backfill material reused from the ditch excavation, why?

A I am assuming that your first statement comes from the General Notes, No. 1 of the Typical Ditch Configurations shown in the Design Manual. As is quite apparent from the quantity of bedding and padding material calculated by Engineering, they did not adhere to this statement. This was a very preliminary note and was never used for the estimating of bedding and padding material either by Engineering or by PMC estimators. Engineering actually figured that all ditch would require bedding and padding and that all bedding and padding material, except in a few site specific areas of Type I ditch, would come from material sites. In a few areas of Type I ditch, they did figure that in situ material would be suitable for bedding and padding.

WILLIAMS BROTHERS ENGINEERING COMPANY

Engineering did not include a right-of-way loss for excavated material reused as backfill because they assumed that this loss would be taken care of by the excess excavated material.

The allowance provided by PMC for right-of-way loss is based on construction experience. Ditch spoil, if reusable, will be placed on the off-side of the ditch on a non stripped right-of-way. Spoil material coming into contact with the ground surface is not recoverable and cannot be utilized for back filling the ditch. This material will be regraded during restoration.

6. Is the civil progress schedule on page 6-18 of the NWA response just for material site operation associated with select backfill material or is it for the total material site operation?

A The civil progress schedule is applicable to the total material site operation.

7. Why are material site losses considered for common material being reused from ditch excavation?

A This is an error. No material site losses should be applied to common material that is being reused from ditch excavation.

8. What do the *(asterisks) mean in the backfill quantities for common and select backfill in the excavation and backfill summary prepared by Fluor on 11-18-80, in response to trail staff's comments?

A The asterisks were put there originally as reference to a footnote which stated that those unit quantities contained errors in calculation. If corrected, the numbers should read as follows: Common - Total 1.57, 1.47, 1.47, 1.38, 1.47, 0.71, 2.87, 3.72, 4.62, 5.57, 6.57, 2.30, 2.44, 2.57, 2.70 and 2.83. Select-Total 2.13, 2.05, 2.13, 1.92, 2.05, 1.78, 2.49, 2.49, 2.49, 2.49, 2.49, 3.15, 3.90, 4.70, 5.55 and 6.44. These corrections would change the Common-Total from 6,624,754 to 7,100,785 and the Select-Total from 8,676,731 to 9,274,935.

Based on the fact that the CCE is only an estimate and has numerous variables, it was decided that these corrections would not be made. However, if you wish to make these corrections at this time, NWA/PMC has no objection.

9. Why are 2,000,000+ bcy of useable ditch excavation not used for backfill?

A The major reason that the material was not used as back fill is that it would not be cost effective to do so. If common material could be obtained from a nearby material site and hauled to the right-of-way at less cost then hauling excavated material a long distance along the right-of-way, the excavated material was not used. The majority of this excess excavated material (2,000,000 + BCY) is used for maintenance and the remainder is used for restoration.

10. If the material will be used for maintenance, were the material site maintenance quantities adjusted by this amount? (refer to question #9)

A Yes they were (Refer to No. 9)

11. Won't the use of the 50 ton aggregate bin with conveyor in the workpad crushing operation negate the need for a 988 loader to stockpile product?

A No it will not. Normally, the hauling units will take the aggregate directly from the bin and will not require a loader for loading. However, a loader or a dozer will be required to bulk-up the material into stockpiles after the haul units have dumped the aggregate. A loader was used in lieu of a dozer because of its increased mobility and wider use potential.

12. How was the .14 bcy per LF of common R.O.W. losses estimated? The flow sheet indicates .05 bcy per LF.

A The CCE is based on the assumption that the material will be windrowed along the right-of-way. This windrow is estimated to have an average base width of 8 LF. The bottom 6 inches of material in this windrow will not be recoverable. The following calculation was used: $0.14\ BCY/LF = \frac{7'+8'}{2} \times .5' \times \frac{1}{27}$.

The 0.05 BCY/LF shown on the flow sheet represents an average loss along the entire pipeline length for common material obtained from material sites.

13. Is the berm material over the type IIA ditch, common backfill or workpad material? Is there a difference?

A The berm material over the Type II A ditch is common material. There has been no differentiation between common backfill material and the workpad material in the estimate.

14. The design manual refers to "Ditch Degradation Potentials", in terms of: the time of year the ditch is open, the soils, the ground water table, and the thermal condition.

Were these D.D.P.'s developed for the entire pipeline and were they used during the estimation of trench excavation?

A The D.D.P.'s were developed by Engineering for the entire length of the pipeline.

These D.D.P.'s were used by Engineering for estimating their excavation quantities. PMC estimators did not use these. The ditch cross sections were revised and the excavation quantities determined utilizing the March Charts and construction experience.

15. If not, what factors were primarily considered?

A Refer to No. 14 above.

16. The estimate of backfill quantities considers that no usable ditch excavation will be 2 inch minus material suitable for use as bedding and padding, correct?

A That is correct. Refer to No. 5.

4144-812

WILLIAMS BROTHERS ENGINEERING COMPANY

INTER-OFFICE CORRESPONDENCE

DATE May 19, 1981

SUBJECT: Additional Questions Asked Of Fluor And NWA Concerning The NWA Response And The CCE.

TO: Del Grassman

COPIES: D. Pierce ✓ OFI File ✓

FROM: Jeff Wenzell

Jeff Wenzell

The following list contains five additional questions addressed to Fluor on May 14, 1981 and answers received May 18, 1981. These questions concern civil crushing and backfill quantities.

1. Why were no costs included in the NWA Response, page 6-6, for Atigun Pass work pad crushing?

A The NWA Response was prepared based on the format of the WBEC Report. In the WBEC Report Atigun Pass is included at the back of the report, not with Section 2, and for this reason was overlooked. The costs for Atigun Pass should have been included.

2. Why were no costs included in the NWA Response, page 6-14, for Atigun Pass select backfill crushing?

A Refer to No. 1.

3. Why does the total select backfill crushing operation manufacture 10,109,000 bcy while the total select backfill material hauled only equals 8,677,000 bcy?

A The difference in quantities comes from plant waste, or loss during crushing and a buffer allowance in case of an overrun of the estimated amount of select backfill. An allowance of 22 percent was made for this item; but because some select material is available, which does not require crushing, the overall average allowance was reduced to approximately 17 percent.

4. How was the quantity of extra material calculated? (Refer to 3)

A Refer to 3.

5. Refer to your comments of May 12, 1981 prepared in response to my Telex of May 5, 1981: Does the total corrected common backfill material quantity shown in "8" as 7,100,785 bcy include material site losses for common backfill material reused from ditch excavation? (Refer to my memo dated 5/13/81)

A The quantity as shown was corrected for mathematical errors, but was not corrected to exclude material site loss from common backfill material reused from ditch excavation. We are in the process of recalculating these quantities and will inform you of the results.

JW:ml

WILLIAMS BROTHERS ENGINEERING COMPANY

TELECOMMUNICATION SERVICES REQUISITION

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A. Questions regarding Permits and Trend A264

A-1) Response Pages 7-10, 7-62 and 7-64 show 79,100 additional man-hours, plus 58,968 hours from CCE for a total of 138,060 hours. Man power development chart on Page 7-65 shows 138,060 hours for Irvine and Houston plus 36,400 hours for Fairbanks. Text on Page 7-62 says increase is for Irvine, Houston and Fairbanks. Where are additional hours for Fairbanks costed?

A-2) Irvine subtotals on Response Page 7-65 are confusing. What are correct subtotals by quarter? Which positions are counted to arrive at subtotals?

A-3) Response Page 7-64 shows 59,968 hours from CCE for permits. Volume XXXII of CCE, Page 65, shows following:

Operation 11, Proj. Engr. - Permits for 87 man-quarters

Operation 28, Clerical - Permits - Irv. for 24 man-quarters

Operation 28, Clerical - Permits - Houston for 37 man-quarters

At 468 hours per quarter, these three positions total 69,264 man-hours. Why the difference between Response Page 7-64 and CCE Volume XXXII Page 65? In the CCE, who provides supervision for the Houston clerical - permits staff?

A-4) The man power development chart on Response Page 7-65 does not identify a Project Engineer - Permits as shown on Page 65 of CCE Vol. XXXII. Does the man power chart in Trend A264 replace the Project Engineers shown in the CCE? The trend chart does not show a clerical staff for Houston. Have these positions been eliminated?

A-5) The trend chart on Response Page 7-65 shows a Section Supervisor and six positions for Sections One through Six. Are these the six pipeline sections? If so, what differentiates the duties of the six sections from the pipeline position shown under Facilities Supervisor? From the Minerals and Materials Sites position?

A-6) Response Page 7-64 shows base salary computed at $12.34 per hour for all hours, which is same as CCE average for Area 84. Have you computed average for positions shown on Response Page 7-65? If so, does it match figure shown on Page 7-64?

B. Questions regarding Environmental Affairs

B-1) Response Page 7-113 indicates that the environmental staff of 14 in CCE should be increased to 24 per 1981 scope of work. The 24 equivalent positions on Pages 7-114 through 7-117 do not include all of the 14 positions on Page 64, CCE Volume XXXII. Does the staff shown on Response Pages 7-114 to 7-117 replace the CCE staff?

B-2) Please provide hourly rate, and duration and/or beginning and ending quarter for each assignment on Response Pages 7-114 to 7-117 (similar to detail on Page 64, Vol. XXXII).

B-3) Response Page 7-115 shows Coordinator of Unit 20 PMC Biological Programs as full time consultant service position but shows zero under "Number Required." Why is the position shown with zero staffing level?

B-4) Response Page 7-113 says CCE should be increased by 39,000 man-hours. Page 7-119 shows 39,000 hours for Irvine and 13,100 hours for Fairbanks. Summary on Response Page 7-10 shows 52,100 hours for Trend A-265. Please provide backup for Fairbanks hours in same detail as CCE.

IT-015-FLUOR 5365/4[50] Carolyn
Rush 4[45] Carolyn

1981 JUN -5 PM 1:58

37783

CORPORATE HEADQUARTERS

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D. W. Brown

ENGINEERS AND CONSTRUCTORS, INC.
Southern California Division

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TELEX: 69-2486

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DEX 700: (714) 975-52/2
RAPIFAX: (714) 975-5271
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Number of documents including lead sheet: 8

Company Name: Williams Brothers Engineering Company

Attention: Doyle Berry (496-5364)

Originator's Name: D. W. Brown/J. W. Griffin Extension: 6654

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A. Questions Re: Permits and Trend A264

A-1) There are no additional manhours requested for Fairbanks in Trend A264 response page 7-64. The text on response page 7-62 is incorrect and should refer to only Irvine and Houston. The Fairbanks Staffing presented on response page 7-65 is consistent with that in the CCE.

A-2) See attached copy of response page 7-65. The correct Irvine subtotals and positions are enclosed in a △.

A-3 The hours reflected on response page 7-64 (Potential Trend A264) are incorrect. The definitive trend in process will reflect the following manhours taken directly from page 75, Volume XXXII of the CCE.

Operation 11, Proj. Engr. (Irvine) - 87 Manquarters
Operation 11, Proj. Engr. (Houston) - 15 Manquarters
Operation 28, Clerical (Irvine) - 24 Manquarters
Operation 28, Clerical (Houston) - 37 Manquarters

At 468 hours per quarter, these total 76,284 manhours. Your total of 69,264 manhours did not reflect the two Project Engineers for Houston at 15 manquarters.

In answer to who provides supervision for the Houston Permits Clerical in the CCE. It is provided by the Permits Project Engineers.

A-4 The Manpower Development Chart (Trend Chart) on response page 7-65 does replace the manpower displayed in the CCE, and except for the Clerical Operation 28 on the Trend Chart, the staff is still composed of Project Engineers, Operation 11.

The clerical staff for Permits in Houston has been eliminated. Clerical support is provided from a pool which is budgeted under an element other than Project Directorate, i.e. Pipeline.

A-5) The Section Supervisor and six positions for sections shown on response page 7-65 are for the six Pipeline Sections.

The attached Permits PMC Functional Organization Chart shows the differentiation between the duties of the six sections and the Pipeline position under Facilities Supervisor.

The duties of the Minerals & Material Sites Pipeline position include the assembly and preparation of documents required to obtain all of the sand, gravel and similar materials for work pads, pipe bedding and backfill and concrete aggregate for the entire pipeline. This activity has developed into a major task requiring a full time person.

A-6) The base salary rate shown on response page 7-64 is the CCE Average for Project Directorate. This rate is used on Rough Order of Magnitude Potential Trends i.e. A264. The Definitive Trend in process will reflect the CCE rates for the Permits Staff and will not match the figure on response page 7-64. This rate is $14.31/Hour and will adjust the total accordingly.

B. Questions Regarding Environmental Affairs

B-1 The staff shown on response pages 7-114 to 7-117 does replace the positions on page 64, CCE Volume XXXII.

B-2) See Attachment #3.

B-3) The position for Coordinator of Unit 20 PMC Biological Programs on response page 7-115 reflects a zero staffing level because the position will not be filled by a PMC person. The exhibit addresses PMC Staff only. The coordinator position will be filled by one outside consultant.

B-4) See Attachment #4.

ATTACHMENT 1

IN PROSEC CONTROLE BUDGET

		1980		'81				'82				'83				'84				'85				'86	
IRVINE																									
Manager	OP. 11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						
Secretarial-Clerical	22	1	1	2	3	4	4	5	5	5	5	5	5	5	5	6	4	4	3	3	3	2	3	2	2
Control Team	25																								
Section Supervisor	11			1	1	1	1	1	1	1	1	1	1	1	1	1	1								
Section 1	11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0									
2	11		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
3	11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1				
4	11			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1							
5	11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
6	11		1	1	1	1	1	1	1	1	1	1	1	1	6										
Facilities Supervisor	11		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Minerals & Mtl. Sites	11		1	1	1	1	1	1	1	1	1	1	1	1	1	1									
Temporary Facilities	11			1	1	1	1	1	1	1	1	1	1	0											
Pipeline	11				1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						
Compressor Stations	11					1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
Subtotal		6	9	13	14	18	18	19	19	19	19	19	19	18	17	15	14	12	11	7	5	4	4	3	3
	4605.9 19557			8	12	14	16	18	18	15	15	13	1?	17	16	12	13	11	10	6	4	4	4	3	3
FAIRBANKS																									
Section Supervisor	11			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
Sections North	11			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						
Sections South	11	50	30. 400			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		
Subtotal				1	2	3	3	3	3	3	3	3	3	3	3	3	2	3	3	2	1	1	1		
				2	2	3	3																		
HOUSTON (FOS)																									
Permits Supervisor	11	16	7400 1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						

Base case page 7-63

PERMITS & DOCUMENTATION GROUP PMC ORGANIZATION

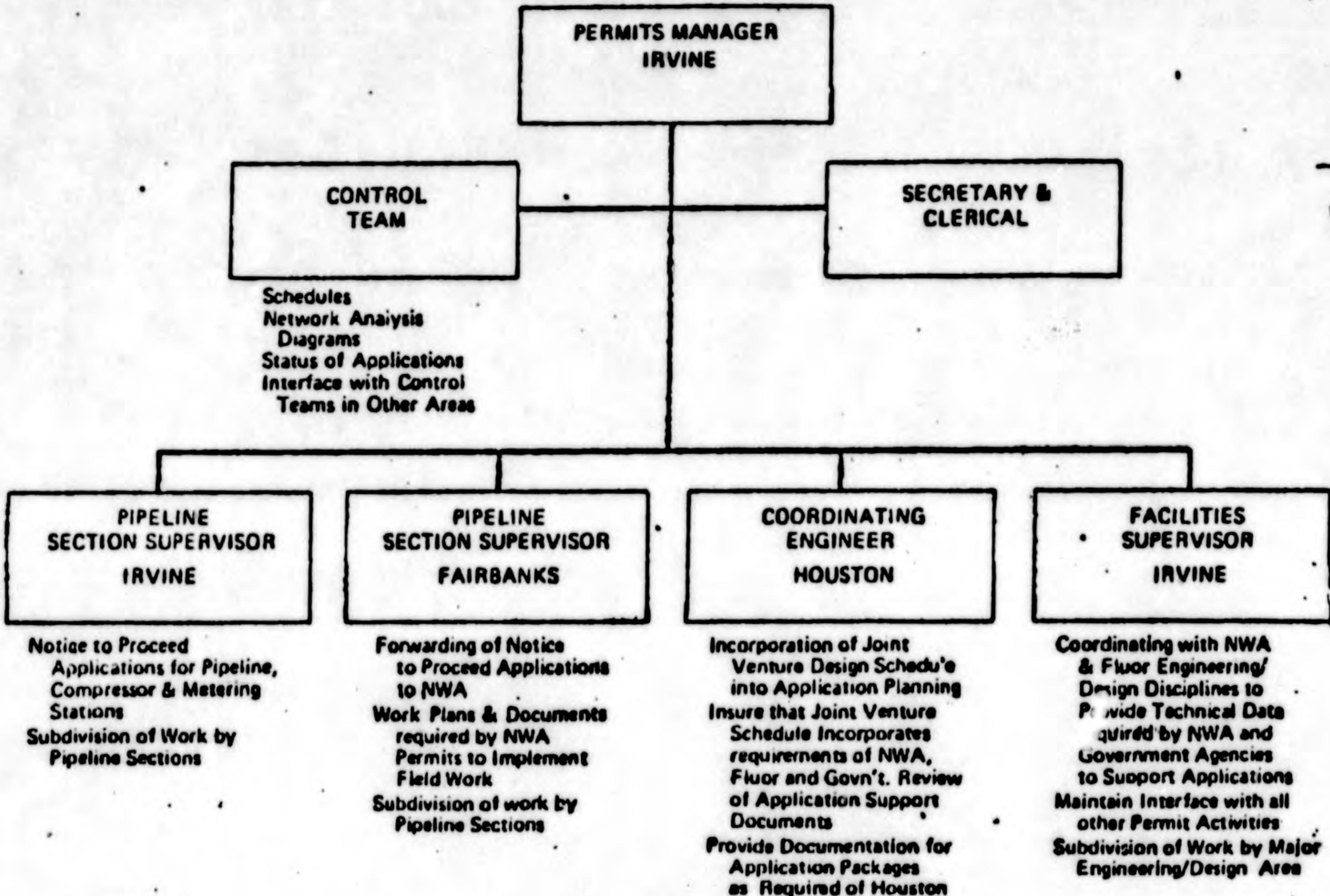

Figure 9.1-1

ATTACHMENT 3

Summary of Manquarters

Area 50

Irvine/Houston	Labor Grade	Pay Grade	1980 1st	1980 2nd	1980 3rd	1980 4th	1981 1st	1981 2nd	1981 3rd	1981 4th	1982 1st	1982 2nd	1982 3rd	1982 4th
Envir. Mgr.	E10	20.97	1	1	1	1	1	1	1	1	1	1	1	1
Coord. Staff Oper.	E9	19.04					1	1	1	1	1	1	1	1
Superv. Permits	E5	13.01	1	1	1	1	1	1	1	1	1	1	1	1
Sect. Team Biologists	E5	13.01					4	6	6	6	6	6	6	6
Superv. Info. Mgmt.	E8	17.31	1	1	1	1	1	1	1	1	1	1	1	1
Info. Mgmt. Librarian	NE6	7.93			1	1	1	1	1	1	1	1	1	1
Info. Mgmt. Data Controller	E5	13.01					1	1	1	1	1	1	1	1
Staff Biologist	E5	13.01	1	1	1	1	1	1	1	1	1	1	1	1
Coord. Envir. Eng.	E7	15.75	1	1	1	1	1	1	1	1	1	1	1	1
Envir. Eng.	E5	13.01	1	1	1	1	3	3	3	3	3	3	3	3
FERC Filing Coord.	E9	19.04	1	1										
Houston														
Coord. Civil Eng.	E8	17.31			1	1	1	1	1	1	1	1	1	1
Visual Resource Specialist	E5	13.01			1	1	1	1	1	1	1	1	1	1
Staff Specialists	E3	10.76			1	1	3	3	3	3	3	3	3	2
Envir. Eng.	E5	13.01					1	1	1	1	1	1	1	1
			7	7	10	10	21	23	23	23	23	23	23	22
Steno & Clerical	NE4	6.17	1	1	1	1	1	1	1	1	1	1	1	1
GRAND TOTAL			8	8	11	11	22	24	24	24	24	24	24	23

ATTACHMENT 4 a

Environmental Engineering

Summary of Manquarters

Area 50

Fairbanks	Labor Grade	Pay Grade	1980 1st	1980 2nd	1980 3rd	1980 4th	1981 1st	1981 2nd	1981 3rd	1981 4th	1982 1st	1982 2nd	1982 3rd	1982 4th
Environmental Mgr.	E9	23.06						1	1	1	1	1	1	1
Administrative Asst.	N6	10.90									1	1	1	1
Subtotal								1	1	1	2	2	2	2
no & Clerical	N3	7.37					1	1	1	1	2	2	2	2
Environ. Engr. Super.	E7	17.33	1	1	1	1	1	1	1	1	1	1	1	1
Assess & Permit Coord.	E5	15.76								1	1	1	1	1
Air Quality Specialist	E5	15.76										1	1	1
Waste Mgmt Specialist	E6	17.32						1	1	1	1	1	1	1
Hyd & Sanitary Engr.	E5	15.76									1	2	2	2
Restor. Eng. Superv.	E7	19.07										1	1	1
Restor. Eng.	E5	15.76					1	1	1	1	1	1	1	1
Agronomist	E5	15.76											1	1
Design Technician	N5	9.50												1
Oil Spill Specialist	E6	17.33									1	1	1	1
Environ. Orient Coord.	E5	15.76					1	1	1	1	1	1	1	1
Biologist Supervisor	E7	19.07							1	1	1	1	1	1
Biologist	E5	15.76	2	2	2	2	3	4	4	4	4	4	4	4
Data Mgmt. Superv.	E7	19.07										1	1	1
Biologist	E5	15.76										1	1	1
Archaeologist	E5	15.76										1	1	1
Technician	N5	9.58										1	1	1
Data Controller	E5	15.76										1	2	2
Subtotal			3	3	3	3	7	9	10	11	19	22	23	
Grand Total			3	3	3	3	7	10	11	12	15	23	26	27

ATTACHMENT 4 b

Summary of Manquarters

Area 50

Fairbanks

	Labor Grade	Pay Grade	1983 1st	1983 2nd	1983 3rd	1983 4th	1984 1st	1984 2nd	1984 3rd	1984 4th	1985 1st	1985 2nd	1985 3rd	1985 4th	Total Man Qtrs.
Environmental Mgr.	E9	23.06	1	1	1	1	1	1	1	1	1	1	1	1	17
Administrative Asst.	N6	10.90	1	1	1	1	1	1	1	1	1	1	1		15
Subtotal			2	2	2	2	2	2	2	2	2	2	2	1	32
Steno & Clerical	N3	7.37	2	2	2	2	2	2	2	2	2	2	2	2	34
Environ. Engr. Super.	E7	17.33	1	1	1	1	1	1	1	1	1	1	1		23
Assess & Permit Coord.	E5	15.76	2	2	2	2	2	2	2	2	1	1			
Air Quality Specialist	E5	15.76	1	1	1	1	1	1	1	1	1	1			13
Waste Mgmt Specialist	E6	17.33	1	1	1	1	1	1	1	1	1	1	1	1	18
Hyd & Sanitary Engr.	E5	15.76	3	3	3	3	3	3	3	3	3	3	3		40
Restor. Eng. Superv.	E7	19.07	1	1	1	1	1	1	1	1	1	1	1	1	15
Restor. Eng.	E5	15.76	1	2	2	2	3	3	4	4	4	4	4	4	39
Agronomist	E5	15.76	1	1	1	1	1	1	1	1	1	1	1	1	14
Design Technician	N5	9.50	1	1	1	1	2	2	2	2	2	2	2	2	21
Oil Spill Specialist	E6	17.33	1	1	1	1	1	1	1	1	1	1	1		17
Environ. Orient Coord.	E5	15.76	1	1	1	1	1	1	1	1	1	1			18
Biologist Supervisor	E7	19.07	1	1	1	1	1	1	1	1	1	1			16
Biologist	E5	15.76	4	4	4	4	4	4	4	4	3	2			65
Data Mgmt. Superv.	E7	19.07	1	1	1	1	1	1	1	1	1	1	1	1	15
Biologist	E5	15.76	1	1	1	1	1	1	1	1	1	1	1		14
Archaeologist	E5	15.76	1	1	1	1	1	1	1	1	1	1	1		14
Technician	N5	9.58	1	1	1	1	1	1	1	1	1	1	1		14
Data Controller	E5	15.76	2	2	2	2	2	2	2	2	2	2	2		27
Subtotal			25	26	25	26	28	28	29	29	27	26	20	10	406
Grand Total			29	30	30	30	32	32	33	33	31	30	24	13	490

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

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

SEP 26 1980

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

INTERIM REPORT TO THE COMMISSION

BY THE ALASKAN DELEGATE

AND THE DIRECTOR, AUDIT AND COST ANALYSIS,

OFFICE OF THE FEDERAL INSPECTOR

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

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

Cost Estimate Formats

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

IROR Methodology Issues

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

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

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

1. Separation distance between the ANGTS and the Trans-Alaska (oil) Pipeline System (TAPS);

2. The possiblity of utilizing a tunnel of approximately two and one-half miles in length to bypass the most difficult portion of the Atigun Pass in the Brooks Mountain Range in northern Alaska;

3. Burial of the pipeline in a s[illegible] or embankment mode, rather than in a trench; and

4. Access roads and work pads constructed of snow, with increased emphasis on winter construction, as opposed to access roads and work pads made of gravel, with emphasis on summer and "shoulder" months for the construction period.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. In addition to filing and serving the cooperative study agreement, we asked that the sponsors file and serve the communication from DOI regarding the right-of-way grant.

2. We have developed a working paper on IROR concepts which is being circulated as an attachment to this report.

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

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

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

Several parties (including, in particular, the trial staff) expressed reluctance to consider the IROR issues until after the parameters of the outstanding design issues had been clarified in the conferences. On the other hand, we felt that it was important to begin exploration of IROR questions early in the conferences, as application of the IROR mechanism is an important element of the context in which the Commission and the parties consider the sponsors' cost estimate filings. The compromise that we struck was to begin exploration of the IROR topics in a special conference in the week of October 6, 1980, then return to it at the end of the conferences.

Schedule of Future Conferences

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

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

September 30

October 14

October 28

November 11

November 25

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

Each conference will commence on a Tuesday, and will continue for as many days as the parties consider useful and appropriate, but will terminate no later than the Friday of the week in which it commenced. The Alaskan Delegate or the OFI Division Director will preside at each of these conferences, and a limited transcript will be kept (as discussed below).

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

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

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

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

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

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

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

Transcripts

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

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

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

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

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

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

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

Exchanges of Information

The Delegate first noted the August 15, 1980 comments from the Commission's trial staff, dealing, in large part, with the area of discovery. The Delegate pointed out that the technical conferences were intended to deal with the CCE, CP and related IROR matters only. To the extent that trial staff or other parties seek information that is to be dealt with in the final FERC certification proceeding (e.g., information relating to the financing plan or the marketability of Alaskan gas) or that relates to matters which are the responsibility of the OFI (e.g., the project sponsors' management plan), they must rely on methods of access available to them through means other than the technical conferences. The parties should deal directly with each other in obtaining access to documents and other information. The Delegate or the Division Director will rule on the production of documents directly relevant to this proceeding when the parties cannot reach agreement among themselves.

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

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

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

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

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

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

John B. Adger, Jr.
Alaskan Delegate

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

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Alaska Northwest Natural Gas Transportation Company — Docket No. CP80-435

Notice of Technical Conferences

(September 23, 1980)

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

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

The next succeeding conference will be held at the Commission's offices in Washington, D.C., beginning at 10:00 a.m. on Tuesday, October 7, 1980. This conference will consider a report from the Office of the Federal Inspector on major outstanding design issues, certain additional submissions regarding potential design changes from the project sponsors, and any further submissions from any other parties, in beginning to address the issue of the treatment of major design changes under the incentive rate of return (IROR) mechanism prescribed for the ANGTS by the Commission, and to address the development of guidelines to govern the design change process called for by that same IROR mechanism. That conference will also continue until adjourned, in any event no later than Friday, October 10. The precise location of this conference at the Commission's offices will be posted on the day of the conference, on the second floor bulletin board at 825 North Capitol Street, Washington, D.C. Further information about this conference can be obtained from Miss Jeanne Barrie at (202) 357-8900.

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

John B. Adger, Jr
Alaskan Delegate

WORK PAPER WP-1

THE FERC REGULATORY FRAMEWORK OF THE CENTER POINT OF THE IROR MECHANISM

James D. McCullough

September 22, 1980

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

TABLE OF CONTENTS

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

I. Introduction

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

II. Center Point Definitions

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

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

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

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

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

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

Design Changes and Scope Changes will be discussed below.

III. Center Point Relationship by Formula to IROR Schedule

a. Definitions

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

2. "Incentive Rate of Return Schedule -- A table or formula establishing a value of the Incentive Rate of Return for each value of the Cost Performance Ratio."[2]

b. Center Point Relationship to Center Point

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

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

[2]Order 17, op. cit., pages 20-21.

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

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

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

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

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

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

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

---

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

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

[3]Order 31, op. cit., page 249.

Center Point = [1.3 x (March 1977 Cost Estimate + Finance Charge)]/[Certification Cost Estimate + Finance Charge]

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

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

Center Point = [1.1 x March 1977 Cost Estimate + Finance Charge)]/[Certification Cost Estimate + Finance Charge]

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

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

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

(1) The nature of the changes in the project from that assumed at the time of the Decision.....

(2) The value or benefit to the Nation and gas consumers of construction of this project in light of the revised cost estimates.....

(3) The cost increases or cost overruns above the Certification Estimates that may reasonably be expected to occur....."[2]

---

[1]Ibid, page 247.

[2]Ibid, pages 52-53

Northern Border elected to follow the formula, and the Commission determined that their Center Point is 1.0758.[1] The Northern Border IROR schedule is shown on Figure 1.

> "The Commission, in Order 31, gave the project sponsors two choices or options as to how the Center Point would be determined. The first option was to utilize a formula based upon a comparison of the Certification Cost and Schedule Estimate and the estimates in the President's Decision. In its Motion for Rehearing, Alaskan Northwest objects to this formula approach. Under the second option, the project sponsors could request a Center Point without reference to the formula as part of the Certification Cost and Schedule Estimate submission if a major change had occurred in the project, including likely overruns, that exceeded the estimates in the Decision.
>
> Alaskan Northwest's motion states that '...it now appears very clear that a reasonable cost estimate for the Alaska Segment of the project will exceed the March 1977 cost estimate by more than 30 percent.' The Commission interprets this statement to mean that a major change in the Alaskan segment of the project has occurred since the President's Decision, and thus that Alaskan Northwest has rejected the option of setting the Center Point using a formula approach. Consequently, the Commission will not require that the formula approach be used for the Alaskan segment."[2]

IV. Minimum Value of Center Point

Upon petition by NWA, the Commission ruled that:

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

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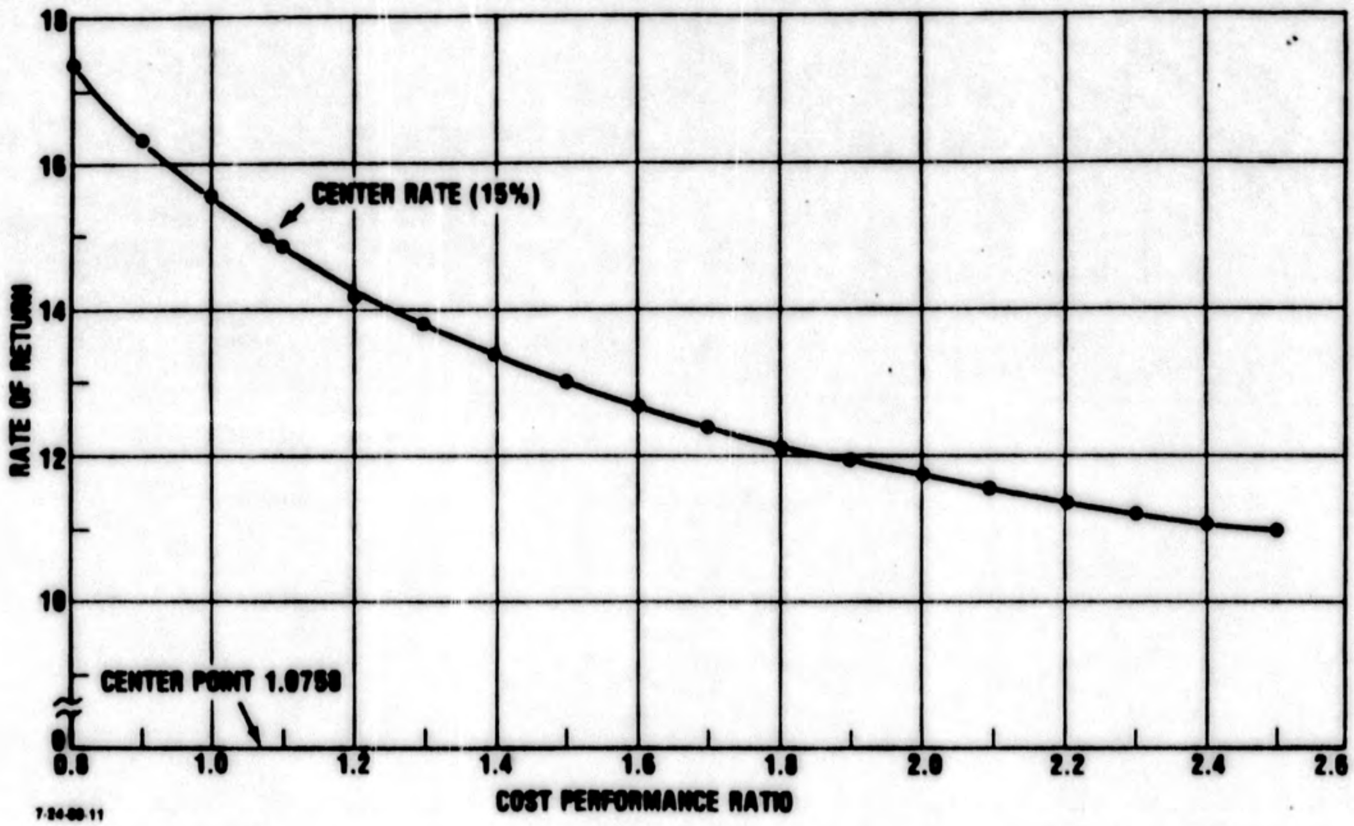
[1]FERC - *Findings and Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas,* Docket Nos. CP78-123, et. al., April 28, 1980, page 103.

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

[3]Ibid, page 5.

Figure 1

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



7-24-80-11

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

a. Abnormal Events to be Excluded from the CCE.

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

b. **Categories of Abnormal Events**

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

> "The Commission has previously dealt with the relationship between normal contingencies and the Center Point of the IROR schedule in its orders defining the IROR mechanism.[119/] In those orders, the Commission has distinguished among Change in Scope events, abnormal events and the conventional approach to estimation. These references may be categorized into three sets of "events" as concerns the Center Point:
>
> (1) Abnormal or unlikely events of such importance and consequence that the Commission has designated them as "Change in Scope" events.[120/] The cost consequences of these events are to be excluded from the cost estimates submitted for use in determining the Center Point. The project sponsors will be permitted to increase the Projected Capital Costs, which serve as the target for assessing cost and schedule control performance, by the estimated costs of Change in Scope Events as approved by the Federal Inspector.
>
> 119 See, especially, Order No. 31-B at pages 6-7.
>
> 120 See Condition 10, Order No. 31-B at page 73.

[1]Order 31, op cit., page 54.

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

(2) Normal or likely events of a routine nature but of an unknown (but not significant) cost impact, such as are normally included in pipeline construction cost estimates as contingency or management reserve at rates, for example, of 5-7 percent. The cost consequences of these "anticipated unknown" events are to be included as contingencies in estimates submitted for use in determining the Center Point.

(3) Abnormal or unexpected events that could substantially increase costs but which are not included in the list of Change In Scope events. Examples of such events are 100 year storms, major fires and floods. The cost consequences of these "unanticipated unknown" events are to excluded from the normal contingency allowance discussed above, but because these events are not Change In Scope events they are covered only by the Center Point mechanism itself."

VI. Change in Scope Events

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

"Such Change in Scope events shall be limited to:

(1) declared or undeclared war, including civil war or a formally declared blockade,

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

[1]Order 31-B, *op. cit.*, pages 74-75.

(4) major changes in pipeline routing or capacity ordered by Federal or State Governments for the Alaska Natural Gas Transportation System from that approved by the Federal Inspector in the Final Design of the pipeline, and

(5) delay in the issuance of a government permit or certificate necessary for completion of the pipeline system, when such delay (a) occurs subsequent to approval of the Final Design, (b) occurs through no fault of the project sponsors and (c) causes significant cost increases."

VII. Normal Contingencies

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

> "In-scope estimating uncertainty was carefully defined to separate its impact on project costs from the impact of unexpected events, design changes, and changes in scope. In-scope estimating uncertainty was explicitly defined as the variation in project costs and schedules resulting from:
>
> - Accuracy of material quantity estimates.
> - Accuracy of material price estimates.
> - Human productivity assumptions.
> - Equipment reliability assumptions.
> - Engineering/design development.
> - Accuracy of scheduled durations.
> - Accuracy of bid specifications based on current project definitions."

VIII. Design Changes Prior to Final Design Approval

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

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

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

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

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

> "The Commission takes this opportunity to clarify one aspect of Order No. 31-B, regarding revisions to the Projected Capital Costs target for the IROR mechanism. At pages 41 and 42 of Order No. 31-B, the Commission expressed a willingness to accept Northern Border's proposal that Projected Capital Costs should not be reduced for design changes that reduce costs. It has occurred to us that, in theory at least, abuses could arise in the following two types of situations:
>
> (1) Project sponsors were aware of cost-saving design changes at the time of consideration of the CCSE, but postponed them until after CCSE approval in order to retain a high CCSE and thus improve their expected cost performance ratio, and consequently their IROR; or
>
> (2) Certain optional assumptions (of which the project sponsors had knowledge at the time of preparation of the CCSE), such as alternate (cheaper) sources or (lesser) specifications for materials or equipment, were omitted in preparing the CCSE for the purpose of increasing its value, only to be changed once the CCSE had been approved.

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[1]Order 31, op. cit., pages 244-245.

[2]Order 31-B, op. cit., pages 41-42.

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

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

(1) Project sponsors did not know about cost-saving design changes at the time of preparation of the CCSE if such design changes are to be approved without lowering Projected Capital Costs; and

(2) If optional assumptions were made in preparation of the CCSE, cost-saving design changes will continue to utilize those same assumptions unless the assumption made was the correct one at the time of preparation of the CCSE but had since become inappropriate.

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

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

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

(1) Exclusion From "Wars":

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

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[1]Order 31-B, op. cit., page 33.

(2) Design Changes:

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

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

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

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

[1]Ibid, page 39.

[2]Order 31, op. cit., page 128.

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

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

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

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

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[1]Ibid, page 133.

[2]Ibid, pages 128-129.

X Recap of Key Points Related to the Alaska Segment

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

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

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

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

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

consumption continues to decrease

One of the reasons for the current downturn in demand is the effect of price increases during 1979 and 1980. Real gasoline prices rose more than 50% since the beginning of 1979, while gasoline use during the last 12 months declined 8% from the prior 12-month period.

Some of this decline reflects supply problems in early 1979 caused by the Iranian disruption and Department of Energy allocation rules. But, API pointed out that the reduced level of gasoline use has continued far beyond that period.

Fuel efficiency factor. API also detailed the trend toward greater fuel efficiency in the U.S. auto fleet.

Improvements in fuel efficiency in domestic cars during the past 6 years are partly the result of higher gasoline prices which in turn have given increasing importance to fuel efficiency in vehicle purchase decisions.

And government regulations have been setting higher fuel efficiency standards for automakers.

By itself, however, the supply of more fuel-efficient vehicles has only a partial effect on total gasoline use, API noted.

First, it takes time to replace the existing vehicle fleet. The average age of cars currently in use is about 6 years.

Second, an increase in fuel efficiency of all vehicles on the road wouldn't necessarily result in a matching decline in fuel use. That's because some owners of more fuel-efficient vehicles may use at least part of their fuel efficiency advantage for increased travel rather than translating it entirely into a savings in fuel costs.

Nevertheless, API said, fuel efficiency is becoming an increasingly important factor in vehicle purchase decisions.

Smaller U.S. cars and imports have gained an increasing share of the market in recent years, at the expense of larger cars. Small domestic cars—compacts and subcompacts—and imports have increased their share of retail sales from 38% in 1972 to more than 60% in the first quarter of 1980 on a seasonally adjusted basis.

Other categories. API also reported that total U.S. petroleum deliveries in May declined 1.16 million b/d, or 6.5%, from year-earlier levels.

Unleaded gasoline represented about 43.3% of total motor gasoline deliveries, somewhat less than the 45% share of the previous month. But API said similar small month-to-month reductions have occurred randomly in the past.

As a result of continuing lower product demand and high inventories, crude imports dropped by about 1 million b/d and product imports by 434,000 b/d from May 1979 to May 1980. Imports amount to about 37.8% of current total U.S. supply, compared with 43.5% last year.

Crude stocks, despite the lowest import level since mid-1976, continued to set records and ended the month about 61 million bbl above last year. API said crude inventory levels continue to reflect reduced product demand and refiners' uncertainty about future crude supplies.

Motor gasoline stocks dropped about 11 million bbl last month. But API said month-end inventories have declined from April to May every year for the past 10 years except for 1976 and 1977, with the decreases ranging from 3 million to 19 million bbl.

Distillate stocks increased about 6 million bbl and stand 64 million bbl above last May's level. The current inventory level of 187 million bbl is the highest end-of-May level in the past 10 years, topping the next highest level by about 25 million bbl.

Deliveries of distillate fuel were 436,000 b/d or 14.6% below May 1979 levels. The high inventory level may have had some part in encouraging reduction or delay of distillate purchases.

Other major factors appear to be continued price increases—about 40% in real dollars since last May—and fuel switching.

Total estimated supply during May was 1.1 million b/d below year-earlier levels, reflecting the net effect of a 308,000-b/d increase in domestic supply and a 1.4 million b/d decrease in imports.

FERC reaffirms approval of N. Slope prebuild

ACTING on a rehearing, the Federal Energy Regulatory Commission has reaffirmed its approval of early construction of a portion of the western Lower 48 leg of the Alaska Natural Gas Pipeline System (Angts).

FERC also approved expansion of other pipeline systems to transport additional Canadian gas to southern California as part of a "prebuild" project to aid financing of the 4,800-mile, $15-25-billion system proposed to move Alaska North Slope gas through Canada to markets in the Lower 48.

FERC now has approved prebuilding of the western and eastern legs of the system in the Lower 48. Both approvals impose dollar limits on the volume of Canadian gas that may be imported to the U.S. before North Slope gas goes on stream.

The project cleared a major hurdle when three big North Slope producers agreed to pay half of the $500-million outlay for design, engineering, and final cost estimate of the 743-mile Alaskan segment of the system (OGJ, June 23, Newsletter).

The other half will be paid by Alaskan Northwest Natural Gas Transportation Co., the pipeline group sponsoring the project.

The North Slope producers—Exxon Corp., Standard Oil Co. (Ohio), and Atlantic Richfield Co.—also agreed to participate "in a substantial way" with Alaskan Northwest in financing of the Alaskan line and Prudhoe Bay conditioning plant "upon reasonable terms and conditions."

This part of the agreement provides that the producers aren't placed in the position of becoming the ultimate guarantors of completion of the system and that their financial exposure is "effectively limited."

Meanwhile, in Canada, the Foothills pipeline group called for construction bids on the 36-in.-diameter prebuild western leg to be laid in Alberta and British Columbia. Foothills expects to have all government construction approvals in hand shortly.

The entire system—the Alaskan segment and eastern and western legs in Canada and the Lower 48—is scheduled for completion in 1985. It will carry about 2.4 billion cfd of gas to U.S. markets on the West Coast and in the Midwest.

FERC reaffirmation. FERC's latest action backs up its Jan. 11 decision to approve construction of 160 miles of 36-in. loop by Pacific Gas Transmission Corp.

The loop will run from Kingsgate,

B.C., to Stanfield, Ore.

From there, gas will flow to California through existing and new facilities of Northwest Pipeline Corp. and El Paso Natural Gas Co. in Idaho, Utah, and Arizona.

Expansion of the Northwest Pipeline system will involve 351 miles of looping and additional compressor horsepower on the company's system in Oregon and Idaho. Ownership of these facilities is shared, with Northwest Pipeline owning 70% and Pacific Interstate Transmission Co., purchaser of the Canadian gas, owning 30%.

However, FERC said additional capacity created by Northwest's looped line must be reversible so that gas from developing Rocky Mountain fields can be transported to the Pacific Northwest and northern California. Cost of the expansion will be about $160 million.

The commission changed its earlier order to allow Alaskan Northwest to import and sell to Pacific Interstate up to an average of 300 MMcfd of Canadian gas. In the original order, FERC approved only 240 MMcfd in such sales.

And FERC will allow Alaskan Northwest to pay Pan-Alberta Gas Ltd., the supplier, the new import price of $4.47/MMBTU, up from the $3.45/MMBTU agreed to earlier. The Canadians increased the price last March (OGJ, Mar. 31, p. 70).

FERC set a $256.9-million/year limit on buyers' take or pay obligations for the imported gas through the western leg during November 1980-October 1983. This would allow Alaskan Northwest to buy about 65% of the 300 MMcfd average authorized by FERC for import during those years.

During November 1983-October 1984 the limit will be increased to $321.1 million/year, during November 1984-October 1986 the limit will be $215.1 million/year, and during November 1986-October 1987 the limit will be $263.3 million/year, a FERC spokesman said.

In approving the eastern leg of the system in the Lower 48, FERC set an $856.3-million limit on buyer's take or pay obligations (OGJ, June 9, p. 27).

The FERC take-or-pay ceiling for the eastern leg means that at current prices that portion of the project may operate at only 70% of capacity instead of the planned 85%, says William Deyell, executive vice-president of Foothills Pipe Line (Yukon).

FERC set the rate of return on equity investment for the prebuild facilities at 13.5% for Pacific Gas and 13.75% for Pacific Interstate and Northwest Pipeline.

FERC also approved incremental tariff treatment for the cost of the prebuild facilities and allowed rolled-in pricing for the transportation charges and cost of the gas.

Canadian action. Construction bids were asked by Foothills Pipe Line (South B.C.) and Foothills Pipe Line (Alberta), operating subsidiaries of Foothills Pipe Lines (Yukon) Ltd.

Foothills (South B.C.), responsible for laying 53.1 miles of line in southern British Columbia, expects to award a construction contract in mid-July.

Foothills (Alberta) plans to lay a 74.4-mile section in Alberta. It expects to award construction contracts in early August. Construction schedule calls for an August start on the project with completion in mid-December.

In a related development, Canada's Northern Pipeline agency granted Foothills (Alberta) permission to use additional land for pipeline right-of-way in Alberta. Foothills had asked for an 89-ft right-of-way for looping in a number of areas to facilitate construction of the Alberta prebuild project.

Shell, AGTL to form petrochem firm

SHELL Canada Ltd. and Alberta Gas Trunk Line Ltd. plan to form a new company to produce and sell petrochemical derivatives in Canadian and international markets.

J. P. Sutherland, AGTL vice-president, said, "We aren't talking about a $100-million venture but of a major capital investment program in the $1-billion range."

The joint venture company, to be 60% owned by AGTL and 40% by Shell, would be located in Alberta.

AGTL, extensively involved in Alberta's petrochemical industry, said the objective of the joint venture with Shell will be to build worldscale petrochemical plants in Alberta throughout the 1980s.

First project will be a 600-million-lb/year styrene plant, already in an advanced stage of planning. Styrene will be manufactured from ethylene produced by Alberta Gas Ethylene Ltd., an AGTL subsidiary, and from benzene to be produced at a proposed Shell Canada-Husky Oil Ltd. joint venture refinery planned near Edmonton, Alta.

AGTL said other projects currently in various stages of planning will be disclosed later.

Robert L. Pierce, executive vice president of AGTL and head of its petrochemicals division, said the supply and security of petrochemical feedstocks in Alberta provide the basis for an Alberta-based and Canadian controlled company to compete on the world petrochemical market.

Pierce points out that an Alberta-based petrochemical industry using ethylene as feedstock and representing a $1.5 billion investment has been in operation since 1979.

"The joint venture with Shell will provide substantial and early impetus to future downstream development and diversification of the petrochemical industry in Alberta," he says.

U.S.S.R. expands plan for gas lines

THE Soviet Union has disclosed that it expects to build "no less" than seven parallel 56-in., 1,000-mile gas pipelines southwest from western Siberia's supergiant Urengoiskoye field on the Arctic Circle to Chelyabinsk on the eastern slope of the Ural Mountains.

Previously announced plans called for three Urengoiskoye-Chelyabinsk lines. Two of those have been completed.

Even at current rated throughput of about 30 billion cu m (1.06 trillion cu ft)/year for conventional Soviet 56-in. western Siberian gas pipelines, a seven-line Urengoiskoye-Chelyabinsk system could handle an apparent world record of 210 billion cu m (7.41 trillion cu ft)/year.

But capacity will be far higher if any of the five lines still to be built are of the "new generation" type recently described by B. Shcherbina, U.S.S.R. minister for construction of oil and gas industry enterprises. These lines could double or triple throughput by using new high-strength pipe permitting higher operating pressures, by reducing distance between compressor stations, and by chilling the gas to minus 30° C. (OGJ, June 9, p. 24).

Meanwhile, the Soviets have completed extension of the first Urengoiskoye-Shelyabinsk gas pipeline across the Ural Mountains and on southwest to Petrovsk, about 60 miles northwest of the Volga River port of Saratov. The final 350 miles of the 2,050-mile line from Urengoiskoye are being tested between Petrovsk and Novopskov in the Ukraine.

FERC Modifies Certain Conditions Attached to Authorization of Eastern Leg of Alaskan Gas Pipeline

On 6/20/80 the FERC modified certain aspects, but largely denied rehearing of a 4/28/80 order which granted various authorizations related to "prebuild" of the Eastern Leg portion of the Alaska Natural Gas Transportation System (ANGTS).1/

More specifically, the Commission's 4/28/80 order approved the import of 800,000 Mcf/d of Canadian gas by Northwest Alaska Pipeline Co. (CP78-123 et al.) at Monchy, Saskatchewan for resale to Northern Natural Gas Co., United Gas Pipeline Co. and Panhandle Eastern Pipeline Co.; construction by Northern Border Pipeline Co. (CP78-124) of 809 miles of 42-inch pipeline from Monchy to an interconnection with Northern's system near Ventura, Iowa (representing the "prebuild" portion of the Eastern Leg) in order to transport the imported volumes; and transportation/displacement and exchange arrangements by Northern, United and Panhandle. These authorizations were conditioned or otherwise limited by the Commission in several respects. On rehearing, the FERC revised certain conditions and reaffirmed others. (See REPORT NOS. 1259, pp1-3 and App. pp1-10; 1264, pp9-13.)

Among other conditions, the FERC's approval of Canadian gas imports (at the present border price of $4.47/MMBtu) was subject to modification of the take-or-pay obligations in Northwest Alaska's gas supply contracts with Pan-Alberta Gas Ltd.2/ so as to provide for payment of minimum daily and annual revenues rather than payment for minimum daily and annual volumes of gas. The purpose of this condition was to free U.S. purchasers from an "open-ended" obligation to take high proportions of available gas regardless of future border price increases and competitive fuel price relationships in the U.S., while at the same time assuring Canadian producers of minimum revenues to support financing of required gathering and conditioning facilities. The Commission arrived at daily and annual revenue "caps" of $1.38 million and $856 million, respectively, based on application of a $3.45/MMBtu border price to the required daily or annual volumetric takes (50% or 85%) assuming availability of 800,000 Mcf/d. The $3.45/MMBtu price was selected by the Commission for this purpose because it was the level at which the proposed imports were shown by the record in this proceeding to be marketable.

1/ The previous week, on 6/13/80, the FERC approved construction of about 350 miles of pipeline looping which will complete the Western Leg prebuild segment of the ANGTS to transport up to 300,000 Mcf/d of Canadian gas to consumers in southern California. In an earlier order issued 1/11/80, the FERC approved construction of the first 160 miles of the Western Leg segment between Kingsgate, British Columbia and Stanfield, Oregon, just below the Washington-Oregon border, and deferred decision on the remainder of the Western Leg facilities. In the 6/13/80 order, the Commission denied rehearing of the 1/11/80 order and authorized construction of 350 miles of pipeline looping by Northwest Pipeline Corp., as well as additional compression, along its existing right-of-way in Oregon and Idaho. In so doing, the Commission rejected an alternative routing favored by the FERC Staff and the California PUC south of Stansfield, Oregon involving greater looping of the Pacific Gas Transmission and Pacific Gas & Electric systems. The Commission conditioned its authorization to require that the 350 miles of looping be reversible so that gas from developing Rocky Mountain fields can be transported to the Pacific Northwest and northern California. (See REPORT NO. 1266, pp2-8.)

2/ These contracts contained minimum daily and minimum annual take provisions requiring that the purchaser take not less than 50% of the contemplated daily quantity on any given day, and not less than 85% of the contemplated annual quantity during any contract year. These same features are carried forward in Northwest Alaskan's contracts for resale of the gas to the U.S. shippers.

On rehearing, the Commission denied a request by Foothills Pipelines Ltd. and Pan-Alberta to use the present border price of $4.47/MMBtu (and any new border prices subsequently approved by the Economic Regulatory Administration) rather than the "obsolete" $3.45 border level, but provided for adjustment of the $3.45 unit price multiplier for general inflation in the U.S. Escalations for inflation shall be in accordance with the methodology prescribed in Section 101(a) of the NGPA for monthly adjustment of first sale maximum lawful prices, provided that such escalations never operate to increase the proportion of contract quantities required to be taken by the importers above the levels specified in the Pan-Alberta contracts (namely, 50% on a daily basis and 65% on an annual basis). Based on the above determinations, the Commission said it can assure Foothills and Pan-Alberta that the principles for calculating the revenue stream will not be changed during the authorized term of the imports. In addition, the FERC noted its concern over the National Energy Board's characterization of the take-or-pay modification as "out of harmony with the Canadian contribution." The Commission emphasized that it chose a unit multiplier of $3.45, rather than the $2.16/MMBtu border price at the time Pan-Alberta entered into contracts with Canadian producers, in an effort to balance the need for initiatives to move the ANGTS forward with the need for a limitation on the exposure of the importing companies. Similarly, a key reason for providing an escalation for inflation is to remove, to the maximum extent possible, "any remaining doubts about the viability of the prebuild projects as proposed, conditioned and approved... ."

A second major condition imposed by the 4/28/80 order was the requirement for adjustment of Northern Border's depreciation schedule -- which rested on a unit of throughput method assuming a total throughput of 4.164 Tcf (achievable by shipments of 800,000 Mcf/d through Northern Border for 15 years at 95% load factor) -- to reflect Alaskan volumes at the time construction commences on the Alaskan segment of ANGTS rather than when Alaskan gas begins to flow, as proposed. In addition, the depreciation base must be adjusted if additional volumes are contracted for shipment through Northern Border from Consolidated Natural Gas Ltd. and Progas Ltd. Northern Border and Trans-Canada contended in an application for rehearing that revenues based on the unit of throughput methodology must be assured for a minimum of four years, without modification to reflect Alaskan gas, to satisfy the requirements of lenders providing the debt financing. Northern Border and Trans-Canada accordingly urged that the Commission provide for adjustment of depreciation upon the later of (1) the expiration of four years from the date on which the Eastern Leg prebuild project is completed and commissioned; or (2) the date on which main pipeline construction of the Alaskan segment commences. The Commission was also asked to clarify that the 4.164 Tcf depreciation base will not be modified by the commitment of Consolidated and Progas export volumes to Northern Border.

In the instant order on rehearing, the Commission reiterated its prior conclusion that commencement of construction of the Alaskan segment is the appropriate date to consider Alaskan volumes for depreciation purposes. Once construction of the Alaskan segment begins (in May 1983 according to Northern Border's application), the FERC explained, there is very little risk that Northern Border will not be used for transportation of Alaskan volumes. Accordingly, there is very little danger that Trans-Canada -- in its financial "backstopping" capacity -- will be required to repay the balance of the bank loan for the "prebuild" project upon maturity, with the result that certain limitations on the size of the "balloon" payment due at maturity (not more than 40% of the original amount of the loan) are unlikely to cause any problem. Nevertheless, because of the "unique role and material importance" of the Trans-Canada "backstop" commitment in financing of the Eastern Leg prebuild project and because lenders may consider the 40% loan balance requirement at maturity as a "real and necessary limitation" on liability, the Commission agreed to accept the depreciation adjustment provision recommended by TransCanada and Northern Border in their application for rehearing -- provided that any difference in depreciation expense and related taxes under this recommended schedule and the amount which would have resulted under the schedule previously imposed by the Commission (assuming adjustment for Alaskan volumes upon commencement of construction of the Alaskan segment) be collected subject to refund. The refund obligation would be extinguished in the event that TransCanada were required to assume full responsibility for repayment of the loan at maturity. On the other hand, the amounts involved would have to be refunded, with interest, at the end of the maturity of the loan if TransCanada does not assume sole responsibility for repayment (or at any earlier time that TransCanada's contingent liability to assume the payment at maturity may be eliminated).

Regarding the total throughput level of 4.164 Tcf contemplated as the economic life of the Northern Border prebuild project, the Commission affirmed the need to revise this throughput for economic life purposes under certain circumstances. However, based on the configuration of facilities inherent in the prebuild project, the Commission anticipated that any additional throughput beyond the initial 800,000 Mcf/d design capacity in the first six years could be achieved at a relatively small increase in capital cost, and that the revised facilities package would be justified with an economic life of 4.164 Tcf of expected throughput.

With respect to tracking issues raised on rehearing, the Commission adhered to its prior determination that shippers over the prebuilt Northern Border facilities may not commence charges to their customers until gas deliveries begin. While Northern Border was authorized to commence billing upon completion of construction (but before any flow of gas) in order to reduce risks and hence lower financing charges, the Commission said there is no similar financing benefit in permitting shippers to track the Northern Border charges before gas flows.

In addition, the Commission declined Foothills' request to provide at this time any general statement of principle to the effect that tracking of Canadian transportation charges will be permitted without further FERC review as soon as the appropriate Canadian regulatory authority has granted "leave to open." At the same time, the Commission made clear that it will continue to cooperate with Canadian regulatory authorities to develop an appropriate mechanism for U.S. shipper tracking of NEB-approved Canadian transportation charges.

The Commission also denied a request by the General Service Customer Group (comprising nine distributor customers of Panhandle) to eliminate the requirement that shippers classify Northern Border charges as demand charges. The Commission emphasized that charges to each shipper are predicated on the shipper's right to demand service and will not vary with volumes actually transported for the shipper. Hence, these payments can only be characterized as a demand charge.

Commissioner Holden dissented to the required classification of Northern Border's charges to shippers as demand charges. By this treatment, "the Commission chooses to dump on the residential, small commercial and other high priority customers a much greater share of the fixed costs than is obviously dictated by any facts of record."